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VIA ELECTRONIC MAIL AND HAND DELIVERY

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Dear Mr. Lee:

The Sierra Club submits these comments to address the Bay Area Air Quality Management District's (the "District") BACT analysis in the re-noticed draft Statement of Basis ("SOB") and PSD permit[1] for the Russell City Energy Center ("RCEC").

The RCEC will generate up to 600 MW[2] net of electricity using two Westinghouse 501F combustion turbine generators, firing 2,038.7 MMBtu/hr of natural gas. The hot turbine exhaust gases are routed to two heat recovery steam generators ("HRSGs"). The HRSGs, or boilers that recover waste heat from the turbine exhaust, are each equipped with duct burners that burn 200 MMBtu/hr of natural gas. The HRSG and duct burners convert water into steam which drives a 235 MW steam turbine ("the Project").

This same project was proposed by the applicant, Calpine, and licensed by the California Energy Commission ("CEC") in 2002. The proposed facility location was

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[1] Statement of Basis for Draft Amended Federal "Prevention of Significant Deterioration" Permit, Russell City Energy Center, Bay Area Air Quality Management District Application Number 15487, December 8, 2008.

[2] We note that the Permit assumes 622 MW, presumably gross, while the CEC licensed a project rated at only 600 MW, presumably net. We assume that the difference is the auxiliary power load. See Russell City Energy Center, Amendment No. 1 (01-AFC-7C), Final Commission Decision, October 2007, p. 2. http://www.energy.ca.gov/2007publications/CEC-800-2007-003/CEC-800-2007-003-CMF.PDF.

subsequently moved 1,300 feet to the northwest of the approved location and thus required a modification to its CEC license and a new PSD permit.[3]

I. BACT for Carbon Dioxide (CO2)

The applicant asked the District to undertake a top-down BACT analysis for greenhouse gases.[4] The District conducted a BACT analysis and concluded that if BACT is required for CO2 emissions, an enforceable limit of 1,100 lb/MWh would suffice. Compliance would be demonstrated by an enforceable fuel throughput limit of 2,944.3 MMBtu/hr of heat input.[5]

We agree that the permit should include a BACT limit for CO_2. While the U.S. Environmental Protection Agency has wavered as to whether CO_2 is a "pollutant subject to regulation," within the meaning of the Clean Air Act's BACT definition, both the Clean Air Act and EPA's governing interpretations indicate that CO_2 falls within the pollutants demanding a BACT limit. *See* Ex. 1 **(In the Matter of: EPA Final Action Published at 73 Fed. Reg. 80300 (December 31, 2008), titled "Clean Air Act Prevention of Significant Deterioration (PSD) Construction Permit Program; Interpretation of Regulations That Determine pollutants Covered by the Federal PSD Permit Program," Petition for Reconsideration (January 6, 2009))**. However, the District's CO_2 limit and compliance provision as currently written do not satisfy BACT requirements, for the reasons below.

A. Failed To Consider More Efficient Options

The District acknowledges that an effective means to reduce CO2 emissions is to use the most efficient generating technology available; increased efficiency allows more of the fuel's energy content to be used to generate electricity, reducing emissions of CO_2 (and other pollutants). The District has not, however, conducted a full BACT analysis of efficient generating technologies. Instead, the District concludes (without supporting analysis) that the proposed "combined-cycle natural gas turbine technology" is "among the most efficient electrical generating technology created to date."[6]

BACT requires an emission limit based on the maximum degree of reduction that is achievable; limiting the District's review to a technology that is "among the most" effective fails to satisfy those "strong, normative terms." *Alaska Dep't of Envtl. Conservation* 540 U.S. 461, 485-86 (2004). As discussed in Section II, below,

[3] Statement of Basis for Draft Amended Federal "Prevention of Significant Deterioration" Permit, Russell City Energy Center, Bay Area Air Quality Management District Application Number 15487, December 8, 2008.
[4] SOB, p. 58.
[5] SOB, p. 63.
[6] SOB, pp. 60-61.

the proposed generating technology is not the most efficient available. It is not sufficient to stop one's inquiry with the a broad classification of the thermodynamic cycle, combined-cycle, but rather, one must look deeper, at the components of the cycle – the gas turbine, HRSG, duct burners, and steam turbine.[7] There are many different turbines that could be used in the same combined-cycle configuration and more efficient ways to generate peaking power. The technology proposed by the applicant was selected eight years ago. BACT is determined as of the date of issue of the PSD permit. By failing to examine more efficient means to generate electricity, the District has failed to properly fulfill its duty, under the BACT requirements, to examine all methods and processes of pollution-reduction, including "innovative combustion processes." 42 U.S.C. § 7579(3).

B. <u>Failure to Set Proper CO2 BACT Limit</u>

After improperly concluding that the applicant had selected the most efficient power generation technology, the District next considered a range of CO_2 emissions expressed in units of pounds per megawatt hour ("lb/MWh") of net (presumably) electric generation. The values considered were regulatory levels proposed by various states (675 lb/MWh in Oregon to 1,900 lb/MWh in Delaware)[8] and certain California test data (794 to 1,058 lb/MWh).[9]

From this data, the District concluded that CO_2 BACT is 1,100 lb/MWh. The lower values were rejected without technical explanation, arguing that "a reasonable compliance margin" is required to assure the limit is met.[10] The selected limit is conveniently the minimum emission performance standard that certain gas fired power plants in California must meet. This limit is 39% higher than the lowest reported CO_2 emission level identified by the District. No justification is provided for a "reasonable compliance margin" of 39% or for the concept that such a "compliance margin" applies to BACT.

Generally, when there is uncertainty as to what can be achieved, an optimization period is built in to a permit with a requirement to design the system to meet the goal and time to achieve the goal. The permit should require the system to be designed to meet a much lower CO_2 level. The design basis should be submitted to the District to establish that the intent was met. The permit should also establish protocols that identify (a) test methods that will be used to measure CO_2 and MWh net; (b) frequency of testing; (c) length of optimization period; (d) averaging period for limit; and (e) methods and criteria that will be used to

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[7] David Gordon Wilson and Theodosios Korakianitis, <u>The Design of High-Efficiency Turbomachinery and Gas Turbines</u>, 2nd Ed., 1998; Kam W. Li and A. Paul Priddy, <u>Power Plant System Design</u>, 1985.
[8] SOB, p. 59, Table 20.
[9] SOB, pp. 62.
[10] SOB, p.63.

determine the lowest achievable CO2 limit. The permit should be drafted to require as BACT the lowest achievable limit, based on this testing demonstration.

The District tosses out all measured data, characterizing it as no more than a "snapshot" of turbine performance and not a continuous demonstration of compliance with an enforceable limit. The District also tosses out the lower end of the regulatory range and sets CO2 BACT at 1,100 lb/MWh,[11] based on California's interim performance standard for complying with a Senate Bill.

The 1,100 lb/MWh value was adopted by the California Public Utilities Commission under the Electricity Greenhouse Gas Emission Standards Act (SB 136812) as a performance standard for the state's investor owned utilities. It applies to new investments in existing plants, new or renewed contracts with plants outside of California, and new base load plants. Thus, it had to broadly apply across the existing gas-fired fleet that serves California.

The 1,100 lb/MWh value was not selected in a top-down BACT analysis, but rather through a political negotiation. It was a compromise between a value of 800 lb/MWh, which could then be achieved by the most efficient combined cycle plant, and 1,400 lb/MWh, which would envelop the majority of natural gas burning technologies (e.g., steam cycle boiler, simple cycle turbine).[12] Such a standard does not satisfy BACT, but (at most) serves as a floor for BACT.

Modern, efficient combined-cycle power plant in 2009 can cost-effectively achieve far lower emissions. The District failed to acknowledge that CO2 emissions from similar facilities have been continuously monitored for many years under the Acid Rain Program and publicly reported.[13] These data show that similar combined cycle power plants routinely meet CO2 emission levels of less than 800 lb/MWh.

Further, some of this data has been certified and reported to the California Climate Action Registry.[14] This data shows that Elk Hills, a similarly configured combined cycle project licensed by the CEC in 2000, reported CO2 emissions of 796 lb/MWh in 2006 and 794 lb/MWh in 2007. Calpine, the RCEC applicant who owns a number of similar gas-fired combined cycle projects in California, reported system-wide CO2 emissions from all fossil fuel generation of 891 lb/MWh in 2005 and 850 lb/MWh in 2006. This fleet includes many less efficient gas-fired facilities than proposed at RCEC.

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[11] SOB, pp. 62-63.

[12] Gary Collord, Implementation of SB 1368 Emission Performance Standard, Staff Issue Identification Paper, November 2006, p. 13.

[13] Clean Air Markets, Emissions Monitoring, http://www.epa.gov/airmarkets/emissions/.

[14] Climate Action Registry Reporting Online Tool, https://www.climateregistry.org/CARROT/public/Reports.aspx.

Similar facilities are also currently being licensed by the CEC with lower CO2 emissions. These include Avenal (500 lb/MWh);[15] Willow Pass Generating Station (933 lb/MWh);[16] and Lodi Energy Center (829 lb/MWh).[17] The State of Florida concluded that in 2007, new natural gas fired combined cycle plants could achieve 800 lb/MWh.[18] Based on this evidence, BACT should be an enforceable CO2 emission limit no higher than 800 lb/MWh.

C. Output-Based Limit Should Be Established

The District opted to determine compliance with the output-based CO2 emission limit, 1,200 lb/MWh, by setting an input-based fuel limit. In effect, this renders the limit input-based. Output-based measurements link the emissions from a power plant to the energy they produce. In 1998, the NSPS for utility and industrial boilers was changed from input to output based. Further, EPA has published an output-based guidance document under the NOx SIP Call as an option for states in the NOx Budget Trading Program.[19]

The use of an output-based CO2 limit is particularly critical here as the only currently feasible control option is more efficient energy production.[20] The District used a CO2 emission calculation to demonstrate that a heat input limit assures emissions remain below 1,100 lb/MWh. The Permit, however, does not cap electric output at 622 MW (a key assumption of the calculation). The calculations are, moreover, based on input rather than output, and utilize the wrong natural gas heat content (1050 instead of 1023 Btu/scf). The heat input method of determining compliance, for example, would not detect a decrease in efficiency due to aging of the equipment or due to changes in the equipment at a future time.

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[15] From Avenal Energy Application for Certification 08-AFC-01, February 2008, Vol. II, Appx. 6.2-1, Table 6.2-1.1. The highest values, calculated from CO2 in lb/hr divided by plant net output in MW. Table 6.2-41, the facility would emit 1.71 MT/yr of CO2, is 499.7 lb/MWh, based on case 12 (137,055 lb/hr/304.8 MW = **499.7 lb/MWh**). See: http://www.energy.ca.gov/sitingcases/avenal/documents/applicant/afc/

[16] From the Willow Pass AFC 08-AFC-6, Table 7.1-19, the facility would emit 987,970 MT/yr of CO2. From Figure 2.5-3, it would generate 266.5 MW net under worst-case conditions, 100% load and 94 F, 32% RH. This works out to: (987,970 MT/yr)(2204.6 lb/MT)/(266.7 MW)(8760 hr/yr) = 932.98 **lb/MW-hr** net and 905.8 lb/MWh gross. This is an air cooled plant so auxiliary power loads are higher than for a water cooled plant, such as RCEC. See: http://www.energy.ca.gov/sitingcases/willowpass/documents/applicant/afc/index.php.

[17] Lodi Energy Center Application for Certification 08-AFC-10, September 2008, Table 5.1-22. See: http://www.energy.ca.gov/sitingcases/lodi/documents/applicant/afc/.

[18] Florida Department of Environmental Protection, Electric Utility Greenhouse Gas Emissions Reductions, Initial Rule Development Workshop, August 22, 2007.

[19] Susan Freedman and Suzanne Watson, Output-Based Emission Standards, Northeast-Midwest Institute, 2003, http://www.nemw.org/output_emissions.pdf.

[20] SOB, pp. 60-61.

Net electrical output and CO_2 can both be monitored continuously using widely used, standard measurement technology. Thus, the Permit should be revised to set an explicit limit on CO_2 emissions in pounds per megawatt-hour.

D. Other Greenhouse Gases and Sources

The District only performed a BACT analysis for CO_2 emissions from the gas turbines and duct burners. Other sources emit greenhouse gases, including diesel generators and heaters. Further, other Greenhouse Gases are emitted by gas-fired power plants, including methane (CH_4) and nitrous oxide (N_2O) (from combustion sources) and sulfahexafluoride (SF_6) (which is used in circuit breakers). The BACT analysis should be revised to include these other gases and sources.

II. The BACT Analysis Did Not Consider More Efficient Processes

The BACT analysis for NOx, CO, and PM emissions from the gas turbine/HSRG equipment considered only two classes of control options – combustion controls and post combustion controls. However, the amount of pollution that is generated by combustion sources depends upon the efficiency of power generation. The more fuel that is burned to produce a megawatt of electricity, the more NOx, CO, and PM10 that is emitted. Similarly, the less fuel burned, the lower the emissions. The District did not consider the efficiency of the power generation cycle in making its BACT determination for NOx, CO, or PM (though it paid lip service to efficiency considerations in its BACT determination for CO_2).

Consideration of more efficient generating technologies is required under BACT, which requires a case-by-case, comprehensive assessment that includes "*production processes* and available methods, systems, and techniques, including fuel cleaning, clean fuels, or treatment or *innovative fuel combustion techniques* for control of each . . . pollutant" regulated under the PSD program. 42 U.S.C. § 7479(3) (emphases added). A BACT analysis should, accordingly, not be limited to a comparative assessment of combustion controls and add-on controls, but must consider "'inherently lower-polluting process[es]/practice[s]' that prevent[ ] emissions from being generated in the first instance." *In re Knauf Fiber Glass, BMBH,* 8 E.A.D. 121, 129 (EAB 1999) (citing NSR Manual at B.10, B.13). *See also In re CertainTeed Corp.*, 1 E.A.D. 743, 746 (EAB 1982) (Affirms BACT is an emission limitation achievable through application of "production processes and available methods, systems, and techniques" for control of pollutants, denying applicant review of permit based on argument that BACT does not include production and process requirements). Furthermore, the history of the Clean Air Act amendment adding the term "innovative fuel combustion techniques" shows that the amendment was intended to include all actions taken by the fuel user, such as selecting the combustion process. 123 Cong. Rec. S9421, S9434-35.[21]

Russell City will use two Westinghouse 501 FD combustion turbines with fired heat recovery steam generators to generate 600 MW net of electric power. This is not the most efficient combination to generate said power and thus does not satisfy BACT for at least three reasons.

First, the efficiency of the unfired system (without duct burners) is reported to be 55%.[22] While that may have been an efficient mark eight years ago, when the turbines were selected, there are far more efficient turbines on the market today. These include the Westinghouse 501G, a more advanced turbine by the same manufacturer and its successors. It has a combined cycle net efficiency of 58%.[23] This turbine is in widespread commercial operation, including at the Charlton Power Plant, MA (since 2001); Lakeland McIntosh Unit 5, FL (Ex. 12);[24] West County, FL; Lower Mount Bethel, PA; Ennis Power, TX; Wolf Hollow, TX; and Port Westward, OR, among others.[25]

Other more efficient turbines have entered the market since 2001, with efficiencies up to 60%.[26] If turbines with a net combined cycle efficiency of 60% were selected, RCEC would emit over 8% less NOx, CO, and PM than the selected turbines when operated in unfired mode. In fact, the same applicant, Calpine, is scheduled to complete construction of Inland Empire Unit 1 in January 2009 and Unit 2 in July 2009. These two turbines were licensed in 2003 at 56.5% lower heating value without duct firing[27] compared to only 55% for RCEC which is being

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[21] "*It is the purpose of this amendment to leave no doubt that in determining best available control technology, all actions taken by the fuel user are to be taken into account* - be they the purchasing or production of fuels which may have been cleaned or up-graded through chemical treatment, *gasification*, or liquefaction." (emphases added). 123 Cong. Rec. S9421, S9434-35.

[22] Russell City Energy Center Application for Certification, 01-AFC-7, May 2001 ("RCEC AFC"), p. 10-3, http://www.energy.ca.gov/sitingcases/russellcity/documents/applicant_files/afc/ and Russell City Energy Center, Application for Certification 01-AFC-7, Commission Decision, p. 74. http://www.energy.ca.gov/sitingcases/russellcity/documents/2002-09-12_COMMISSION_DECIS.PDF

[23] Gerard McQuiggan and others, Westinghouse's Advanced Turbine Systems Program.

[24] Gregory R. Gaul, Ihor S. Diakunchak, and Alfred M. Dodd, The W501G Testing and Validation in the Siemens Westinghouse Advanced Turbine Systems Program, Paper 2001-GT-399, International Gas Turbine & Aeroengine Congress & Exhibition, June 4-7, 2001.

[25] Universal Energy UEI LLC, Management Services for Power, Petrochemical, Offshore, and Industrial Facilities, Experience List, February 2006. http://www.univenergy.com/PDFs/Industrial%20Capabilities%20020306.pdf.

[26] Gas Turbine World 2007 -08 Handbook, Combined Cycle Ratings; GE Energy, News Release, GE's H System Achieves Technology Milestone: 8,000 Operating Hours at Baglan Bay; GE Power Systems, GE Combined-Cycle Line and Performance. http://www.gepower.com/prod_serv/products/tech_docs/en/downloads/ger3574g.pdf.

[27] Inland Empire Application for Certification 01-AFC-17, Commission Decision, November 14, 2003, p. 74. http://www.energy.ca.gov/sitingcases/inlandempire/documents/2003-12-22_COM_DECISION.PDF.

permitted in 2009. Inland Empire will use the higher efficiency GE PG7252(FB) turbines.

Second, RCEC will use an inefficient method to generate peaking power. When the duct burners are not operating, the gas turbines will produce 184.3 MW each and the steam turbine 198.4 MW, for a net plant output of 552.6 MW. The heat rate, or amount of energy in BTUs per kilowatt hour of electricity produced, for this mode of operation is 6,177 BTU/kWh based on the lower heating value.[28] During periods of peak demand, the duct burners are turned on to generate more steam. The heat rate for this condition is not reported in documents we reviewed.

Duct burners are inefficient compared to gas turbines. The files we reviewed do not report the efficiency of incremental power generation by the duct burners, nor does it include a heat/mass balance diagram that could be used to estimate the impact of duct firing on fuel efficiency. However, such estimates have been made in other similar cases. Based on these, the incremental heat rate of peaking capacity could range from about 8,890 to 9,000 Btu/kWh, corresponding to an efficiency of about 40%.[29] The peaking heat rate is higher than can be achieved by some simple cycle gas turbines. (Ex. 18)[30] Thus, peaking power generation by simple cycle gas turbine should have been considered in the BACT analysis as an alternative to duct burners. Further, the inclusion of duct burners in a combined cycle plant reduces the overall efficiency of the combined cycle plant as the steam cycle has to be sized to provide base load plus peaking load. This adds a fuel efficiency penalty during baseload unfired operation.

Third, as cited in Knauf (8 E.A.D, 129), the NSR Manual explicitly recognizes that "[c]ombinations of inherently lower-polluting processes/practices (or a process made to be inherently less polluting) and add-on controls are likely to yield more effective means of emissions control than either approach alone...These combinations should be identified in Step 1 of the top down process for evaluation in subsequent steps." NSR Manual, p. B.14. The BACT analysis for NOx, CO, and PM did not identify any inherently lower-polluting processes or practices and thus failed to consider whether combinations of these and add-on controls could further reduce NOx, CO, and PM.

The EPA's RACT/BACT/LAER Clearinghouse indicates that lower emission limits have been permitted for other facilities, including 1.5 ppm NOx at IDC Bellingham and numerous facilities at less than 4 ppm CO. These lower CO limits include Kleen Energy Systems, CT (0.9 ppmvd); CPV Warren, VA (1.3 and 1.8 ppmvd); and 2 ppmvd at: Goldendale Energy, WA; Garnet Energy, ID, Wallula

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[28] RCEC AFC, Figure 2.2-3b.
[29] CPV Vaca Station Application for Certification 08-AFC-11, October 2008, p. 2-2; Presiding Members Decision for Inland Empire 01-AFC-17, November 14, 2003, p. 75.
[30] Gas Turbine World 2007-08 Handbook, Simple Cycle Ratings.

Generation, WA; Lawrence Energy, OH; Linden Generating Station, NJ; COB Energy Facility, OR; Vernon City Light & Power, CA; Magnolia Power Project, CA, and many others.

The BACT analysis should be revised to consider the efficiency of the energy production process and the draft SOB and Permit re-circulated for public review.

III. BACT for Carbon Monoxide (CO)

The District concluded that BACT for CO is an emission limit of 4 ppmvd at 15% oxygen based on a 1 hour average, achieved using an oxidation catalyst.[31] This is not BACT for several reasons.

A. The District Used an Illegal Process

The District argues that NOx and CO are inversely related, that is, when NOx is reduced, CO increases. Thus, the District prioritizes NOx and VOC reductions over CO reductions because the Bay Area is not in compliance with ozone standards but does comply with CO standards. The District requires applicants to minimize NOx to the greatest extent feasible, and then optimize CO and VOC emissions for that level of NOx control.[32]

This process is inconsistent with BACT, which requires that an emission limit be set for each pollutant based on the maximum degree of reduction for that pollutant. Further, even assuming this process were legal, it was improperly implemented. The emissions of both NOx and CO can be simultaneously reduced by using a higher efficiency power production system or more efficient post combustion controls. This flawed process resulted in picking a CO BACT level of 4 ppm based on a 1 hour average. As discussed below, CO BACT is lower than 4 ppmvd.

B. Power Production Cycle

As discussed in Comment I, a higher efficiency power production cycle coupled with the proposed controls would lower all emissions, including CO.

First, the applicant's emissions data show that with duct firing, an inefficient method to produce peaking power, uncontrolled CO emissions increase from 0.1 lb/MMBtu to 0.25 lb/MMBtu,[33] or by a factor of 2.5. Requiring a more efficient method of producing peaking power, such as a small aero-derivative turbine or more efficient duct burners, would allow a lower CO emission limit to be achieved.

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[31] SOB, p. 34.
[32] SOB, pp. 22, 31.
[33] Russell City Energy Center Application for Certifications (AFC) 01-AFC-7, Amendment No. 1, November 2006, Appendix 3.1A, Table 3.1A-2.

Second, the turbines chosen for this project, Westinghouse 501Fs generally emit more CO than comparable GE turbines. The Westinghouse 501F turbine outlet CO is about 10 ppm, compared to 9 ppm from a typical GE Frame F turbine. Further, the Westinghouse 501F is not as stable across loads and at low loads up to about 50-60% as GE Frame F turbines, requiring more catalyst to achieve the same CO outlet as for other turbines. Thus, the District should have considered alternative combustion processes to reduce CO emissions.

C. Maximum Degree of Removal

The District selected an oxidation catalyst as satisfying BACT, but fails to disclose the assumed CO control efficiency or the CO concentration at the inlet to the device, both required to complete the Step 3 top-down BACT ranking. Instead, the District jumps to a list of permitted exhaust gas CO concentrations. This leap of faith skips a critical step in the top-down process, the ranking of technologies according to their control effectiveness.[34]

The top technology can achieve over 98% CO control (Ex. 19)[35] and has been commonly specified at 90+% CO control on numerous projects in the past 5 years. (Ex. 20 [36] and 21[37]) Assuming an oxidation catalyst design basis of 0.25 lb/MMBtu during duct firing (112 ppm),[38] a 98% CO control efficiency would result in a CO concentration of 0.005 lb/MMBtu or 2.2 ppmvd at 15% oxygen. This is much lower than the proposed CO BACT limit of 4 ppmvd. The District should determine the design basis of the proposed oxidation catalyst, revisit its CO BACT determination, modify the SOB to disclose the design basis of the oxidation catalyst, and re-circulate it for public comment as meaningful review is not possible without this information.

D. Test Data

In selecting the 4.0 ppmvd limit, the SOB states that the District only reviewed CEMS data for a single facility, Metcalf. There are many other similarly controlled gas-fired Frame F turbines operating in combined cycle mode in California and elsewhere, including the Delta Energy Center and Sutter, similar Calpine projects.[39] In 2001, for example, there were 87 such units in California.[40] Stack

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[34] NSR Manual, pp. B.6, B.7

[35] BASF, Oxidation Catalyst - Power Generation.

[36] Engelhard Oxidation Catalyst Experience List, 2003 (Engelhard is now BASF).

[37] Mike Durilla, Fred Booth, Ken Burns, and William Hizny, Engelhard, The Use of Oxidation Catalysts for Controlling Emissions from Gas Turbines: A Historical Perspective with a View Towards the Future, Power-Gen International 2001.

[38] Russell City Energy Center Application for Certifications (AFC) 01-AFC-7, Amendment No. 1, November 2006, Appendix 3.1A, Table 3.1A-2.

[39] See California projects at: http://www.energy.ca.gov/sitingcases/all_projects.html and

tests for many of these facilities indicate that lower CO emissions are being routinely achieved. The Metcalf data alone should not determine BACT for RCEC. The District should be required to look more broadly.

The District misapplied the Metcalf data. The District concluded BACT is 4 ppmvd as the Metcalf CEMS data suggested it could only meet 2 ppm during some operations. During transient loads, CO emissions increased to 4 ppm.[41] Most of the exceedances of 2 ppmvd at Metcalf were in the first year of operation during optimization of the system and thus not relevant to what can be achieved during optimized operation.

Our review of the Metcalf CO data indicate that during the first year of operation, a CO concentration of 2 ppmvd was exceeded 54 times out of 730 measurements (2 turbines x 365 days) during the first year of operation (6/1/05 – 5/1/06), or about 8% of the time. However, during the next two plus years of operation (6/1/06 – 8/08), a CO concentration of 2 ppmvd was exceeded only 6 times out of 822 measurements, or only about 0.4% of the time. This small number of very small exceedances in the post-shakedown period could easily be accommodated by requiring a more efficient oxidation catalyst than the one installed on Metcalf.

This is excellent performance, given the Metcalf design basis and permit limit. Metcalf was permitted in 2000 with a CO limit of 6 ppmvd based on a 3-hour average, *without an oxidation catalyst.* According to the Permit, if stack tests and CEMS data indicated a lower CO limit could be achieved on a consistent basis, the District could reduce the limit to 4 ppmvd.[42] The District should only have considered the data collected after the optimization period.

Both Metcalf and RCEC are Calpine projects based on the same power generation system, a 2-on-1 combined cycle configuration using the same turbines and duct burners. Thus, the achievable CO limit, given the same pollution generation equipment, ultimately depends only upon the presence or absence of an oxidation catalyst and its CO control efficiency. The District disclosed neither. However, our research indicates that an oxidation catalyst was installed in the as-built Metcalf HSRG,[43] guaranteed to remove 76% of the CO. The District's analysis indicates that this facility has met its permit limit. However, this is not credible evidence that RCEC, eight years later, cannot do better.

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http://www.energy.ca.gov/sitingcases/alphabetical.html.

[40] Durilla et al. 2001

[41] SOB, p. 32.

[42] Final Determination of Compliance (FDOC), Metcalf Energy Center, August 24, 2000, Condition 20(d). http://www.baaqmd.gov/pmt/public_notices/1999_2001/27215/index.htm.

[43] The CEC ultimately required an oxidation catalyst to control VOCs. See: The Metcalf Energy Center, Application for Certification 99-AFC-3, Commission Decision, p. 166, Condition AQ-55.

Arguendo, if Metcalf could meet a CO limit of 6 ppmvd, 3 hour average uncontrolled in 2000, as reflected by the Metcalf permit and SOB, RCEC should be able to meet at a CO limit of less than 1 ppmvd with a 90% efficient oxidation catalyst today (0.1x6.0 = 0.6 ppmvd). Alternatively, assuming the 6 ppmvd could only be met with a 76% efficient oxidation catalyst, a 2 ppm limit could have been met with a 92% efficient catalyst.

Regardless, just because Metcalf meets a BACT limit established over eight years ago does not mean that in 2009, the RCEC cannot do better. BACT is determined as of the date of issue of the Permit. There is now a large amount of CO test data from which to make a more informed decision. The District should evaluate it, taking into consideration the installed controls, and make a new CO BACT determination. Further, there are at least three oxidation catalyst vendors in the market who are willing to guarantee 98%+ CO reduction from natural gas fired combustion turbine exhaust. There is simply no excuse for not requiring a CO BACT limit that is comparable to those in many permits that have been issued at 2 ppmvd or lower.

E. Lower Permitted Limits

The District compiled recent BACT determinations for CO from similar gas turbine projects. This tabulation included many BACT determinations that are lower than the 4 ppmvd 1 hour average required for RCEC. These include Turner Energy Center, BP Cherry Point, Wanapa, Morro Bay, Goldendale Energy, Sumas Energy, Bellingham, Magnolia, McDonough, and CPV Warren. Most of these were permitted at 2 ppmd.[44]

In spite of this impressive list of plants with lower CO limits, the District argues a limit in the 2-3 ppm range "may not be achievable for the proposed Russell City Energy Center."[45] The District advances several arguments in support of that limit, none of which have merit.

First, the District tosses out all lower CO limits that are permitted to emit NOx at higher levels on the theory that NOx and CO are inversely related and NOx is more important to reduce. As discussed above, higher NOx is not a valid reason to reject a lower CO limit. Further, once the pollution generating equipment has been selected, which is common to all subject facilities, the degree of CO reduction and NOx reduction are independent of the underlying combustion processes and depend only on the control efficiency of the SCR and oxidation catalyst. The control efficiency of these devices is not related. The lower NOx limit selected as BACT for RCEC does not in any way restrict the efficiency of the oxidation catalyst used to control CO. In fact, the District's tabulation proves the point. It includes one unit,

[44] SOB, pp. 32-33, Table 11.
[45] SOB, p. 34.

IDC Bellingham, that was permitted with both lower NOx (1.5 ppm, 1 hour average) and lower CO (2 ppm, 1 hour average).

Second, the District tosses out lower numeric limits that have longer averaging times. The RCEC limit is based on a 1 hour average, while some of the numerically lower limits are based on 3 hour averages. The District argues these longer averaging times are less stringent as emissions can be averaged over a longer period of time. However, the District fails to point out that a numerically higher limit, regardless of averaging time, represents more pollution than a lower limit. Thus, a 4 ppmvd limit based on a 1 hour average, as proposed for RCEC, will emit twice as much CO as a 2 ppmvd limit based on a 3-hour average. Regardless, averaging time is irrelevant for an oxidation catalyst, which achieves the same level of control on a continuous basis. Averaging time is not specified in an oxidation catalyst quote for this reason, the guarantee is assumed to be met continuously.

Third, the District argues that the majority of facilities with equivalent NOx limits (2 ppm, 1 hour average) have not been built and thus there is no operational data with which to evaluate performance.[46] However, this is not correct. The District shows that two units that have 2 ppm NOx limits and 2 ppm CO limits are operational – Goldendale Energy and Magnolia . The District did not analyze the CO data from these two facilities. Further, there are others that are operational with lower limits that the District did not consider. The District did not evaluate the CO CEMS data for these other facilities. Regardless, another agency's determination that a given CO level is achievable is by itself sufficient to conclude that it is feasible for RCEC, absent a clear demonstration that circumstances exist at RCEC which distinguish it from the other sources with lower limits.[47]

The District argues that operational data is required to make a CO BACT determination. If operational data were required, BACT would present a chicken and egg problem. BACT is intended to be technology forcing, and thus requires the exercise of engineering judgment as to the applicability of transferable or new methods of pollution control. The large number of CO BACT determinations made by many other agencies indicates that a much lower CO limit is achievable, and the District is required to assess the achievability of such lower limits.

Finally, the District's list of recent BACT determinations is incomplete. It omits Kleen Energy Systems, CT (0.9 - 1.7 ppmvd); CPV Warren, VA (1.3 and 1.8 ppmvd); Malburg Generating Station, CA (2.0 ppm), and several Massachusetts plants that were permitted and are operating with a NOx limit of 2 ppm, based on a 1 hour average, and a CO limit of 2 ppm, based on a 1-hour average, including Sithe Mystic

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[46] SOB, p. 34.

[47] See, e.g. NSR Manual, p. B.29

(Ex. 26[48]) and Sithe Fore River (Ex. 27[49]). These similar operating facilities with lower CO limits and identical NOx limits establish CO BACT for RCEC.

If you have any questions or concerns, please do not hesitate to contact me at (415) 977-5769 or sanjay.narayan@sierraclub.org. Thank you for your time and attention.

Sincerely,

Sanjay Narayan / SB

Sanjay Narayan

[48] SCAQMD, Section II: Non-AQMD LAER/BACT Determinations, Application No. MBR-99-COM-012, Sithe Mystic Development LLC. http://www.aqmd.gov/bact/MBR-99-COM-012-Mystic2.doc.
[49] Massachusetts Department of Environmental Protection, PSD Permit, Sithe Four River Station, March 10, 2000.

Exhibits

BEFORE THE ADMINISTRATOR
UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

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

AMENDED PETITION FOR RECONSIDERATION

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

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

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

INTRODUCTION

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

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

BACKGROUND

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

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

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

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

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

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

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

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

OBJECTIONS

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

C. The Johnson Memo Substantively Amends the PSD Program

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

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

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

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

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

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

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

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

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

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

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

1. The Delaware SIP

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

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

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

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

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

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

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

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

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

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

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

2. <u>Section 821</u>

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

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

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

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

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

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

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

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

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

1. The 1978 Preamble

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

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

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

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

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

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

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

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

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

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

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

2. The 2002 Regulation

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

III. EPA SHOULD STAY THE EFFECT OF THE JOHNSON MEMO

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

CONCLUSION

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

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The Design of High-Efficiency Turbomachinery and Gas Turbines

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Contents

Chapter 3

Thermodynamics of gas-turbine cycles

Gas-turbine engines are rotors and stators with blading, combustors, casings, heat exchangers and so forth. Each molecule of gas that enters the engine undergoes a sequence of processes that is called a "cycle". In a theoretical cycle, and in actual so-called "closed-cycle" gas turbines, the gas molecule returns to its original state. Most gas turbines work on the "open" cycle, in which ambient air enters the compressor, fuel is burned in the air, and the products of combustion emerge from the engine exhaust at above-atmospheric temperature. The regeneration of this gas by cooling and by the conversion of carbon dioxide to oxygen is then carried out in the atmosphere by natural processes.

The cycle to be used for a gas-turbine engine must be chosen before any component design can be started. The thermodynamic analysis of the cycle will yield the potential efficiency, power output and approximate size of the engine.

Gas turbines, in contrast to steam turbines, spark-ignition and compression-ignition engines, can operate on a wide variety of different cycles. In this chapter we develop the performance of "simple" (compressor, burner, expander; or "CBE") cycles; similar cycles that incorporate an exhaust-gas heat exchanger ("CBEX"); and heat-exchanger cycles that use an intercooled, instead of a nonintercooled, compressor (e.g., "CICBEX" cycles)[1]. We will also describe and briefly discuss some other cycles (for instance, turbojet and turbofan cycles for jet propulsion, and combined and steam-injection cycles for industrial power generation) among the many that have been designed or considered.

This chapter is concerned with the start of the design process. The first decisions the designer must make before the start of a stand-alone piece of turbomachinery or of a gas-turbine engine is the choice of the thermodynamic conditions, including the temperatures, pressures, pressure losses, component efficiencies and so forth. The designer might, in fact, have only limited freedom in many of these respects. The customer or someone at a more-senior level might already have chosen the overall component specifications or the engine cycle. The component efficiencies, pressure losses and so on may be very

[1]This is a slightly modified version of the cycle-designation system apparently developed by E. S. Taylor at MIT. We have substituted the generic "expander, E" for "turbine, T".

restricted choices. The designer is more likely to choose a type of compressor, for instance (from the principal types: axial-flow, radial-flow or axial-centrifugal combinations) and accept whatever efficiency is produced by either a very conservative or a very aggressive approach to the type chosen. If you, the reader, are being exposed to turbomachinery for the first time you will not have the experience to choose appropriate values, and you will need to be guided by the typical numbers used in the examples in this chapter. You will be able to choose some values for yourself after going through chapters four and five, which cover the performance of diffusing components and the preliminary design of fans, compressors, pumps, and turbines. Much more precise estimates of component efficiencies, including those of heat exchangers, can be made after the material in chapters 7 through 10 is absorbed.

3.1 Temperature-entropy diagrams

By definition, a gas turbine uses a gas as a working fluid. In the great majority of gas-turbine applications, the working fluid is air, or is a gas that is well removed from its liquefaction temperature in the cycle conditions chosen (for instance, hydrogen or helium). Under these conditions, it is a good approximation to treat the working fluid as a perfect or semi-perfect gas, defined as a substance that obeys the equation of state:

$$pv = RT$$

where p is the pressure, v is the specific volume, R is a constant (the "gas constant"), and T is the (absolute) temperature. It is convenient to perform initial analyses of cycles assuming that the working fluid is a perfect gas simply because the calculations are greatly simplified, and because the resulting ease of analysis makes it possible to gain a deeper insight into the variations that may be expected from changes in cycle conditions. Final calculations may then be made using real-gas properties in the knowledge that conditions will not be greatly changed. We shall give examples of calculations made using different assumptions for working-fluid properties.

Property diagrams are particularly useful for giving the conditions of, and relationships among, the end points of processes making up gas-turbine cycles. Perfect gases are simple substances, for which the state can be found from the value of any two independent properties. Therefore we could make cycle diagrams on charts with axes of p and v, or v and h, for instance.

More suitable choices for the axes of a diagram to represent the ideal gas-turbine cycle, which is known as the Brayton or Joule cycle in one form, and the Ericsson cycle in another form, are T and s or h and s. The fluid stagnation temperatures at compressor and turbine inlets are normally part of the cycle specifications. The ideal compression and expansion processes are isentropes in the Brayton cycle, and isothermals in the ideal Ericsson cycle (for compression which in practice could be approached by using many intercoolers and expansion by using many reheat combustors). Both are easily drawn on $T - s$ diagrams. The thermodynamic or material limits for gas-turbine cycles are lines of constant temperature, again easily drawn. Atmospheric temperature is one limit

This cryogenic application is one case where the use of reheaters between expansion stages would be easily practicable and would increase the power output and the efficiency. Many stages of compression and expansion are needed to produce a change of temperature sufficient for the use of intercoolers or reheaters when hydrogen is used, because of the very high specific heat. Whether or not the high additional cost of intercoolers and reheaters would be justified would depend on the value of the additional power produced.

Cycles that incorporate water or steam

The combined cycle is the most-used variation of the basic gas-turbine cycle in the last part of the twentieth century. The simplest form is the combined-heat-and-power plant, or CHP. A gas-turbine engine, usually one working on the "simple cycle" (CBE), exhausts hot gas into a heat-recovery steam generator (HRSG). In the case of CHP, the steam from the HRSG is led to a process application (for instance, a paper-making plant), or to building or district heating (figure 3.48). In a true combined-cycle plant the steam operates a steam-turbine plant (figure 3.49), and the plant is sometimes called a "CCGT" plant, for "combined-cycle gas turbine", although manufacturers like to devise their own names for their particular offerings. GE uses "STAG", for "steam and gas". Sometimes the gas-turbine part is called the "topping cycle" and the steam-turbine portion the "bottoming cycle". Most of the new generating plants being built around the world are designed to this cycle. Efficiencies of the small plants are in the range of 50%, while for the larger plants it can go as high as 60% (figure 3.50). (This is forecast for the GE Power Systems "H" technology, which uses steam in another way, blade cooling, to allow turbine-inlet temperatures of 1430 °C (2600 °F), to be reached in heavy-duty gas turbines. The 60-percent figure is for the so-called STAG 109H, a 480-MW combined-cycle plant.) The efficiencies rise with power output partly because Reynolds-number effects and tip-clearance losses become relatively smaller as gas-turbine plants become larger, and partly because the incorporation of efficiency-improving measures in steam-turbine plant (feed-water heating for instance) is economic only for the largest plants.

There is sufficient oxygen in the exhaust of a simple-cycle gas turbine to support additional combustion. However, most combined-cycle plants do not have supplementary

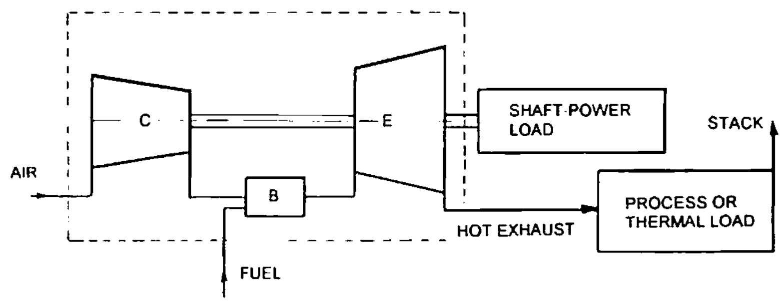

Figure 3.48. Combined heat and power (CHP) plant

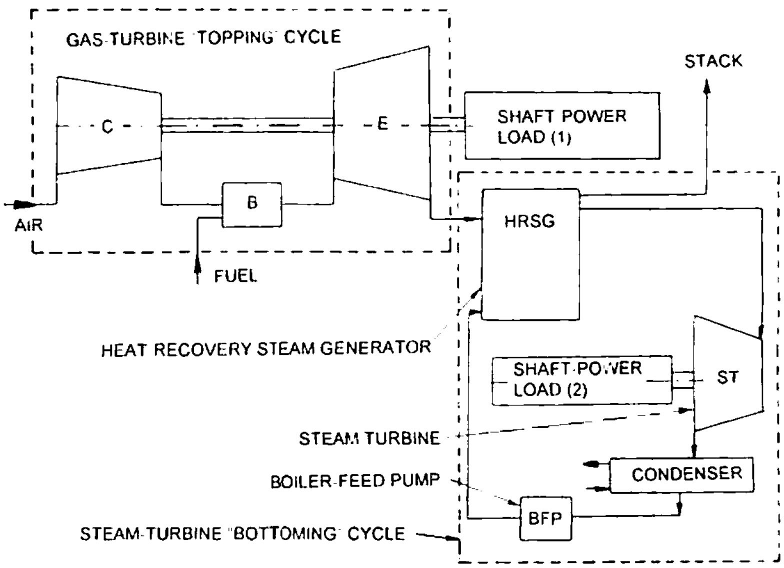

Figure 3.49. Combined-cycle plant

firing. The temperature of the steam at the stop-valve of large steam turbines is around 566 °C (1050 °F), a temperature limit set by hydrogen embrittlement of superheater tubes (at high pressures and temperatures water dissociates to OH^- and H^+). It is desirable that the steam reach, but not exceed, this temperature. The increasing turbine-inlet temperatures of modern gas-turbine plant match the required steam conditions without the need for further combustion. There is also benefit in increasing the output of the gas-turbine by incorporating intercooling and reheat.

Another variation is the integrated-gasification combined cycle (IGCC) that incorporates a system producing gas from coal. Where the gasifier is oxygen-fed, the system must include an oxygen plant in addition to the gasification plant, leading to a capital cost reported as approximately three times that of a CCGT fired by natural gas. The ability to use a low-cost fuel, coal, in an environmentally benign manner will justify the additional capital cost in certain circumstances today, and presumably in more circumstances in the future when natural-gas prices are certain to rise. The 250-MWe Demkolec plant in the Netherlands started trial operation in 1994, and the Wabash River plant in Indiana started trials in 1995. The capital cost of larger plants is estimated at about $1600/kW; several other IGCC plants are in the advanced planning stage (Stambler, 1996).

Coal is also being used to power combined-cycle gas turbines by using pressurized fluidized beds for combustion, initially in Spain, Japan, and the US. The beds contain limestone and other sorbents that, together with slag-melting on the walls and base of the bed, produce a hot gas that can pass through a gas turbine expander without causing more than minor erosion, corrosion, or deposition. The prices forecast for the plants are 75 percent of those for the IGCC plants.

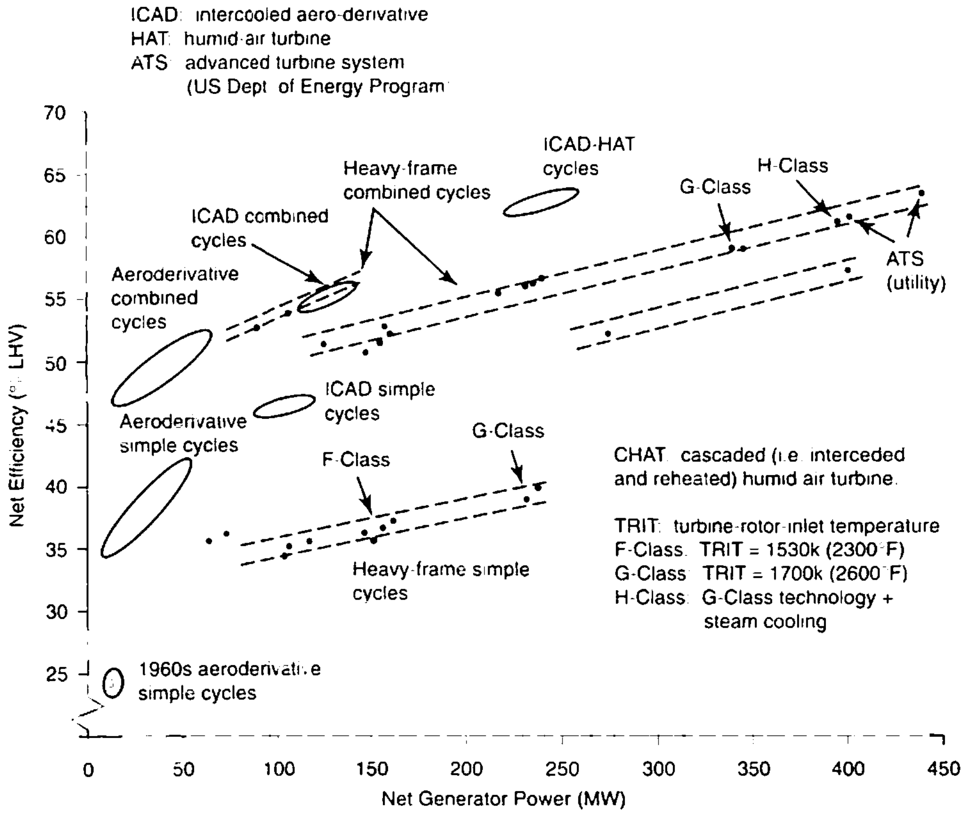

Figure 3.50. Thermal efficiency versus power output and type. From Touchton (1996)

Steam injection in a location where it will expand through the turbine blading with the combustion gases is a third use of the steam generated in a HRSG (figure 3.51). It is a modern version of the system pioneered by Lemale and Armengaud in the first decade of this century (see the historical introduction). Steam may be injected upstream of or into the combustion chamber, or into the turbine nozzles anywhere along the expansion. The steam does less work the further along the expansion it is injected. In comparison with the combined cycle, the steam-injected cycle has the following advantages. A substantial increase in power can be obtained from the gas-turbine engine with no modification in the configuration of the expansion turbine itself. The part-load efficiency is improved. The production of NO_x is reduced. In a review of the status of steam-injected gas turbines, Tuzson (1992) states that combined-cycle turbines have demonstrated the highest power-generation efficiencies and the lowest cost in sizes above 50 MW (although he also quotes a study giving the power level below which steam-injection systems become more attractive than combined cycles as 150 MW). At lower power levels the steam-injected

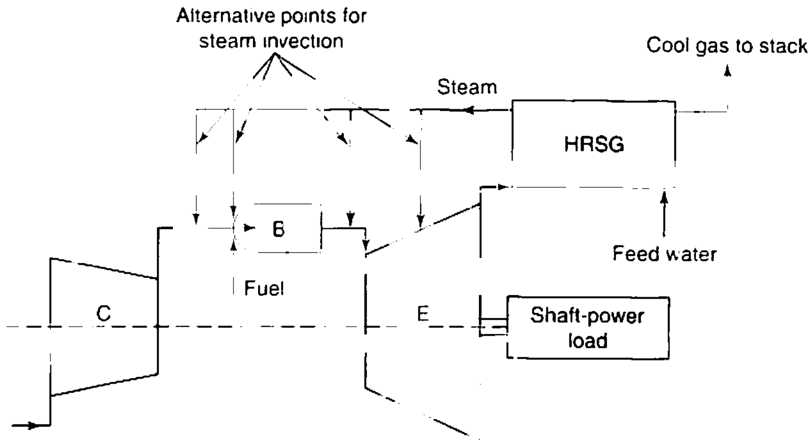

Figure 3.51. Steam-injection gas turbine

gas turbine becomes attractive because of the avoidance of the large cost of the steam turbine. A typical power gain from steam injection for a GE LM5000 gas-turbine engine was quoted as increasing the engine output from 34 MW to 49 MW, together with an efficiency increase from 37 percent (simple cycle) to 41 percent. GE analyzed the gains that would be obtained from a combination of intercooling and steam injection for the LM5000: a power increase from 34 MW to 110 MW and an efficiency improvement from 37 to 55 percent. The water-purification requirements are more demanding for steam injection than for the combined cycle because virtually all the water is normally lost in the exhaust rather than being circulated in a closed system, and because the specifications are more stringent. Any dissolved solids that become deposited on the turbine blades or elsewhere could form corrosion sites or potential blockages. However, Tuzson states that water-purification cost is of the order of five percent of the fuel cost and is not, therefore, a decisive factor. The reliability of early steam-injected units has been high, for instance 99.5 percent. Rather surprisingly, combustor-liner durability has been found to increase.

One of the advanced gas-turbine systems being developed in Japan uses an intercooled-reheated gas turbine (the intercooler is a water-spray direct-contact type) in which the steam raised in the HRSG can power a conventional steam turbine, or the steam can be injected into the gas turbine (Takeya and Yashui, 1988). The configuration shown in figure 3.52 is for the steam-injection system. The output, 400 MW, and the predicted efficiency, 54.3 percent, place it outside Tuzson's guidelines above.

A gas turbine is a good candidate for steam injection if the compressor has a wide range of operation (in particular, a good "surge margin"—see chapter 8) because the increased flow creates a higher back pressure. A high pressure ratio and a high turbine-inlet temperature are also desirable. These conditions seem to favor the aircraft-derivative turbine. However, Tuzson (1992) points out that heavy-duty industrial turbines can accommodate concentrations of contaminants about five times higher than can the aircraft-derivative turbines.

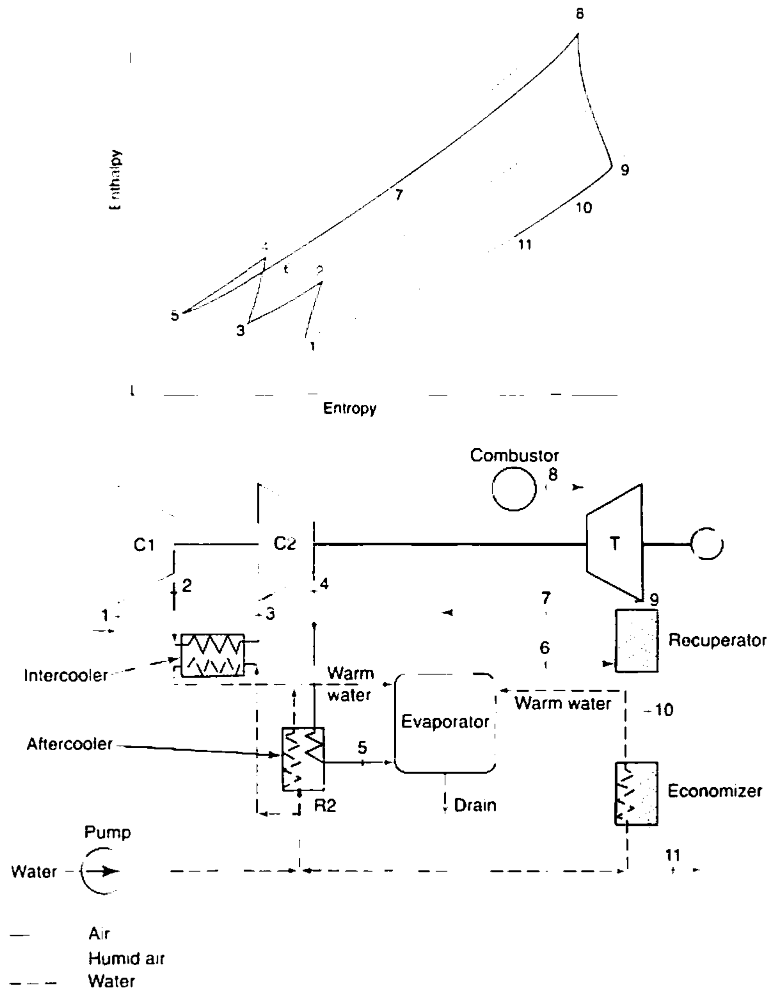

Figure 3.54. Humid-air cycle

rated water at exhaust temperature and at its partial pressure in the exhaust products of combustion is returned to the steam-turbine cycle). The flow rate of air at the gas-turbine inlet is ($\dot{m}_{15}$, station 15), and the flow rate of steam at the HP steam-turbine inlet is ($\dot{m}_3$, station 3). Energy available from condensation of the flue gas and from the steam-turbine condenser provide district hot-water heating $\Delta\dot{E}$ at 110 °C. For typical values of CBE-cycle compressor pressure ratio and turbine-inlet temperature, they obtained figures such as 3.57 showing power-plant thermal efficiency versus specific power and effectiveness versus specific energy of district heating as functions of F2/F1, ratios of steam plant to

White Bluff Steam Electric Station Units #1 and #2 of Arkansas Power and Light Co., 1983. The plant consists of two coal-fired units, each rated at approximately 800 MW, complete with electrostatic precipitators and natural draft cooling towers. Steam conditions are 2400 psig, 1000 F superheat, and 1000 F reheat. Coal fuel is low-sulfur, western subbituminous, delivered by unit trains. (Courtesy of Arkansas Power and Light Co.)

Power Plant System Design

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Preface

This textbook is the outgrowth of our consulting engineering work and teaching in electric power generation. It was written to meet the needs of mechanical engineering students and engineers. In the last 20 years, the changes in technology include substantial growth in unit size (from approximately 200 MW in the 1950s to 1100 MW in the 1970s) and the use of different steam conditions (from subcritical in the 1950s to supercritical conditions in the 1970s). In addition, the plant capital and fuel costs have escalated so rapidly that the plant system design has become a subject of increasing importance in the power industry.

The aim of this book is the design of optimum power plant systems. There are two basic concepts in power plant design that will be embodied in this book: component design and system design. The system generally consists of one or more components related to each other to perform one particular task. In power plants the system may be very simple, such as a section of steam pipe between the superheater and the high-pressure turbine, or very complex, such as the turbine cold-end system, which may consist of the turbine exhaust end, condenser, and cooling tower. This book will emphasize systems rather than components. The selection of components will be made in terms of its impacts on the system. However, basic knowledge of the components is a necessary ingredient for understanding the system.

Design is a decision-making process. The design process frequently results in a set of drawings, or a report that may include calculations and descriptions of equipment. In this textbook attention will be focused on the system design rather than the component design; on the thermal design rather than the mechanical design. When we write "thermal design" we mean that the calculations or decisions are based on the principles of thermodynamics, heat transfer, and fluid mechanics. The system design procedures will generate several optional solutions. Apparently, not all these solutions are equally acceptable. Some are better than others. The final decision as to which solution to use will be made by utilizing various simulation and optimization techniques.

This book serves as an introduction to power plant system design. Since the electric power generating system is complex, we do not intend to cover all aspects. Rather, attention is focused on the steam turbine, steam supply systems, condenser, and cooling tower, as well as their combined system. However, the design methodology introduced here is so general that it can be easily adapted to other system design problems.

The use of the digital computer in power plant design is another feature of this textbook. Several computer programs are introduced and may be obtained from us. These programs have been thoroughly verified and tested in a Boston consulting firm. The reason for including these programs is to provide students have to spend a lot of time in design calculation and not have enough time to appreciate the effects of various design parameters. These computer programs may also serve as models for the further development of computer programs for power plant system design. However, the computer materials were presented in such a way that omitting them would not in any way disturb the continuity of the text.

The book is intended for use at the undergraduate and beginning graduate levels. It should provide sufficient materials, including homework problems, for one four-credit course in universities and colleges. The prerequisites are the first course of thermodynamics, heat transfer, and fluid mechanics. This book is also suitable as a reference for engineers in consulting engineering firms and in utility and manufacturing companies.

The subject matter included in this text is arranged to provide the instructor with a certain degree of flexibility in developing a particular engineering course. When the text is used in a system course (such as power plant system design or thermal system design in general), some background and component materials should be omitted. For this purpose it is suggested that Chapters 2, 5, and 6 be quickly reviewed or entirely omitted. When the text is used in a low-level course such as "Energy Conversion" or "Introduction to Power Plant Systems," the design materials presented in the text should be de-emphasized to some extent. In either case the instructor must select the material to be covered according to the background of the student and the purpose of the course.

During the preparation of this book students were foremost in the our minds. The objective was to develop in students an awareness and understanding of the relationship between the power plant system design and thermal science courses. Efforts were made to demonstrate by examples the use of the principles and working procedures in system design. The book has been tested for two years at North Dakota State University. In 1982 it was also used as a text for the short course "Power Plant System Simulation and Design Optimization" at the Center for Professional Advancement in New Brunswick, New Jersey. We appreciated very much the constructive criticisms both from the practicing engineers and university students.

No claim is made for complete originality of the text. We have been influenced by the excellent publications of many organizations and individuals, especially *Steam/Its Generation and Use* by Babcock & Wilcox, *Combustion*, *Fossil Power Systems* by Combustion Engineering, and those by General Electric and Westinghouse. We feel that these excellent publications should be acknowledged separately in addition to their being listed in the reference sections in the text.

We are indebted to Northern States Power Company (Minneapolis), Chas. T. Main, Inc. (Boston), and North Dakota State University for the assistance rendered in their professional development. We also thank North Dakota State's Department of Mechanical Engineering and Applied Mechanics for their support in preparing the manuscript and to Brenda Stotser and Debbie Coon for their typing.

Kam W. Li

Contents

Power Plant System Design

The mean effective pressure is given by

$$\text{MEP} = \frac{w_{\text{net}}}{v_b - v_a} = \frac{\eta_{cy} \times q_h}{v_1 - v_2}$$

$$= \frac{(0.585)(850)(778)}{(13.1 - 1.46)(144)} = 230.8 \text{ psia}$$

EXAMPLE 2-8. An air-standard Diesel cycle has a compression ratio of 15 and a cutoff ratio of 3. At the beginning of the compression process the conditions are 14.7 psia and 60 F. Calculate the cycle efficiency, the mean effective pressure, and the cycle maximum temperature.

Solution: Designating the states as shown in Fig. 2-27, we first calculate the maximum temperature in the cycle as follows:

$$v_1 = \frac{RT_1}{P_1}$$

$$= \frac{53.34 \times 520}{14.7 \times 144} = 13.1 \text{ ft}^3/\text{lb}$$

$$v_2 = \frac{v_1}{r_v} = \frac{13.1}{15} = 0.873 \text{ ft}^3/\text{lb}$$

$$T_2 = T_1\left(\frac{v_1}{v_2}\right)^{k-1} = 520(15)^{0.4} = 1536 \text{ R}$$

$$T_3 = \alpha T_2 = 3 \times 1536 = 4608 \text{ R}$$

The temperature T_3 is the maximum temperature in the cycle. To calculate the cycle efficiency, we simply use Eq. (2-60) and have

$$\eta_{cy} = 1 - \frac{1}{r_v^{k-1}}\left[\frac{\alpha^k - 1}{k(\alpha - 1)}\right]$$

$$= 1 - \frac{1}{15^{0.4}}\left[\frac{3^{1.4} - 1}{1.4(3 - 1)}\right]$$

$$= 0.558 \quad \text{or} \quad 55.8\%$$

The cycle network is the product of the cycle efficiency and the heat transfer to the air. That is,

$$w_{\text{net}} = \eta_{cy} q_h = \eta_{cy} c_p (T_3 - T_2)$$

$$= 0.558 \times 0.24 \times (4608 - 1536)$$

$$= 411.4 \text{ Btu/lb}$$

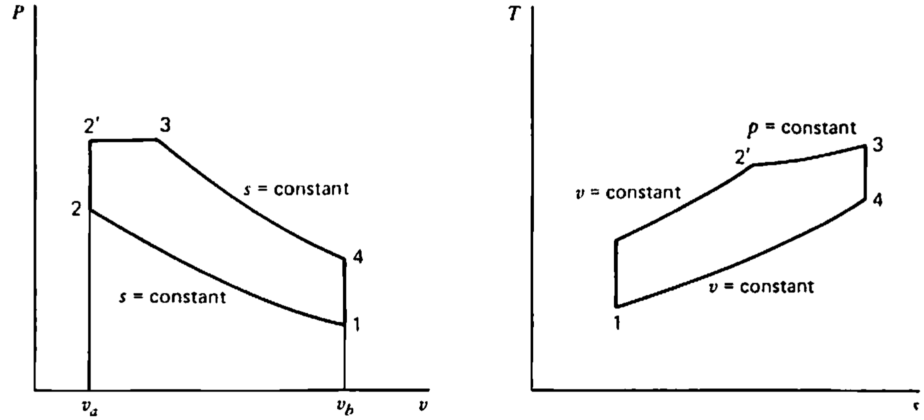


Figure 2-28. The air-standard dual cycle.

Finally, the mean effective pressure of the cycle is

$$\text{MEP} = \frac{w_{\text{net}}}{v_1 - v_2}$$

$$= \frac{411.4 \times 778}{(13.1 - 0.873) \times 144} = 181.8 \text{ psia}$$

It should be emphasized that the thermal efficiency calculated by the air-standard cycle approach is always greater than the actual efficiency. This is simply because the assumptions in the air-standard cycle analysis are not compatible with reality and very difficult to implement in practice. In an actual engine, the combustion may not be complete, and the compression and expansion processes are not isentropic because of friction and heat loss. The engine operation involves an inlet and an exhaust process, and certain amount of work is usually required to overcome the friction in the processes. However, as previously mentioned, the main value of the air standard cycle is to enable engineers to identify the important parameters and qualitatively determine their influence on the engine performance.

It should be noticed that the main difference between the Otto engine and the Diesel engine is in the combustion. The Otto engine has a constant volume process for combustion, while the Diesel engine has a constant pressure process. Consequently, there is an intermediate class of engine whose performance may lie between these two extremes. In this kind of engine, combustion initially takes place at constant volume and finishes at constant pressure process. The corresponding air standard cycle is frequently referred to as the dual cycle. Fig. 2-28 shows the P-v and T-s diagrams for a dual cycle. The thermal efficiency can be determined in the same fashion as that for the Otto and Diesel cycles.

2-6 COMBINED AND BINARY CYCLES

Improving the cycle efficiency has been an important objective in any cycle analysis. One convenient approach is to combine two different cycles to form a new

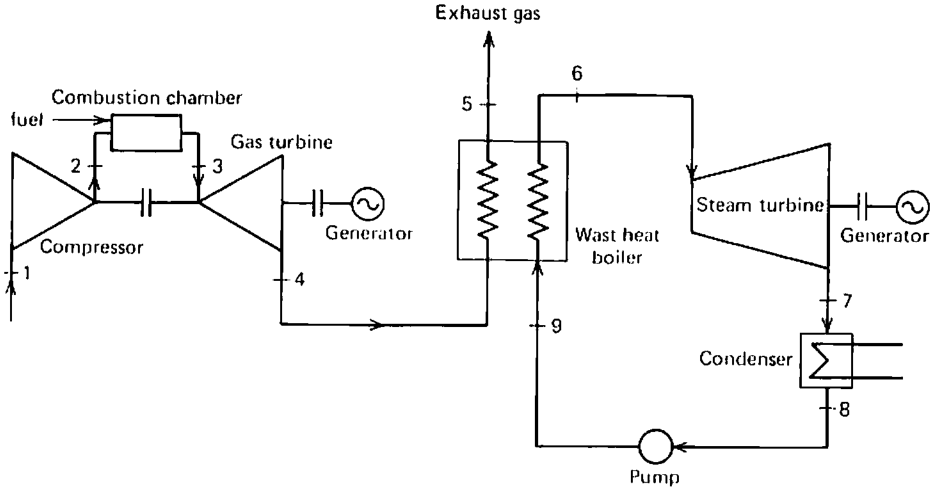


Figure 2-29. Schematic diagram for a combined-cycle system.

power-generating cycle. One of the most popular schemes is the combination of gas turbine cycle and steam turbine cycle as shown in Fig. 2-29. It is seen that the hot exhaust gas from the gas turbine is utilized to generate the steam that is in turn used to drive the steam turbine. In this system, combustion of the fuel is effected only at one point in the cycle, namely, in the combustion chamber of the gas turbine and the cycle work is produced at two different places. The overall thermal efficiency of the combined-cycle system is

$$\eta_{cy} = \frac{w_{gt} + w_{st}}{Q} \tag{2-62}$$

Let

η_{gt} = gas turbine plant efficiency

η_{st} = steam turbine plant efficiency

The gas turbine and steam turbine work, respectively, are

$$w_{gt} = \eta_{gt} \times Q \tag{2-63}$$

and

$$w_{st} = (1 - \eta_{gt}) \times Q \times \eta_{st} \tag{2-64}$$

Substituting these two terms into Eq. (2-62) gives us the combined-cycle efficiency in terms of the single-cycle efficiencies:

$$\eta_{cy} = \eta_{st} + (1 - \eta_{st})\eta_{gt} \tag{2-65}$$

Equation (2-65) shows that the thermal efficiency of the combined cycle is greater than the steam turbine plant efficiency by an amount equal to $(1 - \eta_{st})\eta_{gt}$. With $\eta_{st} = 0.33$ and $\eta_{gt} = 0.26$ as typical values, the combined-cycle efficiency will be approximately 0.5. This cycle efficiency represents an optimistic estimate. When detailed design of a combined-cycle plant is made, it usually shows the plant efficiency in the range of 38 to 42%.

The waste heat steam generator is the component that couples the gas part of the system with the steam part. The turbine exhaust gas enters the bottom of the heat exchanger, moves upward, and releases its energy. At the end of the process, the turbine exhaust gas will leave the plant through a short stack. Fig. 2-30 shows the temperature variation for both hot gas and steam. Water enters the steam generator in the form of compressed liquid. As water receives heat from the hot exhaust gas, it becomes saturated, evaporated, and eventually superheated. The temperature difference between these two streams varies throughout the waste heat steam generator. The minimum value $(T_x - T_s)$ is frequently defined as the pinch point. The pinch point selection is important and can greatly affect the physical size of the heat exchanger. For economic reasons, the pinch point usually ranges between 40 to 80 F. To determine the amount of steam generated in the heat exchanger, we take the evaporator and superheater as a control volume and apply the first law to it. That is,

$$m_g c_p (T_{hi} - T_x) = m_s (h_{ce} - h_1)$$

or

$$\frac{m_s}{m_g} = \frac{c_p (T_{hi} - T_x)}{h_{ce} - h_1} \tag{2-66}$$

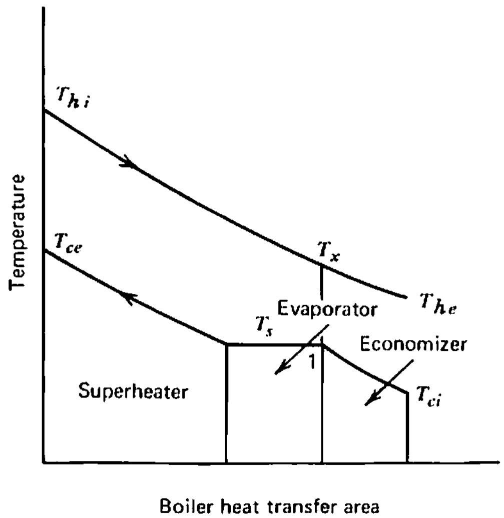


Figure 2-30. Temperature variation in a waste heat steam generator.

This equation gives the amount of steam generated by a unit mass of exhaust gas. In calculation, the pinch point is first selected; the temperature T_x is simply the pinch point plus the steam saturation temperature. The temperature of the gas entering the plant stack is also important and estimated by

$$m_g c_p(T_x - T_{he}) = m_s(h_1 - h_{ci})$$

or

$$T_{he} = T_x - \frac{1}{c_p}\frac{m_s}{m_g}(h_1 - h_{ci}) \tag{2-67}$$

To avoid corrosion from moisture formation in economizer and stack, the minimum gas temperature in the steam generator is always kept higher than the dew point temperature.

EXAMPLE 2-9. Consider the combined-cycle system as shown in Fig. 2-29. The gas side of the system is identical to that in Example 2-4. On the steam side steam enters the turbine at 1200 psia 800 F and exhausts to the condenser at a pressure of 4 in. Hg abs. The steam turbine and pump efficiency are, respectively, 88 and 85%. Calculate the combined-cycle efficiency and the temperature of the gas leaving the stack.

Assume that the boiler pinch point is 60 F.

Solution: Designating the states as shown in Fig. 2-29, we first calculate the amount of steam generated by a unit mass of the hot gas. Since the boiler pinch point is 60 F and the saturation temperature of steam at 1200 psia is 567.2 F, the intermediate gas temperature T_x must be

$$T_x = 60 + 567.2 = 627.2 \text{ F}$$

Also,

$$h_6 = 1379.7 \text{ Btu/lb}$$

$$h_1 = 571.9 \text{ Btu/lb (enthalpy of saturated water at 1200 psia)}$$

$$T_4 = 1410 \text{ R} \qquad \text{or} \qquad 950 \text{ F (from Example 2-4)}$$

Substituting these values into Eq. (2-66) gives us

$$\frac{m_s}{m_g} = \frac{0.25(950 - 627.2)}{1379.7 - 571.9} = 0.099 \text{ lb/lb}$$

Next, we calculate the steam turbine and pump work based on a unit mass of hot gas passing through the boiler. The turbine work is given by

$$w_{st} = \frac{m_s}{m_g}\eta_t(h_6 - h_{7s})$$

$$w_{st} = 0.099 \times 0.88(1379.7 - 894)$$

$$= 42.7 \text{ Btu/lb of gas}$$

and the pump work is

$$w_p = \frac{m_s}{m_g}\frac{1}{\eta_p}v(P_9 - P_8)$$

$$= \frac{0.099 \times 0.01623(1200 - 1.96) \times 144}{0.85 \times 778}$$

$$= 0.42 \text{ Btu/lb of gas}$$

It is seen that the pump work is negligibly small as compared with the steam turbine work. Therefore, it is omitted from the cycle analysis. In this system the combustion chamber of the gas turbine is only one place where the fuel is burned. The heat supplied is given by

$$g_h = c_p(T_3 - T_2)$$

$$= 0.25(2460 - 1096)$$

$$= 341 \text{ Btu/lb}$$

Then, the overall thermal efficiency of the combined cycle is

$$\eta_{cy} = \frac{(w_{gt} - w_c) + w_{st}}{q_h}$$

$$= \frac{118.4 + 42.7}{341} = 0.472 \qquad \text{or} \qquad 47.2\%$$

Finally, to determine the temperature of the gas entering the stack, we use Eq. (2-67) and have

$$T_{stack} = 627.2 - \frac{1}{0.25} \times 0.099 \times (571.9 - 93.7)$$

$$= 437.8 \text{ F}$$

The above calculations are based on the assumption of no pressure drop at the various cycle locations. When these pressure drops are taken into account, the efficiency of the combined cycle is greatly reduced.

In recent years, other arrangements of waste heat steam generator have been veloped. In addition to the unfired boiler just described, the supplemental fired ler and the exhaust-fired boiler are available. In the supplemental boiler, ad- ional fuel is injected and burned in the furnace. Because of the additional firing, temperature of the steam is expected to be somewhat higher than that in the ired boiler and therefore to improve the performance of the steam side in the nbined cycle. The exhaust-fired boiler is similar to the conventional steam erator equipped with a complete set of combustion equipment. Additional fuel is rned in the furnace, and the combustion air is supplied through the gas turbine npressor. In general, the combined system with exhaust fired boiler has higher ciency but the initial investment also costs much more. Chapter 13 discusses the ste heat boiler selection.

There is another approach in combining the gas turbine and steam turbine tem. Figure 2-31 shows the schematic diagram of this combined system. The air ply through the compressor is used to pressurize the combustion chamber of the m generator. The flue gases from the boiler would act as the working substance expand in the gas turbine. The steam generated in the boiler would go through turbine cycle as it does in the conventional steam plant. In this system bustion of the fuel is effected only in the furnace of the boiler, and the useful k is produced by gas and steam turbine. The cycle efficiency can be calculated in same manner as that for the previous combined cycle.

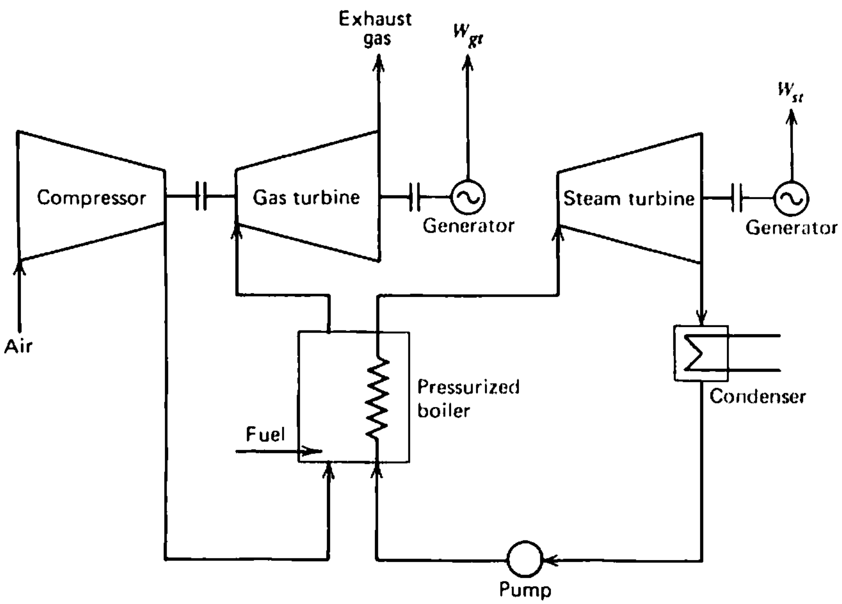


Figure 2-31. Schematic diagram for a combined-cycle system with pressurized boiler.

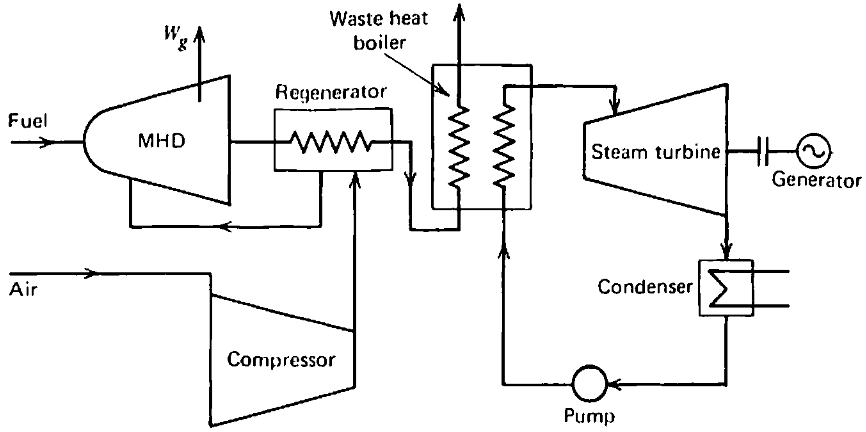


Figure 2-32. Schematic diagram for a combined-cycle system with MHD generator.

In recent years work has been initiated to develop the combined gas-steam plant with magnetohydrodynamic (MHD) generator. Figure 2-32 shows the simplified flow diagram for this system. It is seen that the MHD generator replaces the gas turbine and produces useful work in the gas circuit. Then the gas passes through a regenerator on the way to the steam generator. The steam side of this combined cycle is similar to the steam sides just described.

The principle of MHD operation is based on the Faraday effect, and may be best illustrated in Fig. 2-33. The electrically conducting gas at high temperature enters the

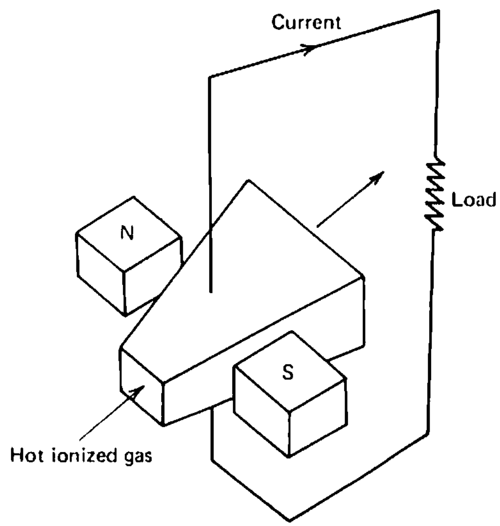


Figure 2-33. Principle of MHD operation.

MHD generator and passes through the diverging channel. An intense magnetic field is created in the direction perpendicular to the direction of gas flow. Interaction of the conducting gas with the magnetic field will then induce an electric field in a direction normal to both the magnetic field and the gas flow. When electrodes are placed in the channel walls that are in contact with the gas stream, the current will flow through the gas, the electrodes, and the external load. In this fashion thermal energy is extracted from the gas stream and electric energy is produced.

The combined system with a MHD generator presents no new problem in a cycle analysis. When the calculation on the MHD generator is completed, the remainder of cycle analysis is similar to those we have discussed before.

It has been demonstrated that the thermal efficiency of the combined cycle is generally greater than the individual cycle efficiency. This is mainly because the combined cycle can take advantage of the best features of each individual cycle. For instance, the high-temperature feature of gas turbine is utilized in the heat addition process of the combined cycle. To avoid high temperature of heat rejection encountered in the gas turbine system, the combined cycle replaces it by a steam turbine system that is characterized by heat rejection in a low temperature. The concept of utilizing the best features from more than one cycle system is easy to understand. In fact, this concept is also utilized in binary cycles. In a binary cycle, two different working substances go through two separate cycles and produce useful work. There is one coupling device (or equipment) in which heat is transferred from one working substance to another. One of the most popular schemes for binary cycles is the mercury-steam cycle as shown in Fig. 2-34. It is seen that a Rankine cycle using dry saturated mercury is superposed on another Rankine cycle using superheated steam. The device coupling these two Rankine cycles is the heat exchanger in which mercury is condensed and water is changed from liquid to vapor phase. To increase the efficiency of the steam side, steam is usually superheated and the superheater is frequently located in the mercury boiler. Not shown in Fig. 2-34 is the economizer of the steam side. The economizer usually placed in the mercury boiler is used to raise the water temperature before the water enters the steam generator (or mercury condenser). The thermal efficiency of mercury-steam binary cycle is given by

$$\eta_{cy} = \frac{w_{Hg} + w_{st}}{Q} \tag{2-68}$$

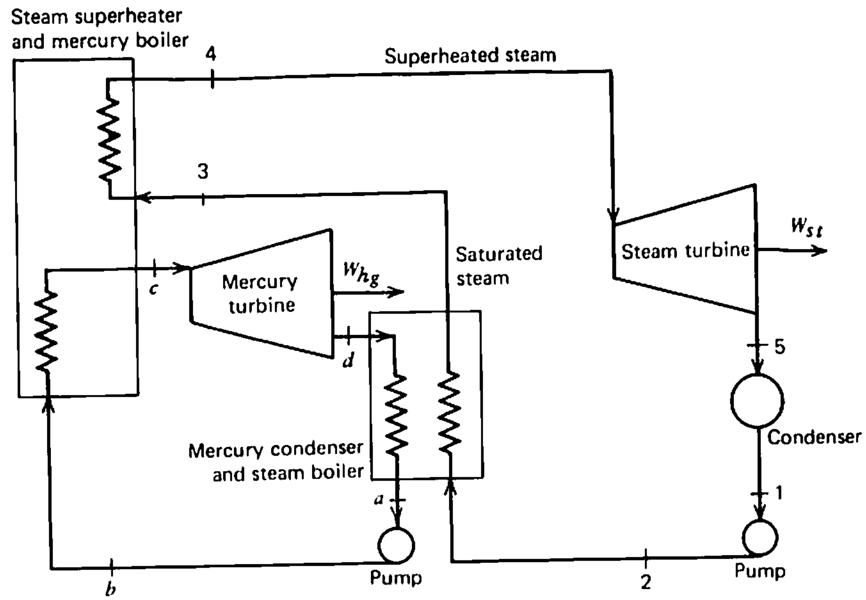
where

w_{Hg} = mercury turbine output

w_{st} = steam turbine output

Q = heat supplied to the binary cycle

For simplicity, the pump works are omitted from consideration. The amount of heat supplied to the binary cycle is divided into two portions; one (x) is given to the



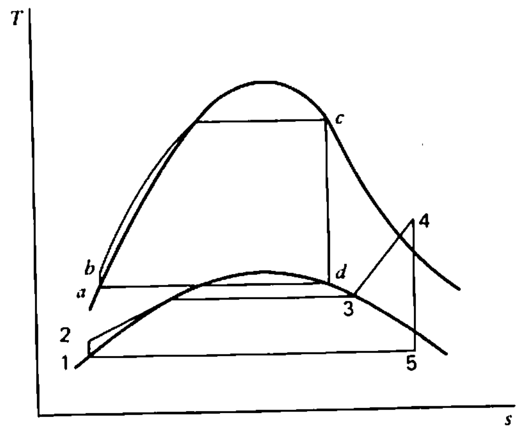


Figure 2-34. A mercury-steam binary cycle.

mercury, while another $(1 - x)$ is given directly to the steam in the superheater. Thus the mercury and steam turbine outputs are, respectively

$$w_{Hg} = xQ\eta_{Hg}$$

and

$$w_{st} = \left[(1 - \eta_{Hg})xQ + (1 - x)Q\right]\eta_{st}$$

where η_{Hg} is the thermal efficiency of the mercury side and η_{st} is the efficiency of the steam side. Substituting these two expressions into Eq. (2-68), we have

$$\eta_{cy} = x\eta_{Hg} + (1 - \eta_{Hg})x\eta_{st} + (1 - x)\eta_{st}$$

After rearranging, the thermal efficiency of the binary cycle becomes

$$\eta_{cy} = \eta_{st} + x\eta_{Hg}(1 - \eta_{st}) \tag{2-69}$$

Equation (2-69) indicates that the binary cycle has greater efficiency than the steam cycle by the amount equal to $x\eta_{Hg}(1 - \eta_{st})$. When there is no superheater and economizer in the mercury boiler, the fraction of heat supplied to the mercury will become a unity (i.e., $x = 1$). Then Eq. (2-69) becomes

$$\eta_{cy} = \eta_{st} + \eta_{Hg}(1 - \eta_{st}) \tag{2-70}$$

Mercury is one of the few working substances used in power plant cycles. For use in binary cycles mercury exhibits certain desirable characteristics that water may not have. These include a low specific heat of liquid mercury, large latent heat of vaporation, and low vapor pressure at high temperature. A low specific heat means a lesser need for feed heating in the mercury cycle. The low specific heat is also evident from the T-s diagram where the saturated liquid line for mercury has a very steep slope and is almost close to the vertical. A large latent heat means a heat addition process close to an isothermal. In other words, large latent heat will maximize the average temperature in which heat is added to the cycle and therefore improve the cycle efficiency. For a given power output the large latent heat also tends to reduce the equipment size. A low vapor pressure at high temperature is an important property for the working substance. It reduces not only the equipment cost, but also safety hazards generally associated with high-pressure operation.

EXAMPLE 2-10. Consider the binary cycle as shown in Fig. 2-34. Dry saturated mercury vapor enters the mercury turbine at 225 psia and exhausts at the pressure 4 psia. In the steam side superheated steam enters the turbine at 680 psia and 900 F and exhausts to the condenser at 1 psia. Both turbine processes are assumed isentropic, and pump works are negligible. Calculate the thermal efficiency of this binary cycle using the following mercury properties:

P (psia)	T (F)	h_f (Btu/lb)	h_v (Btu/lb)	s_f (Btu/lb-R)	s_v (Btu/lb-R)
225	1138	32.20	156.32	0.03565	0.11852
4	557.8	17.16	143.44	0.02373	0.14787

Solution: Designating the states as shown in Fig. 2-34, we find the me properties at various cycle locations as follows:

$$h_c = 156.32 \text{ Btu/lb}$$

$$s_c = 0.11852 \text{ Btu/lb-R}$$

$$s_d = s_c = x_d s_{vd} + (1 - x_d)s_{fd}$$

$$0.11852 = 0.14787x_d + 0.02373(1 - x_d)$$

$$x_d = 0.764$$

$$h_d = x_d h_{vd} + (1 - x_d)h_{fd}$$

$$= (0.764)(143.44) + (1 - 0.764)(17.16)$$

$$= 113.65 \text{ Btu/lb}$$

Neglecting the pump effects, we get

$$h_a = h_b = 17.16 \text{ Btu/lb}$$

The mercury turbine work is given by

$$w_{Hg} = h_c - h_d$$

$$= 156.32 - 113.65 = 42.67 \text{ Btu/lb}$$

and the heat supplied to the mercury is

$$q_1 = h_c - h_b$$

$$= 156.32 - 17.16 = 139.16 \text{ Btu/lb}$$

Next, we move to the steam side and find the steam properties as follows:

$$h_4 = 1460 \text{ Btu/lb}$$

$$s_4 = 1.6614 \text{ Btu/lb-R}$$

$$s_5 = s_4 = x_5 s_{v5} + (1 - x_5)s_{f5}$$

$$1.6614 = 1.9781x_5 + 0.1326(1 - x_5)$$

$$x_5 = 0.828$$

$$h_5 = x_5 h_{v5} + (1 - x_5)h_{f5}$$

$$= (0.828)(1105.8) + (1 - 0.828)(69.73)$$

$$= 927.6 \text{ Btu/lb}$$

Implementation of SB 1368 Emission Performance Standard

Gary Collord
Special Projects
Energy Facilities Siting Division
California Energy Commission

STAFF ISSUE IDENTIFICATION PAPER

NOVEMBER 2006
CEC-700-2006-011

Chapter 4: Emissions Performance Standard

The statute requires the emissions standard for the POU's to be consistent with that developed by the CPUC for its jurisdictional load-serving entities. Since this paper was prepared prior to the CPUC's adoption of a standard for load-serving entities, it raises issues that have been examined in the CPUC process and examines POU-specific issues which may provide a basis for modifying the Energy Commission's standard.

> *(e) (1) On or before June 30, 2007, the Energy Commission, at a duly noticed public hearing and in consultation with the commission and the State Air Resources Board, shall establish a greenhouse gases emission performance standard for all baseload generation of local publicly owned electric utilities at a rate of emissions of greenhouse gases that is no higher than the rate of emissions of greenhouse gases for combined-cycle natural gas baseload generation. The greenhouse gases emission performance standard established by the Energy Commission for local publicly owned electric utilities shall be consistent with the standard adopted by the commission for load-serving entities. Enforcement of the greenhouse gases emission performance standard shall begin immediately upon the establishment of the standard. All combined-cycle natural gas powerplants that are in operation, or that have an Energy Commission final permit decision to operate as of June 30, 2007, shall be deemed to be in compliance with the greenhouse gases emission performance standard.*

The CPUC staff proposed 1,100 pounds carbon dioxide per megawatt-hour as an Interim Emissions Performance Standard in its October 2, 2006 Final Workshop Report. The standard was selected from proposals ranging from 800 to 1,400 lbs CO2/MWhr, and the earlier Revised Staff Report's recommendation of 1,000 lbs CO2/MWhr (0.46 metric tons CO2/MWhr)[1]. The CPUC staff proposed EPS's of 1,000 or 1,100 lbs CO2/MWhr (0.50 metric tons CO2/MWhr) appear to be a compromise between the 800 lbs CO2/MWhr that the most efficient modern combustion turbine combined cycle plant could achieve, and the 1,400 lbs CO2/MWhr that might envelope the majority of natural gas burning technologies (e.g., steam cycle boiler, simple cycle combustion turbine, reciprocating engine, and a range of combustion turbine combined cycle units).

A proposed standard of 1,100, or 1,000, lbs CO2/MWhr is equivalent to a power plant unit with an effective heat rate, in higher heating value (HHV)[2], of:

	Typical Fuel CO2 emission factor	Effective Heat Rate @ an EPS of 1,000 lbs	Effective Heat Rate @ an EPS of 1,100 lbs

[1] Conversion: pounds to metric tons, multiply by 0.454×10^{3}.

[2] Heating Value: traditionally, heat rates in the USA and of boiler units is specified in higher heating value, while Europe and combustion turbines generally use lower heating value. For this discussion and more direct comparison, the higher heating value is used unless otherwise stated.

Natural gas HHV = 1.11 x LHV

Bituminous coal HHV = approx. 1.05 x LHV

Facility Level Emissions Quick Report
January 20, 2009

Your query will return data for 83 facilities and 188 units.

You specified: **Year(s):** 2007 **Program(s):** ARP **State(s):** CA

State	Facility Name	Facility ID (ORISPL)	Year	Program (s)	# of Months Reported	SO_2 Tons	NO_x Tons	CO_2 Tons	Heat Input (mmBtu)
CA	AES Alamitos	315	2007	ARP	12	5.0	86.2	994,778.8	16,741,572
CA	AES Huntington Beach	335	2007	ARP	12	5.7	58.1	905,556.7	15,239,761
CA	AES Redondo Beach	356	2007	ARP	12	1.7	17.7	343,210.4	5,776,117
CA	Agua Mansa Power	55951	2007	ARP	12	0.2	3.5	29,636.1	498,662
CA	Almond Power Plant	7315	2007	ARP	12	0.3	8.9	53,002.5	891,874
CA	Anaheim Combustion Turbine	7693	2007	ARP	12	0.1	4.6	29,389.7	494,485
CA	Blythe Energy	55295	2007	ARP	12	2.7	74.4	543,528.8	9,145,930
CA	Broadway	420	2007	ARP	12	0.0	1.8	9,391.4	158,042
CA	Cabrillo Power I Encina Power Station	302	2007	ARP	12	11.9	115.3	1,618,095.5	27,309,474
CA	CalPeak Power - Border LLC	55510	2007	ARP	12	0.1	2.1	23,254.6	391,312
CA	CalPeak Power - El Cajon LLC	55512	2007	ARP	12	0.1	1.9	19,764.5	332,576
CA	CalPeak Power - Enterprise LLC	55513	2007	ARP	12	0.1	1.4	16,142.0	271,639
CA	CalPeak Power - Panoche LLC	55508	2007	ARP	12	0.0	0.7	7,444.1	125,275
CA	CalPeak Power - Vaca Dixon LLC	55499	2007	ARP	12	0.0	0.6	7,719.5	129,917
CA	Calpine Gilroy Cogen, LP	10034	2007	ARP	12	0.7	81.1	136,415.8	2,295,417
CA	Calpine Sutter Energy Center	55112	2007	ARP	12	5.7	86.6	1,119,265.0	18,833,808
CA	Carson Cogeneration	7527	2007	ARP	12	2.2	29.3	240,734.3	3,799,976
CA	Carson Cogeneration	10169	2007	ARP	12	1.0	14.4	207,299.1	3,488,275

	Company								
CA	Chula Vista Power Plant	55540	2007	ARP	12	0.0	0.8	1,626.8	27,383
CA	Contra Costa Power Plant	228	2007	ARP	12	0.5	10.7	90,721.0	1,526,531
CA	Coolwater Generating Station	329	2007	ARP	12	2.1	350.9	421,624.0	7,094,649
CA	Cosumnes Power Plant	55970	2007	ARP	12	7.5	69.6	1,480,952.3	24,920,386
CA	Creed Energy Center	55625	2007	ARP	12	0.0	1.3	7,979.3	134,272
CA	Delta Energy Center, LLC	55333	2007	ARP	12	11.1	134.0	2,205,554.9	37,112,676
CA	Donald Von Raesfeld	56026	2007	ARP	12	1.4	15.9	268,881.9	4,524,443
CA	Dynegy South Bay, LLC	310	2007	ARP	12	2.7	46.3	509,294.3	8,569,590
CA	El Centro	389	2007	ARP	12	1.4	268.7	269,356.1	4,532,233
CA	El Segundo	330	2007	ARP	12	0.9	22.0	360,580.8	6,067,472
CA	Elk Hills Power	55400	2007	ARP	12	7.6	83.2	1,505,361.0	25,330,619
CA	Escondido Power Plant	55538	2007	ARP	12	0.0	0.6	2,473.9	41,624
CA	Etiwanda Generating Station	331	2007	ARP	12	2.2	24.3	444,830.3	7,485,126
CA	Feather River Energy Center	55847	2007	ARP	12	0.1	2.0	15,977.9	268,865
CA	Fresno Cogeneration Partners, LP	10156	2007	ARP	12	0.2	3.1	31,505.4	529,858
CA	Gilroy Energy Center, LLC	55810	2007	ARP	12	0.3	58.0	50,910.1	856,689
CA	Gilroy Energy Center, LLC for King City	10294	2007	ARP	12	0.1	1.2	11,615.1	195,579
CA	Glenarm	422	2007	ARP	12	0.1	4.8	24,331.2	409,416
CA	Goose Haven Energy Center	55627	2007	ARP	12	0.0	1.1	9,203.8	154,858
CA	Grayson Power Plant	377	2007	ARP	12	1.0	21.3	139,125.1	1,623,467
CA	Hanford Energy Park Peaker	55698	2007	ARP	12	0.1	2.4	23,232.1	390,918
CA	Harbor Generating Station	399	2007	ARP	12	0.7	25.6	140,435.0	2,363,342
CA	Haynes Generating Station	400	2007	ARP	12	10.2	92.7	2,019,801.5	33,992,772

CA	Henrietta Peaker Plant	55807	2007	ARP	12	0.1	2.4	13,329.7	224,296
CA	High Desert Power Project	55518	2007	ARP	12	9.7	159.4	1,921,877.2	32,339,084
CA	Humboldt Bay	246	2007	ARP	12	43.2	1,052.9	365,324.5	6,104,391
CA	Indigo Generation Facility	55541	2007	ARP	12	0.3	10.8	52,992.5	891,732
CA	Kings River Conservation District Malaga	56239	2007	ARP	12	0.4	5.8	76,028.5	1,279,384
CA	La Paloma Generating Plant	55151	2007	ARP	12	14.2	142.5	2,812,443.5	47,324,777
CA	Lake	7987	2007	ARP	12	0.0	0.9	4,992.2	83,986
CA	Lambie Energy Center	55626	2007	ARP	12	0.0	1.3	9,083.3	152,821
CA	Larkspur Energy Faciity	55542	2007	ARP	12	1.9	5.3	31,838.9	534,423
CA	Los Esteros Critical Energy Fac	55748	2007	ARP	12	0.2	8.8	40,168.5	675,919
CA	Los Medanos Energy Center, LLC	55217	2007	ARP	12	7.8	2,744.9	1,546,010.5	26,014,684
CA	Magnolia	56046	2007	ARP	12	1.7	15.5	328,970.7	5,535,839
CA	Malburg Generating Station	56041	2007	ARP	12	1.7	19.7	341,469.9	5,746,176
CA	Mandalay Generating Station	345	2007	ARP	12	1.4	9.4	275,926.6	4,643,002
CA	Metcalf Energy Center	55393	2007	ARP	12	6.8	77.9	1,337,584.8	22,507,479
CA	Miramar Energy Facility	56232	2007	ARP	12	0.0	0.4	4,281.2	72,036
CA	Morro Bay Power Plant, LLC	259	2007	ARP	12	1.5	86.9	305,629.4	5,142,682
CA	Moss Landing	260	2007	ARP	12	17.3	169.1	3,429,063.6	57,700,641
CA	Mountainview Power Company, LLC	358	2007	ARP	12	13.7	126.9	2,705,366.0	45,522,915
CA	NCPA Combustion Turbine Project #2	7449	2007	ARP	12	0.2	3.5	39,329.2	666,956

CA	Olive	6013	2007	ARP	12	0.0	0.1	1,664.2	28,005
CA	Ormond Beach Generating Station	350	2007	ARP	12	3.1	39.9	619,648.5	10,426,783
CA	Palomar Energy	55985	2007	ARP	12	7.1	76.3	1,403,805.3	23,621,779
CA	Pastoria Energy Facility	55656	2007	ARP	12	10.5	114.5	2,071,866.0	34,863,142
CA	Pittsburg Power Plant (CA)	271	2007	ARP	12	0.7	14.6	136,555.5	2,297,780
CA	Potrero Power Plant	273	2007	ARP	12	1.6	24.9	315,982.1	5,317,019
CA	Redding Power Plant	7307	2007	ARP	12	0.5	2.2	96,630.1	1,648,098
CA	Ripon Generation Station	56135	2007	ARP	12	0.1	2.2	20,980.5	353,028
CA	Riverside Energy Resource Center	56143	2007	ARP	12	0.1	2.3	23,584.1	396,861
CA	Riverview Energy Center	55963	2007	ARP	12	0.1	2.1	16,397.2	275,914
CA	Roseville Energy Park	56298	2007	ARP	6	0.4	3.4	70,844.1	1,192,059
CA	SCA Cogen II	7551	2007	ARP	12	1.9	50.4	380,906.8	6,409,475
CA	Sacramento Power Authority Cogen	7552	2007	ARP	12	2.6	41.9	524,239.4	8,821,321
CA	Scattergood Generating Station	404	2007	ARP	12	14.3	19.6	1,006,825.3	15,907,187
CA	Sunrise Power Company	55182	2007	ARP	12	7.7	74.8	1,528,392.0	25,718,239
CA	Tracy Peaker	55933	2007	ARP	12	0.1	15.3	10,111.1	171,404
CA	Valley Gen Station	408	2007	ARP	12	6.9	90.2	1,340,036.7	22,548,605
CA	Walnut Energy Center	56078	2007	ARP	12	3.3	35.9	663,350.2	11,162,241
CA	Wellhead Power Gates, LLC	55875	2007	ARP	12	0.0	0.7	5,695.9	95,845
CA	Wolfskill Energy Center	55855	2007	ARP	12	0.1	1.7	13,016.6	219,042
CA	Woodland Generation Station	7266	2007	ARP	12	1.0	15.9	203,357.7	3,421,792
CA	Yuba City	10349	2007	ARP	12	0.1	2.0	15,433.5	259,699

	Energy Center								
Total						**272.1**	**7,105.0**	**42,451,035.9**	**712,395,421**

Annual Emissions Report

Elk Hills Power

(Emissions from California operations)

Report Generated On: 01/20/2009 07:55 pm PT

4026 Skyline Road PO Box: 460

Tupman, CA 93276 United States

(661) 763-2727

pramsey@elkhills.com

Legend

Blue = required

Orange = optional

Contact:	Patrick Ramsey
Industry Type:	Electric Power Producer
NAIC Code:	2211-Electric Power Generation, Transmission and Distribution
SIC Code:	4911-Electric Services
Description:	Independent Power Producer
Primary Calculation Methodologies:	The inventory was prepared using the CCAR General Reporting Protocol Version 2.2, March 2007 and the CCAR Power and Utility Reporting Protocol Version 1.0, April 2005. EMISSION EFFICIENCY METRICS Net Generation: 796 lbs CO2/MWh from net owned generation Net Fossil Generation: 796 lbs CO2/MWh from net owned Fossil Fuel Generation
Organizational structure disclosure:	

VERIFIED EMISSIONS INFORMATION

Reporting Year:	**2006**
Reporting Scope:	**CA**
Reporting Protocol:	General Reporting Protocol, Version 2.2 (March 2007); Power/Utility Reporting Protocol, Version 1 (April 2005)
Reporting Boundaries:	
Baseline Year (Direct Emissions):	
Baseline Year (Indirect Emissions):	

Direct Emissions	CO2e	CO2	CH4	N2O	HFCs*	PFCs*	SF6	Unit
Mobile Combustion	**0.00**	0.00	0.00	0.00	0.00	0.00	0.00	-
Stationary Combustion	**1,260,653.08**	1,248,733.95	92.29	32.20	0.00	0.00	0.00	metric ton
Process Emissions	**0.00**	0.00	0.00	0.00	0.00	0.00	0.00	-
Fugitive Emissions	**0.00**	0.00	0.00	0.00	0.00	0.00	0.00	-
TOTAL DIRECT	**1,260,653.08**	1,248,733.95	92.29	32.20	0.00	0.00	0.00	metric ton

* HFCs and PFCs are classes of greenhouse gases that include many compounds. These columns may reflect the total emissions of multiple HFC and PFC compounds, each of which has a unique Global Warming Potential (GWP). Emissions of each gas are first multiplied by their respective GWP and then summed in the total CO2-equivalent column.

Indirect Emissions	CO2e	CO2	CH4	N2O	Unit
Purchased Electricity	**0.00**	0.00	0.00	0.00	-
Purchased Steam	**0.00**	0.00	0.00	0.00	-
Purchased Heating and Cooling	**0.00**	0.00	0.00	0.00	-
TOTAL INDIRECT	**0.00**	0.00	0.00	0.00	-

De Minimis Emissions	CO2e	CO2	CH4	N2O	HFCs*	PFCs*	SF6	Unit
TOTAL DEMINIMIS	**3,296.15**	3,275.81	0.03	0.02	0.01	0.00	0.00	metric ton

Percentage of Total Inventory: 0.26 %

Annual Emissions Report

Elk Hills Power

(Emissions from California operations)

Report Generated On: 01/20/2009 07:55 pm PT

VERIFICATION INFORMATION

Verification Body: Ryerson, Master & Associates, Inc.

Basis of Verification Opinion: Elk Hills Power, LLC (EHP) submitted their California GHG Emission Inventory Report for Year 2006 to Ryerson, Master and Associates, Inc., (RMA) for review and certification against the Registry's General Reporting Protocol, Version 2.2 and the Power Utility Reporting Protocol (April 2005). RMA followed the procedures outlined in the Registry's General Certification Protocol (dated July 2003) and the Power Utility Certification Protocol (April 2005) to complete the certification process. The certification activities were conducted during January through March 2008.

On March 12, 2008, RMA issued a Certification Report to EHP documenting the certification activities and the immaterial misstatements in the EHP inventory. EHP accepted the Certification Report, and made revisions in CARROT and in the PUP spreadsheet to address the RMA findings. On March 20, 2008, RMA provided a Certification Opinion to EHP. RMA completed the Certification Activities Checklist and completed the certification in CARROT on March 20, 2008.

Date Submitted:
3/20/08 1:25 pm

OPTIONAL INFORMATION

Information in this section is voluntarily provided by the participant for public information, but is not required and thus, not verified under California Registry protocols.

Optional Emissions	CO2e	CO2	CH4	N2O	HFCs*	PFCs*	SF6	Unit
	0.00	0.00	0.00	0.00	0.00	0.00	0.00	-
TOTAL OPTIONAL	**0.00**	0.00	0.00	0.00	0.00	0.00	0.00	-

Emissions Efficiency metric: See comments on Certified Emissions Inventory, Fossil generation and Net generation

Emissions Management Programs:

Emissions Reduction Projects:

Emissions Reduction Goals:

REFERENCE DOCUMENTS

Title	Author	Document Status	Publish Date
2006 PUP Report	CCAR	Public	03/13/2008 12:00:00AM

This report includes emissions from California sources

Annual Emissions Report

Elk Hills Power

(Emissions from California operations)

Report Generated On: 01/20/2009 07:53 pm PT

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pramsey@elkhills.com

Legend

Blue	= required
Orange	= optional

Contact:	Patrick Ramsey
Industry Type:	Electric Power Producer
NAIC Code:	2211-Electric Power Generation, Transmission and Distribution
SIC Code:	4911-Electric Services
Description:	Independent Power Producer
Primary Calculation Methodologies:	The inventory was prepared using the CCAR General Reporting Protocol Version 3.0, April 2008 and the CCAR Power and Utility Reporting Protocol Version 1.0, April 2005. Emission Efficiency Metrics Net Generation: 793.99 lbs CO2/MWh net owned generation Net Fossil Generation: 793.99 lbs CO2/MWh net owned fossil generation only
Organizational structure disclosure:	

VERIFIED EMISSIONS INFORMATION

Reporting Year:	**2007**
Reporting Scope:	**CA**
Reporting Protocol:	General Reporting Protocol, Version 3.0, (April 2008); Power/Utility Reporting Protocol, Version 1 (April 2005)
Reporting Boundaries:	Management Control - Operational Criteria
Baseline Year (Direct Emissions):	
Baseline Year (Indirect Emissions):	

Direct Emissions	**CO2e**	**CO2**	**CH4**	**N2O**	**HFCs***	**PFCs***	**SF6**	**Unit**
Mobile Combustion	**0.00**	0.00	0.00	0.00	0.00	0.00	0.00	-
Stationary Combustion	**1,347,966.36**	1,344,042.64	149.45	2.53	0.00	0.00	0.00	metric ton
Process Emissions	**0.00**	0.00	0.00	0.00	0.00	0.00	0.00	-
Fugitive Emissions	**0.00**	0.00	0.00	0.00	0.00	0.00	0.00	-
TOTAL DIRECT	**1,347,966.36**	1,344,042.64	149.45	2.53	0.00	0.00	0.00	metric ton

* HFCs and PFCs are classes of greenhouse gases that include many compounds. These columns may reflect the total emissions of multiple HFC and PFC compounds, each of which has a unique Global Warming Potential (GWP). Emissions of each gas are first multiplied by their respective GWP and then summed in the total CO2-equivalent column.

Indirect Emissions	**CO2e**	**CO2**	**CH4**	**N2O**	**Unit**
Purchased Electricity	**0.00**	0.00	0.00	0.00	-
Purchased Steam	**0.00**	0.00	0.00	0.00	-
Purchased Heating and Cooling	**0.00**	0.00	0.00	0.00	-
TOTAL INDIRECT	**0.00**	0.00	0.00	0.00	-

De Minimis Emissions	**CO2e**	**CO2**	**CH4**	**N2O**	**HFCs***	**PFCs***	**SF6**	**Unit**
TOTAL DEMINIMIS	**3,592.67**	3,572.78	0.03	0.02	0.01	0.00	0.00	metric ton

Percentage of Total Inventory: 0.27 %

This report includes emissions from California sources

Annual Emissions Report

Elk Hills Power

(Emissions from California operations)

Report Generated On: 01/20/2009 07:53 pm PT

VERIFICATION INFORMATION

Verification Body: Ryerson, Master & Associates, Inc.

Basis of Verification Opinion: Elk Hills Power, LLC (EHP) submitted their California GHG Emission Inventory Report for Year 2007 to Ryerson, Master and Associates, Inc., (RMA) for review and verification against the Registry's General Reporting Protocol, Version 3.0 and the Power Utility Reporting Protocol (April 2005). RMA followed the procedures outlined in the Registry's General Verification Protocol, Version 3.0 and the Power Utility Certification Protocol (April 2005) to complete the verification process. The verification activities were conducted during July through October 2008.

On September 30, 2008, RMA issued a Verification Report to EHP documenting the verification activities and the immaterial misstatements in the EHP inventory. EHP accepted the Verification Report, and no revisions in CARROT or in the PUP spreadsheet were made. On October 1, 2008, RMA provided a Verification Opinion to EHP. RMA completed the Verification Activities Checklist and completed the verification in CARROT on October 6, 2008.

Date Submitted:
10/6/08 2:08 pm

OPTIONAL INFORMATION

Information in this section is voluntarily provided by the participant for public information, but is not required and thus, not verified under California Registry protocols.

Optional Emissions	CO2e	CO2	CH4	N2O	HFCs*	PFCs*	SF6	Unit
	0.00	0.00	0.00	0.00	0.00	0.00	0.00	-
TOTAL OPTIONAL	**0.00**	0.00	0.00	0.00	0.00	0.00	0.00	-

Emissions Efficiency metric: See Comments on Certified Emissions Inventory

Emissions Management Programs:

Emissions Reduction Projects:

Emissions Reduction Goals:

REFERENCE DOCUMENTS

Title	Author	Document Status	Publish Date
Elk Hills Power, LLC 2007 PUP Report	Elk Hills Power, LLC	Public	05/28/2008 12:00:00AM

This report includes emissions from California sources

Annual Emissions Report

Calpine Corporation

(Emissions from California operations)

Report Generated On:	01/20/2009 07:56 pm PT

50 W. San Fernando Street

San Jose, CA 95113 United States

www.calpine.com
925-479-6729
bmcbride@calpine.com

Legend
Blue = required
Orange = optional

Contact:	Barbara McBride
Industry Type:	Electric Power Producer
NAIC Code:	2211-Electric Power Generation, Transmission and Distribution
SIC Code:	4911-Electric Services
Description:	Clean, Reliable Power

Calpine Corporation is helping meet the needs of an economy that demands more and cleaner sources of electricity. Founded in 1984, Calpine is a major U.S. power company, capable of delivering nearly 24,000 megawatts of clean, cost-effective, reliable and fuel-efficient electricity to customers and communities in 18 states in the U.S. The company owns, leases and operates low-carbon, natural gas-fired and renewable geothermal power plants. Using advanced technologies, Calpine generates electricity in a reliable and environmentally responsible manner for the customers and communities it serves.

Calpine Quick Facts

Calpine adheres to stringent standards for safe, efficient plant operations.
Calpine is North America's leading geothermal power producer. At The Geysers, about 100 miles northeast of San Francisco, Calpine harnesses naturally heated steam from the earth to create electrical power. This renewable "green" power is available to consumers throughout California.

Primary Calculation Methodologies:	Calpine is using the default Acid Rain CO2 emissions factor = 118.9 lbs CO2/mmbtu No changes to deminimus in 2006.
Organizational structure disclosure:	

VERIFIED EMISSIONS INFORMATION

Reporting Year:	**2006**
Reporting Scope:	**CA**
Reporting Protocol:	General Reporting Protocol, Version 2.2 (March 2007); Power/Utility Reporting Protocol, Version 1 (April 2005)
Reporting Boundaries:	
Baseline Year (Direct Emissions):	
Baseline Year (Indirect Emissions):	

Direct Emissions	CO2e	CO2	CH4	N2O	HFCs*	PFCs*	SF6	Unit
Mobile Combustion	**0.00**	0.00	0.00	0.00	0.00	0.00	0.00	-
Stationary Combustion	**7,484,851.79**	7,484,851.79	0.00	0.00	0.00	0.00	0.00	metric ton
Process Emissions	**197,903.87**	197,903.87	0.00	0.00	0.00	0.00	0.00	metric ton
Fugitive Emissions	**0.00**	0.00	0.00	0.00	0.00	0.00	0.00	-
TOTAL DIRECT	**7,682,755.65**	7,682,755.65	0.00	0.00	0.00	0.00	0.00	metric ton

* HFCs and PFCs are classes of greenhouse gases that include many compounds. These columns may reflect the total emissions of multiple HFC and PFC compounds, each of which has a unique Global Warming Potential (GWP). Emissions of each gas are first multiplied by their respective GWP and then summed in the total CO2-equivalent column.

Annual Emissions Report

Calpine Corporation

(Emissions from California operations)

Report Generated On: 01/20/2009 07:56 pm PT

Indirect Emissions	CO2e	CO2	CH4	N2O	Unit
Purchased Electricity	**0.00**	0.00	0.00	0.00	-
Purchased Steam	**0.00**	0.00	0.00	0.00	-
Purchased Heating and Cooling	**0.00**	0.00	0.00	0.00	-
TOTAL INDIRECT	**0.00**	0.00	0.00	0.00	-

De Minimis Emissions	CO2e	CO2	CH4	N2O	HFCs*	PFCs*	SF6	Unit

Percentage of Total Inventory:

VERIFICATION INFORMATION

Verification Body: Ryerson, Master & Associates, Inc.

Basis of Verification Opinion:

Calpine Corporation submitted their California GHG Emission Inventory Report for Year 2006 to Ryerson, Master and Associates, Inc., (RMA) for review and certification against the Registry's General Reporting Protocol, Version 2.2 and the Power Utility Reporting Protocol (April 2005). RMA followed the procedures outlined in the Registry's Certification Protocol (dated July 2003) and the Power Utility Certification Protocol (April 2005) to complete the certification process. The certification activities were conducted during November 2007 through April 2008.

On April 21, 2008, RMA issued a Certification Report to Calpine documenting the certification activities and the material and immaterial misstatements in the Calpine inventory. Calpine revised the emission inventory in CARROT, and RMA recertified the inventory. A Certification Opinion was provided to Calpine on April 28, 2008. RMA completed the Certification Activities Checklist and completed the certification in CARROT on April 28, 2008.

Date Submitted:
4/28/08 9:47 pm

OPTIONAL INFORMATION

Information in this section is voluntarily provided by the participant for public information, but is not required and thus, not verified under California Registry protocols.

Optional Emissions	CO2e	CO2	CH4	N2O	HFCs*	PFCs*	SF6	Unit
	0.00	0.00	0.00	0.00	0.00	0.00	0.00	-
TOTAL OPTIONAL	**0.00**	0.00	0.00	0.00	0.00	0.00	0.00	-

Emissions Efficiency metric: 644 lbs CO2/mwh

Emissions Management Programs: Total Energy Efficiency Metric = 644 lbs CO2/mwh
lbs of direct CO2 Emissions from stationary fossil fuel combustion/Net MWH from all energy sources.

Fossil Fuel Electricity Generation: 850 lbs CO2/MWH
lbs of CO2 emissions from stationary fossil fuel combustion/Net MWH from fossil fuel sources only.

Emissions Reduction Projects: Calpine will work to improve the fuel efficiency of its natural gas fueled power plants through a series of performance improvement programs, which will reduce CO2 emissions per megawatt hour throughout the fleet.

Annual Emissions Report

Calpine Corporation

(Emissions from California operations)

Report Generated On: 01/20/2009 07:56 pm PT

Emissions Reduction Goals: Calpine's goal is to minimize CO2 emissions per megawatt hour from its power plants and to be recognized as the industry leader in minimizing CO2 emissions from power generation.

REFERENCE DOCUMENTS

Title	Author	Document Status	Publish Date

This report includes emissions from California sources

Annual Emissions Report

Calpine Corporation

(Emissions from California operations)

Report Generated On: 01/20/2009 07:57 pm PT

50 W. San Fernando Street

San Jose, CA 95113 United States

www.calpine.com
925-479-6729
bmcbride@calpine.com

Legend
Blue = required
Orange = optional

Contact:	Barbara McBride
Industry Type:	Electric Power Producer
NAIC Code:	2211-Electric Power Generation, Transmission and Distribution
SIC Code:	4911-Electric Services
Description:	Clean, Reliable Power

Calpine Corporation is helping meet the needs of an economy that demands more and cleaner sources of electricity. Founded in 1984, Calpine is a major U.S. power company, capable of delivering nearly 24,000 megawatts of clean, cost-effective, reliable and fuel-efficient electricity to customers and communities in 18 states in the U.S. The company owns, leases and operates low-carbon, natural gas-fired and renewable geothermal power plants. Using advanced technologies, Calpine generates electricity in a reliable and environmentally responsible manner for the customers and communities it serves.

Calpine Quick Facts

Calpine adheres to stringent standards for safe, efficient plant operations.
Calpine is North America's leading geothermal power producer. At The Geysers, about 100 miles northeast of San Francisco, Calpine harnesses naturally heated steam from the earth to create electrical power. This renewable "green" power is available to consumers throughout California.

Primary Calculation Methodologies: Calpine is using the default Acid Rain CO2 emissions factor = 118.9 lbs CO2/mmbtu
No changes to deminimus in 2004.

Organizational structure disclosure:

VERIFIED EMISSIONS INFORMATION

Reporting Year:	**2005**
Reporting Scope:	**CA**
Reporting Protocol:	General Reporting Protocol, Version 2.1 (June 2006); Power/Utility Reporting Protocol, Version 1 (April 2005)
Reporting Boundaries:	
Baseline Year (Direct Emissions):	
Baseline Year (Indirect Emissions):	

Direct Emissions	CO2e	CO2	CH4	N2O	HFCs*	PFCs*	SF6	Unit
Mobile Combustion	**0.00**	0.00	0.00	0.00	0.00	0.00	0.00	-
Stationary Combustion	**7,374,694.12**	7,374,694.12	0.00	0.00	0.00	0.00	0.00	metric ton
Process Emissions	**204,500.12**	204,500.12	0.00	0.00	0.00	0.00	0.00	metric ton
Fugitive Emissions	**0.00**	0.00	0.00	0.00	0.00	0.00	0.00	-
TOTAL DIRECT	**7,579,194.24**	7,579,194.24	0.00	0.00	0.00	0.00	0.00	metric ton

* HFCs and PFCs are classes of greenhouse gases that include many compounds. These columns may reflect the total emissions of multiple HFC and PFC compounds, each of which has a unique Global Warming Potential (GWP). Emissions of each gas are first multiplied by their respective GWP and then summed in the total CO2-equivalent column.

Annual Emissions Report

Calpine Corporation

(Emissions from California operations)

Report Generated On: 01/20/2009 07:57 pm PT

Indirect Emissions	CO2e	CO2	CH4	N2O	Unit
Purchased Electricity	**0.00**	0.00	0.00	0.00	-
Purchased Steam	**0.00**	0.00	0.00	0.00	-
Purchased Heating and Cooling	**0.00**	0.00	0.00	0.00	-
TOTAL INDIRECT	**0.00**	0.00	0.00	0.00	-

De Minimis Emissions	CO2e	CO2	CH4	N2O	HFCs*	PFCs*	SF6	Unit

Percentage of Total Inventory:

VERIFICATION INFORMATION

Verification Body: Ryerson, Master & Associates, Inc.

Basis of Verification Opinion:

Calpine Corporation submitted their California GHG Emission Inventory Report for Year 2005 to Ryerson, Master and Associates, Inc., (RMA) for review and certification against the Registry's General Reporting Protocol, Version 2.1 and the Power Utility Reporting Protocol (April 2005). RMA followed the procedures outlined in the Registry's Certification Protocol (dated July 2003) and the Power Utility Certification Protocol (April 2005) to complete the certification process. The certification activities were conducted during October through December 2006.

On December 28, 2006, RMA issued a Certification Report to Calpine documenting the certification activities and the material and immaterial misstatements in the Calpine inventory. Calpine revised the emission inventory in CARROT, and RMA recertified the inventory. A Certification Opinion was provided to Calpine on December 29, 2006. RMA completed the Certification Activities Checklist and completed the certification in CARROT on December 31, 2006.

Date Submitted:

12/31/06 9:38 am

OPTIONAL INFORMATION

Information in this section is voluntarily provided by the participant for public information, but is not required and thus, not verified under California Registry protocols.

Optional Emissions	CO2e	CO2	CH4	N2O	HFCs*	PFCs*	SF6	Unit
	0.00	0.00	0.00	0.00	0.00	0.00	0.00	-
TOTAL OPTIONAL	**0.00**	0.00	0.00	0.00	0.00	0.00	0.00	-

Emissions Efficiency metric: 667 lbs CO2/mwh

Emissions Management Programs: Total Energy Efficiency Metric = 667 lbs CO2/mwh
lbs of direct CO2 Emissions from stationary fossil fuel combustion/Net MWH from all energy sources.

Fossil Fuel Electricity Generation: 891 lbs CO2/MWH
lbs of CO2 emissions from stationary fossil fuel combustion/Net MWH from fossil fuel sources only.

Emissions Reduction Projects: Calpine will work to improve the fuel efficiency of its natural gas fueled power plants through a series of performance improvement programs, which will reduce CO2 emissions per megawatt hour throughout the fleet.

Annual Emissions Report

Calpine Corporation

(Emissions from California operations)

Report Generated On: 01/20/2009 07:57 pm PT

Emissions Reduction Goals: Calpine's goal is to minimize CO2 emissions per megawatt hour from its power plants and to be recognized as the industry leader in minimizing CO2 emissions from power generation.

REFERENCE DOCUMENTS

Title	Author	Document Status	Publish Date

APPENDIX 6.2

AIR QUALITY

APPENDIX 6.2-1

EMISSIONS AND OPERATING PARAMETERS

Table 6.2-1.1
Emissions and Operating Parameters for New Turbines
Avenal Energy Project

	Case 1	Case 5	Case 9	Case 2	Case 6	Case 10	Case 4	Case 8	Case 12
	101°F Full Load w/ DB[1]	63°F Full Load w/ DB[1]	32°F Full Load w/ DB[1]	101°F Full Load no DB	63°F Full Load no DB	32°F Full Load no DB	101°F 50% Load	63°F 50% Load	32°F 50% Load
Ambient Temp, °F	101	63	32	101	63	32	101	63	32
GT Load, %	100%	100%	100%	100%	100%	100%	50%	50%	50%
Both GTs Gross Power, MW	344.8	345.0	359.0	345.5	345.6	**359.5**	144.1	168.6	183.2
STG Gross Power, MW	290.8	273.3	254.7	171.6	176.1	177.7	118.3	127.6	130.6
Plant Gross Power Output, MW	635.6	**618.3**	613.7	517.2	**521.7**	537.2	262.5	296.2	313.9
Plant Net Power Output, MW	600.0	600.0	600.0	483.7	506.5	525.5	250.3	286.3	304.8
GTs Fuel Flow, kpph	156.4	156.4	161.8	156.4	156.4	161.8	87.2	96.2	102.2
DBs Fuel Flow, kpph	49.0	39.6	31.0	0.0	0.0	0.0	0.0	0.0	0.0
GTs Heat Input, MMBtu/hr (HHV)	1,794.2	1,794.3	1,855.4	1,795.6	1,795.4	1,856.3	1,001.4	1,104.3	1,171.9
DBs Heat Input, MMBtu/hr (HHV)	562.3	454.4	356.3	0.0	0.0	0.0	0.0	0.0	0.0
Total Heat Input, MMBtu/hr (HHV)	**2,356.5**	2,248.6	2,211.8	1,795.6	1,795.4	**1,856.3**	1,001.4	1,104.3	**1,171.9**
Stack Flow, lb/hr	3,653,000	3,650,000	3,759,000	3,628,000	3,630,000	3,743,000	2,232,700	2,336,800	2,413,300
Stack Flow, acfm	**1,044,365**	**1,025,495**	**1,059,836**	**1,051,531**	**1,037,822**	**1,071,653**	**620,528**	**644,316**	**666,146**
Stack Temp, °F	**195.3**	**184.9**	**189.0**	**207.4**	**198.8**	**200.9**	**180.2**	**175.8**	**177.4**
Stack exhaust, vol%									
O_2 (dry)	11.40%	11.87%	12.34%	13.76%	13.77%	13.78%	14.46%	14.11%	13.93%
CO_2 (dry)	5.42%	5.16%	4.89%	4.09%	4.08%	4.08%	3.70%	3.89%	3.99%
H_2O	10.54%	10.03%	9.12%	8.39%	8.28%	7.78%	8.07%	7.97%	7.63%
Emissions									
NO_x, ppmvd @ 15% O_2	**2.0**	2.0	2.0	2.0	2.0	**2.0**	2.0	2.0	2.0
NO_x, lb/hr[2]	**17.13**	**16.34**	**16.06**	**13.03**	**13.03**	**13.47**	**7.26**	**8.01**	**8.51**
NO_x, lb/MMBtu (HHV)	**0.0073**	0.0073	0.0073	0.0073	0.0073	**0.0073**	0.0073	0.0073	0.0073
SO_2, ppmvd @ 15% O_2 [3]	**0.139**	0.139	0.140	0.140	0.140	**0.140**	0.140	0.140	0.140
SO_2, lb/hr[2,3]	**1.66**	1.59	1.56	1.27	1.27	**1.31**	0.71	0.78	0.83
SO_2, lb/MMBtu (HHV)[3]	**0.0007**	0.0007	0.0007	0.0007	0.0007	**0.0007**	0.0007	0.0007	0.0007
CO, ppmvd @ 15% O_2	**4.0**	4.0	4.0	4.0	4.0	**4.0**	4.0	4.0	4.0
CO, lb/hr[2]	**20.86**	19.90	19.56	15.86	15.86	**16.39**	8.84	9.75	10.36
CO, lb/MMBtu (HHV)	**0.0089**	0.0088	0.0088	0.0088	0.0088	**0.0088**	0.0088	0.0088	0.0088
VOC, ppmvd @ 15% O_2[4]	**2.0**	2.0	2.0	1.4	1.4	**1.4**	1.4	1.4	1.4
VOC, lb/hr[2,4]	**5.96**	5.68	5.59	3.17	3.17	**3.28**	1.77	1.95	2.07
VOC, lb/MMBtu (HHV)[4]	**0.0025**	0.0025	0.0025	0.0018	0.0018	**0.0018**	0.0018	0.0018	0.0018
PM_{10}, lb/hr[2,5]	**11.81**	11.27	10.78	9.00	9.00	**9.00**	9.00	9.00	9.00
PM_{10}, lb/MMBtu (HHV)[5]	**0.0050**	0.0050	0.0049	0.0050	0.0050	**0.0048**	0.0090	0.0081	0.0077
PM_{10}, gr/SCF (dry)[5]	0.00189	0.00179	0.00165	0.00142	0.00142	0.00137	0.00230	0.00220	0.00212
NH_3, ppmvd @ 15% O_2	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0
NH_3, lb/hr[2]	35.39	33.57	32.66	26.28	26.25	26.98	14.60	16.08	17.02
CO_2, lb/MMBtu (HHV)[7]	117.0	117.0	117.0	117.0	117.0	117.0	117.0	117.0	117.0
CH_4, lb/MMBtu (HHV)[6]	0.013	0.013	0.013	0.013	0.013	0.013	0.013	0.013	0.013
N_2O, lb/MMBtu (HHV)[8]	0.00022	0.00022	0.00022	0.00022	0.00022	0.00022	0.00022	0.00022	0.00022
CO_2, lb/hr [5]	275,599	262,984	258,674	210,000	209,976	217,102	117,114	129,153	137,055
CH_4, lb/hr [5]	30.7	29.2	28.8	23.4	23.4	24.1	13.0	14.4	15.2
N_2O, lb/hr [5]	0.52	0.50	0.49	0.40	0.40	0.41	0.22	0.24	0.26

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APPENDIX

7.1 AIR QUALITY

This analysis of the potential air quality impacts of the Willow Pass Generating Station (WPGS) was conducted according to California Energy Commission (CEC) power plant siting requirements. Air pollutant sources belonging to this project will include two new gas-fired combined-cycle gas turbines with associated heat recovery steam generators (HRSGs), and a single natural-gas–fired fuel gas heater to treat the natural gas fuel stream to the turbines. The analysis also addressed U.S. Environmental Protection Agency (U.S. EPA) Prevention of Significant Deterioration (PSD) requirements and Bay Area Air Quality Management District (BAAQMD) permitting requirements for Determination of Compliance/Authority to Construct (DOC/ATC). The assessment of project air quality impacts is presented in nine sections, as summarized below.

Section 7.1.1 describes the local environment surrounding the project site that is relevant to evaluation of the air quality impacts. Section 7.1.2 evaluates the project's air quality impacts from emissions of NO_X, carbon monoxide (CO), sulfur dioxide (SO_2), precursor organic compound (POC) (also called volatile organic compound [VOC] in some regulations but used interchangeably herein), particulate matter less than 10 micrometers in diameter (PM_{10}), and particulate matter less than 2.5 micrometers in diameter ($PM_{2.5}$). Section 7.1.3 discusses the cumulative impacts analysis. Section 7.1.4 describes mitigation measures and the project's emission offset strategy. Section 7.1.5, Best Available Control Technology Analysis, discusses the detailed Best Available Control Technology (BACT) analysis conducted for the project. Section 7.1.6 describes all applicable laws, ordinances, regulations, and standards (LORS) pertaining to the project's emissions of air pollutants. Section 7.1.7 lists the agency personnel contacted during preparation of the air quality assessment. Section 7.1.8 lists the air quality permits required for the project and provides a permit schedule. Section 7.1.9 lists the references used to conduct the air quality assessment.

Some air quality data are presented in other sections of this Application for Certification (AFC), including an evaluation of toxic air contaminants (see Section 7.6, Public Health), information related to the fuel characteristics (see Chapter 5, Gas Supply), and expected capacity factor of the proposed facility and heat rates (see Chapter 2, Project Description).

7.1.1 Affected Environment

This section describes the regional climate and meteorological conditions that influence transport and dispersion of air pollutants, as well as the existing air quality within the project region. The monitoring data presented in this section are considered to be representative of the project site.

Figure 7.1-1 shows the WPGS project boundary and surroundings. The proposed project site is located on the southern side of Suisun Bay, approximately 2 miles from the center of the City of Pittsburg. The WPGS site is 26 acres situated within the approximately 1,000-acre Pittsburg Power Plant (PPP) located at 696 West 10th Street, Pittsburg, CA, 94565. The WPGS site will be located on a separate legal parcel to be created by adjusting the lot lines of two existing legal parcels at the PPP site, both of which are identified as Assessor's Parcel Number 085-010-014.

The WPGS site is currently occupied by the existing retired power generation PPP Units 1 through 4, an unused surface impoundment, an administration building, hazardous materials and hazardous waste materials buildings, Tank 7, temporary buildings, and other ancillary facilities. The project includes the demolition of Units 1 through 4, the administration building, and Tank 7 that are on the WPGS site, as well as replacement of the hazardous materials and hazardous waste buildings. The unused surface impoundment on the WPGS site (north of Tank 1) will be left in place. The new generating units will be located on the south 23.5 acres of the WPGS site. No land disturbance will occur within the north 2.5-acre portion of the WPGS site (adjacent to Suisun Bay). Pacific Gas & Electric Company (PG&E) owns a 36-acre switchyard adjacent to the PPP site, directly southwest of the WPGS site (Figure 2.2-1).

Table 7.1-19
Estimated Greenhouse Gas Emissions from the Project

Emission Rate (metric tons/year)				
CO_2	**CH_4**	**N_2O**	**SF_6**	**Total CO_2 Equivalent**
987,970	72.65	25.34	0.003	997,438

Notes:
CH_4 = methane
CO_2 = carbon dioxide
N_20 = nitrous oxide
SF_6 = sulfur hexafluoride

Table 7.1-20
Surface Moisture Conditions for Years 2002-2005

Surface moisture condition by month for the Antioch Pump Plant 3 Station

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2002	dry	dry	avg	dry	dry	dry	dry	dry	dry	dry	avg	wet
2003	avg	dry	avg	wet	wet	dry	dry	wet	dry	dry	avg	wet
2004	avg	wet	dry	dry	avg	dry	dry	dry	dry	wet	avg	wet
2005	wet	avg	wet	avg	avg	wet	dry	dry	dry	dry	dry	wet

Note: Surface moisture conditions provided by BAAQMD.

Exhibit 9

The California ENERGY COMMISSION

Lodi Energy Center - AFC, Vol. 1 - 08-AFC-10

Name	last modified Color dates added today	
Parent Directory		
LEC 1.0 Executive Summary.pdf	Sep 12 2008	3.7
LEC 2.0 Project Description.pdf	Sep 12 2008	4.4
LEC 3.0 Electric Transmission.pdf	Sep 12 2008	26(
LEC 4.0 Natural Gas Supply.pdf	Sep 12 2008	66.
LEC 5.0 Environmental Info.pdf	Sep 12 2008	43.
LEC 5.10 Socioeconomics.pdf	Sep 12 2008	2.5
LEC 5.11 Soils.pdf	Sep 12 2008	3.2
LEC 5.12 Traffic and Transportation.pdf	Sep 12 2008	6 n
LEC 5.13 Visual.pdf	Sep 12 2008	4.6
LEC 5.14 Waste Management.pdf	Sep 12 2008	18(
LEC 5.15 Water Resources.pdf	Sep 12 2008	4.6
LEC 5.16 Worker Health and Safety.pdf	Sep 12 2008	20(
LEC 5.1 Air Quality.pdf	Sep 12 2008	73:
LEC 5.2 Biological Resources.pdf	Sep 12 2008	14.
LEC 5.3 Cultural.pdf	Sep 12 2008	1.9
LEC 5.4 Geologic Hazards and Resources.pdf	Sep 12 2008	3.2
LEC 5.5 Hazardous Materials.pdf	Sep 12 2008	29
LEC 5.6 Land Use.pdf	Sep 12 2008	15.
LEC 5.7 Noise.pdf	Sep 12 2008	3.9
LEC 5.8 Paleo Resources.pdf	Sep 12 2008	2.2
LEC 5.9 Public Health.pdf	Sep 12 2008	4.5
LEC 6.0 Alternatives.pdf	Sep 12 2008	1.4
LEC Acronyms.pdf	Sep 12 2008	10:
LEC Contents.pdf	Sep 12 2008	10(

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Decisions Pending and Opportunities for Public Participation

Last Modified:

18 hours of base load turbine operation and 12 hours of duct firing for NO_x, CO, and VOC. These assumptions are used as the basis for the calculations and are not intended to be proposed as limits.

Detailed calculations, including quarterly emissions calculations, are shown in Appendix 5.1A, Table 5.1A-6.

TABLE 5.1-21
Criteria Pollutant Emissions from New Equipment

Emissions/Equipment	NO_x	SO_2	CO	VOC	PM_{10}
Maximum Hourly Emissions[a]					
CTG/HRSG	160	6.0	900	16	11.0
Auxiliary Boiler	0.55	0.19	2.37	0.27	0.47
Cooling Tower	—	—	—	—	0.45
Total, pounds per hour	**160.5**	**6.2**	**902.4**	**16.3**	**11.9**
Maximum Daily Emissions[b]					
CTG/HRSG	864.9	136.4	5,641.9	179.8	240.0
Auxiliary Boiler	6.5	2.2	28.5	3.3	11.3
Cooling Tower	—	—	—	—	5.6
Total, pounds per day	**871.4**	**138.6**	**5,670.4**	**183.1**	**256.4**
Maximum Annual Emissions					
CTG/HRSG	71.3	24.3	254.4	17.4	41.9
Auxiliary Boiler	0.13	0.04	0.6	0.1	0.1
Cooling Tower	—	—	—	—	2.0
Total, tons per year	**71.5**	**24.3**	**254.9**	**17.5**	**44.0**

[a]Maximum hourly emissions include CTG in startup (for NO_x, CO and VOC), with auxiliary boiler and cooling tower in operation. Maximum hourly SO_2 and PM_{10} emissions from the CTG assume duct fired operation.

[b]Maximum daily emissions based on full-load turbine operation for 24 hours with 12 hours of duct firing for PM_{10} and SO_x; and 6 hours of cold start, 18 hours of base load turbine operation and 12 hours of duct firing for NO_x, CO, and VOC.

5.1.3.5 Greenhouse Gas Emissions

Greenhouse gas (GHG) emissions from the project have been calculated using calculation methods and emission factors from the California Air Resources Board's December 5, 2007, regulatory update.[6] Calculations are based on the maximum proposed annual fuel use and corresponding generation. The calculations are shown in detail in Table 5.1A-7, Appendix 5.1A and the results are summarized in Table 5.1-22.

[6] California Air Resources Board, "Regulation for the Mandatory Reporting of Greenhouse Gas Emissions," December 5, 2007 (Staff's Suggested Modifications to the Originally Proposed Regulation Order Released October 19, 2007). http://www.arb.ca.gov/cc/ccei/reporting/GHGReportRegUpdate12_05_07.pdf.

TABLE 5.1-22
Greenhouse Gas Emissions from New Equipment

Unit	CO_2, metric tonnes/yr	CO_2. metric tonnes/MWh	CO_2eq, metric tonnes/yr[a]
CTG/HRSG	902,487	0.376	—
Auxiliary Boiler	1,608	Not applicable	–
Total	904,095	0.376	904,971

*Includes CH_4, N_2O and SF_6.

5.1.3.6 Hazardous Air Pollutants

Noncriteria pollutants are compounds that have been identified as pollutants that pose a significant health hazard. Nine of these pollutants are regulated under the federal New Source Review program: lead, asbestos, beryllium, mercury, fluorides, sulfuric acid mist, hydrogen sulfide, total reduced sulfur, and reduced sulfur compounds.[7] In addition to these nine compounds, the federal Clean Air Act lists 189 substances as potential hazardous air pollutants (Clean Air Act Sec. 112(b)(1). The SJVAPCD regulates toxic air contaminant emissions under the SJVAPCD's Integrated Air Toxic Program. This program integrates the state and federal requirements. Any pollutant that may be emitted from the LEC and is on the federal New Source Review list, the federal Clean Air Act list, and/or the SJVAPCD toxic air contaminant list has been evaluated as part of the AFC.

5.1.3.6.1 Toxic Air Contaminant Emissions: New Gas Turbine/HRSG and Auxiliary Boiler

Maximum hourly and annual TAC emissions were estimated for the gas turbine/HRSG and the auxiliary boiler based on the heat input rates (in MMBtu/hr and MMBtu/yr), emission factors (in lb/MMBtu), and the nominal fuel higher heating value of 1004 Btu/scf. Hourly and annual emissions were based on the heat input rates shown in Table 5.1-17. The ammonia emission factor was derived from an ammonia slip limit of 10 ppmv @ 15 percent O_2. At the request of the SJVAPCD [8], Ventura County emission factors were used to quantify other TAC emissions. The Ventura County AB2588 combustion emission factors do not include factors for hexane or propylene oxide or for speciated polyaromatic hydrocarbons (PAHs), so emission factors for these TACs were taken from the California Air Resources Board's CATEF database for natural gas-fired gas turbines. TAC emissions are summarized in Table 5.1-22. Detailed emissions calculations, including emission factors, are provided in Appendix 5.1A, Tables 5.1A-8 and 5.1A-9.

5.1.3.6.2 Toxic Air Contaminant Emissions: Cooling Tower

Maximum hourly and annual TAC emissions from the cooling tower are extremely low. As shown in Table 5.15-23, concentrations of most metals and salts in the water supply were below detection limits. Total TAC emissions from the cooling tower are shown in Appendix 5.1A, Table 5.1A-10.

7 These pollutants are regulated under federal and state air quality programs; however, they are evaluated as noncriteria pollutants by the California Energy Commission.

8 June 5, 2008, email message from Cheryl Lawler to Nancy Matthews, "District's Comments for Lodi Energy Center Modeling Protocol."

Exhibit 10

Electric Utility Greenhouse Gas Emissions Reduction

Initial Rule Development Workshop
August 22, 2007

Department of Environmental Protection
Division of Air Resource Management

Governor's Executive Order 07-127

"The Secretary of Environmental Protection shall immediately develop rules as authorized under Chapter 403, Florida Statutes, to achieve the following:

> Adoption of a maximum allowable emissions level of greenhouse gases for electric utilities in the State of Florida. The standard will require at minimum three reduction milestones as follows: by 2017, emissions not greater than Year 2000 utility sector emissions; by 2025, emissions not greater than Year 1990 utility sector emissions; by 2050, emissions not greater than 20% of Year 1990 utility sector emissions (i.e., 80% reduction of 1990 emissions by 2050)"

Year 2000 & Year 1990 Utility Greenhouse Gas Emissions

First estimates:

- Year 2000: 135,080,858 tons CO_2
- Year 1990: 100,109,860 tons CO_2

Year 2000 value from eGrid (Emissions & Generation Resource Integrated Database) developed by EPA, Office of Atmospheric Programs, Climate Protection Partnerships Division.
http://www.epa.gov/cleanenergy/egrid/index.htm

Year 1990 data estimated by applying ratio of 1990/2000 utility emissions from EPA State Inventory Tool to Year 2000 value.

DEPARTMENT OF ENVIRONMENTAL PROTECTION FLORIDA

Year 2004 Utility Greenhouse Gas Emissions

Coal	65,484,849 tons CO_2
Oil & petcoke	33,404,545 tons CO_2
Natural gas	44,846,881 tons CO_2
➢ Total fossil fuel	143,736,276 tons CO_2

All emissions data from eGrid. Does not include 1,265,244 tons CO_2 emissions from burning of non-biogenic solid waste such as plastics and tires in waste-to-energy facilities.

Fossil-fuel electricity generation accounts for about 45% of Florida's greenhouse gas emissions

Required Utility Greenhouse Gas Reductions from Year 2004 Levels

- By 2017 6%
- By 2025 30%
- By 2050 86%

- But, electric power usage in the state is growing…

Year 2004 Net Generation by Source

- Fossil-fuel generation
  - Coal 61,982,540 MWh
  - Oil & petcoke 37,232,873 MWh
  - Natural gas 76,624,773 MWh
  - Interchange power 18,649,000 MWh
  - Subtotal 194,489,186 MWh (83% of grand total)
- Other generation
  - Biomass 4,950,744 MWh
  - Nuclear 31,215,576 MWh
  - Hydroelectric 265,258 MWh
  - Other waste & phosphate* 2,862,650 MWh
- Grand Total **233,783,414 MWh**

Interchange data from Florida Reliability Coordinating Council; all other data from eGrid. eGrid assigns 70% of generation from solid waste to biomass; 30% to other waste (plastics, tires, etc.).

*Includes waste heat cogeneration in phosphate industry.

Projected Electricity Usage

Year 2016: 325,566,000 MWh

- Equates to 33% increase from actual 2006 net generation—same rate of increase as from 1996 to 2006

Year 2016 projection from "2007 Regional Load and Resource Plan" by Florida Reliability Coordinating Council, available on Public Service Commission website at: www.psc.state.fl.us/utilities/electricgas/10yearsiteplans.aspx.

No Year 2017, 2025 or 2050 projections available.

Year 2004 Average CO_2 Emission Rates for Florida Fossil-Fuel Units

Coal	2,113 lb/MWh
Oil & petcoke	1,794 lb/MWh
Natural gas	1,171 lb/MWh
➢ Weighted avg.	1,635 lb/MWh

CO_2 Emission Rates for Fossil-Fuel Generating Units Compared

- Year 2004 statewide average emission rate:
  1,635 lb/MWh

- Statewide average emission rate to meet 135 million ton cap with total generation of 325 million MWh, 83% of which supplied by fossil fuel (values selected for illustrative purposes; not a DEP-presumed scenario)
  1,000 lb/MWh

- Emission rates achievable by today's new units:
  - Natural gas combined cycle — 800 lb/MWh
  - Pulverized coal or IGCC (w/o carbon capture & storage) — 1,750 lb/MWh

Challenges in Meeting the Caps

- Slowing the state's growth in electricity usage
- Increasing generation from proven non-fossil sources
- Reducing statewide average fossil fuel emission rate
- Developing and deploying advanced technologies

Initial Rule Development Issues

- Definition of electric utility sector
- Nailing down Year 2000 and Year 1990 utility sector emission levels
- How to treat out-of-state interchange power
- Possible rule approaches

Comments

- Mail to:
  Mr. Larry George, Program Administrator
  Division of Air Resource Management, MS-5500
  Department of Environmental Protection
  2600 Blair Stone Rd.
  Tallahassee, FL 32399-2400

  cc: Ms. Lynn Scearce, Rules Coordinator (same address)

- Or e-mail to: larry.george@dep.state.fl.us and lynn.scearce@dep.state.fl.us

- All comments are public records and will be posted on the department's website at www.dep.state.fl.us/air

- To receive updates on this rule development project by e-mail, provide name, affiliation, and e-mail address to Ms. Lynn Scearce at lynn.scearce@dep.state.fl.us

Exhibit 11

OUTPUT-BASED EMISSION STANDARDS

ADVANCING INNOVATIVE ENERGY TECHNOLOGIES

By Susan Freedman and Suzanne Watson
Northeast-Midwest Institute

NORTHEAST-MIDWEST INSTITUTE

The Northeast-Midwest Institute is a Washington-based, private, non-profit, and non-partisan research organization dedicated to economic vitality, environmental quality, and regional equity for Northeast and Midwest states. Formed in the mid-1970s, it fulfills its mission by conducting research and analysis, developing and advancing innovative policy, providing evaluation of key federal programs, disseminating information, and highlighting sound economic and environmental technologies and practices.

The Institute is unique among Washington policy centers because of its close working relationship with the Northeast-Midwest Congressional and Senate Coalitions — co-chaired by Senators Susan Collins (R-ME) and Jack Reed (D-RI) and Reps. Marty Meehan (D-MA) and Jack Quinn (R-NY). The bipartisan coalitions seek to influence those issues of greatest importance to northeastern and midwestern states.

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EXECUTIVE SUMMARY

The United States needs a new means to regulate air pollution, one that will reward the more efficient operation of electricity-generating technologies and encourage the introduction of innovative energy processes. The nation's current regulatory approach — using "input-based emission standards" — provides no correlation between the amount of fuel used and the amount of electricity generated. In contrast, an "output-based" approach would reward those generators producing the same amount or more energy while emitting fewer pollutants.

Output-based standards could advance an array of innovative power technologies that offer enormous potential to improve efficiency and enhance the environment. One such technology, combined heat and power (CHP), produces two outputs — thermal and electric. CHP allows for the productive use of much of the waste heat from electricity production, which accounts for about two-thirds of the energy used to generate electricity.[1] Only output-based measurements can capture the total efficiency provided from such a single source of fuel producing both electricity and thermal energy.

This paper details the growing federal, state, regional, and international efforts to incorporate output-based standards in ways that reward increased energy efficiency and emissions reductions It highlights how those standards can advance innovative energy systems, such as combined heat and power, gas-fired turbines, efficient engines, fuel cells, microturbines, wind and solar, among others.

While **Section I** provides an overview, **Section II** offers a policy framework and explains how output-based standards fit into an environmental permitting strategy. Numerous ongoing policy debates, including electricity restructuring and Clean Air Act amendments, affect the electricity industry and the regulation of its pollutants. This section provides a brief history of these issues in order to frame where an output-based approach fits within current U.S. energy and environmental policy.

Section III, the heart of the report, describes state activities, federal efforts, and alternative models that promote output-based standards. It reviews air-quality regulations and legislation, including emissions performance standards (EPS) for power plants, multi-pollutant proposals, distributed generation permitting programs, and the NOx Budget Program. It pays particular attention to Texas, California, and northeastern and midwestern states, which have considered utility restructuring and pollution regulation alternatives. This section also examines models developed by several organizations for how output-based standards could promote innovative and efficient technologies.

This section also reports on how other countries are addressing air emissions for innovative technologies. Many European nations effectively reduce emissions through fiscal measures like carbon taxes (climate change levies), the removal of coal subsidies, and tax exemptions for renewables and/or combined heat and power technologies. In response to one European Union directive, the United Kingdom has implemented an output-based "quality assessment" for CHP. The European Union also is studying cap-and-trade options for regulating greenhouse gas emissions. Allocation allowances — determined on an output basis (or production based) — are one metric being considered.

Section IV offers policy recommendations and perspectives on the future for output-based standards.

The **Appendices** provide state-specific information resulting from communications with state agencies, interviews with experts and regional groups, and literature searches. They also contain a listing of air-quality policy contacts by state, an example of an output-based model referenced in the report, as well as additional details on the Clean Air Act as it applies to power plants and other combustion sources.

Output-based emission standards (also known as efficiency-based or performance-based) are gaining greater attention as states and the federal government address electricity restructuring and ways to mitigate pollutants responsible for acid rain, ground-level ozone, and climate change. By determining emission levels based on the amount of electricity and/or thermal energy generated, output-based standards support improved efficiency without regard to the type of fuel or technology used to achieve that improvement. Adopting such standards, therefore, could help advance the nation's mutual goals of cleaning the air; protecting public health and welfare; and providing affordable, reliable, and secure supplies of energy.

1: OVERVIEW

An array of innovative power technologies offers enormous potential to improve efficiency and enhance the environment. With a growing demand for electricity and the bulk of America's power plants at retirement age, the U.S. faces a unique opportunity to clean the air while providing major economic benefits. Unfortunately, these innovative technologies face regulatory, financial, and environmental barriers.

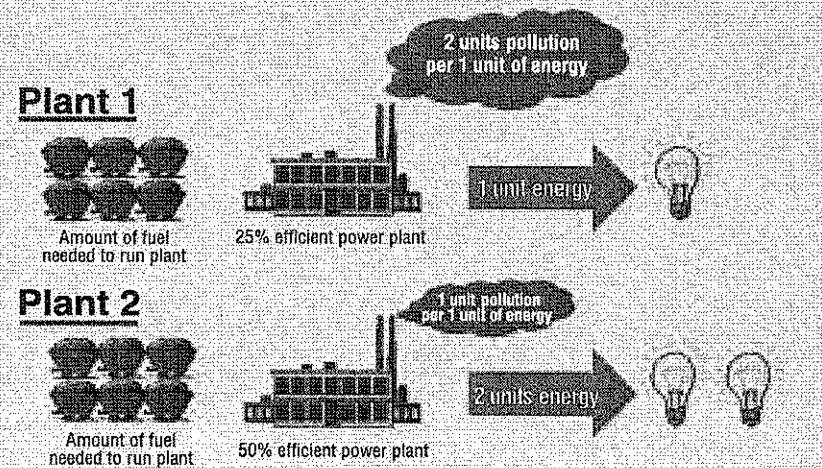
Output-based emission standards can be an effective way to address the environmental barriers since they reward the more efficient operation of energy-generating technologies. The nation's current regulatory approach to cleaning the air relies on "input-based standards" that measure emissions based on units of fuel delivered to the power plant, reported as pounds of pollutant per Btu of fuel. This method, unfortunately, does not recognize system efficiency, and it provides no correlation between the amount of fuel used and the amount of electricity and other energy generated by that fuel.

In contrast, output-based standards link emissions to the generator's final output. Such an approach can reward those generators having the highest "output" of megawatt-hours and the lowest "output" of pollutants.[2] Output-based standards calculate emissions based on the amount of electricity generated, which can be represented in pounds of pollutant per megawatt-hour. Using an output-based measurement encourages greater energy efficiency and pollution prevention.[3] It can minimize the environmental impact of the power sector while enhancing the amount of available power in the U.S.

Figure 1 contrasts the two regulatory approaches by offering a conceptual picture of two power plants, both using the same amount of fuel. Because Plant 2 is more efficient, it is able to produce more electricity and emit fewer pollutants per unit of energy into the air. Current air regulations for power plants do not recognize this air-quality benefit, while an output-based approach would. (Figure 3 on page 12 provides a more detailed example.)

FIGURE 1:

CURRENT INPUT-BASED STANDARDS DO NOT RECOGNIZE EFFICIENCY AND LOWER EMISSIONS*



A power plant producing more useful energy and less pollution for that energy is not rewarded using input-based standards.

Depiction for purposes of demonstrating difference between input and output measurements.

Output-based emission standards (which also have been known as efficiency-based or performance-based) are gaining greater attention as states and the federal government address electricity restructuring and ways to mitigate pollutants responsible for acid rain, ground-level ozone, and climate change. In September 1998, the U.S. Environmental Protection Agency (EPA) revised its New Source Performance Standards (NSPS) for utility and industrial boilers from a fuel-input to an electricity-output basis in order to regulate nitrogen oxide (NOx) emissions.[4] Combined heat and power systems (producing both thermal and electricity) also were to be treated on an output basis. In a memorandum issued October 2001, EPA's Office of Air Quality Planning and Standards advanced the use of output-based standards for combined heat and power (CHP) systems in order to determine whether they constituted a "new source" under certain permitting conditions.[5] In the case of CHP systems, only output-based measurements capture the total efficiency provided from producing both electricity and thermal load (heating and cooling) from a single fuel source.

Using an output-based approach is not a new concept. Such measurements already are used to limit emissions in other regulated sectors. In the transportation sector, for instance, vehicle emissions are monitored on a grams-per-mile basis.[6]

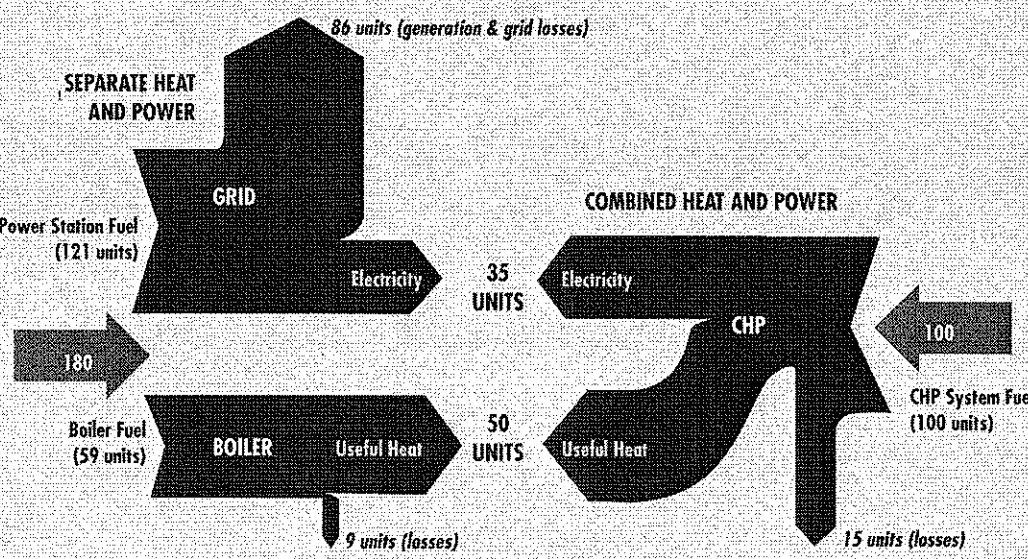
Many organizations and manufacturers of cleaner technologies advocate a shift from current methods to an output-based approach. Such groups include the State and Territorial Air Pollution Program Administrators (STAPPA), Association of Local Air Pollution Control Officials (ALAPCO),[7] Ozone Transport Commission,[8] Pew Center on Climate Change, U.S. Combined Heat and Power Association, and COGEN Europe.

The Pew Center on Global Climate Change in a July 2002 publication stated, "Other reforms to the Clean Air Act also could significantly affect the ability of new highly-efficient generation technologies to enter the market. For instance, air regulations that express limits on an output basis (e.g., pounds per kilowatt-hour, or lbs/kWh) as opposed to input basis (e.g., lbs/Btu of fuel) would encourage investment in new efficient plants."[9]

If output-based standards could encourage the installation of newer and cleaner generating systems, the obvious question is why they are not used more widely in the U.S. The answer is not simple, but part of it relates to simple inertia. For more than 50 years, the U.S. has employed a "central power paradigm" in which

FIGURE 2:

CHP PRODUCES BOTH ELECTRICITY AND THERMAL ENERGY USING LESS FUEL



Source: Kaarsberg (1998)

utility monopolies built large central power plants many miles away from urban centers. That paradigm made sense for several years as larger power plants were more efficient, but by the late 1950s, the U.S. electricity industry was operating at only a 33 percent efficiency level, meaning that for every three units of burned fuel only one unit of useful energy was obtained. Figure 2 displays the difference in fuel needed to produce the same amount of energy by a combined heat and power system and conventional separate heat and power systems. Although the utility industry has delivered relatively reliable power and, therefore, gained an image of being as effective as possible, this dismal efficiency record has not improved. Power plants that stand to lose if output-based standards are adopted are the older, inefficient, coal-burning units; utilities owning those plants will use their political clout to maintain the status quo as long as possible.

Still, an output-based permitting approach falls in line with President Bush's goals for helping industry reduce criteria pollutant emissions under the Clean Air Act. In May 2001, the National Energy Plan (NEP) recommended that the president direct the administrator of the Environmental Protection Agency (EPA) to promote CHP through flexibility in environmental permitting. The EPA put forth draft output-based guidance for CHP in accordance with this recommendation.[10] The NEP recognized that,

> *A family of technologies known as combined heat and power (CHP) can achieve efficiencies of 80 percent or more. In addition to environmental benefits, CHP projects offer efficiency and cost savings in a variety of settings, including industrial boilers, energy systems, and small, building scale applications. At industrial facilities alone, there is potential for an additional 124,000 megawatts (MW) of efficient power from gas-fired CHP, which could result in annual emissions reductions of 614,000 tons of NOx emissions and 44 million tons of carbon equivalent. CHP is also one of a group of clean, highly reliable distributed energy technologies that reduce the amount of electricity lost in transmission while eliminating the need to construct expensive power lines to transmit power from large central power plants.*[11]

While output-based emissions standards would be the preferred environmental method to promote innovative technologies, the process could still be a barrier to combined heat and power systems if the added value from producing both thermal and electric energy is not accurately credited. Since a CHP system provides thermal energy, it can avoid the need for (or displace) a separate stand-alone boiler that has its own fuel demands and pollution. Unless special guidance recognizes and accounts for a CHP system's added efficiency benefit, the output-based standard will not be fully effective, nor truly reflect the market value of CHP, thereby stifling investment in highly-efficient, reliable, and low-emitting power technologies.

This report investigates the air quality policies of twenty states (18 northeastern and midwestern states, plus Texas and California); provides an expanded description of steps being taken to adopt output-based emissions standards; and highlights how those standards might increase more innovative energy systems, such as combined heat and power (CHP). Northeast-Midwest Institute staff communicated with state air regulatory agencies in order to assess their actions and/or interest in output-based standards. Special attention was given to Texas, California, and northeastern and midwestern states since most had adopted utility restructuring and seemed more willing to consider air pollution control alternatives.

Northeast-Midwest Institute staff also conducted a literature review on innovative emission standards, again focusing on output-based initiatives and market-based approaches. Highlighted models include emission performance standards, multi-pollutant regulations, and distributed generation permits. Different state, regional, and federal bodies use a variety of terms to represent output-based standards and applicable power generators; the varying terminology is detailed in Section III of this report. Also explored were international efforts to encourage the deployment of innovative and energy-efficient technologies. Several European countries, for instance, have aggressive programs to advance CHP systems, and the European Commission in 1997 argued for the promotion of CHP "through the setting of emission standards for combustion plants."[12]

II: POLICY FRAMEWORK

Policymakers will not consider output-based standards in a vacuum. Numerous ongoing debates, including electricity restructuring and the Clean Air Act amendments, affect the electricity industry and the regulation of its pollutants. This section provides a brief history of these issues in order to frame where an output-based approach fits within current U.S. energy and environmental policy.

A. ELECTRICITY RESTRUCTURING

Electricity industry restructuring has created an impetus to examine how emissions from power generators are regulated. With the potential of increased competition from a variety of power sources in the wholesale and retail electricity markets, the methods to regulate air pollution must be reviewed.

Although restructuring is moving in fits and starts, due largely to the calamitous events experienced in California's energy markets, the process continues in many states with more or less successful results.[13] Electric utilities have remained the nation's last holdout monopoly. The lack of competition has hindered innovation, as evidenced by the utility industry's stagnant efficiency.

The growing awareness of waste within today's electricity system has prompted a new round of energy debates. Americans, according to some estimates, pay roughly $100 billion too much each year for heat and power.[14] Two thirds of the fuel burned to generate electricity is lost. The utility industry's efficiency has not increased since the late 1950s. Because of this inefficiency, U.S. electric generators throw away more energy than Japan consumes.[15] They also are the nation's largest polluters, spewing tons of carbon dioxide, nitrogen oxides, sulfur dioxide, and other contaminants into America's air and water. The average generating plant was built in the early 1960s, using technology from the 1950s, whereas the factories constructing computers have been replaced and updated five times over that same period. More than one fifth of U.S. power plants are more than 50 years old.

The process of restructuring actually began in the late 1970s, in the midst of concerns about petroleum supplies. Congress in 1978 approved the Public Utilities Regulatory Policies Act (PURPA) in order to advance energy efficiency. The little-noticed Section 210 of that law, however, created the first competitive crack in the utility industry's monopoly structure. For the previous several decades, power companies had enjoyed freedom from competition in their service territories in exchange for regulatory oversight by state commissions.

PURPA opened the door for the first time in several decades to the generation of electricity by power plants not controlled by utility monopolies. The legislation required utilities to purchase the extra electricity from independent power producers at a cost equal to that utilities' avoided cost of new capacity additions. PURPA spurred the construction of wind farms and cogenerators, units producing both heat and electricity from a single fuel source — also known as combined heat and power (CHP).

By the late-1980s, non-utility, independent power producers, many as large as 400 megawatts, were entering the marketplace.[16] These large generators did not qualify to take advantage of the PURPA provisions, but their cheaper electricity production encouraged policymakers to believe that greater competition in the marketplace could reduce electricity prices to consumers.

The Energy Policy Act (EPAct) of 1992 tried to remove additional barriers to increased competition in the electric power sector. While PURPA moved regulatory authority toward the Federal Energy Regulatory Commission (FERC), especially at the transmission and wholesale level, EPAct further encouraged the use of a market-based approach to electricity generation and advanced the concept of customer choice.[17]

Since the mid-nineties, 24 states and the District of Columbia have either enacted utility restructuring legislation or issued regulatory orders to implement retail access. Texas has gone to actual retail competition with some success, while California is in full retreat and has suspended its restructuring process for the foreseeable future.

Several of the restructured states are developing output-based initiatives. Restructuring legislation in Massachusetts, New Jersey, and Connecticut called for the development of output-based (performance-based) standards for retail electricity suppliers if certain criteria are met. Massachusetts and New Hampshire also have set output-based regulations targeting emissions reductions from their dirtiest power plants. Texas has created a permit system for distributed generation systems on an output basis that also allows credit for recovered heat in CHP. In contrast, states that have avoided restructuring also have ignored output-based standards, leading to the conclusions that without the impetus of restructuring states may not take steps to address high power-plant emissions and utilities will resist changes that highlight the status quo's inefficiencies and waste.

B. CLEAN AIR ACT

The Clean Air Act (CAA), among other things, regulates air emissions from the nation's central power plants. At least two provisions of the law have inadvertently hindered the development of innovative and efficient electricity technologies. One is a "grandfather clause" under New Source Review (NSR) that allows less-efficient plants — those built prior to 1977 — to avoid the costs associated with more stringent environmental regulation and permitting. A second barrier to energy efficiency is the regulation of plant emissions on an input basis. As a result of the former, new facilities — even those that are significantly more efficient — are required to absorb the bulk of the required emission reductions. Although upgrades have occurred at grandfathered plants which many consider to be "significant modifications," few have been so characterized and the plants have not had to face stricter clean air rules under NSR. (That issue, however, has sparked several pending lawsuits.)

Since the nation's emissions are regulated on the basis of fuel inputs, power companies usually try to reduce emissions at the "end of the pipe" by installing pollution control equipment. That equipment, however, increases a plant's costs and further lowers its efficiency. Output-based standards, which determine emissions based on electricity generated, offer a more flexible and effective means to reduce emissions at the front end of the process.

The Clean Air Act (CAA), approved in 1970 and amended in 1977 and 1990, gives authority to protect ambient air quality in the U.S. to the Environmental Protection Agency (EPA), and it requires permitting of pollution sources at the state level through individual State Implementation Plans (SIPs). The states may enact stricter air-quality regulations and permitting requirements than required by the EPA, but they cannot adopt less-stringent ones. The extensive state-by-state permitting system regulates energy generating technologies, largely systems over one megawatt (MW) in size and considered major sources.

In September 1998, EPA issued a rule to reduce smog in the eastern United States. That rule, known as the NOx SIP Call, required 22 states and the District of Columbia to revise their state implementation plans in order to reduce emissions of nitrogen oxides, which react with other chemicals in the atmosphere to form ozone (smog). Under the NOx SIP call, NOx allowances were originally provided based on heat input. But EPA formed a stakeholder working group to address an output-based approach for allocating NOx allowances, which ended with the publishing of a May 2000 output-based guidance document.

The Clean Air Act also established New Source Review (NSR), the air pollution control program under which many new electric generation sources fall. The NSR includes two preconstruction permit programs governing the construction of new or modified major stationary sources. In nonattainment areas, NSR requires pollution control technologies to achieve the lowest achievable emissions rate (LAER), as well as emission reductions to offset any increases. In attainment areas (clean areas), best available control technology (BACT) is required.

The Clean Air Act excluded plants built before 1977 from strict air pollution restrictions. These "grandfathered" units come under New Source Review requirements only if the facility receives a major modification or upgrade. Congress included the exemption with the expectation that these electric and boiler plants would soon be retired. Yet such expectations have not been realized. In the 1980s, the EPA amended the definition of "modification" to exempt anything considered "routine maintenance," creating a loophole in which utilities could avoid NSR even when modifications are made under the pretense of "routine maintenance." By the 1990s, however, such utility actions spurred a number of EPA lawsuits against utilities and refineries. Debate continues over what constitutes a modification and routine maintenance.

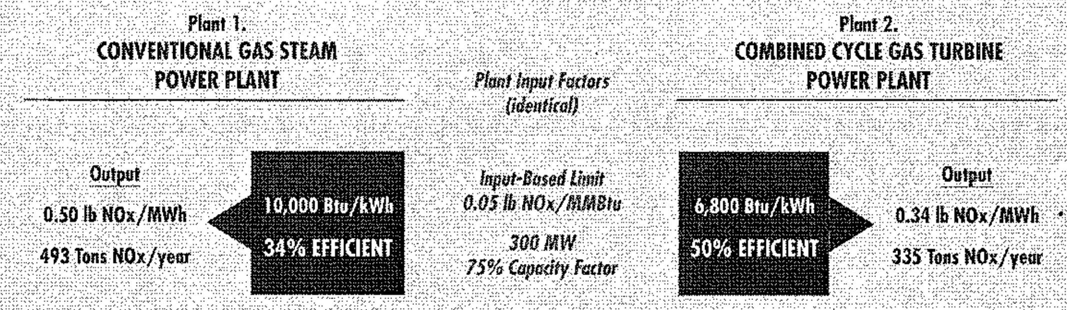
Emissions standards in NSR are based on the amount of fuel required as an input into the generation of electricity. For example, nitrogen oxide emissions have been measured as the pounds of NOx per million Btus of heat input. Currently, the BACT and LAER regulations set targets independent of a system's efficiency, which allows a less-efficient system to burn more fuel and emit more pollution. Output-based emissions regulations would more fairly recognize the environmental benefits of efficiency. For instance, Connecticut, in order to recognize a power system's efficiency, has revised its NSR regulations to credit the thermal output of CHP applications.

C. OUTPUT-BASED STANDARDS IN THE ENVIRONMENTAL PERMITTING STRATEGY

Output-based standards are a means to encourage energy efficiency improvements. Figure 3 (see next page) provides a more detailed contrast of the regulatory approaches, using data from two plants. Again, Plant 2 is more efficient, emits less pollution (in NOx), while producing the same amount of electricity. Yet Plants 1 and 2 are treated as equal in the current regulatory framework. If an output-based approach were used, Plant 1 would have to account for the added fuel used by making the plant more energy efficient, switching to a less polluting fuel, or by running the plant less. Regulations that measure emissions at the point of input do nothing to credit a facility for using energy more efficiently in production. Lower emissions and lower fuel use of highly efficient plants, like CHP, go unrecognized.

Source: Bluestein (2002)

FIGURE 3



This Figure illustrates the relevance of output-based regulation. It compares two 300 MW power plants — Plant 1, a conventional gas steam plant at 34 percent efficiency and Plant 2, a combined cycle gas turbine (CCGT) plant at 50 percent efficiency.

- They both run at the same capacity factor and generate the same amount of electricity.
- They both have the same input-based emission factor of 0.05 lb NOx/MMBtu.

Because of the efficiency difference, however, the less efficient plant creates 493 tons of NOx per year while the more efficient one creates only 335 tons of NOx.

When issuing revised New Source Performance Standards (NSPS) for boilers, EPA requires output-based standards as a way to promote energy efficiency and pollution prevention.[18] Box 1 (see next page) provides more detailed information on the revision to the boiler standard.

EPA also established a NOx Budget Trading Program that requires certain states, primarily in the Northeast and mid-Atlantic, to address stricter ground level ozone and regional haze problems. In May 2000, the EPA released a guidance document[19] for states joining the NOx Budget Trading Program under the NOx SIP Call. The document assists states in determining whether to use output-based NOx allocations for their state implementation plans (SIP) as part of the NOx SIP call. The guidance describes options for developing NOx allowance allocations for power plants, industrial boilers, and turbines using electric and thermal output. The guidance also provides sample regulatory language for state environmental agencies to use. Some states have followed this guidance and adopted output-based standards for their NOx Budget Programs, including Massachusetts, New Hampshire, and New Jersey.

Output-based standards inherently encourage energy efficiency by directly registering the emissions impact of a change in efficiency. Under an output-based standard, a decrease in efficiency would cause an increase in emissions per unit of output, and would require the power plant owner to respond by either restoring its baseline efficiency or reducing its emission rate. Moreover, increases in efficiency anywhere in the regulated process allow the owner to produce more of its salable product within the environmental limit. Thus, the output-based standard provides a built-in market incentive for efficiency. Conversely, a power plant owner currently has no environmental regulatory reason or incentive to respond to increased emissions. In fact, the owner faces a disincentive to respond with a "major" modification of the plant since such a change might trigger New Source Review and require a significant investment of limited capital.

Unlike current air regulations, output-based standards also account for the increased efficiency benefits that occur when heat is recovered in a generation system. They are, in short, essential to encourage the adoption of the cleanest and most efficient electricity generation technologies.

BOX 1

EPA USES OUTPUT-BASED STANDARDS FOR NEW UTILITY AND INDUSTRIAL BOILERS

In September 1998, EPA published revised new source performance standards (NSPS) for emissions of nitrogen oxides (NOx) from both new utility boilers and new industrial boilers. These revisions changed the NOx emission limit for new electric utility steam generating units from a heat input basis to an electrical output basis in order to promote energy efficiency. These standards were based on the performance of best control technologies used by comparable facilities.

In making the revisions, EPA stated that utility NOx emissions were traditionally controlled on the basis of boiler input energy (lb of NOx/million Btu heat input). However, input-based limitations allow units with low operating efficiency to emit more NOx per megawatt (MWe) of electricity produced than more efficient units. Considering two units of equal capacity, under current regulations, the less efficient unit will emit more NOx because it uses more fuel to produce the same amount of electricity. One way to regulate mass emissions of NOx & plant efficiency is to express the NOx emission standard in terms of output energy. Thus, an output-based emission standard would provide a regulatory incentive to enhance unit operating efficiency and reduce NOx emissions.

Pursuant to section 407(c) of the Clean Air Act in subpart Da (Electric Utility Steam Generating Units) and subpart Db (Industrial-Commercial-Institutional Steam Generating Units) of 40 CFR part 60, the EPA revised the NOx emission limits for steam generating units. Only those electric utility and industrial steam generating units for which construction, modification, or reconstruction commenced after July 9, 1997, were affected by these revisions.

The NOx emission limit in the final rule for newly constructed subpart Da units is 200 nanograms per joule (ng/ JO) (1.6 lb/megawatt-hour (MWh)) gross energy output regardless of fuel type. For existing sources that become subject to subpart Da through modification or reconstruction, the NOx emission limits are still regulated on an input basis.

III:
SURVEY OF INITIATIVES TO ADVANCE OUTPUT-BASED STANDARDS

Various federal, state, regional, and international agencies have adopted, or are proposing, output-based initiatives. This section reviews those efforts, which have been made under a variety of air quality policies: new source review, emissions performance standards (EPS) for power plants,[30] multi-pollutant legislation and regulations, distributed generation permitting programs, and the NOx Budget Program. Also examined in this section are several suggested models for developing and implementing output-based standards.

TABLE 1

Air Quality Policies with Output-based Standards:	*State Initiatives and Other Models:*	*Relevance to CHP and Thermal Energy Credited:*
Emissions Performance Standards	MA, CT, NJ, Northeast States for Coordinated Air Use Management (NESCAUM)	Limits emissions by suppliers of retail electricity. Could involve CHP facilities and recognize thermal benefits, but not the policy focus.
Targeted multi-pollutant strategies	MA, NJ, NH	Limits emissions of high-polluting power plants.
Distributed generation regulations	CT, TX, CA, EPA Draft Guidance for CHP, Regulatory Assistance Project (RAP), American Council for an Energy Efficient Economy (ACEEE), Ozone Transport Commission (OTC)	Credits thermal of "qualifying" CHP facilities by quantifying emissions for thermal and electric on output basis; various methods used.
NOx Budget Program allocations	MA, NH, NJ, DE, Ozone Transport Commission (OTC)	Guidance recognizes thermal benefit of CHP. Determines allocations for thermal and electric on an output basis.

Although the highlighted initiatives and models vary in their applications and the factors they employ, each suggests that output-based standards are the preferred way to recognize a power facility's energy efficiency and address the electricity sector's air emissions. Some models and state initiatives see output-based standards as a way to level the playing field among all fossil-fuel-burning power generators, old and new. Output-based standards also inherently showcase zero-emissions power supplies, such as wind, hydrogen, solar, and other renewable resources.

In order to complete its survey, the Northeast-Midwest Institute initially sent electronic-mail questionnaires to state air-permit contacts in search of output-based initiatives for distributed generation, and information on whether any initiatives credited CHP for its added thermal energy product. (Distribution generation technologies produce electricity or thermal energy at or near the point of use.) Recognizing that the use of output-based standards is relatively new to many state contacts, a final question sought to determine if the state air regulator was aware of any efforts in his/her state to recognize energy efficiency in power generation.

Since the initial questionnaires found that few distributed-generation permits were based on output measurements, the Institute conducted a wider survey by telephone and email to state air regulatory agencies on power plant emission policies. That survey identified a limited, but larger, set of air policies measuring emissions on an output basis. In documenting the variety of output-based efforts currently underway in the states and in other venues, this report identifies a slight shift in perception and policy toward an output-based approach.

A. THE STATE INITIATIVES

This section examines how selected states have advanced "output-based" or "efficiency-based" standards as a means to measure and encourage the reduction of power generation emissions. Its purpose is three-fold:

1. To describe where each state currently stands in terms of implementing output-based standards in air quality policies, such as permitting new and significantly-retrofitted power generation facilities;
2. To identify a contact or multiple contacts in each state on output-based air pollution policies and CHP permitting; and
3. To identify any special state-level treatment for permitting CHP, particularly related to output-based emission standards, in order to improve air quality and credit energy efficiency.

Appendix A provides a complete summary of output-based efforts in twenty states. Appendix B contains a listing of air-quality policy contacts by state.

Several states — particularly in the Northeast, California, and Texas — are taking steps to shift their air regulations. Texas and California, for instance, are using output-based measurements for air quality permitting of distributed generation units, and they have given special treatment to CHP. New Hampshire is shifting its air regulations to an output-based approach wherever possible.

Massachusetts's restructuring legislation directs the state Department of Environmental Protection to develop output-based regulations that apply to all power generators involved in the retail sale of electricity. Like Massachusetts, restructuring legislation in Connecticut and New Jersey call for the development of output-based emission standards that apply to retail sellers of electricity. Whereas Massachusetts will implement output-based standards for NOx by May 2003, the other states imposed some stipulations to their implementation. New Jersey's legislation, for instance, calls for output-based rules to be developed only if the state finds that existing federal and regional policies do not address air quality issues satisfactorily or if neighboring states adopt such standards.[31]

Connecticut is the only state to date to take action on New Source Review (NSR), calculating emissions on an output basis and crediting the thermal energy used. The state environmental protection agency completed a major revision to its NSR regulations on December 28, 2001, and those changes went into effect on March 15, 2002. Connecticut also has recognized the public health benefits that output-based standards can generate with regard to the electricity industry.

States have prepared rules for the adoption of output-based standards under three mechanisms/avenues.

1. By setting output-based emissions standards specifically for electric generating units (focusing on distributed generation); and/or
2. By setting output-based emissions standards for one or multiple pollutants and for some or all generating facilities involved in the retail sale of electricity; and
3. By setting output-based emissions standards for nitrogen oxide allocations within the NOx Budget Program.

The first approach sets limits on the amount of air pollution from distributed generators, in turn protecting public health from a potential influx of cheap and highly-polluting diesel generators, while providing incentives to CHP and renewable technologies. The second mechanism encourages energy efficiency on a wider scale and moves the retail electricity market to newer, cleaner technologies that emit less pollution for the same amount of fuel used. The third pertains to summertime NOx emissions and mostly to states in the Northeast that are in nonattainment. Below is a more detailed review of these state efforts. States found to have the most activity are presented here, while Appendix A provides the results of all twenty states surveyed.

Connecticut

Connecticut in December 2001 made major revisions to its New Source Review program in order to permit major sources on an output basis and to credit thermal energy used. Effective March 15, 2002, these revisions apply to all facilities seeking NSR permitting. The modifications are in Section 22a-174-3a of the Regulation of Connecticut State Agencies (RCSA), "Permit to Construct and Operate Stationary Sources."[22] The impetus for state action was twofold: 1) An understanding of the need to credit a facility's energy efficiency, and 2) the lead taken by the U.S. Environmental Protection Agency's release of draft guidance on permitting combined heat and power technologies in NSR.

Since Connecticut's NSR rule provides for CHP incentives, the output basis will reward more efficient projects. The language states that in determining whether to approve BACT (Best Available Control Technology), "The commissioner shall, among other items, not preclude the establishment of an output based emission limitation as BACT provided such application of BACT improves the overall thermal efficiency of the subject source or modification."[23] The permit requirements for nonattainment areas include a provision allowing the commissioner to take into account an output-based emission limitation as LAER (Lowest Achievable Emissions Rate), provided such application of LAER improves the overall thermal efficiency of the subject source or modification.[24]

On April 23, 2002, Connecticut issued its general permit for distributed generators that applies to multiple pollutants and has an annual emissions cap.[25] The permit is not output-based but will only be in effect until December 31, 2003. After that time, the state Department of Environmental Protection expects to adopt the output-based Regulatory Assistance Project Model Rule for distributed generators[26] (which is highlighted later).

In April 1998, Connecticut's electricity restructuring legislation directed the state Department of Environmental Protection to establish generation performance standards for five pollutants: sulfur dioxide (SO2), nitrogen oxides (NOx), carbon dioxide (CO2), carbon monoxide (CO), and mercury (Hg). The standards are to be implemented when "three of the states participating in the northeastern states' Ozone Transport Commission, as of July 1, 1997, with a total population of not less than 27 million, have adopted such a standard." The state electricity restructuring legislation and subsequent law refer to output-based standards as generation performance standards.

Connecticut's Performance Standard Law is Public Act No. 98-28, Sec. 24 and reads:

> *Sec.24. (NEW) Not later than January 1, 1999, the Commissioner of Environmental Protection shall, by regulations adopted in accordance with chapter 54 of the general statutes, establish uniform performance standards for electricity generation facilities supplying power to end use customers in this state. Such standards shall, to the greatest extent possible, be designed to improve air quality in this state and to further the attainment of the National Ambient Air Quality Standards promulgated by the United States Environmental Protection Agency. Such performance standards shall be based on the fuel used for generation of electricity and shall apply to Electric suppliers' generation facilities located in North America and shall limit the amount of air pollutants, including, but not limited to, nitrogen oxides, sulfur oxides, carbon dioxide, carbon monoxide and mercury, emitted per megawatt hour of electricity produced. Such performance standards may provide for a program for purchase of offsetting reductions in emissions and trading of emission credits. A performance standard established by the Department of Environmental Protection for an individual pollutant pursuant to this section shall go into effect when three of the states participating in the northeastern states' Ozone Transport Commission as of July 1, 1997, with a total population of not less than twenty-seven million at that time, have adopted such standard.*

Thus, the Department of Environmental Protection (DEP) is required to have an output-based standard in place, but that standard need not be implemented until other states in the region have adopted similar standards. The state's purpose was to improve air quality. The regulations target retail electricity suppliers, giving the state the ability to require compliance from out-of-state suppliers. As of September 2002, the state Department of Environmental Protection has produced a draft rule, Draft RCSA Section 22a-174-34, based on the NESCAUM regional model regulation (described later). The draft of "Section 34" has been reviewed by the Connecticut Department of Public Utility Control. As of this report's publication, a final rule was not released.

The Connecticut Department of Environmental Protection also has played an integral role in the development of several of the regional model rules to be discussed later in this report. These include the Regulatory Assistance Project's Model Rule for Distributed Generation and the NESCAUM Model Emissions Performance Standard.

Massachusetts

The Massachusetts legislature in late 1997 directed the state Department of Environmental Protection to adopt output-based standards[27] for all power facilities engaged in the retail sale of electricity to end users in the Commonwealth. The standards are for any pollutant of concern to public health. The legislation requires that the state implement the standards for at least one pollutant by May 2003, and it will begin with NOx. If other states in the Northeast implement output-based standards for electricity generation in the meantime, Massachusetts can follow suit. The state DEP has not acted on the generation performance standard to date.[28] The regulatory authority is under Massachusetts General Law c. 111, Sections 142A through 142N.

The state legislature and Department of Environmental Protection believe output-based standards will make it easier to regulate sources that are low-emitting and efficient, while high-emitting and inefficient facilities may need to reduce emissions or purchase allowances from low-emitting sources in order to comply with requirements. The Department of Environmental Protection's background document on the rule declares that "allocating the available state budget based on electrical output promotes pollution prevention in the electric sector by rewarding energy efficiency, and promotes fair competition in the energy market by leveling the environmental playing field for all generators of electricity."[29]

Chapter 111, Section 142N in Massachusetts General Law states that:

> *Section 142N. For the purpose of preventing, mitigating, or alleviating impacts on the resources of the Commonwealth and to the health of its citizens from pollutants emitted by fossil fuel-fired electric generation facilities serving retail customers in the commonwealth, the Department of Environmental Protection shall, in consultation with the office of the attorney general and the Department of Telecommunications and Energy, promulgate rules and regulations to adopt and implement for fossil fuel-fired electric generation facilities uniform generation performance standards of emissions produced per unit of electrical output on a portfolio basis for any pollutant determined by the Department of Environmental Protection to be of concern to public health, and produced in quantity by electric generation facilities. The Department of Environmental Protection shall have said uniform performance standards for at least one pollutant in effect on, but not before, May 1, 2003, unless three or more other northeastern states enact similar standards before that date, in which case the Department of Environmental Protection may adopt such standards prior to May 1, 2003. The Department of Environmental Protection shall issue annually, by March first of each year, an annual report detailing the implementation and compliance of said program, its standards, and its companion rules and regulations.*[30]

As Massachusetts has not developed these standards to date, it is not known whether stipulations for combined heat and power facilities would be included. The state in April 2001 made available a developer's guide to regulations, policies, and programs that affect renewable energy and distributed generation facilities in the Commonwealth. The guidebook references the generation performance standards required in the restructuring legislation.

On another front, in April 2001, Massachusetts took an aggressive step to improve local air quality by targeting reductions at its six dirtiest power plants. Regulation 310 CMR 7.29, "Emissions Standards for Power Plants," requires reductions of NOx, SO2, CO2, and mercury beginning in 2004 (or 2006 depending on reduction choices made by the individual plant). This is accomplished by establishing output-based emission rates for NOx, SO2, and CO2 and establishing an emissions cap on CO2 and Hg emissions from affected facilities. See Table 2 for a summary of the standards, compliance paths, and dates.

The regulation defines "output-based emission rate" as an emission rate for any pollutant, expressed in terms of actual emissions in pounds over a specified time period per megawatt-hour of net electrical output produced over the same time period. "Output-based emission standard" is defined as the emission standards for each applicable pollutant, expressed in terms of pounds of pollutant emitted per megawatt-hour of net elec-

TABLE 2

MASSACHUSETTS POWER PLANT CLEAN UP STANDARDS[31]

(MA DEP Regulation 310 CMR 7.29)

Pollutant	*Emission Standard*	*Standard Pathway Compliance Dates*	*Repowering Pathway Compliance Dates*
NOx	1.5 lbs/MWh	October 1, 2004	October 1, 2006
SO2	6.0 lbs/MWh	October 1, 2004	October 1, 2006
SO2	3.0 lbs/MWh	October 1, 2006	October 1, 2008
CO2	1800 lbs/MWh annual avg.	October 1, 2006	October 1, 2008

trical output produced. The regulation is available online at: http://www.state.ma.us/dep/bwp/daqc/files/regs/729final.doc.

The Massachusetts NOx SIP allocates allowances to generation sources on an output basis. To judge emissions on an output rather than input basis, the state must add data on electrical output, which the Ozone Transport Commission points out is widely available.[32] The state's NOx Allowance Trading Program for 2003 includes an output-based allocation for generating units with useful steam output. The Department of Environmental Protection provides a formula for calculating the steam allocation, which is then added to the electrical output allocation, thereby promoting energy efficiency and recognizing two useful energy outputs. Regulation 310 CMR 7.28 applies to any source greater than 25 MW or greater than 250 mmBtu/hr boiler size. If a source is a CHP facility, then the Department of Environmental Protection allows credit for the CHP portion.[33]

The Massachusetts Department of Environmental Protection also has played an integral role in the development of several of the regional model rules to be discussed later in this report. These include the Regulatory Assistance Project's Model Rule for Distributed Generation and the NESCAUM Model Emissions Performance Standard.

New Jersey

New Jersey's electricity restructuring legislation, approved in February 1999, addressed the potential need for an emissions performance standard, referred to as an environmental portfolio standard. The law directed the Board of Public Utilities, in consultation with the Department of Environmental Protection, to adopt and implement an emission performance standard if such standards became necessary to meet ambient air quality standards beyond current federal and regional actions. A stipulation in the New Jersey legislation also required the adoption of this emissions performance standard if two other states within the PJM interconnection area, comprising at least 40 percent of retail electricity sales, adopt similar standards.

The legislation allows the state Department of Environmental Protection to take action if existing air quality policies do not go far enough to protect citizens from pollution of power plants within the state and the region. In addition, the state will be required to take action if neighboring states adopt this type of emissions regulation. No state has done so to date, and New Jersey has made no decision to promulgate an emissions performance standard.[34]

The emissions portfolio standard language is found within the "Electric Discount and Energy Competition Act," and is as follows:

> *Public Law 1999, Chapter 23, Section C.48:3-87 Environmental disclosure requirements.*
>
> *38. c. (1) The board [of public utilities] may adopt, in consultation with the Department of Environmental Protection, after notice and opportunity for public comment, an emissions portfolio standard applicable to all electric power suppliers and basic generation service providers, upon a finding that:*
>
> > *(a) The standard is necessary as part of a plan to enable the State to meet federal Clean Air Act or State ambient air quality standards; and*
> >
> > *(b) Actions at the regional or federal level cannot reasonably be expected to achieve the compliance with the federal standards.*
>
> *(2) The board shall adopt an emissions portfolio standard applicable to all electric power suppliers and basic generation service providers, if two other states in the PJM power pool comprising at least 40 percent of the retail electric usage in the PJM Interconnection, L.L.C. independent system operator or its successor adopt such standards.*

The legislation's goal was to prevent large amounts of high-emission generation in the state. As part of New Jersey's restructuring legislation, generation companies also are required to disclose environmental characteristics, such as power plant fuels used and emissions generated. This environmental disclosure should allow consumers to understand what's being emitted to produce their electricity.

Certain states — including Connecticut, Massachusetts, New Hampshire, New York, and New Jersey — allocate the allowances available under the NOx Budget Program in ways that recognize energy efficiency. Their purpose is to reduce emissions from power plants and large stationary sources. The New Jersey NOx Budget Program is located in New Jersey Administrative Code, Title 7, Chapter 27, Subchapter 31 and available online at: www.state.nj.us/dep/aqm/rules.htm. The 2003 allocations will be in part on an output basis: both input-based and output-based emission rates are provided. New Jersey also is committed to adopting output-based standards for distributed generation, based on the Ozone Transport Commission's recommendations.[35]

Finally, New Jersey has reached agreement with power companies to reduce multi-pollutants at power plants in the state. This action does not result from regulation but rather is an enforcement action targeting NSR violations. From the state's greenhouse gas initiative came a settlement with Public Service Electric & Gas to reduce CO2 from New Jersey's fossil-fueled electric generating units by a certain amount of pounds per megawatt-hour (MWh) in 2006.[36]

New Hampshire

To the extent it can, the state of New Hampshire tries to regulate all air emissions on an output basis and is currently updating many of its regulations to reflect this approach.[37] New Hampshire has proposed output-based standards targeting four pollutants from the state's highest-polluting power plants. The state in January 2001 released its Clean Power Strategy, which calls for emissions caps based on electricity output for all large electrical generating facilities in the state; put another way, it does not "grandfather" any existing power plant. This action resulted in the Clean Power Act, House Bill 284, which was signed into law in May 2002 and took effect in July 2002.[38] The law requires emissions reductions in SO2, NOx, CO2, and mercury. Section 125-O:3 states that the multi-pollutant strategy shall be implemented in a market-based fashion that allows trading and banking of emission reductions in order to comply with the overall statewide annual emission caps. It also declares that allowances shall be allocated to each affected source based on its output.

In New Hampshire's NOx Budget Program[39] that will go into effect in 2005, allocations will be determined on an output-basis. The allocation language is in the New Hampshire Code of Administrative Rules, Part Env-A 3200. The rule extends New Hampshire's NOx Budget Trading Program for the period 2006 and beyond. This cap-and-trade program does not set output-based "standards," but instead establishes output-based allowance allocations.[40] The Department of Environmental Services followed EPA's guidance for output-based allocations, which includes provisions for thermal heat output for cogeneration; however, there currently are no applicable CHP sources in New Hampshire.

New Hampshire believes output-based standards are a way to encourage greater efficiency and pollution prevention. The state also argues that such standards would help create a level playing field and advance competitive markets.

The state also has a new rule regarding smaller electric generating units (EGUs), Env-A 3700, based on legislation passed during the 1999 legislative session. In House Bill 649,[41] the legislature found it necessary to address emissions from the growing number of smaller generators that were not subject to NOx requirements. The bill acknowledged that many businesses have sought to control their high electric costs by using internal combustion engines that run on fossil fuels to generate electricity. The legislature recognized that these generators have increased nitrogen oxide (NOx) emissions and that additional units could substantially increase such emissions and raise electric rates for customers purchasing electricity from sources subject to more stringent NOx regulations.

The state views this rule as market-based. Sources emitting NOx greater than 7 lb/MWh are subject to either paying fees, buying credits, or installing controls. A new provision was added to RSA 125-J, *NOx-Emitting Generation Source Requirements*, exempting emissions above 7 lb/MWh attributable to cogeneration.

The New Section 125-J:13 reads:

> *I. Each NOx-emitting generation source emitting more than 7 pounds of NOx per megawatt hour generated shall be required to supply to the department NOx emissions information, and the amount of kilowatt hours actually produced during each period listed in subparagraph II(b). Additionally, except as provided either by paragraph I or II of this section, each NOx-emitting generation source shall acquire NOx budget allowances, emissions reduction credits, or other emissions reduction mechanisms on the same basis as a NOx budget source for all of its NOx emissions. However. NOx-emitting generation sources shall not be required to acquire NOx budget allowances, emissions reduction credits, or use emissions reduction mechanisms for the first 7 pounds of NOx emitted for each megawatt-hour of electricity produced and any amounts of NOx above such first 7 pounds that are attributable to the provision of other, non-electric services provided by the generating source, including but not limited to, steam and heat. and any amounts of NOx emitted during any period when the NOx-emitting generation source is operating to provide power during a power shortage at the request of any governmental authority or provider of electrical power to the public generally.*[42]

The New Hampshire Department of Environmental Services also has played an integral role in the development of several of the regional model rules to be discussed later in this report. These include the Ozone Transport Commission Model Rules, and the NESCAUM Model Emissions Performance Standard.

Illinois

The Illinois Resource Development and Energy Security Act (HB 1599), approved on June 22, 2001, calls for a report on reducing multiple pollutant emissions from fossil-fuel-fired electric generating plants. The state Environmental Protection Agency must report on multi-pollutant strategies for NOx, SO2, and mercury to the House and Senate Committees on Environment and Energy before September 30, 2004, but not before September 30, 2003. Although output-based standards are not explicit in the legislative language, the state EPA plans to study this approach.[43] The new provisions applying to fossil-fuel-fired electric generating plants are contained in the Illinois Environmental Protection Act under Section 9.10, 415 ILCS 5/ (IL Compiled Statutes).[44]

Texas

Effective June 1, 2001, the Texas Commission on Environmental Quality (CEQ)[45] established a standard air-emissions permit for NOx from distributed generation in order to encourage the most energy-efficient configurations, such as combined heat and power. The *Air Quality Standard Permit for Electric Generating Units* (EGU),[46] Texas Administrative Code (TAC) Rule 106.511, is a standard permit that was designed to be an expedited method of authorizing clean electric generating units in the state.

The permit, issued under Texas Clean Air Act's Health & Safety Code Sections 382.011, provides a streamlined preconstruction authorization mechanism for electric generating units that are not prohibited by other state or federal permitting statute or regulation. The distributed generation standard is output-based (in lbs/MWh) and establishes pre-certification requirements for a power system.

The standard permit applies to all electric generating units that emit air contaminants, regardless of size, and it reflects BACT (Best Available Control Technology) for electric generating units on an output basis in pounds of NOx per megawatt hour, adjusted to reflect a simple cycle power plant.

For this air quality permit, the state has been divided into two regions — East Texas and West Texas — in order to address ozone nonattainment problem in the East Texas region. In 2005, the permit will require stricter emissions requirements, and the standards for units then will be determined by hours of operation.

The distributed generation permit recognizes that combined heat and power units produce two useful energy outputs, in the form of electricity and heat, and it gives credit for this dual output. The state CEQ produced a guideline, which can be found at: http://www.tnrcc.state.tx.us/permitting/airperm/nsr_permits/files/segu_permitonly.pdf. To meet the emission standards, CHP units may take credit for useful thermal output at the rate of one megawatt-hour for each 3.4 million BTUs of heat recovered. If a CHP unit is not pre-certified by the manufacturer, the owner or operator may submit documentation of the system to receive a CHP credit.

The CHP credit is designed to encourage users to install and use CHP in order to improve the efficiency of generating units where there is a valid need for the recovered heat. In a supplement document, the CEQ offers an example of how this credit works for a 10-megawatt CHP unit.

The Texas CEQ purports that the permit's standards will allow for the cleanest reciprocating engines as well as turbines, microturbines, and fuel cells. This approach should allow the use of more efficient equipment; give an incentive for using CHP without setting standards that would require it; and provide economic incentive for reliable power to be generated at the point of use, as opposed to relying on central plant power with emergency backup.

California

The California Air Resources Board (CARB) has established a distributed generation certification program using output-based emissions standards for NOx, CO, VOCs, and particulate matter. The regulation went into effect on October 4, 2002, and it applies to distributed generation units that had otherwise been exempt from air pollution control requirements.

California Senate Bill 1298[47] (which became Chapter 741 on September 27, 2000) mandated that the Air Resources Board adopt a certification program and uniform emission standards (in lbs/MWh) for electrical generation units that are exempt from other state air district permitting requirements. It also required that the emissions standards reflect the best performance achieved in practice by existing electrical generation technologies.

This law requires CARB to:

1. Adopt uniform emission standards for electrical generation technologies that are exempt from air pollution control or air quality management district permit requirements;
2. Establish a certification program for the distributed technologies subject to these standards; and
3. Issue guidance to the 35 state air districts on the permitting or certification of electrical generation technologies subject to the district's regulatory jurisdiction.

SB 1298 mandated that CARB establish two levels of emission standards for affected distributed generation technologies. The first set of standards had to become effective no later than January 1, 2003, and had to reflect the best performance achieved in practice by existing distributed generation technologies that are exempt from district permits. The law also required that, by the earliest practicable date, the standards be made equivalent to the level determined by CARB to be the best available control technology (BACT) for permitted central station power plants in California.[18] The emission standards must be expressed in pounds per megawatt-hour (lb/MWh) in order to reflect the efficiencies of various electrical generation technologies.

The distributed generation certification regulation is available from the Air Resources Board Distributed Generation Internet site at: http://www.arb.ca.gov/energy/dg/dg.htm. CARB also released its final guidance document for the distributed generation certification regulation in July 2002.[19] In that guidance, CARB set emissions standards for 2003 and 2007, and offered limits for units with and without combined heat and power. In 2005, the CARB will produce a technical review of the distributed generation technologies and emissions criteria in order to determine if any modifications to its certification standards are necessary.

The air quality benefits of combined heat and power (CHP) applications were given special consideration and reflected in their special treatment. Section VII, B. of the guidance states that "efficient" CHP systems will receive an emissions credit for thermal output. Efficient CHP applications must maintain a minimum efficiency of 60 percent in the conversion of the energy in the fossil fuel to electricity and process heat. Thus, the facility's overall lb/MWh can be determined by dividing the facility's emissions, on a pollutant-by-pollutant basis, by the facility's total energy production. The total energy production is the sum of the net electrical production, in megawatts, and the actual process heat consumed in a useful manner, converted to megawatts. More detailed methodologies for calculating the emissions performance standard, and for calculating the CHP credit on an output basis, are provided in the CARB Guidance document appendices C and D.

B. FEDERAL EFFORTS

At the federal level, Congress has begun a new round of debates on the Clean Air Act. Several bills addressing multiple pollutants (known as multi-pollutant bills) were introduced in the 107th Congress, one of which called for emissions to be measured on an output basis. The proposals differed markedly. For much of the 107th session, attention focused on the contrast between a four-pollutant bill from Senator James Jeffords (I-VT), then chairman of the Environment and Public Works Committee, and the Bush Administration's "Clear Skies" initiative, a three-pollutant proposal introduced by Senator Bob Smith (R-NH) in the Senate and Representative Joe Barton (R-TX) in the House.

Senator Thomas Carper (D-DE) in October 2002 introduced a third "multi-pollutant" bill to bridge the gap between the Jeffords and administration proposals. While both the Jeffords and Carper bills would regulate carbon dioxide, the most harmful of the greenhouse gases, the Carper bill regulates most pollutants on an output basis, while the Jeffords legislation considers this as one method but does not commit to a methodology. The Clear Skies proposal does not regulate carbon dioxide, and it does not regulate emissions on a performance basis that could improve air quality.

The Carper bill called for NOx and Hg allocations on a per-megawatt-hour output basis, which would be calculated on a three-year rolling average. It also stated that the EPA shall promulgate regulations that ensured CHP systems received "equitable issuance of allowances." As for CO2, allowances would also be allocated on an output basis, using a three-year rolling average. However, there was no specific mention of CHP or thermal crediting. SO2 retained the Acid Rain program structure with a few minor amendments; the current structure employs an input-based allocation system. The emission cap on annual tonnage of SO2 was to be tightened. Whether the Carper bill or other multi-pollutant initiatives will be introduced in the 108th Congress remains to be seen.

As for CHP, the technology focus of this report, the Bush Administration's National Energy Policy (NEP), released in May 2001, directed the Environmental Protection Agency (EPA) to provide flexibility in environmental permitting.[50] Although the NEP does not specifically mention output-based standards, the implication can be drawn that output-based standards could form the basis of a more fair and flexible system that rewards greater efficiency. The EPA, moreover, sites the NEP's directive as the impetus for a draft guidance it released in 2001 to streamline permitting of some CHP facilities; that guidance measures emissions on an output basis.

The EPA Office of Air Quality Planning and Standards has been finalizing its New Source Review (NSR) guidance in order to recognize output-based standards for CHP systems, siting the above NEP directive as one reason. In October 2001, EPA made available for public comment a draft guidance document that addresses the permitting of CHP systems under EPA's New Source Review and Title V programs.[51] That draft guidance sought to clarify EPA's interpretation of how regulations apply in determining the boundaries for a major stationary source with regard to CHP facilities. Under this draft guidance, CHP facilities may apply for a streamlined permit if the facility is constructed, owned, and operated by a party other than the host or customers. To qualify, a CHP system must meet certain energy-efficiency requirements based on its electric and thermal outputs. The draft guidance also allows the CHP facility to use credits from the shutdown of existing boilers in determining NSR applicability.

The intent of the draft guidance is to clarify how source determinations for CHP facilities should be made under the NSR and Title V permitting regulations. It acknowledges EPA's belief that net environmental benefits will result from CHP emissions replacing old boiler emissions, even if emissions from CHP facilities are not subject to BACT or LAER controls.

While lauding EPA efforts to provide flexibility and streamline environmental permitting process for CHP facilities, CHP advocates recommend certain modifications. For example, since the draft guidance applies to CHP facilities that are owned and operated separately from the host facility, it does not offer any streamlining for those systems under sole ownership. John Jimison, executive director of the U.S. Combined Heat and Power Association, contends that CHP units should be included in the guidance regardless of ownership.[52] Also of importance is the need to create incentives for all facility owners, particularly grandfathered plants that do not fall under NSR, to convert their old boilers and other facilities to more-efficient and less-polluting CHP systems.

Other concerns raised by some analysts have been that energy efficiency levels in the draft guidance are too high, requiring CHP facilities to be more efficient than state-of-the-art natural gas-fired turbine systems — systems that are already significantly more efficient than the industry's average of 33 percent. Critics also worry that the high efficiency measurement could preclude certain renewables, like biomass, from use in CHP since biomass cannot achieve the same level of efficiency as a natural gas-fired system. As of this report's publication, it was not known whether EPA will release a final CHP guidance document.

C. ALTERNATIVE MODELS

Several organizations have developed models for how output-based standards could promote energy efficiency and innovative technologies. Below is a review of those recommended model rules, including environmental permitting for distributed generation and CHP on an output basis and emissions performance standards.

American Council for an Energy-Efficient Economy (ACEEE)

An October 2001 report[53] by the American Council for an Energy-Efficient Economy (ACEEE), the Natural Resources Defense Council (NRDC), and the Center for Clean Air Policy (CCAP) endorses output-based regulation in order to encourage energy-efficient power technologies and to reflect the benefits of combined heat and power. The report provides a model for certifying CHP systems that recognizes the emissions produced in relation to the two usable energy products generated — thermal and electric. ACEEE is a nonprofit organization dedicated to advancing energy efficiency as a means of promoting both economic prosperity and environmental protection.

ACEEE's CHP certification report provides the technical justification for calculating compliance of an individual CHP unit with electric output-based standards. The ACEEE method of accounting for CHP's dual benefits merges the emission standards for electric generators and boilers.

> *When calculating compliance of an individual CHP unit with electric output-based emissions standards, the emissions from the unit should be discounted by the avoided emissions that a conventional system would have otherwise emitted had it provided the same thermal output. For example, a 35-megawatt electric (MWe) CHP system with a power-to-heat ratio of 0.7 produces 50 megawatt thermal (MWt). For this system, we assume that the CHP unit displaces a typical small industrial, commercial, or residential boiler with an efficiency of 80 percent. Using this assumption and the California emissions standard for boilers, we assume that the displaced boiler would emit 0.036 lbs/MMBtu on an input basis, equivalent to 0.154 lbs NOx/MWhe on an output basis (California Clean Air Act 1998). Based on a power-to-heat ratio of 0.7, the emission credit on an electric basis would be 0.220 lbs NOx/MWhe. In other words, a CHP unit could emit 0.72 lbs NOx/MWhe and still comply with California Air Resources Board's proposed 0.5 lbs/MWh standard (since 0.72 lbs NOx/MWhe - 0.220 lbs/MWhe = 0.5 lbs/MWhe).*[54]

Having determined an equitable method of valuing the thermal energy product, and making the conversion entirely to output and electric, a single emissions standard — in pounds per megawatt-hours of electricity for both stand-alone electric generators and CHP units — can be implemented through this method. Other model emissions rules have not fully recognized and accounted for the added benefits of combined heat and power systems or for their technical capabilities.

The ACEEE model also addresses the stringency of energy-efficiency requirements that would exclude any off-the-shelf, low-emitting technologies. Moreover, it realistically addresses the lead-time needed by industry research and development in order to improve these already-innovative technologies. These issues have been raised in public comments for California and Texas, as well as by the Regulatory Assistance Project's model rule for distributed generation.

Regulatory Assistance Project

The Regulatory Assistance Project (RAP) in October 2002 released a final-review-draft model emissions rule[55] for distributed generators. RAP is a non-profit organization, formed in 1992, that provides workshops and education assistance to state public utility regulators on electric utility regulation. RAP is committed to fostering a restructuring of the electric industry in a manner that creates economic efficiency, protects environmental quality, assures system reliability, and applies the benefits of increased competition fairly to all customers.

RAP's draft model rule for distributed generation contains output-based emissions standards in pounds per megawatt-hour for NOx, particulate matter, CO, and CO2 for power generating units too small to trigger new source review. RAP's supporting documentation contains a series of emission calculations and charts detailing pollutant levels for various distributed generation technologies. The rule calls for the pollutant standards to be phased in over three phases in a ten-year period. The emissions limits are for two generation categories: emergency and non-emergency.[56] Based on public comment to the first draft, RAP extended its proposed phase-in periods (beginning in 2004, 2008, and then 2012) in order to better accommodate manufacturer research and development cycles. NOx emission limits for Phases I and II are differentiated for attainment and nonattainment, after which time only one set of limits will apply. RAP will conduct a technological review of the rule by December 31, 2010, and make any changes determined appropriate to the Phase III standards.

The draft rule would impose an air permitting review process on certain power generating facilities not now subject to operating with a permit. It does not apply to existing sources. The rule's purpose is to ensure that air quality will not be unduly impacted by the wider introduction of smaller power generating units into any region. RAP's objectives in designing the rule were:

1. To regulate "the emissions output of distributed generation in a technology-neutral and fuel-neutral approach;"
2. To "facilitate the development, siting, and efficient use of distributed generation in ways that improve or, at least, do not degrade air quality;" and
3. To "encourage technological improvements that reduce emissions output."[57]

The principles guiding development of the rule were to promote technological improvements in efficiency and emissions output by encouraging the use of non-emitting resources and by accounting for the benefits of CHP and the use of otherwise flared gases. Another principle was that the rule be easy to administer so that it could facilitate the development, siting, and efficient use of distributed energy resources.[58]

Section VII, (B) of the rule, under Credit for Concurrent Emissions Reductions, pertains to combined heat and power facilities. For a CHP installation to qualify for a thermal credit, the October 2002 version of the rule lays out two requirements.

1. At least 20 percent of the recovered energy must be thermal and at least 13 percent must be electric.[59] (This corresponds to a power-to-heat ratio of between 4.0 and 0.15.)
2. The design system efficiency must be at least 55 percent.[60]

RAP has made other changes with regard to CHP based on comments to its March 2001 draft document. One change recognizes that CHP replaces a variety of power generation facilities. When determining the emission rates for a displaced boiler, RAP added language to address retrofit CHP facilities. In the case where retrofit-CHP facilities replace existing thermal systems for which actual emission rates can be documented, the CHP unit can receive credit for the actual emission rates (up to a prescribed limit).[61] Otherwise, the thermal credit is based on new natural-gas-fired boilers.

Revisions to the March 2001 draft model were ongoing through Spring and Summer 2002. A final draft model rule, dated October 31, 2002, incorporated the public review comments. As of this report's publication, an official final rule has not been publicly released, but will be available at http://www.raponline.org/

when ready. Regardless of its publication date, the state of Connecticut plans to adopt RAP's model distributed-generation standards to become effective in 2004.[62]

Northeast States for Coordinated Air Use Management (NESCAUM)

The Northeast States for Coordinated Air Use Management (NESCAUM) developed an output-based model emissions rule for power generators in December 1999. NESCAUM is an interstate association of air quality control divisions in northeastern states. It was originally formed to deal with the problem of emissions from large power plants located on or near state borders, but it has tackled other issues, including acid rain and ozone.

If adopted by a state, NESCAUM's proposed output-based standards, known as Emissions Performance Standards (EPS),[63] would apply to any retail electricity supplier's portfolio of generation resources. NESCAUM recognized the large variations in electricity costs and emissions control requirements for power generating facilities across the eastern U.S. It also acknowledged that electricity restructuring could shift retail choice to lower-cost but more-polluting resources unless environmental performance measures were required for all retail suppliers.

In developing its model, the group defined two objectives:

1. To prevent electric utility restructuring from resulting in a degradation of air quality in the Northeast by providing a mechanism to ensure that disparities in environmental regulation would not create a competitive advantage for more polluting resources (i.e., "leveling the environmental playing field"); and
2. To improve air quality in the Northeast and to reduce the adverse impacts of electricity generation on public health and the region's environment.[64]

Some states, like Massachusetts and Connecticut, have passed legislation calling for output-based emissions standards, while others could follow suit in their own restructuring legislation. In order to promote regional coordination and consistency, NESCAUM tried to adhere to objectives within existing state laws. The EPS framework was based on state electricity restructuring legislation, recognizing that generators serving in-state retail customers might be located out of state. The retail sale of electricity was chosen as the compliance trigger since it is tied to a state's authority to license providers of retail electric services.

Finally, the EPS covers NOx, SO2, CO2, and eventually mercury — as had been identified in Connecticut's restructuring legislation. A placeholder to regulate carbon monoxide is provided though no standard is set in the model. To determine compliance with the output-based standards, a retail supplier must use the model's measurement formula to calculate a weighted average emission of its electricity generation portfolio in pounds per megawatt-hour and then compare the result with the pollutant emission maximum level.

The intent of EPS is "to maintain, in the deregulated market, an equal or improved level of environmental performance relative to what would otherwise be required for electricity generation serving the Northeast

TABLE 3

NESCAUM MODEL EMISSION PERFORMANCE STANDARDS[65]

Pollutant	*Emission Performance Standards*
NOx	1 lb/MWh
SO2	4 lb/MWh
CO2	1100 lb/MW
Mercury	Actual Emission Rate

market."[66] The workgroup plans to review the EPS in 2003, make any necessary revisions, and reconvene every five years thereafter.

With regard to emission attributes of combined heat and power installations, Section (g)(B)1.a. of the NESCAUM EPS Model Rule states that:

> *Combined heat and power system emissions shall be assigned an emission rate calculated by allocating emissions on a pro-rata basis between 1) electric energy output and 2) thermal energy output multiplied by a combined heat and power factor. The combined heat and power factor is initially set at 50%. Said factor shall be reviewed and revised on the schedule defined in subsection (f)(3) and any revision shall be consistent with regulations adopted by the Federal Energy Regulatory Commission pursuant to the Public Utilities Regulatory Policy Act.*

The emission performance standards model rule bases its thermal and electric emissions mix on a standard Public Utilities Regulatory Policies Act (PURPA) calculation, assigning 50 percent of emissions to electric output.[67] The model rule provides for periodic review of this assumption, consistent with future revisions to the PURPA calculation. Some reviewers encouraged NESCAUM to better credit thermal cogeneration and to adopt other modifications that acknowledge how CHP's efficiency levels will change over time with improvements in technology and depending on fuel mix used.

The NESCAUM model emissions performance standard can serve as a template for states interested in addressing air quality and competitiveness in their electricity restructuring efforts. States can modify the model as appropriate to their needs. One such modification could be to incorporate the ACEEE method for valuing CHP emissions on an output-basis. State air policy regulators from Connecticut and Massachusetts led the workgroup that developed the EPS and have used the NESCAUM work as a basis for the development of their state rules.

Ozone Transport Commission

The Ozone Transport Commission (OTC) has released models and reports on output-based standards as part of environmental performance standards for electricity generators, distributed generation permits, and NOx Budget Program allocations. The organization recognizes the air quality benefits that measuring emissions on an output basis can yield. The OTC was formed by Congress through the Clean Air Act (CAA) Amendments of 1990 in order to help coordinate control plans for reducing ground-level ozone in the Northeast and mid-Atlantic states. Since its inception, OTC has focused on a number of tasks, including assessing the nature and magnitude of the ozone problem in the region, evaluating potential control approaches, and recommending regional control measures. Twelve states and the District of Columbia are represented in the OTC.

The OTC Technology and Innovations Committee in September 2000 released a report on environmental performance standards[68] that states could use to encourage the development and use of clean power. The OTC identified output-based standards as one control measure to help reduce ozone pre-cursors. The standards would be applied to each electricity product sold to a retail customer in a particular state, and would not apply to specific generating units or wholesale transactions. As a model, the OTC directs states to the NESCAUM emissions performance standard.

The Technology and Innovations Committee in March 2001 released a report and draft model rule to streamline environmental permitting for small-scale distributed generators.[69] In order to foster low-emitting distributed generation technologies and limit the growth of high-emitting sources, OTC proposed that states could ease permit requirements for clean technologies while ensuring that high-emitting diesel engines receive careful review. Low-emitting sources would not need permits unless the units exceeded a given size threshold. The permit emissions thresholds would be reviewed within three years.

The OTC suggested that a draft model permit be required, with few exceptions, for existing, modified, and new electric generating equipment that emit NOx, CO, PM, and SO2 in pounds per megawatt-hour. Distributed generation equipment that would not require a permit in the OTC model included:[70]

- Fuel cells of any generating capacity size fueled by hydrogen;
- Fuel cells with less than 5,000 kW generating capacity fueled by methane;
- Fuel cells with less than 500 kW generating capacity fueled by fuels other than hydrogen and methane;
- Microturbines with less than 500 kW generating capacity fueled by natural gas, verified to emit less than 0.4 lbs/MWh NOx;
- Diesel engines with less than 37 kW generating capacity;
- Diesel engines equal to or greater than 37 kW generating capacity (50 horsepower (HP)) but less than 200 HP that are not located at a major stationary source of NOx emissions;
- Other electric generating equipment with less than 500 kW generating capacity, which is verified to emit less than:
    1. 0.4 lbs/MWh NOx;
    2. 0.25 lbs/MWh CO;
    3. 0.1 lbs/MWh PM;
    4. 0.01lbs/MWh SO2.

In order to reduce the impact of the anticipated influx of permit applications from distributed generation emission sources, the OTC report suggested that states could use a "verification program" approach for general permits or permits-by-rule, similar to the Texas and California distributed-generation permit programs. If the verification approach is taken by some states within the ozone transport region, consistent emission verification programs and standards should be developed and implemented within the region. The OTC distributed generation report mentioned that combined heat and power should be incentivized, but it did not add further detail.[71]

D. COMBINED HEAT AND POWER EFFORTS

The U.S. Combined Heat and Power Association (USCHPA) is a proponent of shifting air quality regulations from an input- to an output-based measurement. The organization brings together diverse market interests to promote the growth of clean, efficient CHP in the United States. It is a private, non-profit association, formed in 1999, to promote the merits of CHP and achieve public policy support.

USCHPA argues that air regulations should recognize and credit CHP systems for their increased efficiency and reduced emissions. The National CHP Roadmap identifies environmental permitting as one of the top barriers to siting more of these highly-efficient systems, and it recognizes the adoption of output-based standards as a solution. The CHP Action Agenda from the Roadmap calls for the development of output-based emissions standards by working with the Environmental Protection Agency in the analysis of alternative technical approaches, development of guidance to state and local air quality officials, and the offering of technical assistance.[72] Regional CHP initiatives, including the Midwest and Northeast, also are concerned with output based standards and receiving credit for the thermal output of CHP systems.

E. INTERNATIONAL EFFORTS

The Northeast-Midwest Institute conducted a literature search in order to learn how other countries have addressed air emissions for electricity producers, including innovative technologies like combined heat and power facilities. The research included data from the International Energy Agency (IEA), Organization for Economic Cooperation and Development (OECD), Commission of the European Communities (CEC), Cogen Europe, U.K.'s Combined Heat and Power Association, and other sources. Communications were engaged with the U.K. CHPA and the World Association for Decentralized Energy (WADE).

It was learned that:

- Energy security, climate change, and electricity and gas restructuring (liberalization) are key drivers behind the promotion of energy efficiency, renewables, and CHP;
- A number of policy directives at the European level apply to power generation and combined heat and power;
- In response to one directive, the U.K. has implemented an output-based "quality assessment" for CHP, and the European Union would like other member states to follow suit;
- The European Union (EU) is currently studying cap-and-trade program options for regulating greenhouse gas emissions. Allocation allowances determined on an output basis (or production based) is one metric being considered;
- Output-based emissions standards are not used for environmental permitting of industrial installations and/or power plants; and
- Many EU member states reduce emissions through fiscal measures like carbon taxes (climate change levies), the removal of coal subsidies, and tax exemptions for renewables and/or combined heat and power technologies.

In December 1997, in the framework of the Climate Change negotiations in Kyoto, the European Union (EU) committed itself to reduce its greenhouse gas emissions by 8 percent for the period between 2008-2010 in relation to its 1990 levels. This commitment is then distributed with different targets among the EU member states, which include Austria, Germany, Netherlands, Belgium, Greece, Portugal, Denmark, Ireland, Spain, Finland, Italy, Sweden, France, Luxembourg, and the United Kingdom. The Commission of the European Communities, or CEC, administers EU policy and ensures that EU legislation is fully implemented in all the member states.

Unlike the U.S., European environmental regulations have not only focused on ozone precursors and acid rain, but also on greenhouse gas emissions from carbon dioxide. European power generating facilities are subject to a series of regulatory requirements. Some of the most important requirements include a council resolution and proposed directive on CHP, the electricity and gas liberalization directives, a pollution prevention directive (IPPC), and a large combustion plant (LCP) directive. See Box 2 on next page for details. In the case of gas turbines, standards differ across Europe. In some countries, no standards exist for small units and standards for bigger installations depend mostly on the 1988 LCP Directive. In other countries, the principle of Best Available Technique (BAT) in the IPPC Directive is applied.

Still, European countries are recognizing the importance of whole system efficiency, and they emphasize pollution-prevention in combustion systems, which differs from the general U.S. approach of relying on add-on controls. Germany's TA-Luft standard, for instance, states that "all possible measures which reduce emissions through improved combustion shall be applied."[73] There has been a strong downward trend in most EU member states in pollutants due to the tightening of emission limits of power plants and the switch to gas.[74] Emission regulations are generally revised downward every few years, taking into account developments in technology.[75]

CHP — and renewables — have been widely recognized both at the European Community level and member state level as technologies that can make a major contribution to achieving targeted greenhouse gas reductions. In December 1997, the CEC formally adopted a resolution for a community strategy to promote CHP and to dismantle barriers to its development.[76] In the resolution, the CEC states that the efficient use of energy from combined heat and power can contribute positively not only to the environmental policies of the European Union, but also to the competitive situation of the EU and its member states and to security of supply. Specifics like recognizing energy efficiency in permitting requirements are not mentioned, but the resolution does state that such measures to promote the use of combined heat and power could include the internalization of external costs and environmental benefits, among other measures.

The proposed Directive on the Promotion of Cogeneration[77] was released on July 7, 2002, in order to provide a framework for achieving EU CHP targets. The Directive obliges member states to publish an analysis of the national potential for "high efficiency" cogeneration; to publish an analysis of the barriers to high efficiency

BOX 2

EUROPEAN COMMISSION DIRECTIVES RELATING TO CHP AND POWER GENERATION

The proposed Directive on the Promotion of Cogeneration was released on July 7, 2002 to provide a framework for achieving EU CHP targets. The Directive obliges Member States to publish an analysis of the national potential for "high efficiency" cogeneration, to publish an analysis of the barriers to high efficiency cogeneration, & to report on progress towards increasing the share of high efficiency cogeneration, including the measures taken to promote it. The high efficiency term is used in place of "quality cogeneration" as used in the UK CHP Assessment (detailed later).

The Directive to Liberalize the Electricity Market, Council Directive 96/92/EC, concerns common rules for the internal market in electricity, & became effective January 8, 1997. The Directive obliges an opening of at least 25% of the European Electricity market by February 1999, 28% by 2002 & 33% by 2005. This directive establishes common rules for the generation, transmission & distribution of electricity. Throughout the directive, preference is given to renewable energy sources & CHP. The level of implementation of this Directive varies among Member States. Energy sector liberalization in Europe is expected to be complete by 2010.

The Directive to liberalize the Gas market, Council Directive 98/30/EC, is to establish common rules for the transmission, distribution, supply & storage of natural gas. It is similar to that for electricity: Member States must gradually liberalize their gas market. The Directive addresses access to the market, operation of systems, & the criteria & procedures applicable to the granting of authorizations for transmission, distribution, supply & storage.

continued on next page

cogeneration; and to report on progress towards increasing the share of high efficiency cogeneration, including the measures taken to promote it. The high efficiency term is used in place of "quality cogeneration" as used in the U.K. CHP Assessment (detailed later).

The CHP Directive relies on output-based qualifying measurements for thermal and electric generation. "Heat efficiency" is defined as the annual useful heat output divided by the fuel input used for heat produced in a cogeneration process and for gross electricity production. In the case of cogeneration with district heating, useful heat output is measured at the point of outlet to the heat distribution network, decreased by a realistic estimation of losses in the distribution network. In the case of other cogeneration applications, useful heat output is measured at the point of use.[78] "Electrical efficiency" is defined as the annual electricity production measured at the point of outlet of the main generators, divided by the fuel input used for heat produced in a cogeneration process and gross electricity production. "Overall efficiency" is defined as the annual sum of electricity production and useful heat output, divided by the fuel input used for heat produced in a cogeneration process and gross electricity production. Annex III of the Directive (See Appendix C.) uses these definitions in the methodology of determining the efficiency of cogeneration production and details what it considers "high efficiency" cogeneration.

BOX 2

The Large Combustion Plant Directive,[82] Council Directive 88/609/EEC, limits the emissions of certain pollutants (including SO2 & NOx) into the air from large combustion plants (50 MW or more). Amendments to the LCP Directive include Council Directives 94/66/EC & 2001/80/EC on the limitation of air emissions of certain pollutants from existing large combustion plants. In June 2000 the EU environment ministers agreed to a set of air emission standards to restrict pollution from large power plants & also agreed to national emissions ceilings for 4 substances: sulfur dioxide (SO2), nitrogen oxides (NOx), volatile organic compounds (VOCs) & ammonia (NH3).[83] National & local authorities define final emission limits through national legislation & permit procedures.

The Integrated Pollution Prevention & Control (IPPC) Directive is Council Directive 96/61/EC. The IPPC has a set of common rules on permitting for industrial installations to minimize pollution from various point sources throughout the European Union. All installations covered by Annex I of the Directive are required to obtain an authorization (permit) from the authorities in the member countries. The IPPC directive contains rules for "integrated" permits that must take into account the whole environmental performance of the plant including emissions to air, water & land, generation of waste, use of raw materials, energy efficiency, noise, prevention of accidents, & risk management. New & esixting installations should comply by 2007.

Permits must be based on the concept of **Best Available Techniques (BAT)**, defined in Article 2 of the IPPC Directive. Sector-specific BAT reference documents (BREFs—guidance) are underway. All BREFs should be completed by the end of 2005; several have been finalized & are available from the European IPPC Bureau.[84] The directive requires the member states to ensure that the technical & economic feasibility of providing for CHP is examined, & where feasibility is confirmed, to develop installations accordingly.[85] CHP is BAT for industrial installations.

Furthermore, in the proposed Directive, high efficiency cogeneration is determined in terms of energy savings in comparison with separate heat and power production. Cogeneration production must provide energy savings of at least 10 percent to qualify as high-efficiency cogeneration (or 5 percent for existing facilities). Line losses of 5-10 percent also are counted in central system (in)efficiency.

A European team of experts analyzed the future for cogeneration in Europe stated in their findings that the most frequent barriers to cogeneration include "bureaucratic procedures for obtaining all required authorizations," and "emissions regulations (that) do not take the higher efficiency of cogeneration systems into account."[79]

The European nonprofit organization promoting combined heat and power, Cogen Europe, believes that emission legislation should reflect more clearly the high efficiency of energy conversion. Some countries have prepared specific legislation on CHP but currently only the Netherlands, Flanders (Belgium), and Denmark take efficiency of energy conversion into account in emission regulations.[80] A recent article in the international journal, *Cogeneration and On-Site Power Production*, called for the adoption of output-based emission standards for many combustion sources, including gas turbines used in CHP applications.[81]

In the **United Kingdom**, the regulatory system does not take into account whether heat is recovered from a prime mover, or whether steam from a boiler is used to drive a turbine; it is the fuel-burning components — the gas turbines, engines, and boilers — that are regulated as combustion processes.[86] But like at the EU level, the efficiency of a CHP installation is beginning to be recognized in other policy mechanisms such as the CHP Quality Assessment.

The U.K. has developed an output-based standard measurement for CHP in order to incentivize its installation. Termed the CHP Quality Assessment (or QA), it provides an emissions standard for determining "good quality" CHP in order for CHP facilities to qualify for financial incentives. (Box 3 details the U.K. CHP Quality Assessment.) The European Union recommends that other member states follow the U.K. lead and include a definition of quality (level of efficiency) for CHP. The QA came from a 1997 European Council directive that member states develop a means to distinguish good-quality CHP.

The standard was not created to streamline environmental permitting, but rather as a measure to qualify for special financial treatment in the electricity sector. The following benefits were available from April 1, 2001:

1. Exemption for good-quality CHP from the Climate Change Levy
2. Enhanced capital allowances for good-quality CHP
3. A level playing field for good-quality CHP within Business Rating.[87]

The aim of the CHP Quality Assessment program is to:

1. Provide a practical, reliable method for quality assessment and monitoring of various types and sizes of CHP scheme. This method is based on the energy efficiency and environmental performance of a CHP plant compared to good alternative energy supply options; and
2. Improve the quality of existing and new CHP schemes in order to enhance the "environmental and other benefits" of CHP.[88]

In its Environmental Action Plan, U.K. Office of Gas and Electricity Markets (OFGEM) supports the greater use of flexible, market-based mechanisms for environmental regulation. OFGEM's role includes issuing Levy Exemption Certificates (LECs) based on qualifying output from accredited generators. One LEC is issued for each qualifying megawatt-hour produced.[90] In the 2002 Budget, the government announced the extension of the exemption to the Climate Change Levy to all good-quality CHP. OFGEM plans to extend the Climate Change Levy exemption to good-quality CHP in the next year.[91]

Many other European countries have taken steps to promote emissions reductions and energy efficiency. Belgium has no explicit programs that support CHP development directly, but a number of incentives, including tax advantages and direct grants, are available for energy-saving investments based on federal government legislation. For instance, cogeneration that satisfies a "quality" standard, like the EC Directive, receives a better gas tariff.[92] "Quality cogeneration" is a gas-fired cogeneration installation whose functioning allows for savings of primary energy of 15 percent in relation to the separate generation of heat and electricity from a reference installation. Belgium has three regional regimes for environmental standards, notably in Flanders.[93]

In the Netherlands, over 50 percent of total electricity generation is from CHP plants.[94] For permitting, NOx limits for gas turbines are corrected for the electrical efficiency of the CHP installation: higher efficiencies are rewarded with a higher NOx standard.[95] The Dutch electricity sector is influenced by the government's

BOX 3

THE UK CHP QUALITY ASSESSMENT

The program involves a Quality Assessment based on a Quality Index (QI). A suite of definitions is being developed to cover the whole range of schemes, applications, sizes, technologies and fuels. It has been taken into account that, regardless of the electrical efficiency, a project that recovers heat will generally be more efficient than one that does not. The Quality Index (QI) methodology is built on the rationale that electricity supplied is more valuable than heat supplied. It compares CHP to separate electricity-only and heat-only alternatives. The QI therefore offers scope for a major improvement over conventional approaches simply based on overall efficiency.

The general form for QI calculation is: QI = X x Efficiencypower + Y x Efficiencyheat

Where: Efficiencypower = annual power supply (MWhe)/annual fuel use (MWh)

Efficiencyheat = annual heat supply (MWhth)/annual fuel use (MWh)

X is a coefficient for power, related to alternative electricity supply options. Similarly Y is a coefficient for heat generation, related to alternative heat generation options. These coefficients vary to reflect conditions affecting particular classes of CHP plant. For a scheme that supplies electricity only, Efficiencyheat is zero.

"Good Quality" CHP is defined as achieving a certain minimum efficiency of heat and electricity production from the CHP project. The required power efficiency is at least 20% (15% until 2005 for existing projects), with a required CHP efficiency that decreases as power output increases. For a small CHP scheme (1-10MW) producing power at 20% efficiency, the required CHP efficiency would by 69%.

Efficiencies are expressed in terms of Gross Calorific Values (GCV). Annual heat supply is the useful heat supplied by the scheme that displaces heat, which would otherwise have to be supplied by boilers or by direct heating.[88]

policies to reduce CO_2 emissions and improve energy sustainability. The 1989 Electricity Act strongly encouraged market entry by decentralized CHP for environmental reasons.[96] Incentives included government subsidies, tax benefits, and other financial perks. Environmental regulations were not an issue.

Denmark is another leader in CHP use. More than 60 percent of the country's electricity production comes from combined heat and power facilities.[97] The development of cogeneration in Denmark has been backed by promotional policies by the government, including a carbon tax containing incentives for cogeneration. The Danish Energy Agency has recently written a report, "Combined Heat and Power in Denmark," that contains a summary of recent government incentives to promote cogeneration in Denmark.[98]

Germany applies airborne pollutants regulations, known as the TA-Luft standards, to gas turbines that allow higher emission limits for higher-efficiency gas turbine systems in order to account for the lower emissions per unit of output achieved by these systems. These standards have been used in other EU countries as a guideline. May 1991 was the last update of the 1986 TA-Luft to conform with Best Available Technique (BAT) requirements.[99]

Greenhouse Gas Cap and Trade Program

In June 2000, the European Commission established the European Climate Change Program (ECCP) to help identify the most environmentally-beneficial and cost-effective additional measures to achieve the Kyoto Protocol target. The CEC has identified particular sectors that could be initially included in a trading program, including electric heat, pulp and paper, cement, iron and steel, refining, and chemicals.[100] Cap-and-trade options include grandfathering, auctions, and updating. The allocation metrics to measure facility-specific data could include using fuel inputs, product output, emissions, or a combination.

In October 2001, the EU adopted a proposal for a directive to establish a cap-and-trade system for various sources of greenhouse gas emissions as one means of meeting the EU emissions targets in the Kyoto Protocol.[101] Under a cap-and-trade program, individual trading entities are initially allocated emission allowances (the right to emit a ton of pollutant) that cumulatively equal the cap or target for the relevant sectors.

The establishment of cap-and-trade programs in Europe and the United States could be an effective way to recognize efficiency while reducing emissions globally and locally. Determining allocations on useful energy output is a potential mechanism to account for efficiency in a combustion system and credit efficient systems under such an emissions reduction program.

IV: SUMMARY AND RECOMMENDATIONS

This report summarizes actions that demonstrate a slight shift toward the use of output-based standards for regulating air emissions from power plants and distributed generation technologies. Output-based emission standards are being recognized at the state and federal levels, in Europe, as well as in models developed by regional organizations and environmental groups. Such standards:

- Create a level playing field for all power generators regardless of plant age or geographic location;
- Address multiple pollutants in one policy or regulation;
- Provide incentives for energy efficiency by linking air emissions to the end energy product; and
- Protect air quality.

The sooner the U.S. adopts output-based emission standards, the sooner the nation will see innovative energy-efficient technologies improve our air quality and enhance our economic trading position internationally. The change in emissions measurement from input-basedto output-based may occur slowly in the U.S. since owners of inefficient power-generation plants realize that they will be disadvantaged by a change in the status quo, yet such a change would increase the energy industry's efficiency and reduce the nation's pollution.

The movement toward output-based emission standards will continue as consumers learn more about how electricity generation affects the environment. Tracking emissions per megawatt or kilowatt-hour is a logical next step in monitoring air quality. Adoption of output-based standards also will reward and encourage the businesses bringing innovative technologies into the marketplace.

Since the use of output-based standards is still relatively new, states need to learn from each other how best to integrate those measures into future emissions-permitting and cap-and-trade programs. Federal direction also will be needed. Regulations must reflect the environmental benefits of more energy-efficient, cleaner technologies. The marketplace is ready for this change. Policymakers must change the means of regulating air emissions if the nation is to enjoy the benefits of innovative energy systems.

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APPENDIX A. STATE-BY-STATE SUMMARIES

State: CALIFORNIA — *Restructured:* SUSPENDED

The California Air Resources Board (CARB) has established a distributed generation certification program using output-based emissions standards for NOx, CO, VOCs, and particulate matter. The regulation went into effect on October 4, 2002, and it applies to distributed generation units that had otherwise been exempt from air pollution control requirements.

California Senate Bill 1298 (which became Chapter 741 on September 27, 2000) mandated that the Air Resources Board adopt a certification program and uniform emission standards (in lbs/MWh) for electrical generation units that are exempt from other state air district permitting requirements. It also required that the emissions standards reflect the best performance achieved in practice by existing electrical generation technologies.

This law requires CARB to:

1. Adopt uniform emission standards for electrical generation technologies that are exempt from air pollution control or air quality management district permit requirements;
2. Establish a certification program for the distributed technologies subject to these standards; and
3. Issue guidance to the 35 state air districts on the permitting or certification of electrical generation technologies subject to the district's regulatory jurisdiction.

SB 1298 mandated that CARB establish two levels of emission standards for affected distributed generation technologies. The first set of standards had to become effective no later than January 1, 2003, and had to reflect the best performance achieved in practice by existing distributed generation technologies that are exempt from district permits. The law also required that, by the earliest practicable date, the standards be made equivalent to the level determined by CARB to be the best available control technology (BACT) for permitted central station power plants in California.[102] The emission standards must be expressed in pounds per megawatt-hour (lb/MWh) in order to reflect the efficiencies of various electrical generation technologies.

The distributed generation certification regulation is available from the Air Resources Board Distributed Generation Internet site at: http://www.arb.ca.gov/energy/dg/dg.htm. CARB also released its final guidance document for the distributed generation certification program in July 2002.[103] In that guidance, CARB set emissions standards for 2003 and 2007, and offered limits for units with and without combined heat and power. In 2005, the CARB will produce a technical review of the distributed generation technologies and emissions criteria in order to determine if any modifications to its certification standards are necessary.

The air quality benefits of combined heat and power (CHP) applications were given special consideration and reflected in their special treatment. Section VII, B. of the guidance states that "efficient" CHP systems will receive an emissions credit for thermal output. Efficient CHP applications must maintain a minimum efficiency of 60 percent in the conversion of the energy in the fossil fuel to electricity and process heat. Thus, the facility's overall lb/MWh can be determined by dividing the facility's emissions, on a pollutant-by-pollutant basis, by the facility's total energy production. The total energy production is the sum of the net electrical production, in megawatts, and the actual process heat consumed in a useful manner, converted to megawatts. More detailed methodologies for calculating the emissions performance standard, and for calculating the CHP credit on an output basis, are provided in the CARB Guidance document appendices C and D.

State: CONNECTICUT *Restructured:* YES

Connecticut in December 2001 made major revisions to its New Source Review program in order to permit major sources on an output basis and to credit thermal energy used. Effective March 15, 2002, these revisions apply to all facilities seeking NSR permitting. The modifications are in Section 22a-174-3a of the Regulation of Connecticut State Agencies (RCSA), "Permit to Construct and Operate Stationary Sources."[104] The impetus for state action was twofold: 1) An understanding of the need to credit a facility's energy efficiency, and 2) the lead taken by the U.S. Environmental Protection Agency's release of draft guidance on permitting combined heat and power technologies in NSR.

Since Connecticut's NSR rule provides for CHP incentives, the output basis will reward more efficient projects. The language states that in determining whether to approve BACT (Best Available Control Technology), "The commissioner shall, among other items, not preclude the establishment of an output based emission limitation as BACT provided such application of BACT improves the overall thermal efficiency of the subject source or modification."[105] The permit requirements for nonattainment areas include a provision allowing the commissioner to take into account an output-based emission limitation as LAER (Lowest Achievable Emissions Rate), provided such application of LAER improves the overall thermal efficiency of the subject source or modification.[106]

On April 23, 2002, Connecticut issued its general permit for distributed generators that applies to multiple pollutants and has an annual emissions cap. The permit is not output-based but will only be in effect until December 31, 2003. After that time, the state Department of Environmental Protection expects to adopt the output-based Regulatory Assistance Project Model Rule for distributed generators[107] (which is highlighted later).

In April 1998, Connecticut's electricity restructuring legislation directed the state Department of Environmental Protection to establish generation performance standards for five pollutants: sulfur dioxide (SO2), nitrogen oxides (NOx), carbon dioxide (CO2), carbon monoxide (CO), and mercury (Hg). The standards are to be implemented when "three of the states participating in the northeastern states' Ozone Transport Commission, as of July 1, 1997, with a total population of not less than 27 million, have adopted such a standard." The state electricity restructuring legislation and subsequent law refer to output-based standards as generation performance standards.

Connecticut's Performance Standard Law is Public Act No. 98-28, Sec. 24 and reads:

> *Sec.24. (NEW) Not later than January 1, 1999, the Commissioner of Environmental Protection shall, by regulations adopted in accordance with chapter 54 of the general statutes, establish uniform performance standards for electricity generation facilities supplying power to end use customers in this state. Such standards shall, to the greatest extent possible, be designed to improve air quality in this state and to further the attainment of the National Ambient Air Quality Standards promulgated by the United States Environmental Protection Agency. Such performance standards shall be based on the fuel used for generation of electricity and shall apply to Electric suppliers' generation facilities located in North America and shall limit the amount of air pollutants, including, but not limited to, nitrogen oxides, sulfur oxides, carbon dioxide, carbon monoxide and mercury, emitted per megawatt hour of electricity produced. Such performance standards may provide for a program for purchase of offsetting reductions in emissions and trading of emission credits. A performance standard established by the Department of Environmental Protection for an individual pollutant pursuant to this section shall go into effect when three of the states participating in the northeastern states' Ozone Transport Commission as of July 1, 1997, with a total population of not less than twenty-seven million at that time, have adopted such standard.*

Thus, the Department of Environmental Protection (DEP) is required to have an output-based standard in place, but that standard need not be implemented until other states in the region have adopted similar standards. The state's purpose was to improve air quality. The regulations target retail electricity suppliers, giving the state the ability to require compliance from out-of-state suppliers. As of September 2002, the state Department of Environmental Protection has produced a draft rule, Draft RCSA Section 22a-174-34, based on the NESCAUM regional model regulation (described later). The draft of "Section 34" has been reviewed by the Connecticut Department of Public Utility Control. As of this report's publication, a final rule was not released.

The Connecticut Department of Environmental Protection also has played an integral role in the development of several of the regional model rules to be discussed later in this report. These include the Regulatory Assistance Project's Model Rule for Distributed Generation and the NESCAUM Model Emissions Performance Standard.

State: DELAWARE *Restructured:* YES

The state's NOx Budget Program uses output-based NOx budget allocations.

State: ILLINOIS *Restructured:* YES

The Illinois Resource Development and Energy Security Act (HB 1599), approved on June 22, 2001, calls for a report on reducing multiple pollutant emissions from fossil-fuel-fired electric generating plants. The state Environmental Protection Agency must report on multi-pollutant strategies for NOx, SO2, and mercury to the House and Senate Committees on Environment and Energy before September 30, 2004, but not before September 30, 2003. Although output-based standards are not explicit in the legislative language, the state EPA plans to study this approach.[108] The new provisions applying to fossil-fuel-fired electric generating plants are contained in the Illinois Environmental Protection Act under Section 9.10, 415 ILCS 5/ (IL Compiled Statutes).[109]

Output-based standards were discussed during development of the state's NOx SIP, but agreement on the issue could not be reached.

State: INDIANA *Restructured:* NO

The state is currently not considering output-based standards in its air quality regulations.

State: IOWA *Restructured:* NO

The state is currently not considering output-based standards in its air quality regulations.

State: MAINE *Restructured:* YES

State has no regulations on an output basis. Lawmakers have discussed the options, seem to think it's a good idea, but have not moved forward on changing any regulations or permits.[110]

State: MARYLAND *Restructured:* YES

The state is currently not considering output-based standards in its air quality regulations.

Note: Information was gained from literature search and state agency Internet sites only.

State: MASSACHUSETTS *Restructured:* YES

The Massachusetts legislature in late 1997 directed the state Department of Environmental Protection to adopt output-based standards[111] for all power facilities engaged in the retail sale of electricity to end users in the Commonwealth. The standards are for any pollutant of concern to public health. The legislation requires that the state implement the standards for at least one pollutant by May 2003, and it will begin with NOx. If other states in the Northeast implement output-based standards for electricity generation in the meantime, Massachusetts can follow suit. The state DEP has not acted on the generation performance standard to date.[112] The regulatory authority is under Massachusetts General Law c. 111, Sections 142A through 142N.

The state legislature and Department of Environmental Protection believe output-based standards will make it easier to regulate sources that are low-emitting and efficient, while high-emitting and inefficient facilities may need to reduce emissions or purchase allowances from low-emitting sources in order to comply with requirements. The

Department of Environmental Protection's background document on the rule declares that "allocating the available state budget based on electrical output promotes pollution prevention in the electric sector by rewarding energy efficiency, and promotes fair competition in the energy market by leveling the environmental playing field for all generators of electricity."[113]

Chapter 111, Section 142N in Massachusetts General Law states that:

> *Section 142N. For the purpose of preventing, mitigating, or alleviating impacts on the resources of the commonwealth and to the health of its citizens from pollutants emitted by fossil fuel-fired electric generation facilities serving retail customers in the commonwealth, the department of environmental protection shall, in consultation with the office of the attorney general and the department of telecommunications and energy, promulgate rules and regulations to adopt and implement for fossil fuel-fired electric generation facilities uniform generation performance standards of emissions produced per unit of electrical output on a portfolio basis for any pollutant determined by the department of environmental protection to be of concern to public health, and produced in quantity by electric generation facilities. The department of environmental protection shall have said uniform performance standards for at least one pollutant in effect on, but not before, May 1, 2003, unless three or more other northeastern states enact similar standards before that date, in which case the department of environmental protection may adopt such standards prior to May 1, 2003. The department of environmental protection shall issue annually, by March first of each year, an annual report detailing the implementation and compliance of said program, its standards, and its companion rules and regulations.*[114]

As Massachusetts has not developed these standards to date, it is not known whether stipulations for combined heat and power facilities would be included. The state in April 2001 made available a developer's guide to regulations, policies, and programs that affect renewable energy and distributed generation facilities in the Commonwealth. The guidebook references the generation performance standards required in the restructuring legislation.

On another front, in April 2001, Massachusetts took an aggressive step to improve local air quality by targeting reductions at its six dirtiest power plants. Regulation 310 CMR 7.29, "Emissions Standards for Power Plants," requires reductions of NOx, SO2, CO2, and mercury beginning in 2004 (or 2006 depending on reduction choices made by the individual plant). This is accomplished by establishing output-based emission rates for NOx, SO2, and CO2 and establishing an emissions cap on CO2 and Hg emissions from affected facilities. A summary of the standards, compliance paths, and dates are as follows.

MASSACHUSETTS POWER PLANT CLEAN UP STANDARDS[115]

(MA DEP Regulation 310 CMR 7.29)

Pollutant	*Emission Standard*	*Standard Pathway Compliance Dates*	*Repowering Pathway Compliance Dates*
NOx	1.5 lbs/MWh	October 1, 2004	October 1, 2006
SO2	6.0 lbs/MWh	October 1, 2004	October 1, 2006
SO2	3.0 lbs/MWh	October 1, 2006	October 1, 2008
CO2	1800 lbs/MWh annual avg.	October 1, 2006	October 1, 2008

The regulation defines "output-based emission rate" as an emission rate for any pollutant, expressed in terms of actual emissions in pounds over a specified time period per megawatt-hour of net electrical output produced over the same time period. "Output-based emission standard" is defined as the emission standards for each applicable pollutant, expressed in terms of pounds of pollutant emitted per megawatt-hour of net electrical output produced. The regulation is available online at: http://www.state.ma.us/dep/bwp/daqc/files/regs/729final.doc.

The Massachusetts NOx SIP allocates allowances to generation sources on an output basis. To judge emissions on an output rather than input basis, the state must add data on electrical output, which the Ozone Transport Commission points out is widely available.[116] The state's NOx Allowance Trading Program for 2003 includes an output-based allocation for generating units with useful steam output. The Department of Environmental Protection provides a formula for calculating the steam allocation, which is then added to the electrical output allocation, thereby promoting energy efficiency and recognizing two useful energy outputs. Regulation 310 CMR 7.28 applies to any source greater than 25 MW or greater than 250 mmBtu/hr boiler size. If a source is a CHP facility, then the Department of Environmental Protection allows credit for the CHP portion.[117]

The Massachusetts Department of Environmental Protection also has played an integral role in the development of several of the regional model rules to be discussed later in this report. These include the Regulatory Assistance Project's Model Rule for Distributed Generation and the NESCAUM Model Emissions Performance Standard.

State: MICHIGAN *Restructured:* YES

The state is currently not considering output-based standards in its air quality regulations.

On October 9, 2001, Michigan's legislature proposed Senate Bill 693, a multi-pollutant bill with output-based standards for 25 MW or greater electric power generators, but the legislation did not move.

State: MINNESOTA *Restructured:* NO

The state is currently not considering output-based standards in its air quality regulations.

State: NEW HAMPSHIRE *Restructured:* YES

To the extent it can, New Hampshire tries to regulate all air emissions on an output basis and is currently updating many of its regulations to reflect this.[118] New Hampshire has proposed output-based standards targeting four pollutants from the state's highest-polluting power plants. The state in January 2001 released its Clean Power Strategy, which calls for emissions caps based on electricity output for all large electrical generating facilities in the state: put another way, it does not "grandfather" any existing power plant. This action resulted in the Clean Power Act, House Bill 284, which was signed into law in May 2002. The law requires emissions reductions in SO2, NOx, CO2, and mercury.

In New Hampshire's NOx Budget Program[119] that will go into effect in 2005, allocations will be determined on an output-basis. The allocation language is in the New Hampshire Code of Administrative Rules, Part Env-A 3200. The rule extends New Hampshire's NOx Budget Trading Program for the period 2006 and beyond. This cap-and-trade program does not set output-based "standards," but instead establishes output-based allowance allocations.[120] The Department of Environmental Services followed EPA's guidance for output-based allocations, which includes provisions for thermal heat output for cogeneration; however, there currently are no applicable CHP sources in New Hampshire.

New Hampshire believes output-based standards are a way to encourage greater efficiency and pollution prevention. The state also argues that such standards would help create a level playing field and advance competitive markets.

The state also has a new rule regarding smaller electric generating units (EGUs), Env-A 3700, based on legislation passed during the 1999 legislative session. In House Bill 649,[121] the legislature found it necessary to address emissions from the growing number of smaller generators that were not subject to NOx requirements. The bill acknowledged that many businesses have sought to control their high electric costs by using internal combustion engine electricity generators that run on fossil fuels. The legislature recognized that these generators have increased nitrogen oxide (NOx) emissions and that additional units could substantially increase such emissions and increase electric rates for customers purchasing electricity from sources subject to more stringent NOx regulations.

The state views this rule as market-based. Sources emitting NOx > 7 lb/MWh are subject to either paying fees, buying credits, or installing controls. A new provision was added to RSA 125-J, NOx-Emitting Generation Source Requirements, exempting emissions above 7 lb/MWh attributable to cogeneration.

The New Section 125-J:13 reads:

I. Each NOx-emitting generation source emitting more than 7 pounds of NOx per megawatt hour generated shall be required to supply to the department NOx emissions information, and the amount of kilowatt hours actually produced during each period listed in subparagraph II(b). Additionally, except as provided either by paragraph I or II of this section, each NOx-emitting generation source shall acquire NOx budget allowances, emissions reduction credits, or other emissions reduction mechanisms on the same basis as a NOx budget source for all of its NOx emissions. However, NOx-emitting generation sources shall not be required to acquire NOx budget allowances, emissions reduction credits, or use emissions reduction mechanisms for the first 7 pounds of NOx emitted for each megawatt-hour of electricity produced and any amounts of NOx above such first 7 pounds that are attributable to the provision of other, non-electric services provided by the generating source, including but not limited to, steam and heat, and any amounts of NOx emitted during any period when the NOx-emitting generation source is operating to provide power during a power shortage at the request of any governmental authority or provider of electrical power to the public generally.[122]

The New Hampshire Department of Environmental Services has also played an integral role in the development of several of the regional model rules to be discussed later in this report. These include the Ozone Transport Commission NOx Model Rule and the NESCAUM Model Emissions Performance Standard.

State: NEW JERSEY — *Restructured:* YES

New Jersey's electricity restructuring legislation, approved in February 1999, addressed the potential need for an emissions performance standard, referred to as an environmental portfolio standard. The law directed the Board of Public Utilities, in consultation with the Department of Environmental Protection, to adopt and implement an emission performance standard if such standards became necessary to meet ambient air quality standards beyond current federal and regional actions. A stipulation in the New Jersey legislation also required the adoption of this emissions performance standard if two other states within the PJM interconnection area, comprising at least 40 percent of retail electricity sales, adopt similar standards.

The legislation allows the state Department of Environmental Protection to take action if existing air quality policies do not go far enough to protect citizens from pollution of power plants within the state and the region. In addition, the state will be required to take action if neighboring states adopt this type of emissions regulation. No state has done so to date, and New Jersey has made no decision to promulgate an emissions performance standard.[123]

The emissions portfolio standard language is found within the "Electric Discount and Energy Competition Act," and is as follows:

Public Law 1999. Chapter 23, Section C.48:3-87 Environmental disclosure requirements.

38. c. (1) The board [of public utilities] may adopt, in consultation with the Department of Environmental Protection, after notice and opportunity for public comment, an emissions portfolio standard applicable to all electric power suppliers and basic generation service providers, upon a finding that:

(a) The standard is necessary as part of a plan to enable the State to meet federal Clean Air Act or State ambient air quality standards; and

(b) Actions at the regional or federal level cannot reasonably be expected to achieve the compliance with the federal standards.

(2) The board shall adopt an emissions portfolio standard applicable to all electric power suppliers and basic generation service providers, if two other states in the PJM power pool comprising at least 40 percent of the retail electric usage in the PJM Interconnection, L.L.C. independent system operator or its successor adopt such standards.[124]

The legislation's goal was to prevent large amounts of high-emission generation in the state. As part of New Jersey's restructuring legislation, generation companies also are required to disclose environmental characteristics, such as power plant fuels used and emissions generated. This environmental disclosure should allow consumers to understand what's being emitted to produce their electricity.

Certain states — including Connecticut, Massachusetts, New Hampshire, New York, and New Jersey — allocate the allowances available under the NOx Budget Program in ways that recognize energy efficiency. Their purpose is to reduce emissions from power plants and large stationary sources. The New Jersey NOx Budget Program is located in New Jersey Administrative Code, Title 7, Chapter 27, Subchapter 31 and available online at: www.state.nj.us/dep/aqm/rules.htm. The 2003 allocations will be in part on an output basis: both input-based and output-based emission rates are provided. New Jersey also is committed to adopting output-based standards for distributed generation, based on the Ozone Transport Commission's recommendations.[125]

Finally, New Jersey has reached agreement with power companies to reduce multi-pollutants at power plants in the state. This action does not result from regulation but rather is an enforcement action targeting NSR violations. From the state's greenhouse gas initiative came a settlement with Public Service Electric & Gas to reduce CO2 from New Jersey's fossil-fueled electric generating units by a certain amount of pounds per megawatt-hour (MWh) in 2006.[126]

State: NEW YORK *Restructured:* YES

Governor Pataki set up a Greenhouse Gas Task Force to develop policy recommendations, one of which is a multi-pollutant approach for electric generators. A final report of policy recommendations was to be completed by May 2002.

For distributed generation, the Department of Environmental Conservation is under state order to revise emissions standards, beginning in 2000. Output-based standards are being considered.

Counties within the state have proposed their own actions for limiting carbon dioxide emissions on an output basis. In New York City, the City Council put fourth a CO2 proposal for a declining CO2 emissions performance standard for EGUs greater than 25 MW located in New York City. In Suffolk County, government put forth a CO2 law in June 2001 to have a CO2 emissions rate for all EGUs and steam generating units must be set in lbs/MWh in March 2002. Nassau County also has looked into output-based standards.

State: OHIO *Restructured:* YES

The state is currently not considering output-based standards in its air quality regulations.

State: PENNSYLVANIA *Restructured:* YES

The state does not currently use output-based emissions standards in its air quality regulations. The issue of output-based emissions standards or generation performance standards was raised during the comment period for the state NOx SIP, but action was not taken. The state is in preliminary stage of considering a general permit for distributed generation and is aware of the RAP model rule.

State: RHODE ISLAND *Restructured:* YES

The state is currently not considering output-based standards in its air quality regulations.

State: TEXAS *Restructured:* YES

Effective June 1, 2001, the Texas Commission on Environmental Quality (CEQ)[127] established a standard air-emissions permit for NOx from distributed generation in order to encourage the most energy-efficient configurations, such as combined heat and power. The Air Quality Standard Permit for Electric Generating Units (EGU),[128] Texas

Administrative Code (TAC) Rule 106.511, is a standard permit that was designed to be an expedited method of authorizing clean electric generating units in the state.

The permit, issued under Texas Clean Air Act's Health & Safety Code Sections 382.011, provides a streamlined preconstruction authorization mechanism for electric generating units that are not prohibited by other state or federal permitting statute or regulation. The distributed generation standard is output-based (in lbs/MWh) and establishes pre-certification requirements for a power system.

The standard permit applies to all electric generating units that emit air contaminants, regardless of size, and it reflects BACT (Best Available Control Technology) for electric generating units on an output basis in pounds of NOx per megawatt hour, adjusted to reflect a simple cycle power plant.

For this air quality permit, the state has been divided into two regions — East Texas and West Texas — in order to address ozone nonattainment problem in the East Texas region. In 2005, the permit will require stricter emissions requirements, and the standards for units then will be determined by hours of operation.

The distributed generation permit recognizes that combined heat and power units produce two useful energy outputs, in the form of electricity and heat, and it gives credit for this dual output. The state CEQ produced a guideline, which can be found at: http://www.tnrcc.state.tx.us/permitting/airperm/nsr_permits/files/segu_permitonly.pdf. To meet the emission standards, CHP units may take credit for useful thermal output at the rate of one megawatt-hour for each 3.4 million BTUs of heat recovered. If a CHP unit is not pre-certified by the manufacturer, the owner or operator may submit documentation of the system to receive a CHP credit.

The CHP credit is designed to encourage users to install and use CHP in order to improve the efficiency of generating units where there is a valid need for the recovered heat. In a supplement document, the CEQ offers an example of how this credit works for a 10-megawatt CHP unit.

The Texas CEQ purports that the permit's standards will allow for the cleanest reciprocating engines as well as turbines, microturbines, and fuel cells. This approach should allow the use of more efficient equipment; give an incentive for using CHP without setting standards that would require it; and provide economic incentive for reliable power to be generated at the point of use, as opposed to relying on central plant power with emergency backup.

State: VERMONT *Restructured:* NO

In the mid-1990s, the state legislature introduced multi-pollutant, output based standards, but nothing progressed. The state is monitoring efforts in other New England states on addressing electric plants greater than 25 MW and monitoring efforts on the RAP Model Rule for distributed generation.

State: WISCONSIN *Restructured:* NO

The state is currently not considering output-based standards in its air quality regulations.

APPENDIX B. STATE AIR QUALITY BOARD CONTACTS

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CONNECTICUT *Restructured:* YES

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ILLINOIS *Restructured: YES*

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MARYLAND *Restructured: YES*

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MASSACHUSETTS *Restructured: YES*

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MICHIGAN *Restructured: YES*

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NEW HAMPSHIRE *Restructured: YES*

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OHIO *Restructured: YES*

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PENNSYLVANIA *Restructured: YES*

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WISCONSIN *Restructured: NO*

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APPENDIX C. EUROPEAN COMMISSION PROPOSED CHP DIRECTIVE

ANNEX III OF THE CHP DIRECTIVE COM(2002) 415 FINAL

a) High-efficiency cogeneration

For the purpose of this Directive, high-efficiency cogeneration production shall fulfill the following criteria:

- production from new cogeneration units shall provide primary energy savings of at least 10 percent compared with the references for separate production of heat and power;
- production from existing cogeneration units shall provide primary energy savings of at least 5 percent compared with the references for separate production of heat and power;
- production from cogeneration units using renewable energy sources and from cogeneration installations with an installed capacity below 1 MWe providing primary energy savings in the range 0-5 percent may qualify as high-efficiency cogeneration;
- Member States may introduce principles whereby production from cogeneration units below the thresholds referred to in this Annex may be considered to be partially fulfilling the efficiency criteria. If such principles are applied, appropriate methodologies for determining the reduced efficiency of such production, calculated in proportion to the reduced primary energy savings, shall be developed by the member state and shall be notified to the Commission. In such cases, the reduced efficiency of the cogeneration production shall be clearly displayed on the certificate of origin.

b) Calculation of primary energy savings

The amount of primary energy savings provided by cogeneration production defined in accordance with Annex II to this Directive shall be calculated on the basis of the following formula:

$$\text{PES} = \left[1 - \frac{1}{\frac{\text{CHP H}\eta}{\text{Ref H}\eta} + \frac{\text{CHP E}\eta}{\text{Ref E}\eta}} \right] \times 100\%$$

Where: **PES** is primary energy savings

CHP Hη is the heat efficiency of the cogeneration production

Ref Hη is the heat efficiency of the reference for separate heat production

CHP Eη is the electrical efficiency of the cogeneration production

Ref Eη is the electrical efficiency of the reference for separate electricity production

Subject to prior notification to the Commission, member states may use other formula leading to the same results to calculate the primary energy savings from cogeneration. In the cases where alternative formulas are used, such formula shall be published by the member state.

c) Efficiency reference values for separate production of heat and electricity

The principles for defining the references for separate production of heat and electricity referred to in Article 5(2) and in the formula set out in paragraph b) of this Annex shall establish the operating efficiency of the separate heat and electricity production that cogeneration is assumed to displace.

To define the efficiency reference values, the following principles shall be applied:

1) For new **cogeneration units** as defined in Article 3, the comparison with new separate electricity production shall be based on the principle that similar fuel categories are compared. The following indicative efficiency reference values for new separate electricity production may be used:

INDICATIVE EFFICIENCY REFERENCE VALUES FOR NEW SEPARATE ELECTRICITY PRODUCTION

Fuel category	*Operating efficiency*
Natural gas	55%
Coal	42%
Oil	42%
Renewables and waste	22-35%

In the case of cogeneration units connected at the electricity distribution system, the reference values provided in the above table may be lowered with 5-10% to take account of avoided network losses.

2) For new **cogeneration units** as defined in Article 3, the indicative efficiency reference value of new separate heat production shall be an operating efficiency of 90 percent. In the case of heat production based on oil or coal, the efficiency reference value may be lowered to 85 percent. In the case of heat production based on renewable energy sources or waste, the efficiency reference value may be lowered to 80%. In the case of high temperature steam used for industrial processes, the reference values for separate heat production may be lowered to 80 percent.

3) For **existing cogeneration units** as defined in Article 3, the efficiency reference value for separate electricity production shall be based on the average operating efficiency of the national fossil-fuelled electricity production. Where appropriate, possible cross-border trade in electricity having an impact on the reference values may be taken into account.

4) For **existing cogeneration units** as defined in Article 3 the efficiency reference value for separate heat production shall be based on the average operating efficiency of the national heat production mix.

5) Subject to prior notification to the Commission, member states may include additional aspects in the national criteria for determining the efficiency of cogeneration.

APPENDIX D: CLEAN AIR ACT REGULATIONS & PERMITTING ISSUES

The 1990 **Clean Air Act** is a federal law covering the entire country, but the states do much of the work to carry out the act. For example, a state air pollution agency can hold a hearing on a permit application by a power or chemical plant, and it can fine a company for violating air pollution limits. Under this law, EPA sets limits on how much of a pollutant can be in the air anywhere in the United States. This authority ensures that all Americans have the same basic health and environmental protections. The law allows individual states to have stronger pollution controls, but states are not allowed to have weaker pollution controls than those set for the whole country.

Under CAA, states had to develop **state implementation plans** (SIPs). A SIP is a collection of the regulations a state will use to clean up polluted areas. The Environmental Protection Agency (EPA) must approve each SIP, and if a SIP isn't acceptable, EPA can take over enforcing the Clean Air Act in that state.

Under the CAA, **permits** are issued by states or, when a state fails to carry out the Clean Air Act satisfactorily, by EPA. The permit includes information on which pollutants are being released, how much may be released, and what kinds of steps the source's owner or operator is taking to reduce pollution, including plans to monitor (measure) the pollution.

For most electrical generation sources, the primary air pollution control program of concern is **New Source Review (NSR)**. NSR is a district preconstruction program that governs the construction of major new and modifying stationary sources. NSR is intended to ensure that these sources do not prevent the attainment, or interfere with the maintenance, of the national ambient air quality standards.

Title V of the 1990 Clean Air Act Amendments requires all major sources and some minor sources of air pollution to obtain an operating permit. A Title V permit grants a source permission to operate. The permit includes all air pollution requirements that apply to the source, including emissions limits and monitoring, record keeping, and reporting requirements. It also requires that the source report its compliance status with respect to permit conditions to the permitting authority.

Attainment and Nonattainment areas are designated for a few common air pollutants which can injure health, harm the environment, and cause property damage. EPA calls these pollutants "criteria air pollutants" because the agency has regulated them by first developing health-based criteria (science-based guidelines) as the basis for setting permissible levels. One set of limits (primary standard) protects health; another set (secondary standard) is intended to prevent environmental and property damage. A geographic area that meets or does better than the primary standard is called an attainment area; areas that don't meet the primary standard are called nonattainment areas. EPA has estimated that about 90 million Americans live in nonattainment areas.

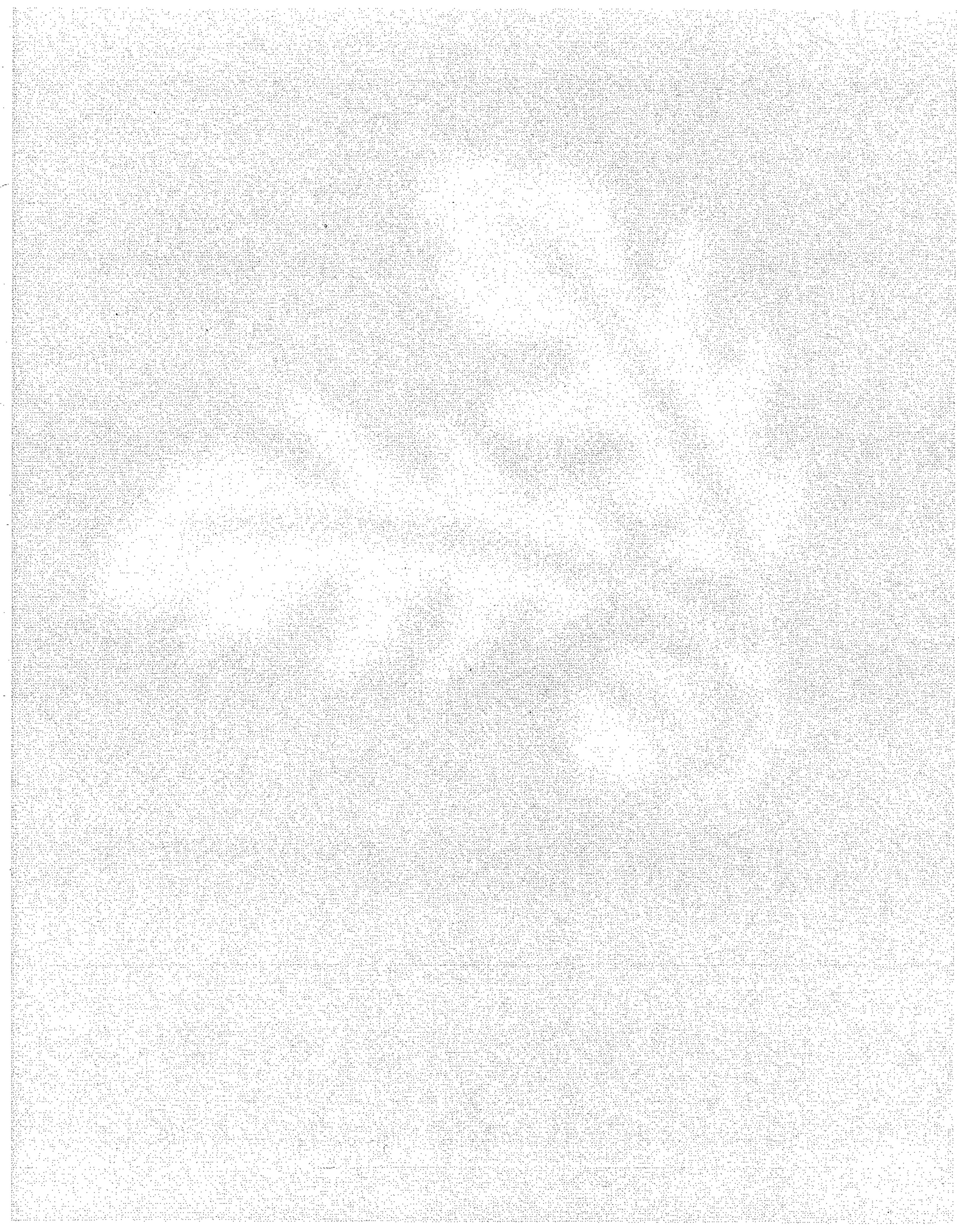

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Exhibit 12

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2001-GT-399

THE W501G TESTING AND VALIDATION IN THE SIEMENS WESTINGHOUSE ADVANCED TURBINE SYSTEMS PROGRAM

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ABSTRACT

The Siemens Westinghouse Advanced Turbine System (ATS) has the ultimate goal of achieving greater than 60% LHV-based net plant thermal efficiency, less than 10 parts per million NOx emissions, a 10% reduction in cost of electricity, and reliability-availability-maintainability (RAM) equivalent to modern advanced power generation systems. The ATS program, which is supported by the U.S. Department of Energy, introduces advanced technologies in three evolutionary steps to minimize risks and to increase the net benefits of the program. The W501G, the first step in the ATS engine introduction, incorporates many ATS technologies such as closed-loop steam cooling, advanced compressor design, and high temperature materials. The lead unit has completed full-load testing at the City of Lakeland McIntosh #5 site in Lakeland, FL and has produced power and revenue for Lakeland Electric since May 2000. Results from the testing are presented and future developments are discussed. Building on the current W501G, advancements will include steam-cooled turbine vanes and leakage enhancements. Continuing this low risk step-wise introduction of new technology, the W501ATS engine adds further advanced designs that achieve the program objectives. Siemens Westinghouse is also infusing ATS technologies into its mature frames in both new units and service upgrades to maximize the benefit of the program.

INTRODUCTION

The Advanced Turbine Systems Program (ATS) funded by the U.S. Department of Energy, Office of Fossil Energy, is an ambitious multi-year effort whose goal is to develop technologies necessary for achieving significant increase in natural gas-fired power generation plant efficiency, a decrease in cost of electricity, and a reduction in harmful emissions, while maintaining the current state-of-the-art reliability, availability, and maintainability (RAM) levels. This thee-phase technology development and demonstration program was started in 1992 and will be completed in 2001 [1–6].

To achieve the ATS Program goals for performance, emissions, electricity cost, and mechanical reliability, significant advancements were required in key technologies applied in gas turbine design. Successful developments were carried out in technologies relating to aerodynamics, combustion, cooling, sealing, materials, and coatings.

The W501ATS engine incorporates new technologies, as well as proven design features developed over the last 50 years and employed successfully in the W501 series of heavy-duty

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industrial and utility engines [7]. These proven design features include single-shaft, two-bearing rotor; cold-end generator drive; compressor blade rings; low-alloy-steel rotor discs; curvic-clutched turbine rotor; four-stage turbine; cooled and filtered rotor cooling air; single first-stage turbine vane segments; tangential exhaust struts; and individual combustor baskets. The W501ATS engine is the latest in successful designs evolving from proven predecessors such as the 186 MW W501F and the 253 MW W501G [8, 9].

EVOLUTIONARY APPROACH

Siemens Westinghouse solicits input from an industry advisory panel comprised of members from major U.S. and international utilities and independent power producers. Based on the input from this panel and market analyses, Siemens Westinghouse is pursuing an evolutionary introduction of the ATS, which incorporates ATS-technology in stages culminating in an engine that meets or exceeds all of the program objectives. This approach has two main advantages. First, the evolutionary approach mitigates the risk associated with introducing multiple, advanced technologies simultaneously. Second, the early introduction of ATS technology expands and accelerates the benefit of the program, as compared with limiting the technologies to only the ATS engine.

The evolutionary approach is shown schematically in Figure 1. First, the introduction of the ATS frame begins with the W501G. Many ATS technologies are incorporated in the W501G and are discussed later. Second, from the initial W501G, future enhancement include steam-cooled turbine vanes, leakage improvements, and increased burner temperature. Third, the W501ATS engine evolves from the W501G, which reduces development risks through early demonstration of many critical technologies.

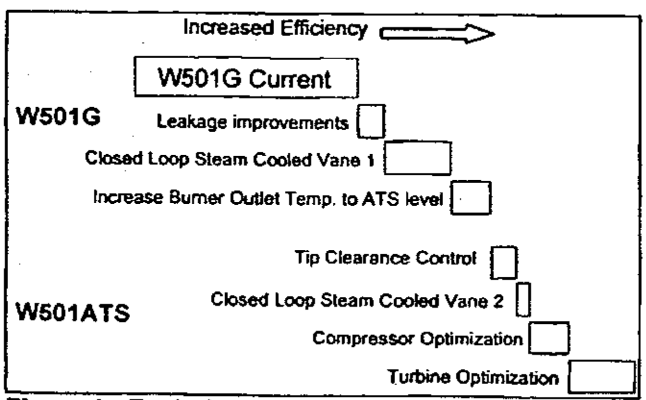


Figure 1 - Evolutionary approach leading to the ATS engine

Siemens Westinghouse is further expanding the benefits of the ATS program by introducing ATS-developed technologies into its mature product lines. For example, the latest W501F incorporates ATS-developed brush seals, coatings, and compressor technology. Furthermore, many of these technologies can be retrofitted into operating units.

Because the F frame accounts for a majority of current new unit sales, this infusion of technology yields significant savings in fuel and emissions. Figure 2 shows the total impact of Siemens Westinghouse ATS technology on CO_2 emissions. Note that much of the net benefit is the result of Siemens Westinghouse's approach of expediting and expanding ATS technology through evolutionary introduction and infusion into mature frames.

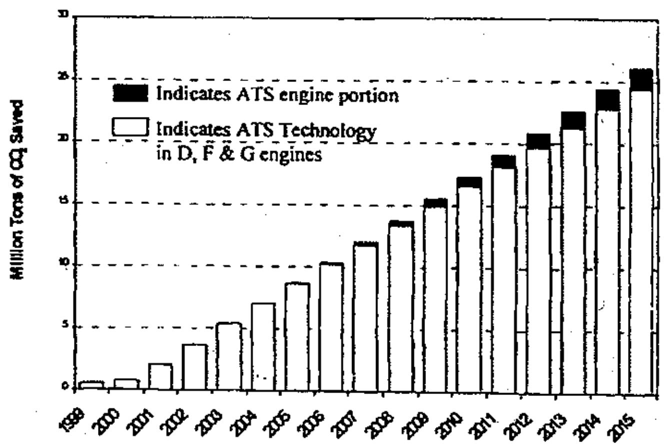


Figure 2 - CO_2 net reductions from ATS Technology

ATS TECHNOLOGY IN OPERATION

The W501G is the first major introduction of the ATS Technology. The W501G incorporates the following ATS engine features:

- ATS advanced 3D compressor
- Advanced brush seals and abradable coatings
- Closed-loop steam cooling
- High temperature thermal barrier coatings
- ATS Row 4 turbine blade.

<u>ATS Advanced 3D Compressor</u>

The W501G incorporates the first sixteen stages of the 27:1 pressure ratio, nineteen-stage, ATS compressor with slight modification of the last three stages, and with vanes 1 and 2 fixed instead of variable. As a result, the W501G operates the ATS mass flow of 558 kg/sec (1230 lbs./sec), but at a pressure ratio of 19:1 – optimized for the G cycle performance.

The design is based on three-dimensional inviscid flow analyses and on custom-designed, controlled-diffusion airfoil shapes. Controlled-diffusion airfoil design technology has been successfully applied in the aircraft industry for many years. The mechanical integrity of each stationary and rotating airfoil was verified by finite element analyses to satisfy steady stress and endurance strength criteria. Each airfoil was tuned to avoid potentially harmful resonant frequencies.

To verify the aerodynamic performance and mechanical integrity of the new high pressure ratio design, the full-scale W501ATS compressor was manufactured and tested in 1997 at a specially-designed facility at the U.S. Navy Base in Philadelphia. To reduce the required power to the 25 MW available at the test facility, the compressor test was carried out at subatmospheric inlet conditions.

The ATS-developed compressor technology has also been retrofitted into the W501F product line. Using the analytical techniques developed and proven in the ATS program, the W501F compressor was upgraded in the latest improvement to this successful frame. This advanced compressor is utilized on new W501F units. In addition, the redesigned compressor can be retrofit to any 42 W501Fs that were built with the original W501F compressor. Applying this ATS technology to the W501F expands the benefit of the ATS program since the W501F compromises more than 70% of future units that are sold or on order at Siemens Westinghouse.

Brush Seals and Abradable Coatings

To minimize air leakage, as well as hot gas ingestion into turbine disc cavities, brush seals were incorporated into the W501ATS engine design at several locations: under the compressor diaphragms, at the turbine disc front, under turbine rims, and at the turbine interstages. Tests were carried out on test rigs for the different brush seal locations to develop effective, rugged, reliable, and long life brush seal systems. At the Philadelphia U.S. Navy Base, full-scale brush seals were tested as part of the ATS Compressor test, which verified the brush seal low leakage and wear characteristics.

To date. ATS-developed brush seals have been successfully incorporated and operated in W501G and later W501F product lines. Pre- and post-upgrade tests have demonstrated performance improvement in retrofit applications.

Considerable performance benefits can be obtained by reducing compressor and turbine blade tip clearances. Abradable coatings permit tip clearances to be minimized without fear of damaging hardware, and they provide more uniform tip clearances circumferentially. Abradable coatings, identified for compressor and turbine applications, were tested to determine abradability, tip-to-seal wear rate, and erosion characteristics. These ATS-developed abradable coatings have been incorporated into the W501F and W501G compressor and front turbine stages (1 and 2). The later turbine stages (3 and 4) employ shrouded blades with honeycomb seals.

Closed-Loop Steam Cooling

Using closed-loop steam cooling on transitions and turbine stationary components has two advantages. First, more compressor delivery air is available for premixing with the fuel gas in the combustor hot end. This allows very lean premixed combustion and makes possible the restriction of NOx emissions to single digits. Second, closed-loop steam cooling significantly improves cycle efficiency by reducing the amount of chargeable air used for cooling and sealing.

The ATS transitions, which duct the hot combustor exit gases to the turbine inlet, are closed-loop steam cooled with air as an alternate coolant at part load. Steam enters the engine through four external connections and is routed to each transition supply manifold through internal piping. The supply manifold feeds the steam to an internal wall cooling circuit. After cooling the transition walls, the steam is collected in an exhaust manifold and ducted out of the engine. The W501G employs the ATS transition.

High-Temperature Thermal Barrier Coatings

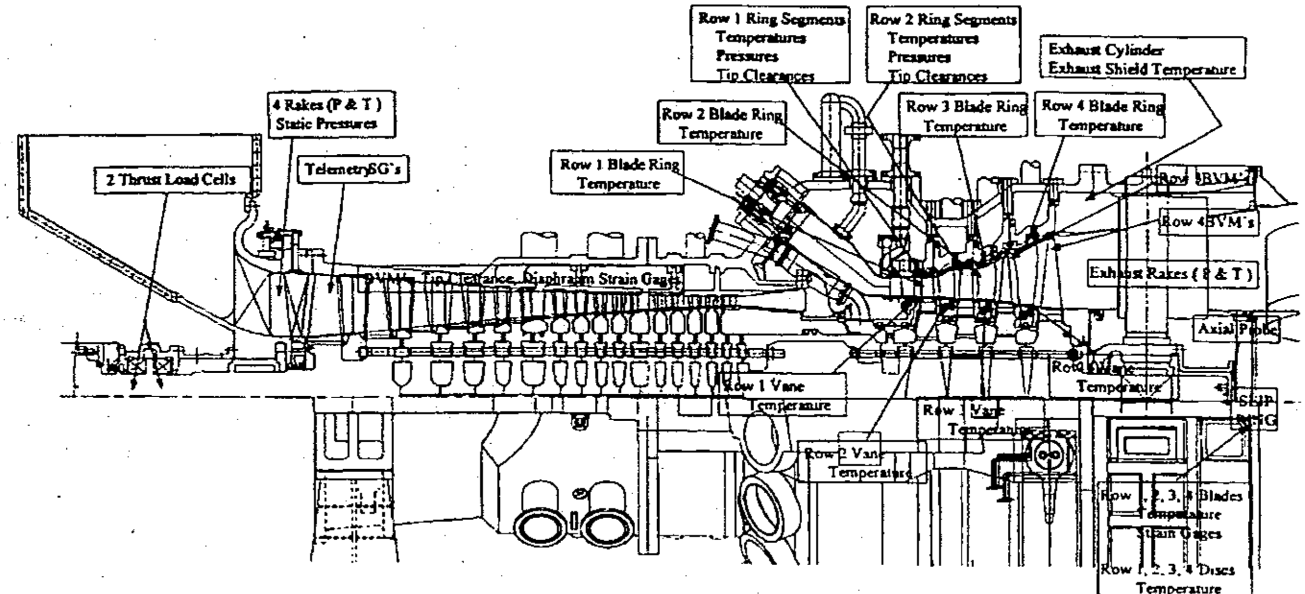
Thermal barrier coatings are an integral part of the W501ATS engine design. A development program is in progress to develop an advanced bond coat/TBC system with a projected service life of more than 24,000 hours. Different bond coats and ceramic materials were evaluated under accelerated oxidation test conditions and down selected. An advanced bond coat/TBC system mechanical integrity and durability was demonstrated in more than 24,000 hours of cyclic testing at 1010°C (1850°F). This advanced bond/coat TBC system has been incorporated on the W501G Row 1 and 2 blades. This coating will improve both the life and durability of these parts, and it can potentially improve future engine performance by reducing the amount of cooling air required.

ATS Row 4 Turbine Blade

The 25% increase in engine mass flow, compared with the baseline F class machines, necessitated an advanced design Row 4 turbine blade to avoid increasing turbine exhaust losses. The ATS Row 4 blade is an uncooled, interlocked, Z-shrouded, cast airfoil. Because the W501G employs the ATS compressor and associated massflow, this blade was first introduced on the W501G. On the first W501G at the City of Lakeland McIntosh #5 site, the blade is instrumented with vibration monitors and strain gauge telemetry. In testing to date the blade has performed as predicted in both aerodynamic performance and mechanical strength.

ENGINE TEST RESULTS

The first W501G was ignited in April 1999, at the City of Lakeland, Macintosh #5 site. The unit has undergone extensive



testing and verification. Since March 2000, the customer has dispatched the unit based on power demands. This lead W501G engine has accumulated over 239 Starts and 850 Fired Hours as of November 2000. Currently, the unit operates in a simple cycle mode with a Once-Through-Steam-Generator for cooling steam production. Construction of the combined cycle plant is underway and will complete in 2002. The W501G Design Plant Performance is shown in Table 1.

Table 1 - W501G Design Plant Performance

Power, Net MW		253
Heat Rate,	kJ/kW-Hr	6,206
	BTU/kW-hr	5,884
Air Flow,	kg/sec	558
	Lbs./sec	1,230
Pressure Ratio		19.5:1

The test program included over 3000 sensors and measured parameters. An engine schematic showing the various sensors is shown in Figure 3. The test program consisted of two phases –emissions/performance mapping and thermal paint testing. For the emissions/performance mapping phase, testing targeted combustion system variables and provided engine performance mapping for different operating conditions such as IGV position and exhaust temperature.

Following the initial testing, turbine flowpath components and combustion components were prepared with thermally reactive paint and installed. The thermally reactive paint changes colors based on exposed temperature. This method is used extensively in aero engine validation since it provides a complete and accurate temperature map of the components at operating conditions. To react the thermal paint, the engine was ramped up to full load, ran for approximately five minutes at full load and then shutdown. The thermal paint test was conducted in two phases. In July 2000, the transitions and row 1 vanes were painted and tested. These components are removable without a major cover lift. In October 2000, a full paint test was conducted which included all turbine blades and vanes and areas of the rotor. Figure 4 shows the scope of the painted components. In addition to the base design, several components were installed with different cooling schemes. The different schemes were tested to evaluate possible cooling flow reductions and component durability enhancements. Both tests were conducted successfully and results are being evaluated.

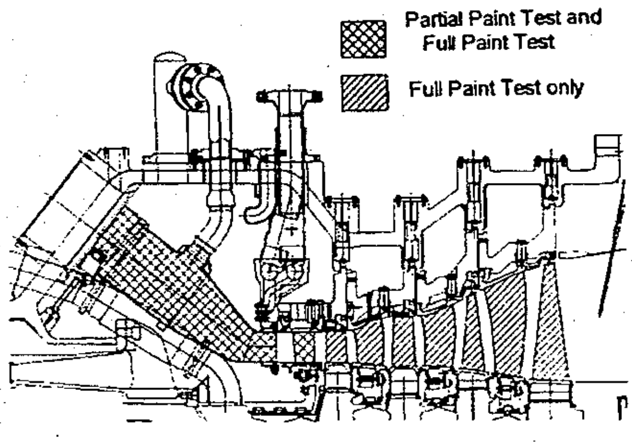


Figure 4 – W501G Paint test

The testing validated the closed-loop steam-cooling in a commercial application. The steam turbine temperatures were measured under both air-cooling at part load before steam quality was achieved and under full-load closed-loop steam cooling. The testing at Lakeland has confirmed the ability to switch between steam and alternate air cooling. As anticipated, actual measured metal temperatures are lower in the new closed-loop steam cooled design than in existing open-loop air-cooled design. The temperatures were measured along the length of the transition and are shown in Figure 5.

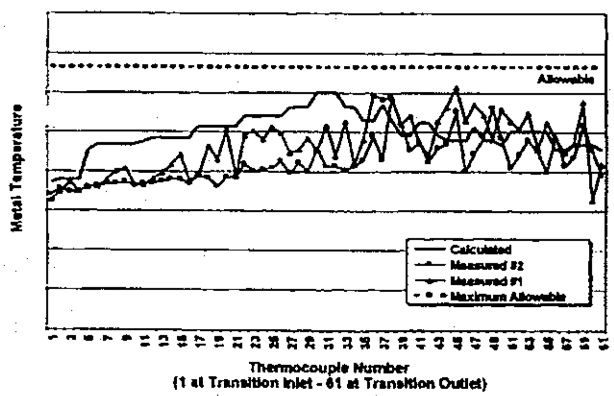


Figure 5 – W501G Transition temperatures

OPERATING EXPERIENCE

During testing and validation, two significant issues were encountered and resolved: vibration on front compressor diaphragms and combustor high frequency dynamics.

The front compressor diaphragms on stages 1, 2 and 3 exhibited signs of distress after approximately 200 hours of operation. A root cause investigation identified High Cycle Fatigue due to high excitation of airfoils combined with residual stresses and high stress concentration factors. A minor design modification was initially applied and validated in the W501G at the City of Lakeland McIntosh #5 site. Additional dynamic strain gauges were applied for monitoring dynamic stresses. The redesign has operated successfully for a total of over 1000 hours in W501G engines. A full cover lift and NDE inspection at the City of Lakeland McIntosh #5 site was completed and no operating restrictions are in effect.

During testing, high combustion dynamics were observed at approximately 2200 Hz causing distress to combustion system components. A root cause investigation identified insufficient aerodynamic damping as result of closed-loop steam cooling of the transition. To eliminate the dynamics, resonators tuned for 2200 Hz dynamics were added to the transitions. The resonator design was first tested and validated at the Siemens Westinghouse high pressure combustor test facility at Arnold Engineering Development Center in Tullahoma, TN. Subsequently, the modified transitions were validated at the City of Lakeland and successfully dampened the combustor dynamics. As an added precaution, a combustor dynamics monitor has been added as standard supervisory instrumentation as part of digital control system. In the event that combustor dynamics occur, the system will automatically adjust the engine operation to eliminate the dynamics and avoid distress on the components. Validation continues with alternate fuel sources.

Figure 3 – W501G Instrumentation at City of Lakeland McIntosh #5 site in Lakeland, FL

DEVELOPMENT ACTIVITIES

Steam-Cooled Vane

Development activities are focused on extending the W501G frame to ATS efficiencies through the introduction of additional technology advancements. The next major step will add a thin-walled, closed-loop, steam-cooled Row 1 turbine vane to the W501G. The steam-cooled vane will extend the benefits of the steam-cooled transition by eliminating most cooling air from the Row 1 vane. The result will be a combination of increased rotor inlet temperature and decreased burner outlet temperature. The benefit will be improved efficiency and reduced NOx. Single-crystal casting trials have been successfully completed at PCC Airfoils, Inc. in Mentor, Ohio.

The ATS steam cooled vane will be first tested in an engine sector rig. The test rig consists of a full-scale combustor basket and transition and a 1/16th-sector vessel, which will operate up to full ATS pressures and temperatures. The rig will be located at Arnold Engineering Development Center at the Arnold Air Force Base in Tennessee. The vane will be instrumented to verify analytical predictions of metal temperatures, heat transfer coefficients, and stress.

After validation in the 1/16th-sector rig, the vane will be retrofit into a W501G. A comprehensive test program will verify vane performance and improved plant performance. Test parameters will include vane metal temperature, stress, and steam temperatures.

Coatings

Thermal barrier coatings (TBC) are an integral part of the W501ATS engine design. A development program is in progress to develop an advanced bond coat/TBC system with a projected service life of more than 24,000 hours. Different bond coats and ceramic materials were evaluated under accelerated oxidation test conditions and down selected. The mechanical integrity and durability of an advanced bond coat/TBC system was demonstrated in more than 24,000 hours of cyclic testing at 1010°C (1850°F).

Under a related program, DOE-Oak Ridge National Laboratory (Contract DE-AC05-95OR22242), new ceramic compositions and TBC concepts were identified which have a sintering resistance and phase stability superior to that of 8YSZ TBC. These compositions and concepts are being further optimized and will be transferred to components for a 8000 hr engine demonstration under a DOE-Chicago contract DE-FC02-00CH11048.

SUMMARY

Technology development efforts have demonstrated that ATS Program goals are obtainable. The results of the technology development programs were incorporated into the W501ATS design. Based on input from a Customer Advisory Board, Siemens Westinghouse is pursuing an evolutionary introduction of ATS technology. The W501G, the first step in this evolution, introduces several ATS technologies such as closed-loop steam cooling, advanced compressor design, and high temperature materials. The first W501G is in operation at the City of Lakeland McIntosh #5 plant in Lakeland, FL. Through 2003, 28 W501G's are committed which will provide a thorough proof of the major ATS technologies. In addition, Siemens Westinghouse is infusing ATS technologies into its entire product line. This approach will result in a lower-risk ATS engine and will significantly increase and accelerate the net benefits of the program.

ACKNOWLEDGMENTS

This program is administered through the U.S. Department of Energy's Federal Energy Technology Center, Morgantown, WV, under the guidance of FETC's Program Manager, Mr. Charles Alsup. Research is sponsored by the U.S. Department of Energy's Federal Energy Technology Center, under Contract DE-FC21-95MC32267.

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Exhibit 13

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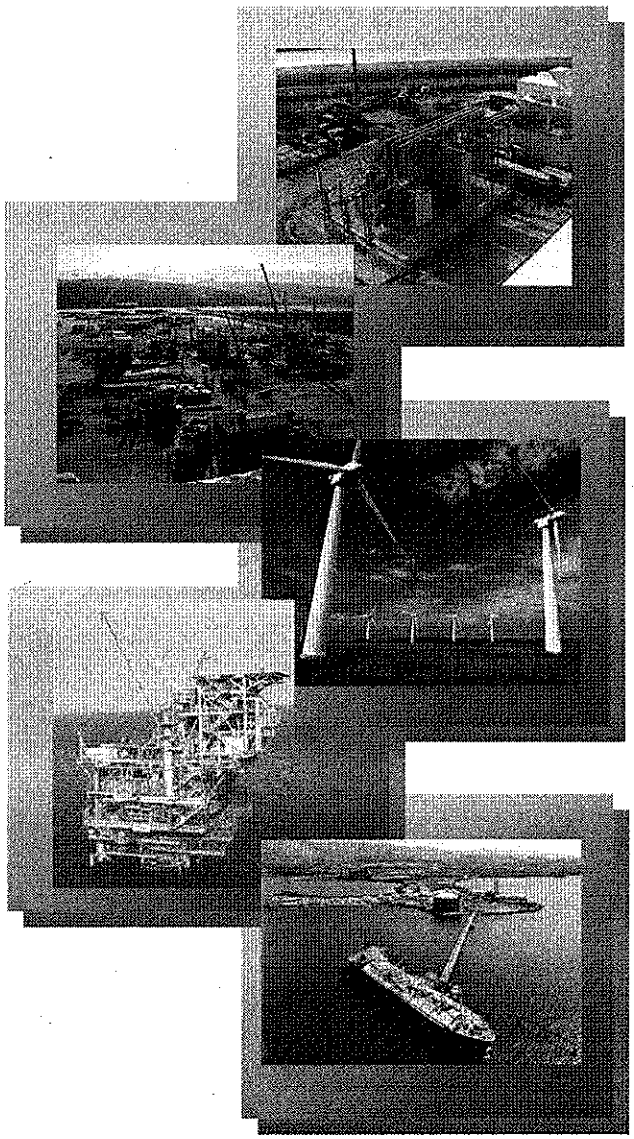

Universal Energy

UEI LLC

Management Services
for
Power, Petrochemical, Offshore,
and
Industrial Facilities

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Universal Energy
UEI LLC

Introduction to Universal Energy

Background

- Specializing in power plant support since 1994
- Over 160 different projects in 10 years, 6 continents, 28 countries, 34 states
- In excess of 54,000 MW of electricity brought on line
- Client List include Fortune 100 Power Plant Owners and EPC Companies

Capabilities

- Broad Base of Management Services
- All sectors of the Power, Petrochemical, Offshore and Industrial Markets
- Development, Engineering, Design, Owner's Engineer, Commissioning and Startup, Plant O&M, Training and Plant Procedures, Manpower Services
- Natural Gas, Coal, Wind, Geothermal, Diesel and other Liquid Fuels
- Gas Turbines, Simple & Combined Cycle, Fired Boilers, Diesel Engines, Compression

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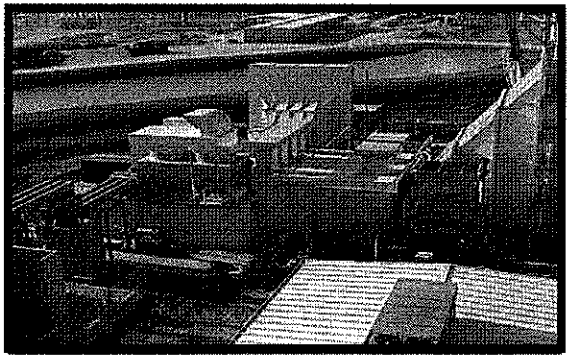
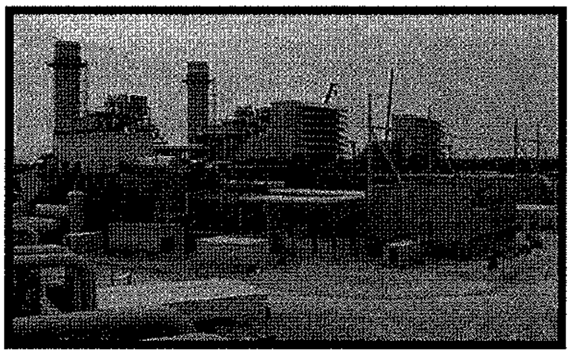
Services Include…



Extensive Experience



Asset Protection

Project Management, Construction & Startup Management

- Full Scope Commissioning & Startup package
- Managers and Manpower Support
- Safety Management
- Mechanical, Electrical, and Instrument & Control/DCS Services
- Planning and Scheduling
- QA/QC Documentation

Distressed Asset Services

- Due Diligence
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- Plant lay-up/de-commissioning/mothball
- Protecting/maintaining the asset
- Transitional O&M Services
- Re-commissioning
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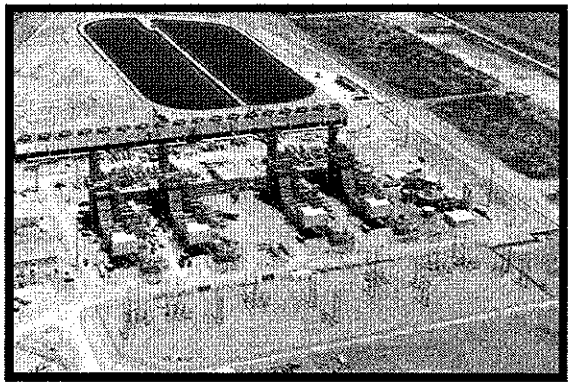
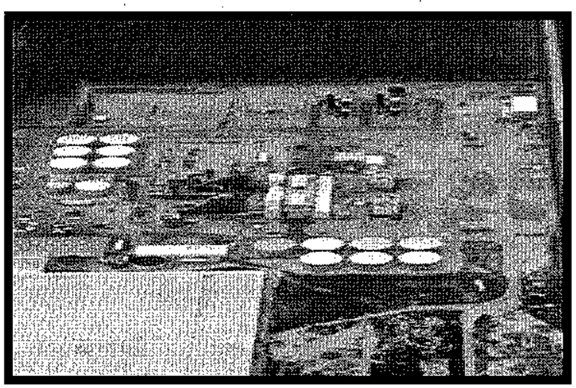


A Unique Team



Unique Solutions

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- Daily Operations & Maintenance, Term Contracts
- O&M Business Management
- Transition & Mobilization Services
- Commercial Management (budget & production control)
- Warranty Management
- Staffing & Training
- LTSA Management & Spare Parts
- Water & Waste Water Management

Owner's Engineer

- Acquisition Audits & Operations Reviews
- Owner's Engineer/Site Representative
- Development Support and Design Review
- Operability, Reliability and Maintainability Reviews
- Plant Performance Review
- Water Usage, Wastewater Reviews, Water Security
- Maintenance Scheduling and Cost Analysis
- Environmental/Safety Compliance Review
- Electrical/Mechanical/Controls Surveys

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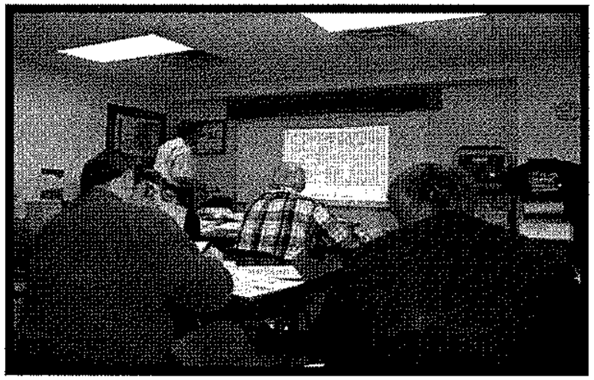
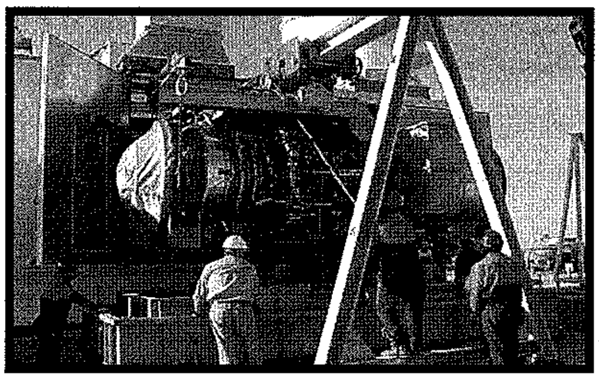


Organizational Development



Technical Skills

Training and Documentation

- Training Audits and Analysis
- Technical Skills Assessment
- Greenfield Operator Training
- Life-Cycle O&M Training Program/OJT
- Operation, Maintenance, Commissioning and Training Procedure Development
- Plant Operating Manuals

Manpower

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- Project Managers & Construction Managers
- Commissioning & Startup Managers
- Mechanical, Electrical, DCS & I/C
- Environmental and Safety
- O&M and Mobilization
- Training & Documentation
- Integrate with the Client Team

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Services Include…

Broad Range of Services

Optional Services Managed by UEI

- Electrical Testing
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- Performance Testing
- Chemical Cleaning Services
- Steam & Process Line Cleaning Services
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Benefits to You

Comprehensive Support

- FULL RANGE OF SERVICES, HARD WORK, QUALITY PEOPLE & COMMITMENT TO THE CLIENT
- Lower costs, competitive rates and service

Project Support

- All inclusive and centrally managed Owner's Engineering Service
- Asset Management and Consulting Services
- O&M at a competitive fee

Project Execution

- Experienced multi-disciplined Project and Startup Management Staff
- Database of experienced and available manpower
- Detailed documentation
- Training and procedures

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Project Highlights

- **Commissioning and Startup:** Over 54,000 MW of thermal power brought online
- **NYPA Emergency Summer Power Program:** Managed Commissioning and Startup of 11xLM6000 units for over 400MW in 6 locations in New York City in the summer of 2001.
- **Peñuelas, Puerto Rico**: Commissioning & Startup and Training – 1MM Bbl LNG Terminal and 500MW Power Plant. Combined LNG terminal, storage, gasification and power facility.
- **Macaé, Brazil**: Commissioning & Startup and Plant Operations –740MW Power Plant. This is the largest multiple-unit simple cycle power plant in the world.
- **Consulting**: Acquisition Due Diligence and Plant Audits – totaling over 19,000MW international and domestic plants. CFB, Waste Coal, Gas and liquid fuels. Combined Cycle, Peaking Plants, Diesels, Geothermal and Biomass Plants.

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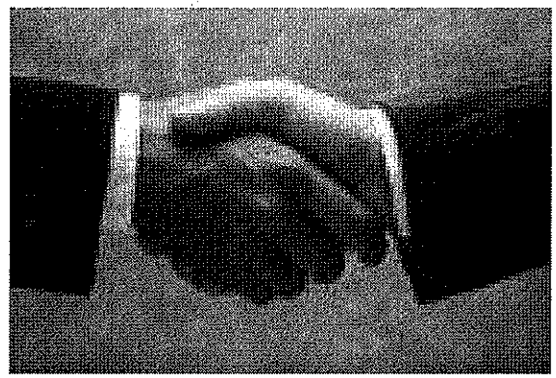

"Work hard,
Do your best,
Keep your word,
Never get too big for your britches,
Trust in God,
Have no fear,
And never forget a friend."
Harry S. Truman

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Exhibit 14

GER-3574G

GE Power Systems

GE Combined-Cycle Product Line and Performance

D.L. Chase
P.T. Kehoe
GE Power Systems
Schenectady, NY

Contents

GE Combined-Cycle Product Line and Performance

Introduction

The development during the past four decades of larger capacity gas turbine designs (50 MW to 380 MW) with increased specific power has led to the parallel development of highly-efficient and economical combined-cycle systems. The GE pre-engineered, combined cycle product line is designated STAG™, which is an acronym for STeam And Gas. Each STAG combined cycle system is an Engineered Equipment Package (EEP) consisting of GE gas turbines, steam turbines, generators, Heat Recovery Steam Generators (HRSGs) and controls. The most efficient of these STAG systems is configured with the GE "H" model gas turbine and is scheduled for commercial operation by the year 2003. The "H" combined cycle will achieve 60 percent (LHV) thermal efficiency.

The STAG EEP is an optimized and matched system of high technology power generation equipment, software, and services configured for convenient integration with the owner's auxiliaries and balance of plant equipment to form an economical power plant. This single source supply of the EEP enables GE to provide guarantees of plant thermal and emission performance as well as warrant system operation.

The product line spans a wide range of capabilities for both 50 and 60 Hz applications. A wide range of configurations is available with standard options that enable the systems to be adapted to suit the economic requirements of each application. The STAG combined-cycle product line includes two major categories:

- Pre-engineered oil- or natural gas-fired systems for electric power generation
- Pre-engineered building blocks for combined-cycle cogeneration systems and coal- or oil-fired integrated gasification combined-cycle (IGCC) power generation systems.

Economical performance of function is the outstanding characteristic of STAG combined-cycle systems. The features that contribute to economical power generation by STAG combined-cycle power generation systems are shown in *Table 1* and those for thermal and power systems are presented in *Table 2.*

- High Thermal Efficiency
- Low Installed Cost
- Fuel Flexibility – Wide Range of Gas and Liquid Fuels
- Low Operation and Maintenance Cost
- Operating Flexibility – Base, Mid-range, Daily Start
- High Reliability
- High Availability
- Short Installation Time
- High Efficiency in Small Capacity Increments

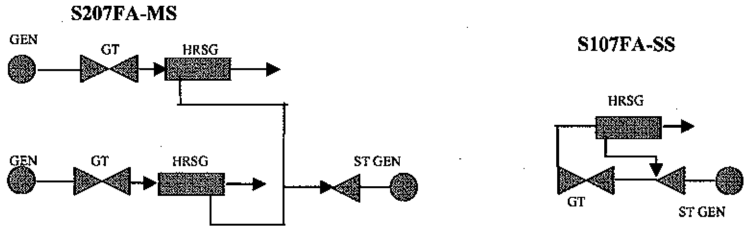
Table 1. STAG combined-cycle power generation system features

- High Thermal Efficiency
- Low Installed Cost
- Low Operation and Mainteance Costs
  - Steam Generation at Process Conditions
  - Extraction/Condensing Steam Turbine
  - Non-Condensing Turbine Exhausting to Process
  - Unfired/Fired HRSGs
  - Gas Turbine DLN/Steam Injection
- High Power to Thermal Energy Ratio
- High Reliability/Availability
- Short Installation Time

Table 2. STAG combined-cycle thermal energy and power system features

STAG Product Line Designations

System designations that identify STAG combined-cycle product line configurations are defined in *Table 3.* This example defines the designation for the single-shaft and multi-shaft combined-cycle configurations.



S	2	0 7FA	- MS		S	1	0 7FA	- SS
STAG™	Two GTs	GT Model Series	Multi-Shaft Configuration		STAG™	One GT	GT Model Series	Single-Shaft Configuration

STAG IS A REGISTERED TRADEMARK OF GENERAL ELECTRIC(USA)
AND IS AN ACRONYM FOR STeam And Gas

Table 3. STAG combined-cycle system designations

STAG Product Line Configurations

The product line includes single-shaft and multi-shaft configurations. Simplified block diagrams of these configurations are presented in *Figure 1.* The single-shaft STAG system consists of one gas turbine, one steam turbine, one generator, and one HRSG with the gas turbine and steam turbine coupled to the single generator in a tandem arrangement on a single shaft. Multi-shaft STAG systems have one or more gas turbine generators and HRSGs that supply steam through a common header to a separate, single steam turbine generator.

Single- and multiple-pressure non-reheat steam cycles are applied to STAG systems equipped with GE gas turbines that have rating point exhaust gas temperatures of approximately 1000°F / 538°C or less. Selection of a single- or multiple-pressure steam cycle for a specific application is determined by economic evalua-

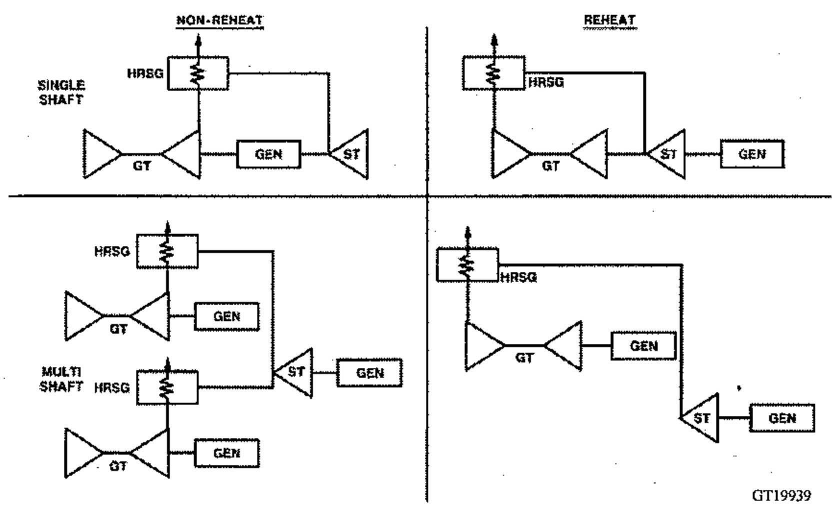


Figure 1. STAG system configurations

tion, which considers plant-installed cost, fuel cost and quality, plant-duty cycle, and operating and maintenance cost.

Multiple-pressure reheat steam cycles are applied to STAG systems with GE gas turbines that have rating point exhaust gas temperatures of approximately 1100°F / 593°C or greater.

A generalized combined-cycle, electric power generation and thermal energy capability map is presented in *Figure 2.* This map is typical of a system supplying process steam at 150 psig/11.4 bars and utilizing a gas turbine with 100 MW rated output.

tomer specific applications in which the need for increased power offsets the corresponding reduction in thermal efficiency.

The most efficient cycles for cogeneration applications are those with fully-fired HRSGs, as indicated by *Figure 2,* at maximum thermal energy output. The fully-fired HRSGs are high in cost because of their water wall construction and need for field erection. Also, fully-fired HRSGs may add to emission considerations as plant siting requirements are evaluated. The primary regions of interest for cogeneration, combined-cycle systems are those with unfired

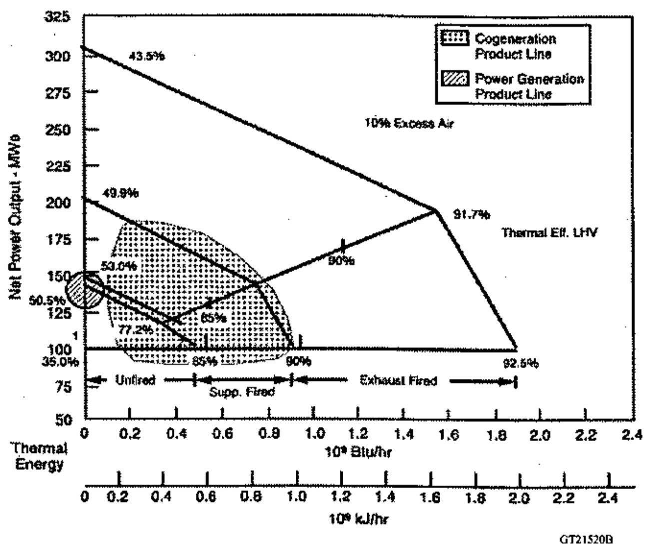


Figure 2. Generalized combined-cycle performance capability

The vertical axis of *Figure 2* with zero thermal energy shows the power and thermal efficiency of combined cycles with unfired, supplementary-fired, and fully-fired steam cycles. The most efficient power generation cycles are those with unfired HRSGs having modular pre-engineered components. These unfired steam cycles are also the lowest in cost and are, therefore, applied in the STAG combined-cycle power generation product line. Supplementary-fired combined-cycle systems are provided for customer specific applications in which the need for increased power offsets the corresponding reduction in thermal efficiency.

and supplementary-fired steam cycles. These systems provide a wide range of thermal energy to electric power ratio, 0–12,000 Btu thermal energy per kW (0–12,660 kJ per kW), and represent the range of thermal energy capability and power generation covered by the product line for cogeneration capability.

STAG Power Generation Product Line

The STAG power generation product line includes an array of steam cycle options, which satisfies a wide range of fuels, fuel cost, duty cycle, and other economic considerations. This enables selection of a steam cycle for each application that suits specific economic and operational requirements. Steam cycles utilized in the STAG product line include:

- **Single-Pressure, Non-Reheat Heat Recovery Feedwater Heating.** This steam cycle, shown in *Figure 3*, has an unfired HRSG with finned tube superheater, evaporator, and economizer sections. Energy is recovered from the exhaust gas by convective heat transfer. The HRSG schematic diagram is shown in *Figure 4*. This is the simplest steam cycle that can be applied in a combined cycle and it has been used extensively. It results in a low installed cost. Although it does not produce the highest combined-cycle thermal efficiency, it is a sound economic

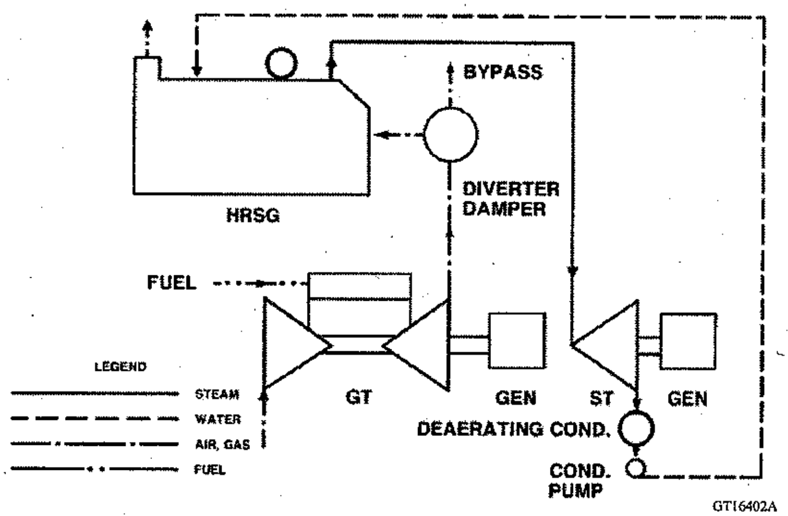


Figure 3. Single-pressure non-reheat cycle diagram

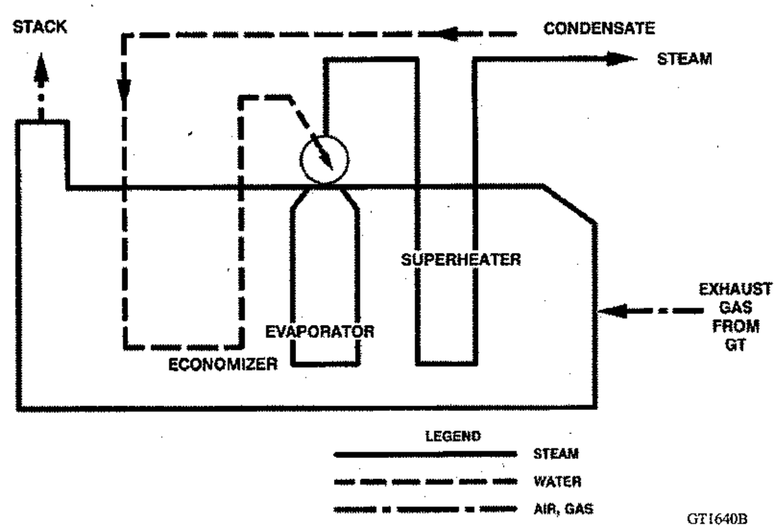


Figure 4. Single-pressure non-reheat HRSG diagram

selection when fuel is inexpensive, when applied in peaking type service, or when burning ash-bearing fuel with high sulfur content. This steam cycle is utilized in the STAG product line primarily with GE gas turbines having a baseload exhaust gas temperature of approximately 1000°F / 538°C or less. The HRSG stack gas temperature with this steam cycle is approximately 340°F / 171°C.

- **Multiple-Pressure, Non-Reheat Heat Recovery / Feedwater Heating.** Multi-pressure steam generation is used to maximize energy recovery from gas turbine exhaust. HRSG gas-side and steam-side temperature profiles for single- and multiple-pressure steam cycles are presented in *Figures 5 and 6.* This illustrates that increasing the number of steam pressure levels reduces the exhaust gas and steam/water energy difference. Two- or three-pressure steam cycles achieve better efficiency than the single-pressure systems, but their installed cost is higher. They are the economic choice when fuel is expensive or if the duty cycle requires a high load factor. The three-pressure steam cycle is shown in *Figure 7* and the HRSG schematic diagram is shown in *Figure 8.* This cycle is similar to the single-pressure cycle with the addition of the low-pressure and intermediate-pressure sections. Improved plant performance with multiple-pressure steam cycles results from additional heat transfer surface installed in the HRSG. The HRSG stack gas temperature is in the range of 200°F / 93°C to 260°F / 127°C.
- **Three-Pressure, Reheat Heat Recovery Feedwater Heating.** The reheat steam cycle matches the characteristics of the "EC," "F," and "H" technology gas turbines. The higher exhaust gas temperature of 1100°F / 593°C or greater provides sufficient high temperature energy to the HRSG to make the reheat steam cycle practical. Fuel gas heating to approximately

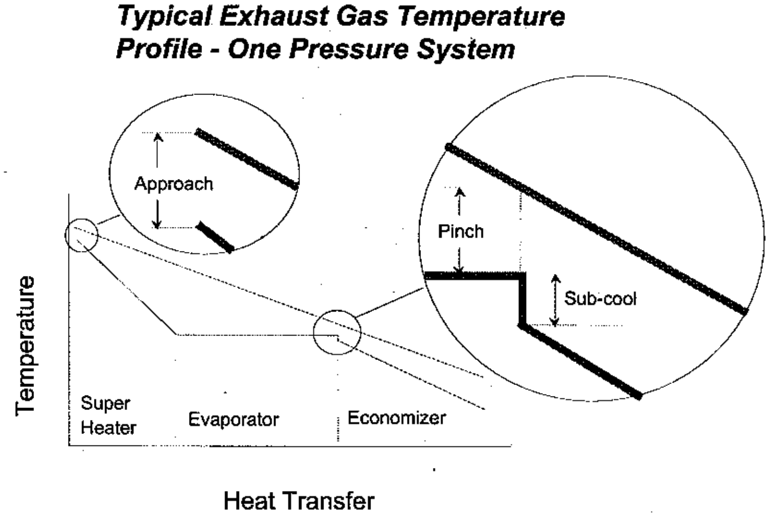


Figure 5. Typical exhaust gas/steam cycle temperature profile for single-pressure system

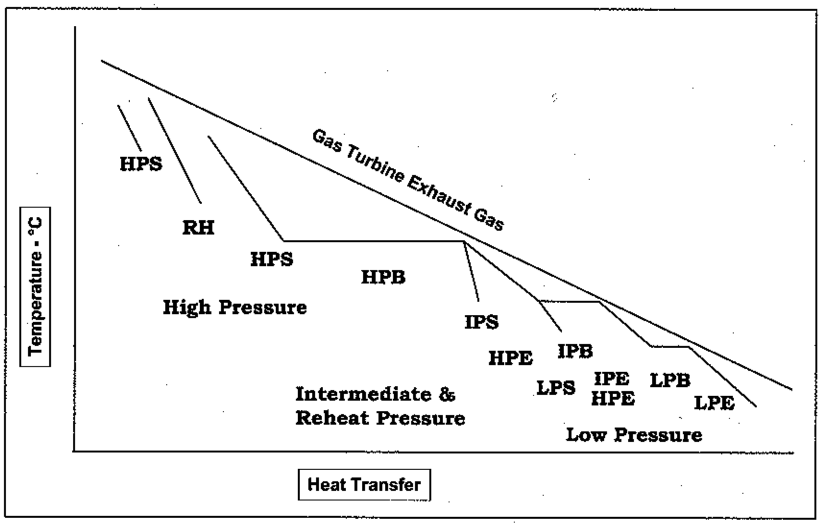


Figure 6. Typical exhaust gas/steam cycle temperature profile for three-pressure system

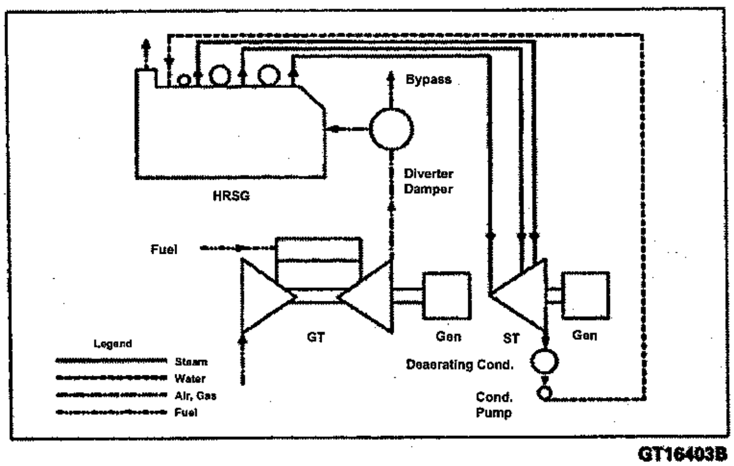


Figure 7. Three-pressure non-reheat cycle diagram

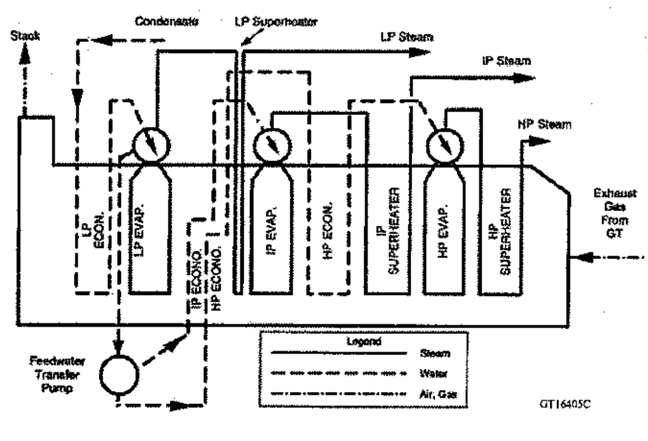


Figure 8. Three-pressure non-reheat HRSG diagram

365°F / 185°C, using water supplied from the HRSG IP economizer discharge, is also included with the "EC" and "F" technology gas turbines. This steam cycle is shown in *Figure 9.* The HRSG schematic is presented in *Figure 10.*

The "H" platform gas turbines, configured with hot gas path components cooled with both a closed-loop, steam-cooling system and an open-loop, air-cooling system design, are designated as MS7001H and MS9001H. The reheat steam cycle utilized with these gas turbines is closely integrated with the gas turbine steam-cooling system. This integration provides additional incentive to select single-shaft STAG configuration for these gas turbines. The steam cycle used with the S107H and S109H is shown in *Figure 11.* The HRSG schematic is shown in *Figure 12.*

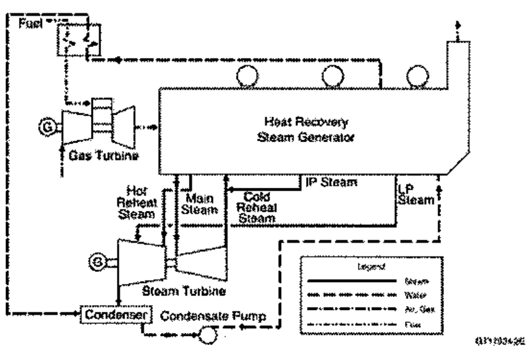


Figure 9. Three-pressure reheat cycle diagram

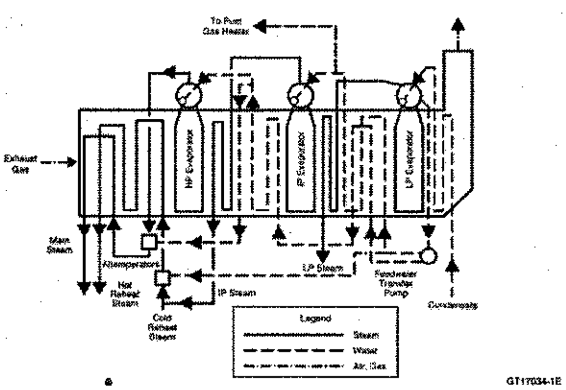


Figure 10. Three-pressure reheat HRSG diagram

These STAG combined-cycle systems are the most efficient power generation systems currently available. The base configuration for the STAG power generation combined-cycle product line is designed for high efficiency when firing natural gas or distillate fuel. A summary of the equipment and system configuration is presented in *Table 4.*

- Unfired, three-pressure steam cycle
  - Non-reheat for rated exhaust gas temperature less than 1000°F/538°C
  - Reheat for rated exhaust gas temperature higher than 1050°F/566°C and fuel heating
  - Heat recovery feedwater heating
  - Feedwater deaeration in condenser
  - Natural circulation HRSG evaporators
- Gas turbine with Dry Low NO_x combustors
- Once-through condenser cooling water system
- Multi-shaft systems
- Single-shaft systems
  - Integrated equipment and control system

Table 4. STAG power generation combined-cycle base configuration

The 60 Hz STAG power generation product line ratings are presented in *Table 5. Table 6* shows the major equipment in each standard STAG system. The 50 Hz product line ratings are presented in *Table 7,* and *Table 8* shows the major equipment in each of these standard STAG systems. These ratings are presented for gas turbine base load operation with natural gas fuel. Nominal throttle and reheat steam conditions for the non-reheat and reheat STAG product lines are defined in *Table 9.*

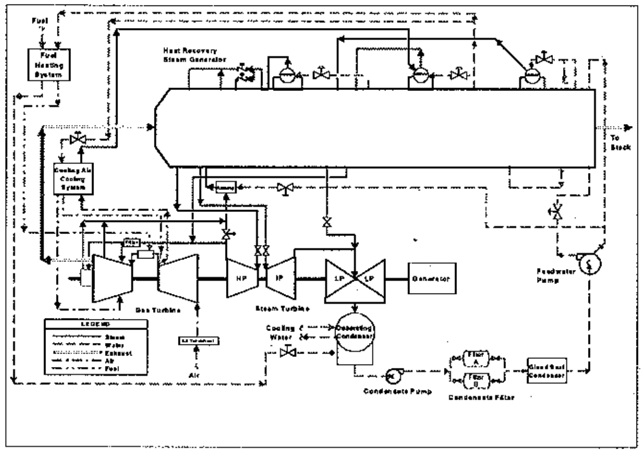


Figure 11. STAG 107H/S109H cycle diagram

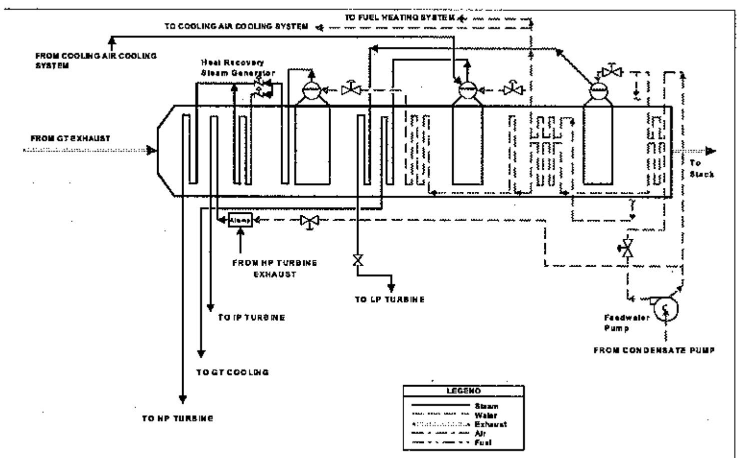


Figure 12. HRSG schematic for S107H/S109H

The STAG product line equipment and plant natural gas fuel ratings defined in *Tables 5 and 7* represent thermodynamic optimum performance that is expected to be the economic optimum configuration for baseload and mid-range dispatch using clean fuels costing about $2.50 per 10^6 Btu, HHV ($2.64 per 10^6 Kj, HHV). A wide array of options is available for the STAG power generation product line to suit specific economic criteria as well as the operating and installation preferences of the owner. *Table 10* lists the most commonly-applied options in addition to the base configuration.

Non-reheat steam cycles with one or two pressures and reheat steam cycles with two pressures are also available for the STAG product-line systems. Typical performance variation for these optional steam cycles is presented in *Table 11.* HRSGs with forced circulation evaporators are available to suit specific installation situations and owner preferences. *Figure 13* shows a two-pressure, non-reheat steam cycle with forced circulation HRSG.

Systems can be provided with a deaerator integral to the HRSG that utilizes low-pressure evaporator energy to perform the feedwater deaeration at positive pressure at a small reduction in thermal efficiency. Those systems that include a

Combined cycle Designation		Net Plant Power (MW)	Net Plant Heat Rate(LHV) Btu/kWhr	kJ/kWhr	Thermal Efficiency (%, LHV)
S106B	(4)	64.3	6960	7340	49.0
S206B	(4)	130.7	6850	7230	49.8
S406B	(4)	261.3	6850	7230	49.8
S106FA	(5)	107.1	6440	6795	53.0
S206FA	(5)	217.0	6355	6705	53.7
S107EA	(4)	130.2	6800	7175	50.2
S207EA	(4)	263.6	6700	7070	50.9
S107FA	(5)	262.6	6090	6425	56.0
S207FA	(5)	529.9	6040	6375	56.5
S107FB	(5)	280.3	5950	6280	57.3
S207FB	(5)	562.5	5940	6260	57.5
S107H	(6)	400.0	5690	6000	60.0

Notes: 1. Site conditions =59 F, 14.7 psia, 60% RH (15 C, 1.013 bar)
2. Steam turbine exhaust pressure = 1.2 inches Hg,A (30.48 mm Hg,A)
3. Performance is net plant with allowance for equipment and plant auxiliaries including those associated with a once-through cooling water system
4. Three-pressure, non-reheat, heat-recovery feedwater heating steam cycle
5. Three-pressure, reheat, heat-recovery feedwater heating steam cycle with integrated fuel, gas-heating system
6. Three-pressure, reheat, heat-recovery feedwater heating steam cycle with integrated turbine steam- and air-cooling and fuel-heating systems

Table 5. 60 Hz STAG product line performance

Designation	Gas Turbine No.	Gas Turbine Frame	HRSG No.	HRSG Type	Exhaust No.	Steam Turbine LSB Inches	Steam Turbine LSB mm	Exhaust Config.
• *Heavy Duty GT*								
S106B	1	PG6581 B	1	Non-Reheat, Unfired	1	23	584	Axial
S206B	2	PG6581 B	1	Non-Reheat, Unfired	1	33.5	851	Axial
S406B	4	PG6581 B	2	Non-Reheat, Unfired	2	33.5	851	Down
S106FA	1	PG6101 FA	1	Reheat, Unfired	1	30	762	Axial
S206FA	2	PG6101 FA	1	Reheat, Unfired	2	30	762	Down
S107EA	1	PG7121 EA	1	Non-Reheat, Unfired	1	33.5	851	Axial
S207EA	2	PG7121 EA	2	Non-Reheat, Unfired	2	33.5	851	Down
S107FA	1	PG7241 FA	1	Reheat, Unfired	2	30	762	Down
S207FA	2	PG7241 FA	2	Reheat, Unfired	4	30	762	Down
S107FB	1	PG7251 FB	1	Reheat, Unfired	2	30	762	Down
S207FB	2	PG7251 FB	2	Reheat, Unfired	4	30	762	Down
S107H	1	PG7001 H	1	Reheat, Unfired	2	40	1016	Down

Table 6. 60 Hz STAG product line equipment

low-pressure economizer for high thermal efficiency will require material that resists corrosion because feedwater passing through this section may have a high oxygen concentration, and the external tube surface temperature may be below the exhaust gas dew point temperature. *Figure 14* shows a three-pressure non-reheat HRSG with integral deaerator.

Fuel characteristics affect combined-cycle performance in a variety of ways. High hydrogen content in fuels such as natural gas results in high water content in the combustion products. Water has a higher heat content than air or other combustion products, so fuels with high hydrogen content increase output and efficiency. Ash-bearing fuels foul the gas turbine and HRSG; therefore, equipment and system design considerations that accept fouling reduce plant output and efficiency. Sulfur content in the fuel may require adjustment in the temperature of the stack gas and the water entering the HRSG economizer to prevent condensation of corrosive sul-

Combined cycle Designation		Net Plant Power (MW)	Net Plant Heat Rate (LHV) Btu/kWhr	kJ/kWhr	Thermal Efficiency (%, LHV)
S106B	(4)	64.3	6950	7340	49.0
S206B	(4)	130.7	6850	7230	49.8
S406B	(5)	261.3	6850	7230	49.8
S106FA	(5)	107.4	6420	6775	53.2
S206FA	(4)	218.7	6305	6650	54.1
S109E	(4)	189.2	6570	6935	52.0
S209E	(4)	383.7	6480	6840	52.7
S109EC	(5)	259.3	6315	6660	54.0
S209EC	(5)	522.6	6270	6615	54.4
S109FA	(5)	390.8	6020	6350	56.7
S209FA	(5)	786.9	5980	6305	57.1
S109H	(6)	480.0	5690	6000	60.0

Notes: 1. Site conditions = 59 F, 14.7 psia, 60% RH (15 C), 1.013 bar)
2. Steam turbine exhaust pressure = 1.2 Inches HgA (30.48 mm HgA)
3. Performance is net plant with allowance for equipment and plant auxiliaries including those associated with a once-through cooling water system
4. Three-pressure, non-reheat, heat recovery feedwater heating steam cycle
5. Three-pressure, reheat, heat-recovery feedwater healing steam cycle with integrated fuel gas heating system
6. Three-pressure, reheat, heat-recovery feedwater heating steam cycle with integrated turbine steam and air cooling and fuel heating systems.

Table 7. 50 Hz STAG product line performance

Designation	Gas Turbine No.	Gas Turbine Frame	HRSG No.	HRSG Type	Exhaust No.	Steam Turbine LSB Inches	Steam Turbine LSB mm	Exhaust Config.
• *Heavy Duty GT*								
S106B	1	PG6581 B	1	Non-Reheat, Unfired	1	17	432	Axial
S206B	2	PG6581 B	1	Non-Reheat, Unfired	1	33.5	851	Axial
S406B	4	PG6581 B	2	Non-Reheat, Unfired	2	33.5	851	Down
S106FA	1	PG6101 FA	1	Reheat, Unfired	1	26	660	Axial
S206FA	2	PG6101 FA	2	Reheat, Unfired	1	42	1066	Axial
S109E	1	PG9171 E	1	Non-Reheat, Unfired	1	42	1066	Down
S209E	2	PG9171 E	2	Non-Reheat, Unfired	2	42	1066	Down
S109EC	1	PG9231 EC	1	Reheat, Unfired	1	42	1066	Down
S209EC	2	PG9231 EC	2	Reheat, Unfired	2	42	1066	Down
S109FA	1	PG9351 FA	1	Reheat, Unfired	2	33.5	851	Down
S209FA	2	PG9351 FA	2	Reheat, Unfired	4	33.5	851	Down
S109H	1	PG9001 H	1	Reheat, Unfired	2	42	1066	Down

Table 8. 50 Hz STAG product line equipment

furic acid. The increased stack gas temperature required by higher sulfur content decreases output and efficiency. Performance variation with fuel type (hydrogen, ash and sulfur content typical of each) is presented in *Table 12.*

The STAG product line includes gas turbines with Dry Low NO_x (DLN) combustors that can operate with stack gas NO_x emission concentration as low as 9 ppmvd at 15% oxygen (15.5 g/GJ) without water or steam injection, when operating on natural gas fuel. Water or steam injection may be required to meet NO_x emission requirements when operating on distillate oil fuel. Also, gas turbines are available with conventional, diffusion flame combustors operating with water or steam injection to meet NO_x emission limits. *Table 13* presents stack gas NO_x emissions from gas turbines in typical STAG combined cycle systems for operation with DLN or diffusion flame combustors with natural gas fuel. The effect of water- or steam-injection on NO_x abatement and thermal performance is also presented.

Selective catalytic reduction (SCR) is a stack gas NO_x reduction system that uses ammonia to react with NO_x over a catalyst that reduces NO_x to nitrogen and water. These systems increase the plant installation and operating cost, but

Heat Recovery Feedwater Heater Steam Cycle	Non-Reheat Three-Pressure			Reheat Three-Pressure
Steam Turbine Size (MW)	≤ 40	> 40 <60	≥ 60	> 60
Throttle Pressure (psig) (Kg/cm²,g)	820 (58)	960 (68)	1200 (84)	1400-1800 (98)
Throttle Temperature (°F) (°C)	40 Approach to Gas Turbine (22) Exhaust Gas Temperature			1000-1050 (538-566)
Reheat Pressure (psig) (Kg/cm²,g)	-- --	– –	– –	300-400 (21-28)
Reheat Temperature (°F) (°C)	-- --	– –	-- --	1000-1050 (538-566)
IP Admission Pressure (psig) (Kg/cm²,g)	100 (7)	120 (8)	155 (11)	300-400 (21-28)
IP Admission Temperature (°F) (°C)	20 Approach to Exhaust Gas Temperature (11) Upstream of Superheater			
LP Admission Pressure (psig) (Kg/cm²,g)	25 (1.8)	25 (1.8)	25 (1.8)	40 (2.8)
LP Admission Temperature (°F) (°C)	20 Approach to Exhaust Gas Temperature (11) Upstream of Superheater			

Table 9. STAG product line steam turbine throttle and admission steam conditions

they can reduce NO_x to less than 9 ppmvd at 15% oxygen (15.5 g/GJ) for all combined-cycle systems in the product line. The SCR catalyst typically operates in the 570°F/300°C to 750°F/400°C temperature range, so the catalyst is typically installed within the high-pressure evaporator as shown in *Figure 15.* The ammonia injection grid is installed upstream of the evaporator where the gas temperature is below the temperature at which ammonia oxidizes to form NO_x. This provides intimate mixing of the ammonia and NO_x as the gas passes through the pre-evaporator section.

Carbon monoxide (CO) emissions are low at gas turbine loads above 50%, typically less than

STEAM CYCLE	NO_X CONTROL
• Single pressure	• Water injection
• Two pressure	• Steam injection
• **Three pressure***	• SCR (NO_X and/or CO)
• Reheat	• **Dry Low NOx combustion***
• Non-reheat	CONDENSER
DEAERATION	• **Water cooled (once-through system)***
• **Deaerating condenser***	• Water cooled (evaporative cooling tower)
• Deaerator/evaporator integral with HRSG	• Air-cooled condenser
HRSG DESIGN	FUEL
• **Natural circulation evaporators***	• **Natural gas***
• Forced circulation evaporators	• Distillate oil
• **Unfired***	• Ash bearing oil
• Supplementary fired	• Low BTU coal and oil-derived gas
	• Multiple fuel systems

* Base configuration

Table 10. Power generation combined-cycle product line system options

STAG 207EA		
STEAM CYCLE	**NET PLANT OUTPUT (%)**	**NET PLANT THERMAL EFFICIENCY (%)**
THREE PRESSURE, REHEAT	**+0.7**	**+0.7**
THREE PRESSURE, NON-REHEAT	**BASE**	**BASE**
TWO PRESSURE, NON-REHEAT	**-1.0**	**-1.0**
SINGLE PRESSURE, NON-REHEAT	**-4.7**	**-4.7**
STAG 107EA		
STEAM CYCLE	**NET PLANT OUTPUT (%)**	**NET PLANT THERMAL EFFICIENCY (%)**
THREE PRESSURE, REHEAT	**BASE**	**BASE**
TWO PRESSURE, REHEAT	**-1.1**	**-1.1**
THREE PRESSURE, NON-REHEAT	**-1.2**	**-1.2**
TWO PRESSURE, NON-REHEAT	**-2.0**	**-2.0**

Table 11. Performance variation with steam cycle

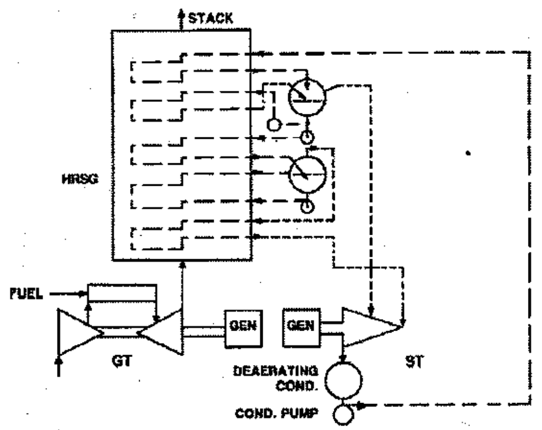


Figure 13. Two-pressure non-reheat steam cycle with forced circulation HRSG

5–25 ppmvd (9-43 g/GJ). Low CO emissions are the result of highly-efficient combustion. Catalytic CO emission abatement systems are also available, if required, for lower emission rates. The CO catalyst is installed in the exhaust gas path, typically upstream of the HRSG superheater.

Options such as compressor inlet cooling, steam or water injection for power augmentation, HRSG supplementary firing and gas turbine peak load capabilities are available for combined-cycle plant power enhancements. They are generally applied primarily for peak period capacity additions.

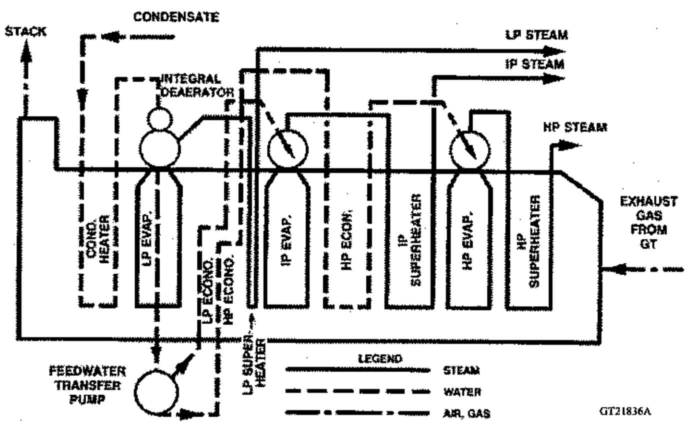


Figure 14. Three-pressure non-reheat HRSG with integral deaerator

	STAG 209E	
FUEL	NET PLANT OUTPUT (%)	NET PLANT THERMAL EFFICIENCY (%)
NATURAL GAS	BASE	BASE
DISTILLATE OIL	-3.0	-2.1
RESIDUAL OIL	-9.3	-7.6

NOTES 1. OPERATING POINT = BASE LOAD
2. TWO PRESSURE, NON-REHEAT RECOVERY FEEDWATER HEATING SYSTEM CYCLE

Table 12. STAG combined-cycle performance variation with fuel characteristics

Gas Turbine	MS7001EA						MS7001FA			
Combustion System	DLN	Diffusion Flame					DLN	Diffusion Flame		
NOx PMVD at 15% O2 (g/GJ)	9 (15.5)	160 (275)	42 (72)		25 (43)		9 (15.5)	212 (365)	42 (72)	
Diluent Injection Water/Fuel by Wt	0	0	0.81	-	1.04	-	0	0	0.89	-
Steam/Fuel by Wt	0	0	-	1.22	-	1.58	0	0	-	1.62
STAG Plant Performance Net Power (Δ%)	Base	Base	+3.5	+1.0	+5.0	+1.1	Base	Base	+5.4	+2.8
Net Heat Rate (Δ%)	Base	Base	+3.6	+2.1	+5.2	+3.4	Base	Base	+3.9	+3.1
Steam Cycle	Non-Reheat, Three Pressure						Reheat, Three Pressure			
Notes:	1. Site Conditions 59°F, 14.7 psia, 60% RH (15°C, 1.013 bars)									
	2. Fuel – Natural Gas									

Table 13. Effect of NO_x control on combined-cycle performance

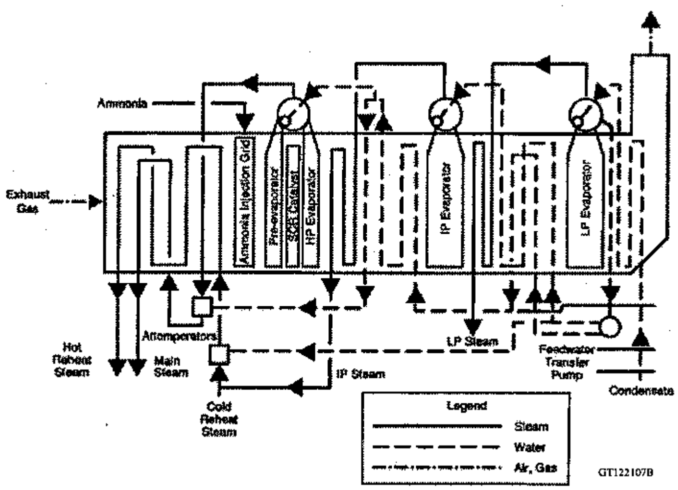


Figure 15. Three-pressure reheat HRSG with SCR

Compressor inlet cooling that uses evaporative cooling is an effective means of adding plant capacity for applications with high ambient air temperature and low relative humidity. An 85% effectiveness evaporative cooler is expected to increase plant output by about 5% during operation at 90°F / 32°C and 30% relative humidity site conditions.

Evaporative and mechanical chiller systems may be used to cool gas turbine inlet air to as low as 45°F / 7°C. These inlet cooling systems can achieve up to 11% capacity increase during operation at site conditions of 90°F / 32°C and 30% relative humidity. Evaporative cooling and chilling systems do not improve combined-cycle plant efficiency; however, they may provide economic peak power addition during warm summer periods.

Supplementary firing of the HRSG can be utilized to increase steam turbine capability by as much as 100%. This will increase plant capacity by about 25%. Cogeneration of power and process energy is usually the incentive for HRSG supplementary firing; however, peaking capacity credits, or leveling fuel consumption over the ambient temperature range to accommodate "take-or-pay" fuel contracts may also justify this option. The incremental efficiency for power produced by supplemental firing is in the 34–36% range based on the lower heating value of the fuel.

While gas turbine water or steam injection can be applied to enhance plant output as well as reduce NO_x emissions, plant efficiency is degraded.

Gas turbine peak load capability is available with many gas turbine configurations and can add 3–10% combined-cycle plant capacity. This may be the most economic approach to small capacity additions for short periods of time because peak load operation significantly impacts gas turbine parts life and maintenance cost. *Table 14* summarizes the performance impact of these combined-cycle power enhancement options.

Combined-cycle systems can be integrated with gasification systems to form efficient coal- or oil-fired power plants with outstanding environmental performance. The standard modules in the STAG combined-cycle product line can be readily adapted to integrated gasification combined cycles (IGCCs).

Figure 16 shows a diagram of an advanced technology "H" platform combined-cycle IGCC system with oxygen-blown gasifier and integration of the air separation unit with the gas turbine. This advanced technology IGCC system promises to be an economical power generation system that can fire coal, petroleum coke, heavy residual oil and other solid or low-grade liquid fuels. The range of ratings for the advanced technology IGCC plants is as follows:

IGCC Unit	Frequency (Hz)	Capacity Range (MW)	Net LHV Thermal Eff. Range (LHV)
STAG 107H	60	400-460	49-51 %
STAG 109H	50	480-550	49-51%

The capacities and efficiencies are shown as ranges because they vary with the type of gasifiers, gas clean-up systems, air and steam cycle integration, coal or other fuel analysis, and fuel moisture content.

Power Enhancement Option	Typical Performance Impact Δ Output	Δ Heat Rate
Base Configuration	Base	Base
Evaporative Cooling GT Inlet Air (85% Effective Cooler)	+5.2%	-
Chill GT Inlet Air to 45°F	+10.7%	+1.6%
GT Peak Load	+5.2%	-1.0%
GT Steam Injection (5% of GT Air Flow)	+3.4%	+4.2%
GT Water Injection (2.9% of GT Air Flow)	+5.9%	+4.8%
HRSG Supplementary Firing	+28%	+9%
Notes: 1. Site Conditions = 90°F, 30% RH 2. Fuel = Natural Gas 3. Three Pressure, Reheat Steam Cycle		

Table 14. STAG system power enhancement options

STAG Combined-Cycle Major Equipment

The major equipment for STAG combined-cycle electric power generation systems includes the line of packaged gas turbine power generation units, unfired HRSGs, steam turbine-generators, and controls. This is a line of proven, reliable equipment with excellent performance characteristics for combined-cycle systems. This equipment includes gas turbine generators and steam turbine generators manufactured by GE as well as HRSGs and controls selected to form a coordinated combined-cycle system for each application. Features of the major equipment that are significant for efficient, reliable combined-cycle systems are presented in the following discussion.

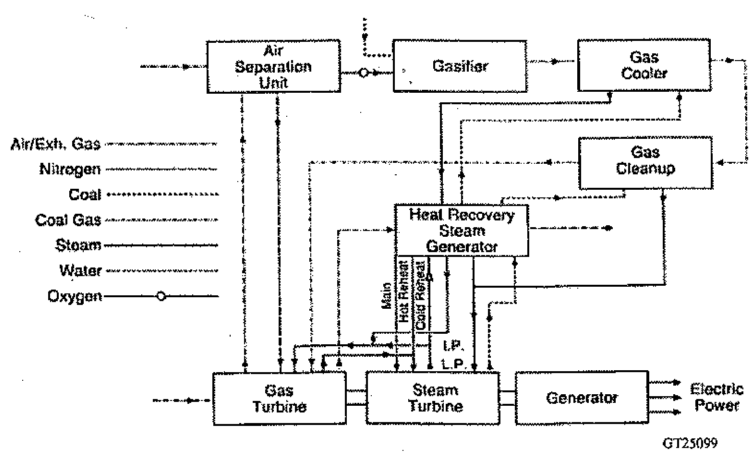


Figure 16. Advanced technology IGCC system

Gas Turbines

The ratings of GE gas turbines applied in the STAG combined-cycle product line are presented in *Table 15*. *Figure 17* shows a cross-section of the PG7121EA gas turbine typical of GE gas turbines with 2035°F / 1113°C firing temperature. The PG9171E gas turbine firing temperature is 2055°F / 1124°C. A cross-section of the PG9351 FA gas turbine is shown in *Figure 18*, which is typical of the GE gas turbines with 2420°F / 1327°C firing temperature, including the PG7241FA.

The next generation "FB" and "H" platform gas turbines are expected to be in commercial service in the first half of this decade. The cross-section of the "H" gas turbine is shown in *Figure 19*. This new machine features closed-loop steam cooling for the first and second stages of its four-stage turbine. In order to optimize performance at the 2600°F / 1426°C firing temperature, a higher-pressure ratio compressor derived from the GE CF680C2 aircraft engine is utilized.

These gas turbines have the following features that uniquely suit them for combined-cycle applications:

- The key performance characteristic of the gas turbine that influences combined-cycle performance is specific power. Specific power is the power produced by the gas turbine per unit of airflow (kW output per lb/sec of compressor airflow). Combined-cycle thermal efficiency

Heavy-Duty	Output (kW)	Frequency (Hz)
PG6581 B	42,100	50 and 60
PG6101 FA	70,140	50 and 60
PG7121 EA	85,400	60
PG7241 FA	171,700	60
PG9171 E	123,400	50
PG9231 EC	169,000	50
PG7251 FB	184,400	60
PG9351 FA	255,600	60
MS7001 H	*	60
MS9001 H	*	50

Notes: 1. Fuel = Natural Gas
2. Site Conditions = ISO Ambient
3. Operating Mode = Base Load, Simple Cycle
*Single-Shaft STAG Combined Cycle Configuration Only

Table 15. GE gas turbines applied to STAG product line

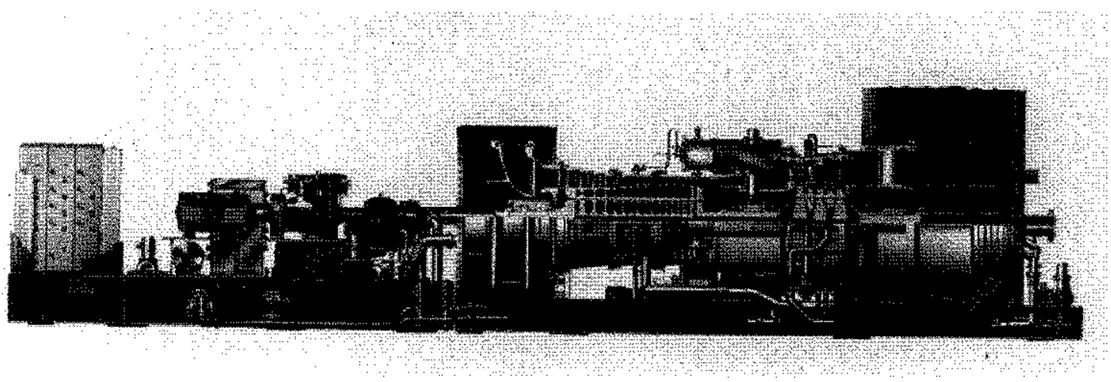


Figure 17. MS7001EA heavy-duty gas turbine

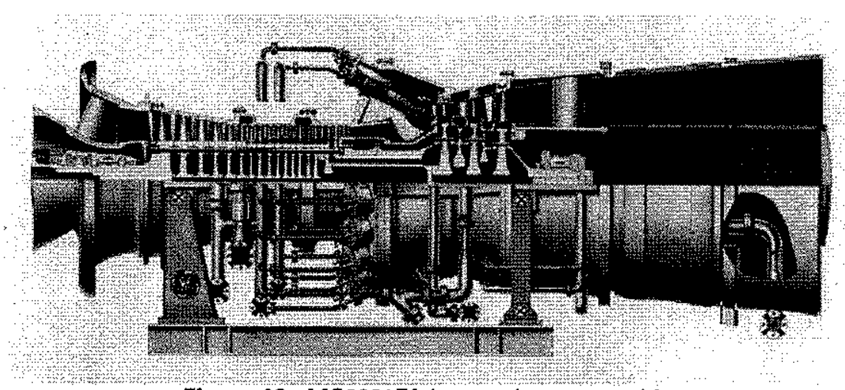
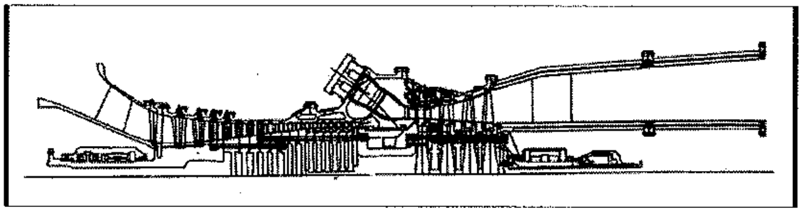


Figure 18. MS9001FA heavy-duty gas turbine

increases as gas turbine specific power increases, as shown in *Figure 20.* This figure shows that gas turbine firing temperature is the primary determinant of specific power. Improvements in combined-cycle thermal efficiency have developed primarily through the increases in gas



Features
- ***Closed Loop Steam Cooling***
- ***4-Stage Turbine***
- ***Compressor Scaled From Proven Design***
- ***Dry Low No_x Combustor***

GT25129

Figure 19. "H" gas turbine cross-section

turbine firing temperature, which have resulted from the development of high-temperature / high strength materials, corrosion-resistant coatings, and improved cooling technology. Commercial development of combined cycles and improvements in combined-cycle efficiency have proceeded in parallel with advances in gas turbine technology.

- STAG systems that utilize the "F" technology gas turbines achieve net thermal efficiencies of 53% (LHV) or greater. STAG systems that utilize "H" technology gas turbines achieve net thermal efficiencies of 58–60% (LHV). These gas turbines have a rated firing temperature of 2420°F / 1327°C and 2600°F / 1426°C, respectively. The "FA" technology turbine has a 15.5 pressure ratio, whereas the "H" technology turbine has a 23.0 pressure ratio. These designs provide the highest gas turbine specific power for this firing temperature. High specific power provides the lowest simple-cycle installed cost in addition to high combined-cycle efficiency.
- The exhaust gas temperature range of 1000–1100°F / 538–566°C is uniquely suited to efficient combined cycles because it enables the transfer of heat from exhaust gas to the steam cycle to take place over a minimal temperature difference. This temperature range results in the maximum in thermodynamic availability while operating with highest temperature and highest efficiency steam cycles.
- Multiple can-annular type combustors with film and impingement cooling meet the environmental requirements for applications throughout the world. They provide reliable operation at high firing temperatures while burning fuels that range from natural gas to residual oil.
- Turbine materials, coatings and cooling systems enable reliable operation at high firing temperatures. This achieves high gas turbine specific power and high efficiency for combined-cycle systems.

- Most GE current product line gas turbines are configured with open-loop cooling of the turbine hot gas path. Hot gas path components are in large part cooled by film cooling that uses air supplied from the compressor. This results in a significant exhaust gas steam temperature drop across the first stage nozzle, and requires significant "chargeable air" to cool the turbine stages. The temperature drop across the first stage nozzle and the chargeable cooling losses increase as turbine inlet temperature increases.
- The advanced "H" platform gas turbine is configured with an integrated closed-loop steam-cooling system. The change in strategy to the closed-loop, steam-cooled system without film cooling allows higher turbine inlet temperatures to be achieved without increasing combustion temperature. This is because the temperature drop across the first stage nozzle is significantly reduced, as shown in *Figure 21.* Gas turbine NO_x emissions can then be maintained at low levels at increased turbine inlet temperature. Another important benefit of the integrated closed-loop, steam-cooling system is the elimination of "chargeable cooling air" for the first- and second-stage rotating and stationary airfoils. This results in two percentage points improvement in combined cycle thermal efficiency.
- Factory packaging and containerized shipment of small parts achieve low installed cost and short installation time.
- Reliable operation results from evolutionary design development that improves parts and components, a high-quality manufacturing program that includes operational factory testing of the gas turbine and accessory systems, follow-up service support by experienced installation and service personnel, and effective spare parts support.
- Low maintenance costs are the result of the combination of the above features and a design to allow convenient access. These include borescope ports to permit inspection of key parts and components without dismantling the equipment.
- The heavy-duty gas turbine product line has fuel flexibility provided by accessory systems, combustion systems, and turbine components, which enable utilization of a wide range of liquid and gaseous fuels. These include 150-400 Btu/scf (6520-16,850 kj/nm^3) gaseous fuels, including those derived from coal, coke, or heavy petroleum products, and liquid fuels including naphtha, light distillates, heavy distillates, crude oil and residual oil.

HRSG

HRSGs in the GE STAG product line are unfired and feature modular construction with finned-tube heat transfer surface and natural or forced-circulation evaporators. *Figure 22* illustrates a natural circulation HRSG with modular construction. An installation showing two of these HRSGs operating with MS7001EA gas turbines is shown in *Figure 23. Figure 24* illustrates the modular-construction, forced-circulation HRSG, and *Figure 25* shows an installation of this type HRSG in a STAG 107EA system.

Each gas turbine exhausts to an individual HRSG. For STAG systems with a MS6001B gas turbine, the standard gas ducting is designed so that two gas turbines exhaust to a single HRSG. These STAG systems are also available with one HRSG per gas turbine. The HRSG and auxiliaries are designed for the specific operating requirements of the STAG combined cycle system. Design features include:

- Exhaust gas bypass system to provide fast startup and shutdown and flexibility of operation for multi-shaft STAG systems. Exhaust gas bypass systems are not used with single-shaft STAG units.
- Flexible tube support system to enable fast startup and load following capability.
- Low gas side pressure drop for optimum gas turbine performance.
- Large, factory-tested modules that can be shipped to provide short

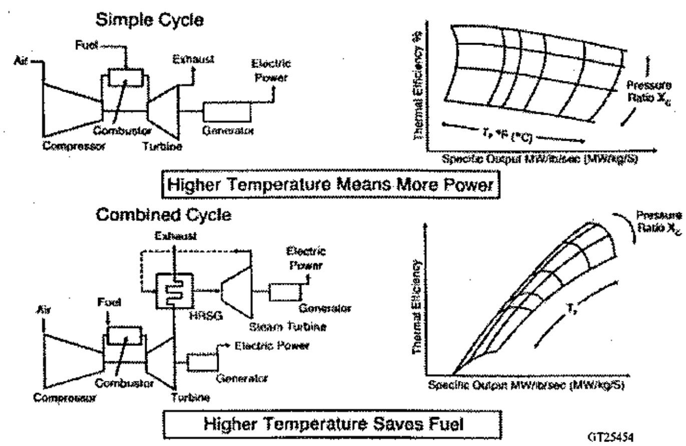


Figure 20. Gas turbine performance thermodynamics

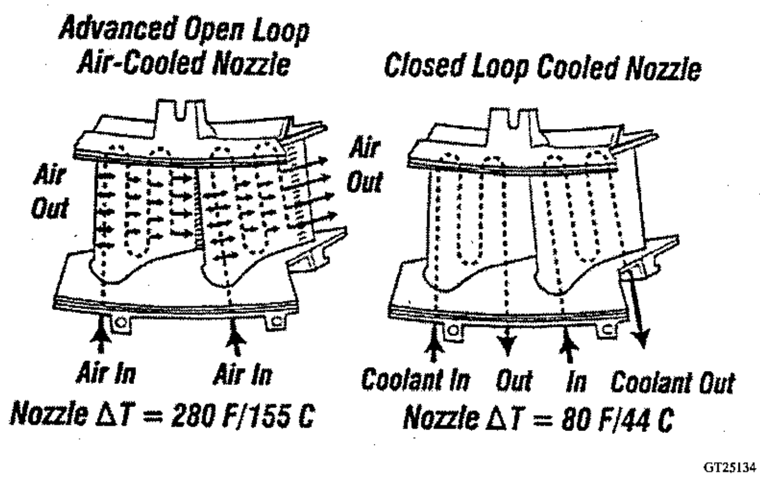


Figure 21. Impact of stage-one nozzle cooling method

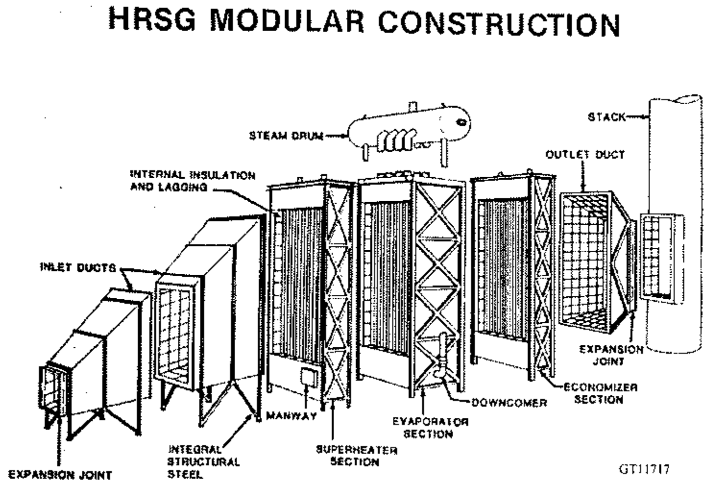


Figure 22. Natural-circulation HRSG modular construction

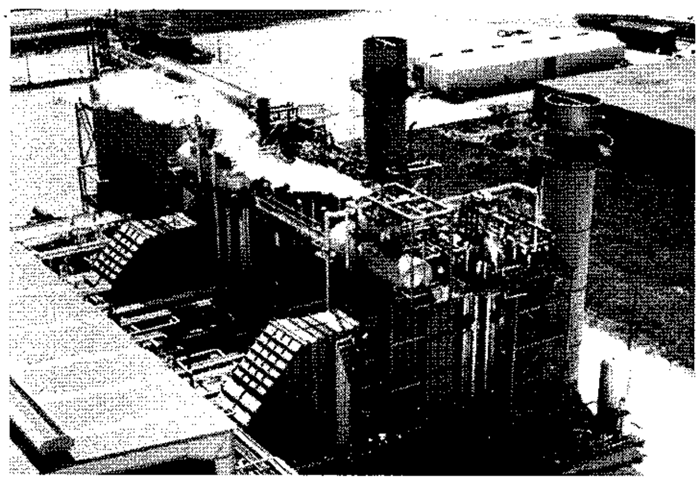


Figure 23. Two natural-circulation HRSGs operating with MS7001EA gas turbines

installation time and low construction cost.

- Fuel flexibility provided by the ability to operate reliably and efficiently, using exhaust gas from gas turbines that burn fuels ranging from natural gas to residual oil.

Steam Turbine

GE offers a complete line of steam turbines for combined-cycle applications. Two or more steam turbine selections are available for each STAG product line offering. Steam turbines with different exhaust annulus areas are available to permit optimization to meet specific condenser cooling conditions. Steam turbines with large exhaust annulus areas are more expensive, but provide increased capability and may be the most economic selection for applications with low steam turbine exhaust pressure. For applications in which steam turbine exhaust pressures are high, small exhaust annulus-area steam turbines provide comparable or higher capability and low cost, and therefore are the economic choice. *Figure 26* illustrates

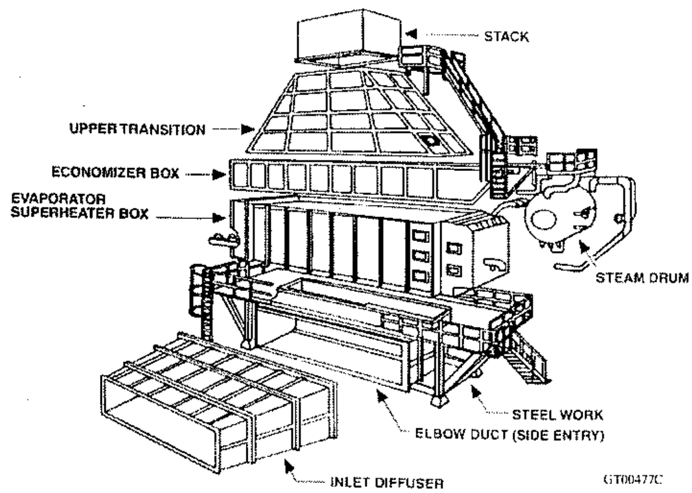


Figure 24. Forced-circulation HRSG modular construction

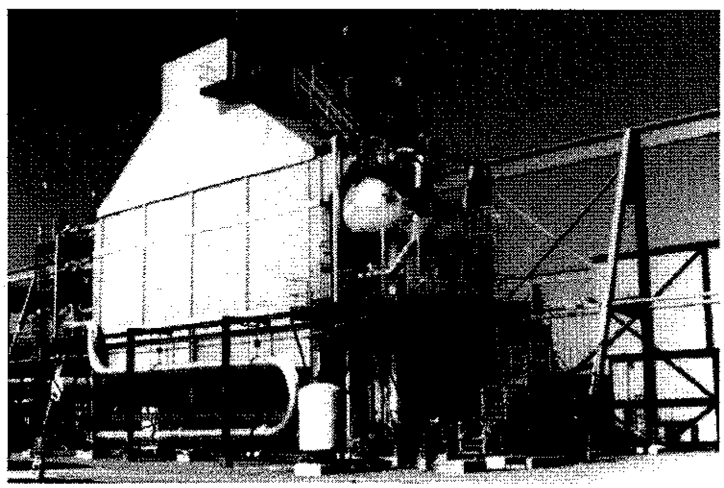


Figure 25. Forced-circulation HRSG with PG7111EA gas turbines

the performance difference for four last-stage buckets that are available for the STAG 107FA combined cycle. Steam turbine last-stage bucket lengths for the STAG product line steam turbines range from 14.3 inches / 363 mm to 42 inches / 1067 mm.

Because there are no extractions for feedwater heating, and steam is generated and admitted to the turbine at three pressures, the flow at the exhaust is approximately 30% greater than the throttle flow. The turbine's last stage generates up to 15% of the steam turbine output, so the efficiency of the turbine's last stage and the sizing of the exhaust annulus area are particularly important for combined-cycle applications.

As with all modern GE steam turbine last-stage buckets, the continuously-coupled design is used for high efficiency and reliability. Continuously-coupled designs permit the use of many relatively slender blades with narrow,

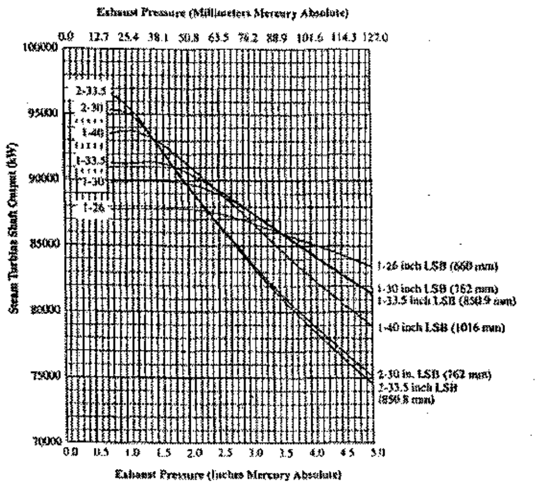


Figure 26. STAG steam turbine last-stage bucket selection

closely-controlled flow passages, particularly in the critical high-velocity tip region. Covers reduce tip leakage losses, provide damping, and help to maintain control of the flow passage.

Steam turbine designs for high exhaust pressure operation typical of those that are needed for air-cooled condenser operation at high ambient temperature are available. These steam turbine designs are capable of reliable and efficient operation at exhaust pressures up to 15 inches Hg,a/381mm Hg,a.

Advanced 3D aero packages incorporate advanced vortex design, contoured inlet section sidewalls, and additional radial tip spill strips for steam turbines larger than 80 MW, which contribute to maximum combined cycle thermodynamic efficiency.

The STAG combined-cycle product line steam turbines include axial exhaust and down exhaust configurations. Axial exhaust is preferred for the single-flow steam turbines, typically applied in the small capacity STAG systems. *Figure 27* shows a single-flow axial exhaust steam turbine.

A line of reheat steam turbines designed specifically for combined-cycle service is available for STAG systems employing the "EC," "F," and "H" technology gas turbines. The single-shaft STAG 107FA, STAG 109FA and STAG 109H are designed as integrated machines with a solid turbine/generator coupling and a single-thrust bearing that includes common lubrication and hydraulic and control systems for both gas turbine and steam turbine. A two-flow reheat steam turbine is shown in *Figure 28.*

Steam turbines specially designed for combined-cycle service have features that include:

- Assembled modules that can be shipped and assembled with a low profile installation that reduces installation time and cost. (Building cost, for indoor installation, also is reduced with the low profile design.)
- Access for borescopic inspection of buckets and nozzles without removal of the turbine upper casing.
- Fast startup and load-following capability provided by minimum shaft diameter in the vicinity of the first stage, large fillets between wheels and rotor, long coupling spans, vertical flexible plate support near the centerline with keys for maintenance of alignment, and off-shell valves with full-arc steam admission.
- All main steam, cold reheat and hot reheat steam pipes connect to the lower half of the shell. This facilitates removal of the upper half shell for maintenance, and eliminates the need for bolted connections in a high temperature piping.
- Sliding pressure operation with the control valves wide open. A control stage at the inlet is, therefore, not

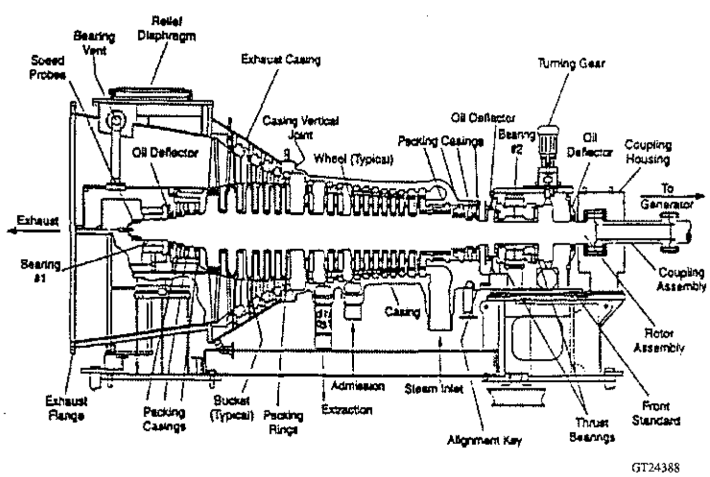


Figure 27. Non-reheat, single casing, axial exhaust steam turbine

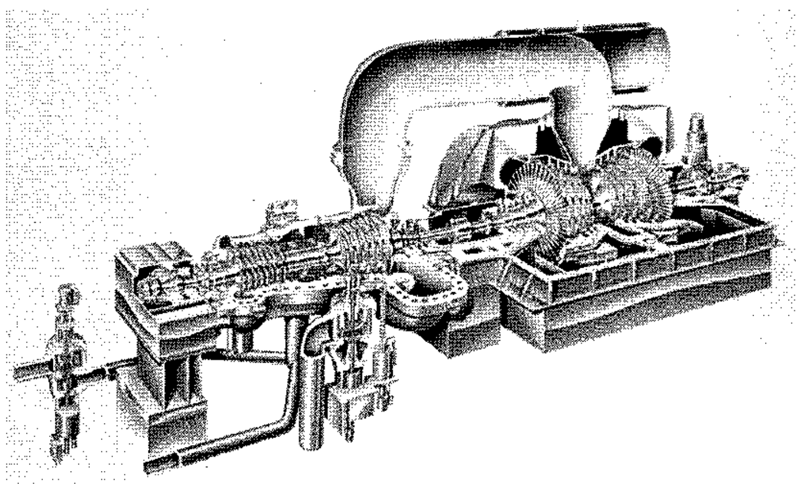


Figure 28. Two-flow, reheat steam turbine

required.

- Applications at 1800 psig/124 bar,g use a single wall construction at the high-pressure stages as well as the reheat inlet. With 2400 psig/165 bar,g applications, a short inner shell encloses the early high-pressure stages. This reduces the load on the horizontal joint bolting and reduces the thickness of the shell flange.

Generators

Generators for the STAG combined-cycle product line gas turbines and steam turbines are factory assembled and tested. Air-cooled generators are standard for the smaller STAG systems using PG6581B, PG6101FA and PG7121EA gas turbines. They may be open-ventilated or totally enclosed water-to-air cooled. If open-ventilated, they are equipped with self-cleaning air filters for desert or other dusty or dirty environments, as shown in *Figure 29.* Hydrogen-cooled generators are standard for the single-shaft and larger multi-shaft STAG systems. The hydrogen-cooled generators can be cooled by plant-cooling water or by ambient air with water-to-air heat exchangers. *Figure 30* shows a typical packaged hydrogen cooled generator for gas turbine application.

Controls

The STAG combined-cycle plant has a distributed digital control system with a redundant data highway. The station operator consoles provide interactive color graphic displays of the overall STAG plant, with sufficient detail to enable the operator to conveniently operate the plant.

The control systems for multi-shaft and single-shaft STAG combined-cycle system fundamentally follow the same principle objectives of simplicity, easy starting, automated operation and superior load following ability. All main components of the combined-cycle plant have individual control panels and interfaces that relay information and instructions to and from the plant operator through data highways to the operator console. The operator console will have a detailed graphic display with a high level of detail that enables convenient and informative interaction with the plant as required.

The single-shaft power train is a simple tandem arrangement that does not include an exhaust

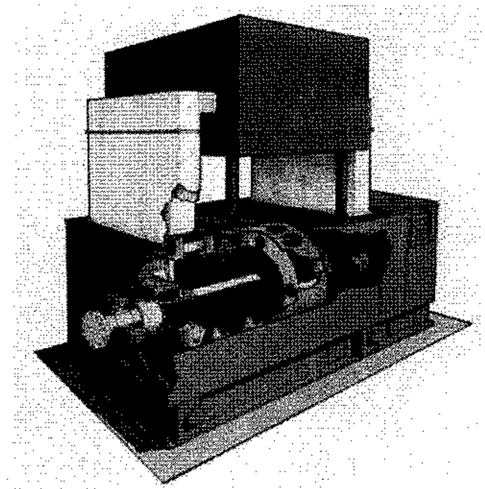


Figure 29. Air-cooled generator with self-cleaning air filter

bypass system and is solidly coupled to one generator with a common overspeed protection device with less auxiliary equipment. *Figures 31 and 32* show block diagrams for multi-shaft and single-shaft arrangements.

The heat recovery combined cycle is a simple system with a minimum of control loops, as shown by the control diagram (*Figure 33*) for a single-pressure, multi-shaft STAG system. The simplicity of this system, coupled with well-established, automated operation of system components, enables effective automation of

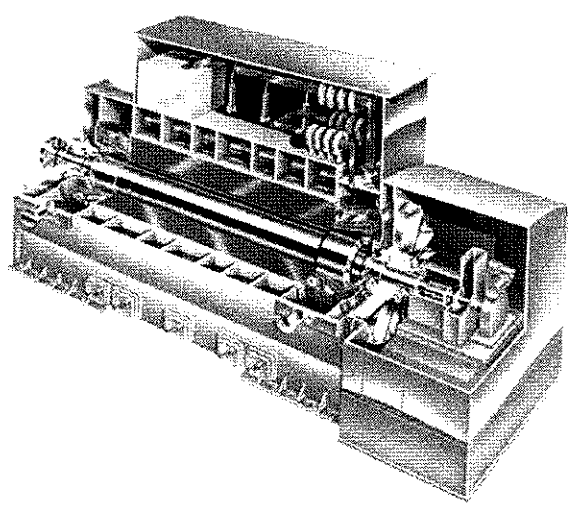


Figure 30. Typical packaged hydrogen-cooled generator

the complete power plant. This minimizes the number of control room operators. Most STAG systems operate with only one control room operator and one roving operator.

The multi-shaft STAG control is configured to enable automated startup and operation after remote manual starting of plant auxiliaries, remote manual operation of each major component, or operation of the gas turbine-generator units from local-control compartments. The control configuration enables maximum availability because the plant can be operated remotely with no additional control room operators. The equipment protection system is provided within the unit controls, so normal protection is maintained during all modes of operation, including local or remote manual operation.

The single-shaft STAG unit control system is a microprocessor-based controller that coordinates the operation of the components in each integrated combined-cycle unit and communicates with the plant control. Because of the simple steam cycle, the tandem coupling of the gas

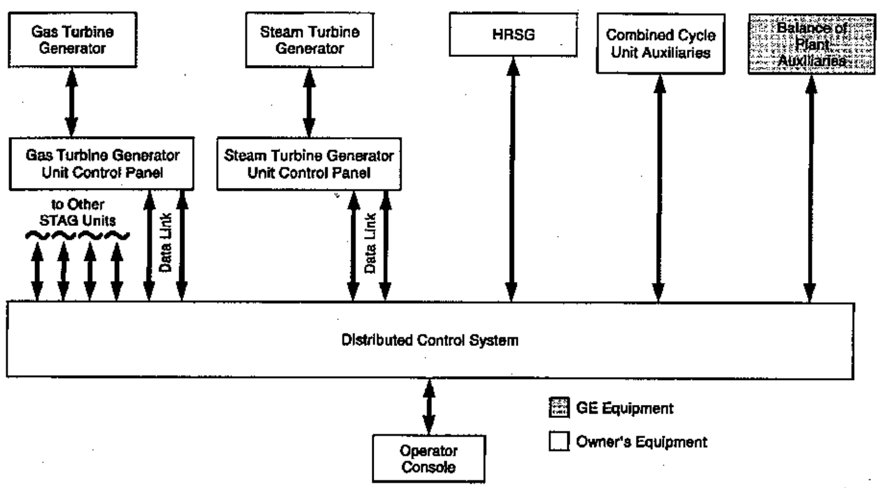


Figure 31. Distributed control system for plant with multi-shaft STAG combined cycle

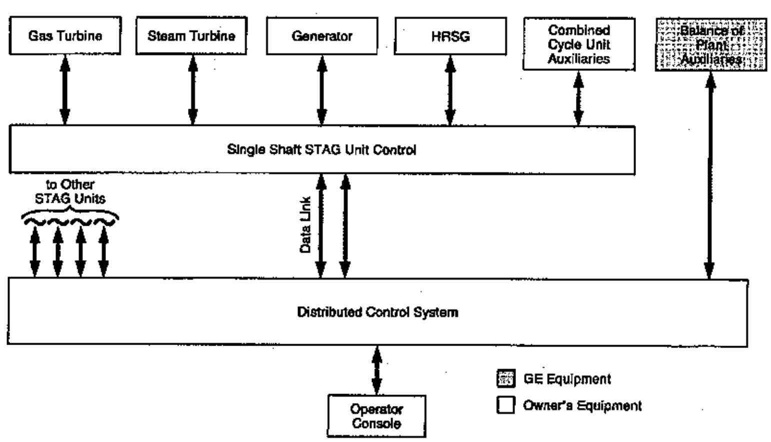


Figure 32. Distributed control system for plant with single-shaft STAG combined cycle

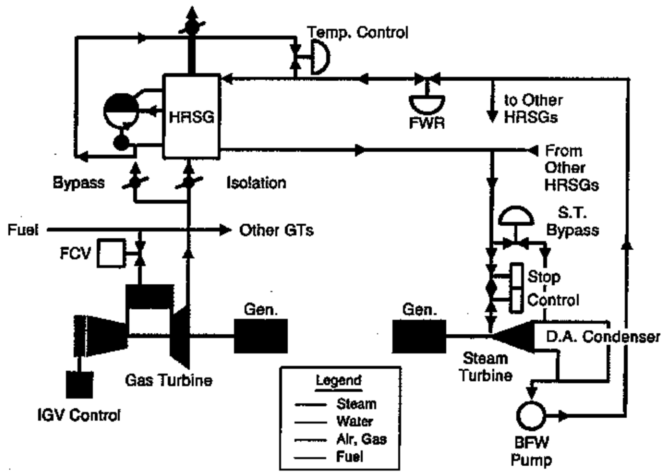


Figure 33. Multi-shaft STAG control diagram

and steam turbines to a single generator, and the elimination of the HRSG exhaust-gas, bypass system, the single-shaft STAG combined-cycle control is very simple. Starting, operation, and shutdown of individual units are automatic. Single-shaft STAG units are controlled by a local unit control system that is coupled to the central control room operator's console by a data highway. One control room operator can operate one or more single-shaft STAG combined-cycle units with this type of control system and the aid of one local operator.

Auxiliaries

The STAG product line ratings are based on plants with once-through systems (seawater or river water) for steam turbine condenser cooling. STAG combined-cycle configurations are also available for operation with a wide range of owner-specified auxiliaries, including evaporative cooling towers and air-cooled condensers. Plant capability and efficiency with these systems is expected to be lower because steam turbine exhaust pressure and cooling system auxiliary power consumption are increased.

Plant Operation

Typical STAG plant performance variation with ambient air temperature is illustrated by the heat rate and power-output capability ambient-temperature effect curves in *Figure 34.* Low heat rate throughout the ambient-air-temperature range is typical of these plants. The low heat rate and increase in output as ambient temperature decreases are achieved by the gas turbine characteristics and optimum equipment matching.

Gas turbine exhaust flow and temperature vary with ambient temperature and barometric pressure. Steam production and steam turbine output vary with the exhaust gas flow and temperature supply to the HRSG. Steam turbines are selected to suit specific application requirements. The steam turbines in the standard systems are sized so that their rated flow matches the steam production.

Excellent part-load heat rate is achieved on multi–shaft systems or multiple single-shaft units by sequentially loading gas turbines to meet system requirements (*Figure 35*). This curve also shows that the plant can operate efficiently following system load with all gas turbines operating. The heat rate increases only 1% at approximately 80% of rating.

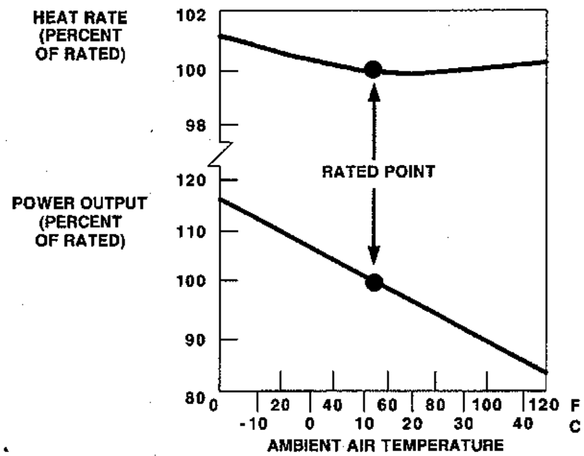


Figure 34. Combined-cycle, ambient air temperature effect curve

The modulated, inlet guide vanes (IGV) on the gas turbine compressor contribute significantly to the excellent part-load performance. The inlet guide vanes are modulated to control air flow in the power plant between the "hash mark" and the point marked "B." Varying the air flow maintains nearly constant gas turbine firing temperature so that the thermodynamic quality of the cycle remains essentially constant. The stack and condenser losses vary almost proportionally with output, so that the heat rate remains almost constant. At loads below the hash mark, the gas turbine operates with constant air flow, and firing temperature is reduced as load is reduced.

Fast starting and loading is characteristic of STAG combined-cycle generation systems. This enables them to operate in mid-range, with daily start peaking service as well as baseload. Typically, STAG systems can achieve full load within one hour during a hot start and within approximately three hours for a cold start. Multi-shaft STAG systems allow the gas turbines to start independently of the steam cycle and provide about 65% of the plant capability within 15–25 minutes, depending on the size of the gas turbine, for hot, warm, and cold starts, as illustrated in *Figure 36.* Single-shaft STAG systems are started and loaded to full capacity in about the same time period as the multi-shaft STAG systems. The startup sequence and load profile for the single-shaft systems differ because the gas and steam turbines are started as a single integrated unit and not as two separate units. Single-shaft STAG startup is illustrated in *Figure 37.*

Plant Arrangements

The STAG combined-cycle equipment can be adapted to installation requirements demanded by varying climactic conditions, system configu-

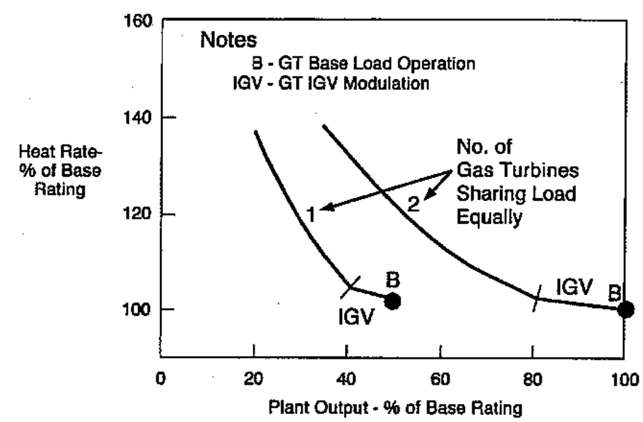


Figure 35. STAG 200 part-load performance

rations and owner/operator preferences. The equipment is suitable for outdoor installations, semi-outdoor installations, or fully-enclosed installations. Plant arrangements have been designed for each STAG system.

Plan views of STAG combined-cycle arrangements are shown in *Figure 38* (multi-shaft, S406B), *Figure 39* (multi-shaft, S207EA), Figure 40 (single-shaft S109E), *Figure 41* (multi-shaft, S207FA), and *Figure 42* (single-shaft, S107FA). An elevation of the single-shaft S107FA is shown in *Figure 43*. *Figure 44* shows the S107H and S109H plan and elevation views. The S107H provides about 58% increase in combined-cycle power output with only about 10% increase in footprint area.

A 220 MW STAG 207E installation is shown in *Figure 45*. *Figure 46* presents a STAG 109FA combined cycle installation. *Figure 47* shows a 4000 MW installation with eight STAG 107F and four STAG 207FA systems at one site. These arrangements have indoor turbine-generator equipment and outdoor HRSGs. *Figure 48* shows a plant with two STAG multi-shaft combined-cycle units in an indoor installation. For outdoor installations, the standard gas turbine enclosures are weatherproof, and weatherproof lagging is available for the steam turbines.

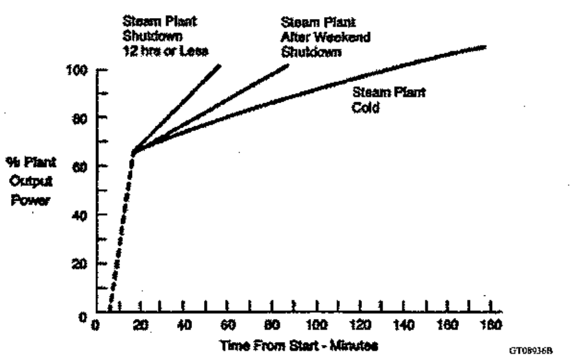


Figure 36. Multi-shaft STAG starting times

Installation

The short installation time and low installation cost of STAG combined-cycle systems are key features contributing to economical power generation. This is due to factory packaging of all major components and containerized shipment of small parts. In addition to low direct construction cost, the short installation time reduces interest payments during construction. The standard factory modules and standardized designs also reduce plant engineering time and cost.

The time from order to commercial operation for pre-engineered, standardized STAG designs is typically 24 months, not including permitting time. The multi-shaft STAG systems can be installed in two phases to reduce the time between order and initial power production. The gas turbines contribute 65% of the plant capacity. Typically, the gas turbine can be installed in less than 18 months to provide power generation while the steam system is being installed. *Figure 49* is a typical two-phase multi-shaft STAG combined-cycle installation schedule.

Utility Load Growth

Power generation economics can be enhanced by the installation of generation capacity in small increments as utility load grows. STAG combined-cycle plants fit this economical pattern because efficient, low-cost plants are available in small blocks of generating capacity.

Flexibility is also available with the pro-generation approach to capacity addition. Initial natural gas/distillate oil-fired, simple-cycle gas turbine installations can be converted to combined cycle later, when power demands require capacity increases. Plot plan area for the steam cycle equipment and transmission line capability are the main considerations during the initial com-

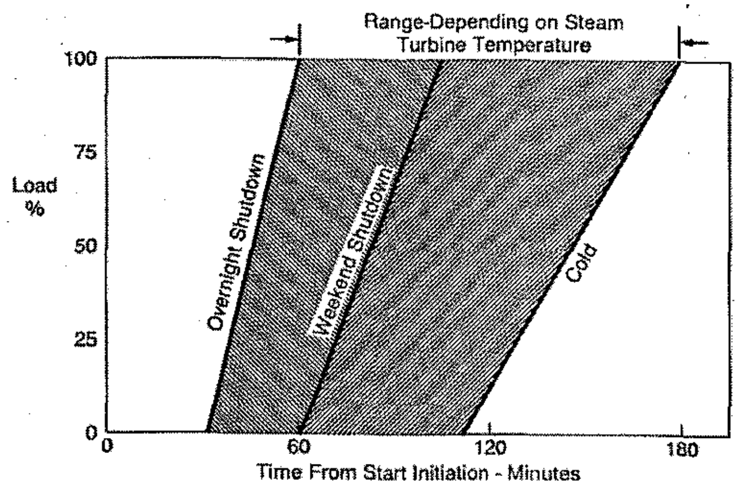


Figure 37. Single-shaft STAG starting times

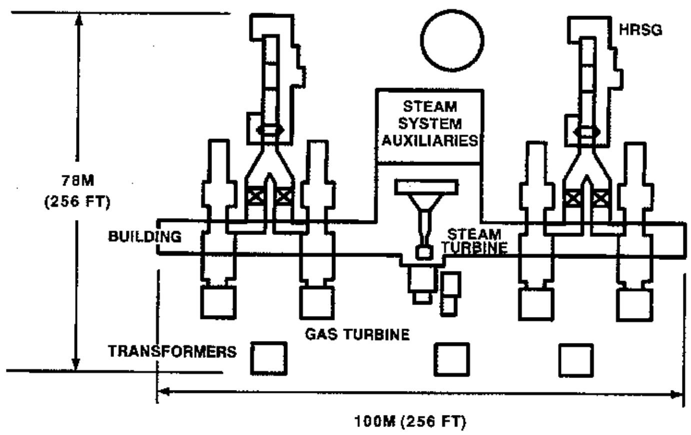


Figure 38. STAG 406B combined-cycle plan

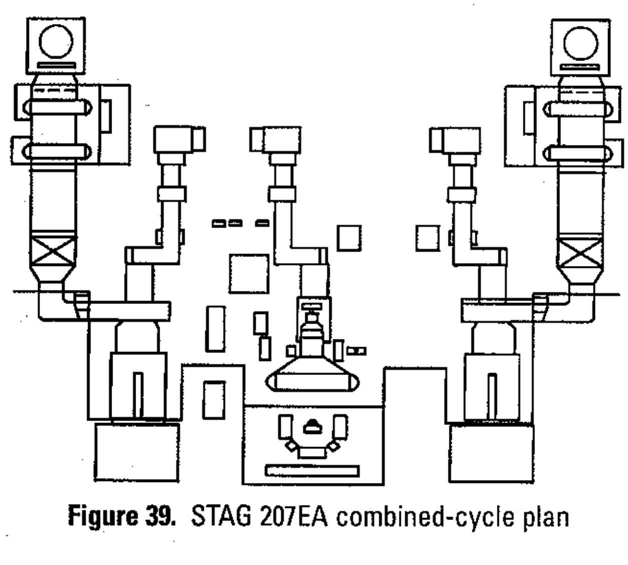


Figure 39. STAG 207EA combined-cycle plan

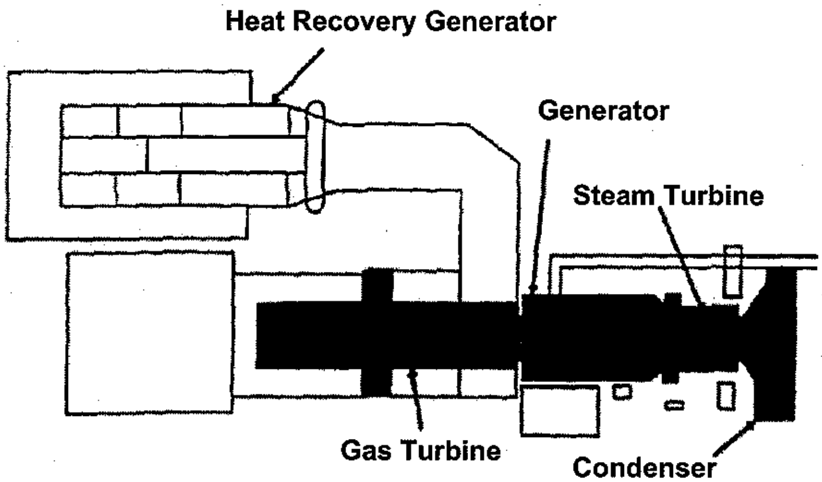


Figure 40. STAG 109E combined-cycle plan

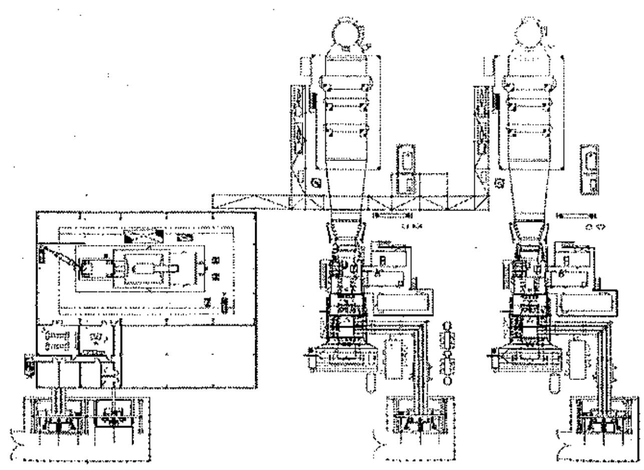


Figure 41. STAG 207FA multi-shaft combined-cycle plan

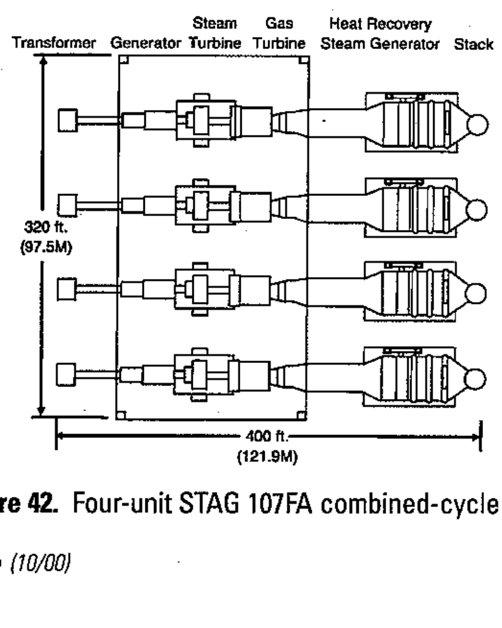


Figure 42. Four-unit STAG 107FA combined-cycle plan

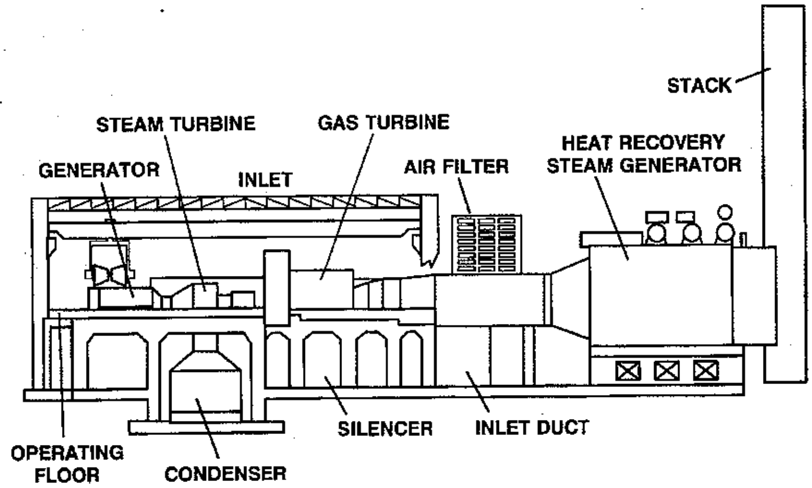
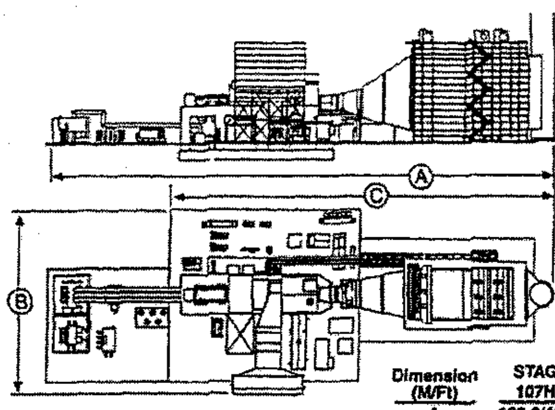


Figure 43. STAG 107FA single-shaft combined-cycle elevation



Dimension (M/Ft)	STAG 107H	STAG 109H
A	129.2/424	135.7/445
B	46.3/152	48.6/159
C	94.2/309	98.9/325

GT25050

Figure 44. Single-shaft S107H and S109H plan and elevation

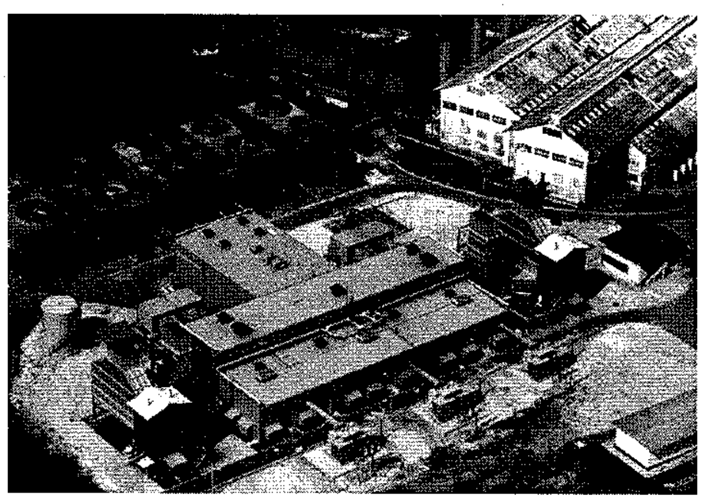


Figure 45. STAG 207E installation

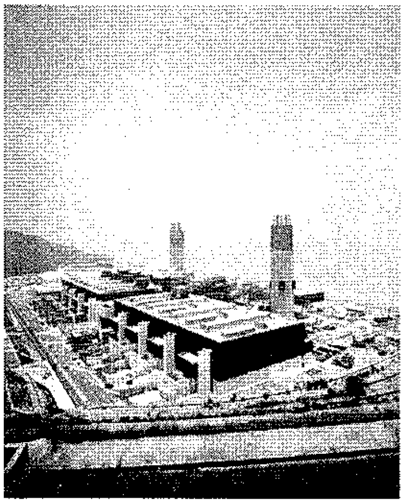


Figure 46. Indoor S109FA installation

mitment for simple-cycle gas turbines. Future conversion to coal-derived fuels also is an option for dealing with the long-range uncertainties of conventional fuel availability and price.

Thermal Energy and Power System Product Line

The product line of thermal energy and power combined-cycle systems (cogeneration and district heating systems) are designed with structured flexibility to provide a wide range of power and thermal energy capacities to suit varied application requirements. The most commonly supplied systems are:

- Steam generation at process conditions with HRSG (no steam turbine)
  - Unfired HRSG
  - Supplemental-fired HRSG
- HRSG and non-condensing steam turbine exhausting to process
  - Unfired, one-pressure HRSG
  - Unfired, two-pressure HRSG
  - Supplemental-fired, one-pressure HRSG
- HRSG with extraction/condensing steam turbine
  - Unfired, one-pressure HRSG
  - Unfired, two-pressure HRSG
  - Supplemental-fired, one-pressure HRSG

The capabilities of the thermal energy and power systems are unique for each gas turbine frame size, as well as each set of process steam conditions for systems with both unfired process HRSGs and unfired HRSGs that have non-condensing steam turbines. The systems

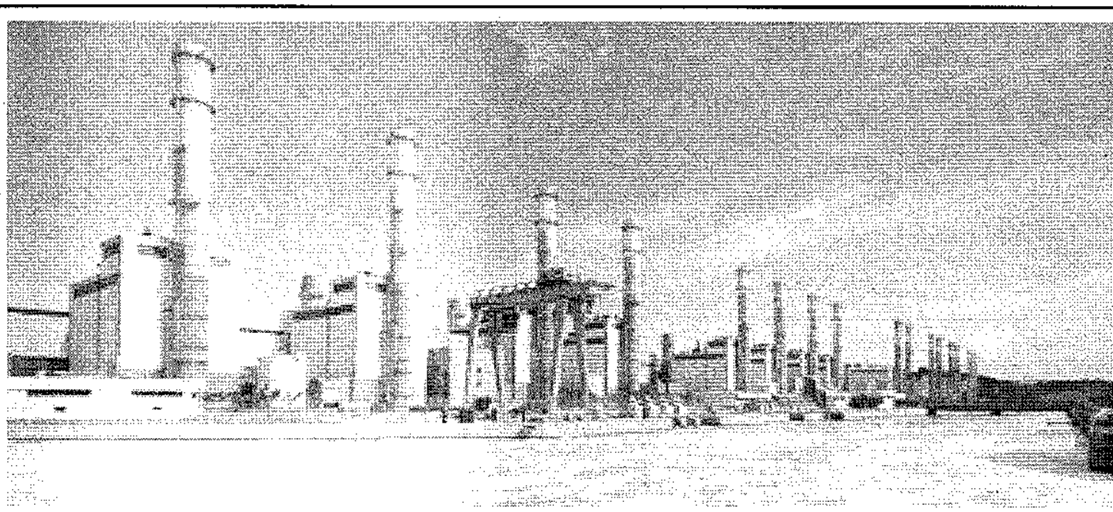


Figure 47. 4000 MW multi-shaft STAG installation

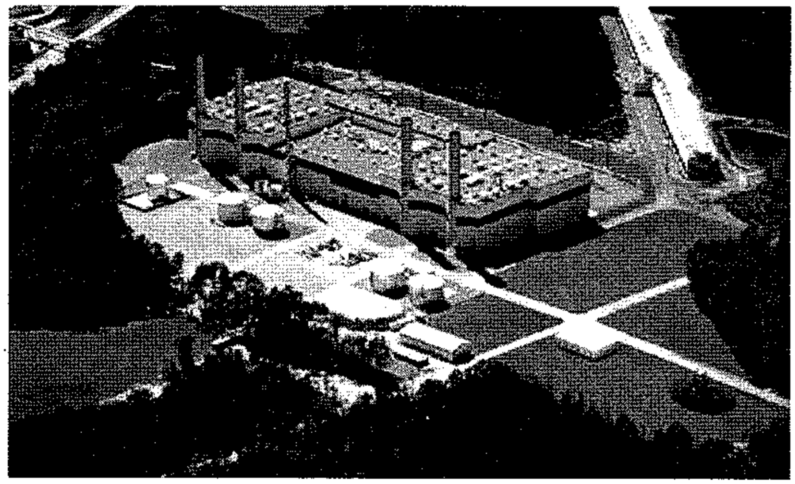


Figure 48. Two 207FA multi-shaft combined-cycle installation

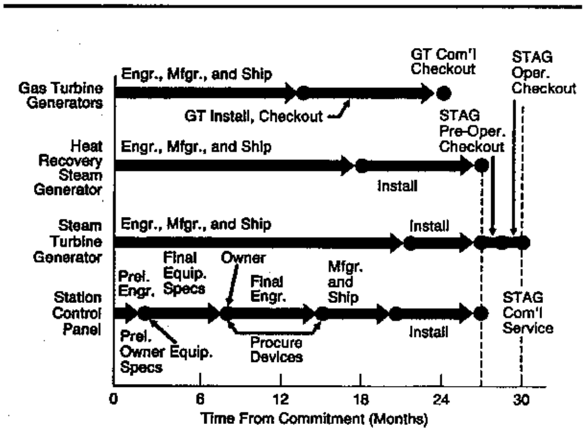


Figure 49. Typical multi-shaft, combined-cycle project schedule

with fired HRSGs and condensing steam turbines provide extraordinary flexibility in both thermal energy and power generation capacity for each gas turbine frame size.

The performance characteristics include the net plant power, LHV heat content in fuel consumed, thermal energy in steam to process, and thermal efficiency and fuel charged to power (FCP). The thermal efficiency for these systems is calculated by the following equation:

$$\eta_{TH} = 100 \times \frac{(Q_p + Q_{TE})}{Q_F}$$

Symbols:

η_{TH} = Thermal efficiency - LHV (%)
Q_F = LHV heat content of fuel consumption (Btu/hr, kJ/hr)
Q_p = Net power output (Btu/hr, kJ/hr)
Q_{TE} = Thermal energy in process steam (Btu/hr, kJ/hr)

The fuel charged to power (FCP) is a useful parameter for comparing an integrated thermal energy and power system with separate systems generating the same power and thermal energy. For this comparison, the LHV heat content of fuel that would be consumed by a conventional fired boiler in producing the same thermal energy is subtracted from the LHV heat consumption of the integrated thermal energy and power system. The resulting FCP can then be compared with the heat rate of a separate power generation facility. This will assess the relative performance of the integrated thermal energy and power system with separate thermal energy and power generation systems. FCP is calculated by the following equation:

$$FCP = 100 \times \frac{(Q_p - [Q_{TE}/\eta_B])}{p}$$

Symbols:
FCP = Fuel charged to power = LHV

(Btu/kWH, kJ/hr)

Q_F = LHV heat content of fuel consumption (Btu/hr, kJ/hr)

Q_{TE} = Thermal energy in process steam (Btu/hr, kJ/hr)

η_B = LHV efficiency of fired boiler producing equivalent thermal energy (%)

P = Net electrical output (kW)

Cycle diagrams for thermal energy and power combined cycle with steam generation at process conditions is presented in *Figure 50.*

These systems include generation of steam at process conditions. *Figure 50* shows combined-cycle cogeneration systems that produce process steam with an unfired or supplementary-fired HRSG. HRSG design for supplementary firing provides the maximum process steam energy supply. *Figure 51* shows combined-cycle cogeneration systems that are equipped with non-condensing steam turbines.

Many variations of these systems can be furnished to satisfy specific process plant energy requirements, including:

- Single automatic-extraction steam turbines to efficiently supply steam at two or three pressures.
- Multi-pressure HRSGs to supply steam at multiple-pressure and temperature conditions. The most flexible thermal energy and power systems are those that include extraction condensing steam turbines. Simplified cycle diagrams for typical systems with single automatic extraction are shown in *Figure 52.* This system has the capability to operate at lower process steam demands while using the excess steam generation to produce power in the condensing section of the steam turbine. These systems can be furnished with double automatic extraction steam turbines and multiple-pressure HRSGs to satisfy specific process steam requirements.

Engineered Equipment Package

The GE Combined-Cycle Engineered Equipment Package (EEP) is a unique combination of equipment and services. It provides the owner with a plant performance guarantee and warranty of operation, and the ability to service the complete power generation system, as well as the capability to customize the plant design, auxiliaries, and structures. This is achieved by including in the GE scope the major combined-

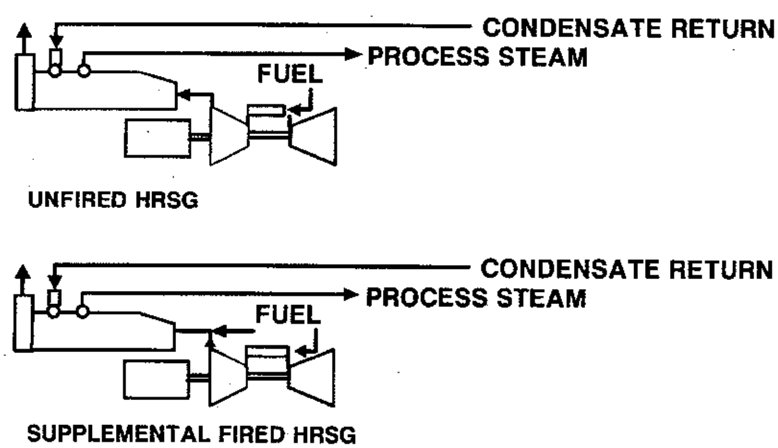


Figure 50. Cycle diagrams – thermal energy and power combined cycle with steam generation at process conditions

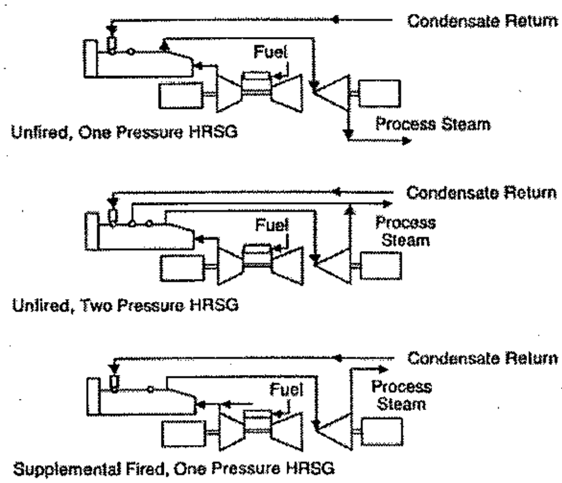


Figure 51. Cycle diagrams – thermal energy and power combined cycle with non-condensing steam turbine

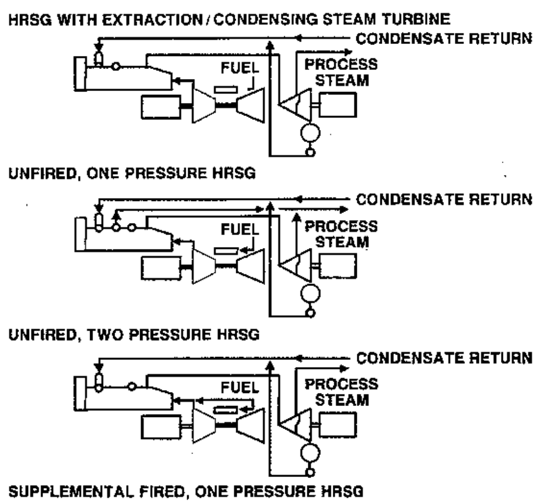


Figure 52. Cycle diagrams – thermal energy and power combined cycle with extraction/condensing steam turbines

cycle equipment that requires close coordination for assurance of meeting the performance and operating objectives. The equipment scope split between GE and the owner is shown in *Table 16.*

The services and software scope split is presented in *Table 17.* Key elements in the GE EEP scope are the combined-cycle system design and the interface definition that enable the owner ,or the owner's architect-engineer or engineer-constructor, to design the plant to meet project specific requirements.

Conclusion

The STAG combined-cycle product line, including power generation systems and thermal energy and power systems ranging from 60 MW to 750 MW, are efficient, low-cost systems that meet the environmental requirements of all countries. The GE combined cycle EEP provides assurance of satisfying performance and operating objectives while allowing a customized plant that incorporates the owner's practices and preferences. The attractive economics, reliability, and operating flexibility of these systems recommend their consideration for all power generation applications.

GENERAL ELECTRIC
• GAS TURBINE(S)
• STEAM TURBINE(S)
• GENERATOR(S)
• HEAT RECOVERY STEAM GENERATOR(S)
• PLANT CONTROLS
OWNER
• MECHANICAL AUXILIARIES
• ELECTRICAL AUXILIARIES
• MAIN ELECTRICAL CONNECTIONS
• BALANCE OF PLANT
– FOUNDATIONS AND STRUCTURES
– SWITCHYARD
– FUEL HANDLING AND STORAGE
– PLANT COOLING SYSTEM
– CONSTRUCTION MATERIALS
– SITE PREPARATION MATERIALS

Table 16. Equipment scope split with engineered equipment package

General Electric
• Plant performance and environmental guarantee
• Combined cycle system design and warranty
• Balance of plant equipment functional specifications
• Equipment interface drawings
• Steady state and dynamic interface definition
• Equipment operation and maintenance
• Operation and maintenance training
• Construction and operation permit support
• Performance and environmental test support
Owner
• Construction and operation permits
• Plant design
• Plant construction
• Plant start-up, commissioning and operation
• Performance and environmental testing
• Site preparation
• Project administration

Table 17. Services and software split with engineered equipment package

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Exhibit 15

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§§1.5.4, 3.4.8, 3.7.2, and 3.10.3; Ex. 67, p. 6.3-3.) Staff testified that for the next few years, natural gas supplies appear to be adequate to supply the IEEC. Beyond this time frame, a new interstate transmission line will likely be needed to supply these markets with inexpensive natural gas. Staff testimony indicated that free market forces will work to ensure that a new interstate natural gas transport system is constructed, or some other means are developed to provide natural gas to the IEEC and San Diego area. (Ex. 67, p. 6.3-3.)

3. Compliance with Energy Standards

No standards apply to the efficiency of IEEC or other non-cogeneration projects. (Ex. 67, p. 6.6-3; *see* Pub. Resources Code, § 25134.)

4. Alternatives to Wasteful or Inefficient Energy Consumption

Applicant provided information on alternative generating technologies, which were reviewed by Staff. (Ex. 1, §3.10; Ex. 67, p. 6.3-6; *See* the **Alternatives** section of this Decision.) Given the project objectives, location, and air pollution control requirements, Staff concluded that only natural gas-burning technologies are feasible. (*Ibid.*) Staff also reviewed alternatives to an F-class gas turbine and concluded that the project configuration and generating equipment appear to be the most efficient feasible combination to satisfy project objectives. (Ex. 67, p. 6.3-7.)

Under expected project conditions, electricity will be generated at a base load efficiency of approximately 56.5 percent LHV without duct firing and 53.2 percent LHV with duct firing.[7] (Ex. 67, pp. 6.3-2 to 6.3-3.)

[7] The average fuel efficiency of a typical utility company base load power plant is approximately 35 percent LHV. (Ex. 67, p. 6.3-3.)

Exhibit 16

Application for Certification

Volume I

CPV Vaca Station

Submitted by

CPV Vacaville, LLC

Submitted to

California Energy Commission

With Technical Assistance by

CH2MHILL

October 2008

ES122007003SAC

without the use of duct firing. Heat balances for additional operating cases are presented in Appendix 2A. The predicted net electrical output of the facility under these conditions is approximately 500 MW at a heat rate of approximately 6,885 British thermal units per kilowatt hour (Btu/kWh) on a higher heating value (HHV) basis. This corresponds with an efficiency of about 55 percent. With HRSG duct firing, the facility will be able to produce a net output of up to 600 MW at an ambient temperature of 75°F with evaporative cooling of the CTG inlet air to 68°F using the GE Energy Frame 7FA. The incremental heat rate of the peaking capacity will range between approximately 9,270 and 9,290 Btu/kWh, corresponding to an efficiency of 38 percent, which is comparable to that of a CTG operating in simple-cycle mode.

Figure 2.1-4b is a similar heat balance assuming the use of Siemens SGT6 5000F CTGs. The predicted net electrical output of the facility under these conditions is approximately 560 MW at a heat rate of approximately 6,875 Btu/kWh on an HHV basis, corresponding to an efficiency of about 55 percent. With HRSG duct firing, the facility will be able to produce a net output of up to 670 MW at an ambient temperature of 75°F with evaporative cooling of the CTG inlet air to 68°F using the Siemens SGT6 5000F CTGs. The incremental heat rate of the peaking capacity will range between approximately 8,890 and 8,910 Btu/kWh, corresponding to an efficiency of 40 percent, which is comparable to that of a CTG operating in simple-cycle mode.

The combustion turbines and associated equipment will include the use of best available control technology (BACT) to limit emissions of criteria pollutants and hazardous air pollutants. NO_x will be controlled to 2.0 parts per million by volume, dry basis (ppmvd), corrected to 15 percent oxygen through the use of dry low-NO_x combustors and SCR. Good combustion practices and a carbon monoxide catalyst also will be utilized to control carbon monoxide emissions to 3.0 ppmvd at 15 percent oxygen. Emissions of volatile organic compounds also will be controlled to 2.0 ppm. BACT for particulate matter with a diameter less than 10 microns (PM_{10}) and sulfur dioxide will be the exclusive use of natural gas. Ammonia slip will be limited to 5 ppmvd to meet the BACT requirements.

2.1.3 Power Plant Cycle

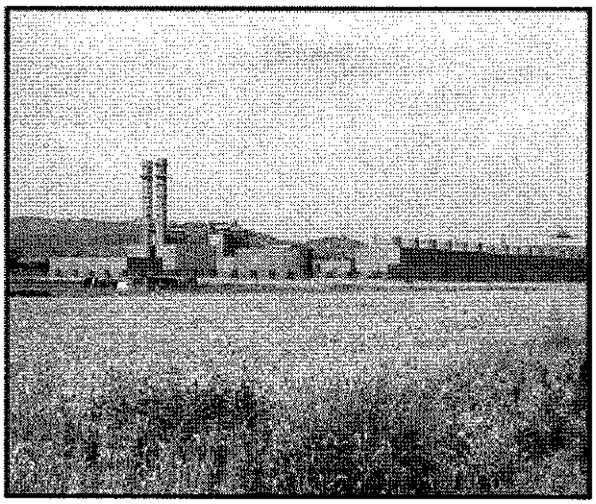
CTG combustion air will flow through the inlet air filters, evaporative coolers, and associated air inlet ductwork, be compressed in the CTG compressor section, and then enter the CTG combustion sections. Natural gas fuel will be injected into the compressed air in the combustion sections and ignited. The hot combustion gases will expand through the power turbine section of the CTGs, causing them to rotate and drive both the electric generators and CTG compressors. The hot combustion gases will exit the turbine sections and enter the HRSGs, where they will heat water (feedwater) that is pumped into the HRSGs. The feedwater will be converted to superheated steam and delivered to the steam turbine at high pressure (HP), intermediate pressure (IP), and low pressure (LP). The use of multiple steam delivery pressures will permit an increase in cycle efficiency and flexibility. High-pressure steam will be delivered to the HP section of the steam turbine, intermediate pressure steam will augment the reheat section of the HRSG and will deliver this steam to the IP section of the STG, low pressure steam will be injected at the beginning of the LP section of the steam turbine, and both flows will be expanded in the LP steam turbine section. Steam leaving the LP section of the steam turbine will enter the deaerating surface condenser and transfer heat to circulating cooling water, which will cause the steam to condense to water.

Exhibit 17

CALIFORNIA
ENERGY
COMMISSION

INLAND EMPIRE ENERGY CENTER

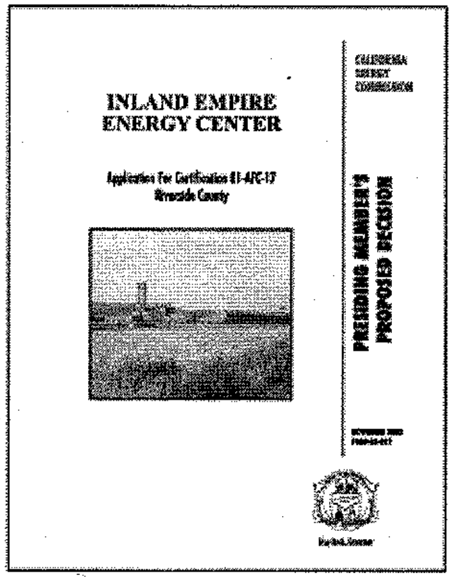
Application For Certification 01-AFC-17
Riverside County



PRESIDING MEMBER'S PROPOSED DECISION

NOVEMBER 2003
P800-03-017

Gray Davis, Governor


INLAND EMPIRE
ENERGY CENTER

Application For Certification 01-AFC-17
Riverside County

CALIFORNIA ENERGY COMMISSION

PRESIDING MEMBER'S
PROPOSED DECISION

CALIFORNIA ENERGY COMMISSION

1516 9th Street
Sacramento, CA 95814
www.energy ca.gov/sitingcases/inlandempire

ROBERT PERNELL
Presiding Committee Member

JAMES D. BOYD
Associate Committee Member

KERRY WILLIS
Hearing Officer

Project fuel efficiency, and therefore its rate of energy consumption, is determined by the configuration of the power producing system and by selection of generating equipment. (Ex. 67, p. 6.3-3.) IEEC is configured as a combined cycle power plant. Electricity will be produced by two gas turbines with a reheat steam turbine that operates on heat energy recuperated from gas turbine exhaust. (Ex. 1, §§ 1.5.2, 3.4.2.) By recovering this heat, which would otherwise be lost up the exhaust stacks, the efficiency of a combined cycle power plant is considerably increased compared with either a gas turbine or a steam turbine operating alone. Staff concluded that the proposed configuration is well suited to the large, steady loads met by a base load plant. (Ex. 67, p. 6.3-4.)

Project efficiency will also be enhanced by inlet air foggers, HRSG duct burners (re-heaters), three-pressure HRSG, a steam turbine unit and circulating water system. (Ex. 1, § 3.4.2, Ex. 67, p. 6.3-4.) Staff's testimony establishes that these features contribute to meaningful efficiency enhancement to the IEEC. The two-train CT/HRSG configuration also allows for high efficiency during unit turndown because one CT can be shut down, leaving one fully loaded, efficiently operating CT. *(Ibid.)*

The IEEC will employ the advanced model turbines instead of the conventional or the next generation models. Applicant plans to use two large advanced model General Electric (GE) Power Systems "F" class combustion turbine generators in a two-on-one combined cycle power train. Staff testified that the F-class gas turbines to be employed in the IEEC represent some of the most modern and efficient machines now available. (Ex. 1, § 3.4.3.1) This configuration is nominally rated at 530 MW and 56.5 percent efficiency LHV at ISO conditions. (Ex. 67, p. 6.3-5.) At base load, the plant will be operating at a heat rate of approximately 6,700 Btu/kwh on a higher heating value basis. The incremental heat rate for peaking capacity will range from 8,100 to 9,000 Btu/kwh (HHV), depending on ambient and operating conditions, (Ex. 1, p. 3-10.)

Exhibit 18

Combined Cycle Ratings
– 2007-08 GTW Handbook –

Model	Year	Net Plant Output	Heat Rate Btu/kWh	Net Plant Efficiency	Heat Rate kJ/kWh	Condenser Vacuum (Hg)	Gas Turbine Power	Steam Turbine Power	No. & Type Gas Turbine	Comments
Alstom (50 Hz)										
KA8C2-2	1998	165 000 kW	6783 Btu	50.3%	7156 kJ	45	*****	*****	2 x GT8C2	dual pressure non-reheat HRSG
KA11N2-2	1993	344 800 kW	6647 Btu	51.3%	7013 kJ	45	*****	*****	2 x GT11N2	dual pressure non-reheat HRSG
KA13E2-1	1993	252 800 kW	6458 Btu	52.8%	6813 kJ	45	*****	*****	1 x GT13E2	dual pressure non-reheat HRSG
KA13E2-2	1993	507 400 kW	6435 Btu	53.0%	6789 kJ	45	*****	*****	2 x GT13E2	dual pressure non-reheat HRSG
KA13E2-3	1993	763 200 kW	6417 Btu	53.2%	6770 kJ	45	*****	*****	3 x GT13E2	dual pressure non-reheat HRSG
KA26-1	1996	424 000 kW	5850 Btu	58.3%	6172 kJ	45	*****	*****	1 x GT26	with once through cooler
KA26-2	1996	850 300 kW	5835 Btu	58.5%	6156 kJ	45	*****	*****	2 x GT26	with once through cooler
KA26-2 ICS	2006	857 700 kW	5785 Btu	59.0%	6103 kJ	45	*****	*****	2 x GT26	with once through cooler
Alstom (60Hz)										
KA8C2-2	1998	163 500 kW	6837 Btu	49.9%	7213 kJ	45	*****	*****	2 x GT8C2	dual pressure non-reheat HRSG
KA11N2-2	2001	348 500 kW	6582 Btu	51.8%	6944 kJ	45	*****	*****	2 x GT11N2	dual pressure non-reheat HRSG
KA24-1	1998	278 900 kW	5978 Btu	57.1%	6307 kJ	45	*****	*****	1 x GT24	with once through cooler
KA24-2	1998	560 000 kW	5955 Btu	57.3%	6282 kJ	45	*****	*****	2 x GT24	with once through cooler
Ansaldo Energia (50 Hz)										
COBRA 164.3A	*****	115 400 kW	6301 Btu	54.2%	6648 kJ	*****	75 550 kW	41 800 kW	1 x V64.3A	ISO based performance with
COBRA 264.3A	*****	232 900 kW	6242 Btu	54.7%	6586 kJ	*****	151 100 kW	85 770 kW	2 x V64.3A	4"/12" losses for all models
COBRA 194.2	*****	246 400 kW	6599 Btu	51.7%	6962 kJ	*****	161 300 kW	90 100 kW	1 x V94.2	
COBRA 294.2	*****	499 200 kW	6515 Btu	52.4%	6873 kJ	*****	323 000 kW	186 600 kW	2 x V94.2	
COBRA 394.2	*****	747 100 kW	6529 Btu	52.3%	6889 kJ	*****	483 900 kW	278 200 kW	3 x V94.2	
COBRA 194.3A	*****	411 600 kW	5900 Btu	57.8%	6225 kJ	*****	277 800 kW	140 900 kW	1 x V94.3A	
COBRA 294.3A	*****	820 300 kW	5922 Btu	57.6%	6248 kJ	*****	556 000 kW	278 800 kW	2 x V94.3A	
Bharat Heavy Electricals (50 Hz)										
CC105P	1988	38 500 kW	8180 Btu	41.7%	8630 kJ	*****	25 900 kW	18 200 kW	1 x MS5001	dual pressure
CC205P	1988	77 800 kW	8110 Btu	42.1%	8550 kJ	*****	51 800 kW	27 200 kW	2 x MS5001	dual pressure
CC305P	1988	117 200 kW	8070 Btu	42.3%	8510 kJ	*****	77 700 kW	41 400 kW	3 x MS5001	dual pressure
CC106B	1997	64 300 kW	6960 Btu	49.0%	7340 kJ	*****	41 600 kW	23 800 kW	1 x MS6001B	dual pressure
CC206B	1997	130 700 kW	6850 Btu	49.8%	7320 kJ	*****	83 200 kW	49 400 kW	2 x MS6001B	dual pressure

Model	Year	Net Plant Output	Heat Rate Btu/kWh	Net Plant Efficiency	Heat Rate kJ/kWh	Condenser Vacuum (Hg)	Gas Turbine Power	Steam Turbine Power	No. & Type Gas Turbine	Comments
Bharat Heavy Electricals (50 Hz) continued										
CC106C	2004	62 700 kW	6315 Btu	54.1%	6660 kJ	*****	41 700 kW	21 900 kW	1 x MS6001C	dual pressure
CC206C	2004	126 200 kW	6275 Btu	54.4%	6620 kJ	*****	83 400 kW	44 700 kW	2 x MS6001C	dual pressure
CC106FA	2003	117 000 kW	6300 Btu	54.2%	6645 kJ	*****	75 200 kW	43 500 kW	1 x MS6001FA	triple pressure, non reheat
CC206FA	2003	234 800 kW	6280 Btu	54.4%	6625 kJ	*****	150 400 kW	87 800 kW	2 x MS6001FA	triple pressure, reheat
CC109E	2003	190 700 kW	6640 Btu	51.4%	7000 kJ	*****	124 000 kW	70 000 kW	1 x MS9001E	dual pressure
CC209E	2003	384 000 kW	6600 Btu	51.7%	6960 kJ	*****	248 000 kW	142 100 kW	2 x MS9001E	dual pressure
CC309E	2003	577 000 kW	6560 Btu	52.0%	6920 kJ	*****	372 000 kW	214 000 kW	3 x MS9001E	dual pressure
CC1.942	1998	232 500 kW	6630 Btu	51.5%	6990 kJ	*****	152 000 kW	85 500 kW	1 x V94.2	dual pressure
CC2.942	1998	467 500 kW	6600 Btu	51.7%	6960 kJ	*****	304 000 kW	173 000 kW	2 x V94.2	dual pressure
CC3.942	1998	701 000 kW	6600 Btu	51.7%	6960 kJ	*****	456 000 kW	259 000 kW	3 x V94.2	dual pressure
CC109FA	2003	383 600 kW	6164 Btu	55.4%	6502 kJ	*****	251 700 kW	137 000 kW	1 x MS9001FA	triple pressure reheat
CC209FA	2003	772 000 kW	6125 Btu	55.7%	6461 kJ	*****	503 400 kW	279 000 kW	2 x MS9001FA	triple pressure reheat
Ebara (50/60 Hz)										
FT8 PowerPac	1990	32 910 kW	6865 Btu	49.7%	7243 kJ	*****	24 165 kW	8 755 kW	1 x FT8	all with dual pressure HRSGs
FT8 TwinPac	1990	66 745 kW	6770 Btu	50.4%	7143 kJ	*****	48 725 kW	18 020 kW	2 x FT8	and 1.0 psia condenser
FT8-3 PowerPac	1990	36 570 kW	6750 Btu	50.6%	7122 kJ	*****	26 564 kW	10 006 kW	1 x FT8-3	
FT8-3 TwinPac	1990	74 185 kW	6655 Btu	51.3%	7022 kJ	*****	53 688 kW	20 597 kW	2 x FT8-3	
GE Energy Aeroderivative (50Hz)										
LM2000PS	2000	24 123 kW	7 682 Btu	44.4%	8105 kJ	1.0"	18 275 kW	6 417 kW	1 x LM2000PS	
LM2000PJ	2000	24 410 kW	7 231 Btu	47.2%	7629 kJ	1.0"	17 769 kW	7 222 kW	1 x LM2000PJ	
LM2500PE	1981	31 153 kW	6 906 Btu	49.4%	7286 kJ	1.0"	22 239 kW	9 604 kW	1 x LM2500PE	
LM2500PE	1981	31 345 kW	7 385 Btu	46.2%	7791 kJ	1.0"	22 949 kW	9 088 kW	1 x LM2500PE	
LM2500PJ	1995	30 375 kW	6 934 Btu	49.2%	7315 kJ	1.0"	21 713 kW	9 340 kW	1 x LM2500PJ	
LM2500+ RC	2005	46 946 kW	7 106 Btu	48.0%	7497 kJ	1.0"	35 851 kW	12 026 kW	1 x LM2500+ RC	
LM2500+ RD	2005	43 957 kW	6 693 Btu	51.0%	7061 kJ	1.0"	32 723 kW	12 124 kW	1 x LM2500+ RD	
LM6000PC	1997	53 128 kW	6 990 Btu	48.8%	7374 kJ	1.0"	43 131 kW	11 020 kW	1 x LM6000PC	
LM6000PC Sprint	1998	62 546 kW	6 889 Btu	49.5%	7268 kJ	1.0"	50 592 kW	13 119 kW	1 x LM6000PC	
LM6000PD	1997	53 578 kW	6 556 Btu	52.0%	6917 kJ	1.0"	42 527 kW	12 086 kW	1 x LM6000PD	
LM6000PD liquid	2005	51 915 kW	6 589 Btu	51.8%	6951 kJ	1.0"	40 802 kW	12 128 kW	1 x LM6000PD	distillate fuel
LM6000PD Sprint	2000	58 668 kW	6 637 Btu	51.4%	7002 kJ	1.0"	47 277 kW	12 503 kW	1 x LM6000PD	
LM6000PF	2006	53 578 kW	6 556 Btu	52.0%	6917 kJ	1.0"	42 527 kW	12 086 kW	1 x LM6000PF	
LM6000PF Sprint	2006	59 646 kW	6 593 Btu	51.8%	6956 kJ	1.0"	47 809 kW	12 964 kW	1 x LM6000PF	

Model	Year	Net Plant Output	Heat Rate Btu/kWh	Net Plant Efficiency	Heat Rate kJ/kWh	Condenser Vacuum (Hg)	Gas Turbine Power	Steam Turbine Power	No. & Type Gas Turbine	Comments
GE Energy Aeroderivative (50Hz) continued										
LMS100PA	2006	117 578 kW	6 811 Btu	50.1%	7186 kJ	1.0"	102 504 kW	16 951 kW	1 x LMS100PA	
LMS100PB	TBD	113 512 kW	6 557 Btu	52.0%	6918 kJ	1.0"	97 967 kW	17 366 kW	1 x LMS100PB	
GE Energy Aeroderivative (60 Hz)										
LM2000PS	2000	23 957 kW	7 589 Btu	45.0%	8006 kJ	1.0"	18 412 kW	6 102 kW	1 x LM2000PS	
LM2000PJ	2000	23 911 kW	7 168 Btu	47.6%	7562 kJ	1.0"	17 657 kW	6 816 kW	1 x LM2000PJ	
LM2500PE	1981	31 931 kW	6 795 Btu	50.2%	7169 kJ	1.0"	23 292 kW	9 332 kW	1 x LM2500PE	
LM2500PE	1981	32 203 kW	7 257 Btu	47.0%	7656 kJ	1.0"	24 049 kW	8 850 kW	1 x LM2500PE	
LM2500PJ	1995	31 125 kW	6 821 Btu	50.0%	7196 kJ	1.0"	22 719 kW	9 087 kW	1 x LM2500PJ	
LM2500+ RC	2005	47 359 kW	7 046 Btu	48.4%	7434 kJ	1.0"	36 333 kW	11 961 kW	1 x LM2500+ RC	
LM2500+ RD	2005	44 327 kW	6 565 Btu	52.0%	6926 kJ	1.0"	33 165 kW	12 055 kW	1 x LM2500+ RD	
LM6000PC	1997	53 954 kW	6 923 Btu	49.3%	7304 kJ	1.0"	43 843 kW	11 147 kW	1 x LM6000PC	
LM6000PC Sprint	1998	62 372 kW	6 852 Btu	49.8%	7229 kJ	1.0"	50 526 kW	13 007 kW	1 x LM6000PC	
LM6000PD	1997	54 180 kW	6 497 Btu	52.5%	6854 kJ	1.0"	43 068 kW	12 153 kW	1 x LM6000PD	
LM6000PD liquid	2005	51 716 kW	6 546 Btu	52.1%	6906 kJ	1.0"	40 712 kW	12 013 kW	1 x LM6000PD	distillate fuel
LM6000PD Sprint	2000	58 678 kW	6 591 Btu	51.8%	6954 kJ	1.0"	47 383 kW	12 401 kW	1 x LM6000PD	
LM6000PF	2006	54 180 kW	6 497 Btu	52.5%	6854 kJ	1.0"	43 068 kW	12 153 kW	1 x LM6000PF	
LM6000PF Sprint	2006	59 684 kW	6 568 Btu	51.9%	6929 kJ	1.0"	48 092 kW	12 719 kW	1 x LM6000PF	
LMS100PA	2006	117 905 kW	6 793 Btu	50.2%	7167 kJ	1.0"	103 045 kW	16 736 kW	1 x LMS100PA	
LMS100PB	TBD	112 806 kW	6 599 Btu	51.7%	6962 kJ	1.0"	98 396 kW	16 204 kW	1 x LMS100PB	
GE Energy Heavy Duty (50 Hz)										
S106B	1987	64 300 kW	6960 Btu	49.0%	7341 kJ	1.2"	41 600 kW	23 800 kW	1 x MS6001B	non-reheat
S206B	1979	130 700 kW	6850 Btu	49.8%	7225 kJ	1.2"	83 200 kW	49 400 kW	2 x MS6001B	non-reheat
S406B	1979	261 300 kW	6850 Btu	49.8%	7225 kJ	1.2"	166 400 kW	99 000 kW	4 x MS6001B	non-reheat
S106C	2002	67 200 kW	6281 Btu	54.3%	6627 kJ	1.2"	44 800 kW	23 100 kW	1 x MS6001C	non-reheat
S206C	2002	136 100 kW	6203 Btu	55.0%	6544 kJ	1.2"	89 600 kW	48 100 kW	2 x MS6001C	non-reheat
S106FA	1991	118 400 kW	6199 Btu	55.0%	6540 kJ	1.2"	76 300 kW	43 900 kW	1 x MS6001FA	reheat
S206FA	1991	239 400 kW	6132 Btu	55.6%	6470 kJ	1.2"	152 600 kW	90 300 kW	2 x MS6001FA	reheat
S109E	1979	193 200 kW	6570 Btu	52.0%	6930 kJ	1.2"	124 300 kW	71 800 kW	1 x MS9001E	non-reheat
S209E	1979	391 400 kW	6480 Btu	52.7%	6835 kJ	1.2"	248 600 kW	148 500 kW	2 x MS9001E	non-reheat
S109FA	1994	390 800 kW	6020 Btu	56.7%	6350 kJ	1.2"	254 100 kW	141 800 kW	1 x MS9001FA	reheat
S209FA	1994	786 900 kW	5980 Btu	57.1%	6308 kJ	1.2"	508 200 kW	289 200 kW	2 x MS9001FA	reheat

Model	Year	Net Plant Output	Heat Rate Btu/kWh	Net Plant Efficiency	Heat Rate kJ/kWh	Condenser Vacuum (Hg)	Gas Turbine Power	Steam Turbine Power	No. & Type Gas Turbine	Comments
GE Energy Heavy Duty (50 Hz) continued										
S109FB*	2002	430 000 kW	5890 Btu	57.9%	6214 kJ	1.7"	275 000 kW	163 500 kW	1 x MS9001FB	reheat
S209FB*	2002	859 400 kW	5895 Btu	57.9%	6219 kJ	1.7"	550 000 kW	327 500 kW	2 x MS9001FB	reheat
*Estimated by GTW; contact GE Energy for latest design ratings										
S109H	1997	520 000 kW	5690 Btu	60.0%	6000 kJ	1.2"	****	****	1 x MS9001H	single shaft w/ reheat
Note: All three models above include three-pressure steam cycle and dry low NOx combustion										
GE Energy Heavy Duty (60 Hz)										
S106B	1987	64 300 kW	6960 Btu	49.0%	7341 kJ	1.2"	41 600 kW	23 800 kW	1 x MS6001B	non-reheat
S206B	1979	130 700 kW	6850 Btu	49.8%	7225 kJ	1.2"	83 200 kW	49 400 kW	2 x MS6001B	non-reheat
S406B	1979	261 300 kW	6850 Btu	49.8%	7225 kJ	1.2"	166 400 kW	99 000 kW	4 x MS6001B	non-reheat
S106C	2002	67 200 kW	6281 Btu	54.3%	6667 kJ	1.2"	44 800 kW	23 200 kW	1 x MS6001C	non-reheat
S206C	2002	136 100 kW	6203 Btu	55.0%	6617 kJ	1.2"	89 600 kW	48 100 kW	2 x MS6001C	non-reheat
S106FA	1991	118 750 kW	6208 Btu	55.0%	6550 kJ	1.2"	76 350 kW	44 200 kW	1 x MS6001FA	reheat
S206FA	1991	238 900 kW	6180 Btu	55.2%	6520 kJ	1.2"	152 700 kW	89 700 kW	2 x MS6001FA	reheat
S107EA	1977	130 200 kW	6800 Btu	50.2%	7173 kJ	1.2"	83 500 kW	48 700 kW	1 x MS7001EA	non-reheat
S207EA	1979	263 600 kW	6700 Btu	50.9%	7067 kJ	1.2"	167 000 kW	100 700 kW	2 x MS7001EA	non-reheat
S107FA	1994	262 600 kW	6090 Btu	56.0%	6424 kJ	1.2"	170 850 kW	95 600 kW	1 x MS7001FA	reheat
S207FA	1994	529 900 kW	6040 Btu	56.5%	6371 kJ	1.2"	341 700 kW	195 800 kW	2 x MS7001FA	reheat
S107FB	1999	280 300 kW	5950 Btu	57.3%	6276 kJ	1.7"	183 150 kW	101 030 kW	1 x MS7001FB	reheat
S207FB	1999	562 500 kW	5940 Btu	57.5%	6266 kJ	1.7"	366 300 kW	204 000 kW	2 x MS7001FB	reheat
S107H	1997	400 000 kW	5690 Btu	60.0%	6000 kJ	1.2"	*****	*****	1 x MS7001H	single shaft w/ reheat
Note: All models above include three-pressure steam cycle and dry low NOx combustion										
Hitachi (50/60 Hz)										
2025	1988	81 360 kW	6818 Btu	50.1%	7193 kJ	****	53 860 kW	27 500 kW	2 x H-25	
3025	1988	122 190 kW	6809 Btu	50.1%	7184 kJ	****	80 790 kW	41 400 kW	3 x H-25	
206B	1986	121 000 kW	6960 Btu	49.0%	7350 kJ	****	78 100 kW	42 900 kW	2 x MS6001B	
106FA	1993	106 300 kW	6530 Btu	52.3%	6890 kJ	****	68 900 kW	37 400 kW	1 x MS6001FA	
206FA	1993	215 300 kW	6450 Btu	52.9%	6800 kJ	****	137 800 kW	77 500 kW	2 x MS6001FA	
Hitachi (50 Hz)										
109E	1986	178 700 kW	6950 Btu	49.1%	7335 kJ	****	119 000 kW	59 700 kW	1 x MS9001E	
209E	1986	359 500 kW	6910 Btu	49.4%	7290 kJ	****	238 000 kW	121 500 kW	2 x MS9001E	
109FA	1995	367 400 kW	6170 Btu	55.3%	6510 kJ	****	234 700 kW	132 700 kW	1 x MS9001FA	
Hitachi (60 Hz)										
107EA	1989	128 200 kW	6820 Btu	50.0%	7200 kJ	****	83 500 kW	44 700 kW	1 x MS7001EA	
207EA	1989	258 100 kW	6780 Btu	50.3%	7160 kJ	****	167 000 kW	91 100 kW	2 x MS7001EA	

Model	Year	Net Plant Output	Heat Rate Btu/kWh	Net Plant Efficiency	Heat Rate kJ/kWh	Condenser Vacuum (Hg)	Gas Turbine Power	Steam Turbine Power	No. & Type Gas Turbine	Comments
Hitachi (60 Hz) continued										
107FA	1995	253 700 kW	6170 Btu	55.3%	6510 kJ	****	164 000 kW	89 700 kW	1 x MS7001FA	
207FA	1995	509 200 kW	6150 Btu	55.5%	6490 kJ	****	328 000 kW	181 200 kW	2 x MS7001FA	
IHI Power Systems (50/60 Hz)										
LM1600PA	1991	17 420 kW	7280 Btu	46.8%	7691 kJ	****	12 820 kW	4 600 kW	1 x LM1600PA	all ratings on natural gas
LM2500PE	1986	30 350 kW	6763 Btu	50.5%	7136 kJ	****	22 150 kW	8 200 kW	1 x LM2500PE	with inlet & exhaust losses
LM2500PK	1998	35 410 kW	6777 Btu	50.4%	7150 kJ	****	26 020 kW	9 390 kW	1 x LM2500PK	
LM2500RB	2006	40 760 kW	6827 Btu	50.0%	7203 kJ	****	31 740 kW	9 020 kW	1 x LM2500RB	
IHI Power Systems (50 Hz)										
LM6000PC	1997	53 520 kW	6570 Btu	51.9%	6932 kJ	****	42 120 kW	11 400 kW	1 x LM6000PC	
LM6000PC	1997	107 450 kW	6546 Btu	52.1%	6906 kJ	****	84 250 kW	23 200 kW	2 x LM6000PC	
LM6000PD	1997	52 850 kW	6528 Btu	52.3%	6887 kJ	****	41 050 kW	11 800 kW	1 x LM6000PD	
LM6000PD	1997	106 000 kW	6509 Btu	52.4%	6867 kJ	****	82 100 kW	23 900 kW	2 x LM6000PD	
MAN Turbo (50/60 Hz)										
THM 1304-11	1999	32 920 kW	7497 Btu	45.5%	7910 kJ	****	21 520 kW	11 400 kW	2 x THM 1304-11	dual pressure HRSG
FT8 PowerPac	1990	32 910 kW	6865 Btu	49.7%	7243 kJ	****	24 737 kW	8 755 kW	1 x FT8	dual pressure HRSG
FT8 TwinPac	1990	66 745 kW	6770 Btu	50.4%	7143 kJ	****	49 828 kW	18 020 kW	2 x FT8	dual pressure HRSG
Mitsubishi Heavy Industries (50 Hz)										
MPCP1(M701)	1981	212 500 kW	6635 Btu	51.4%	7000 kJ	****	142 100 kW	70 400 kW	1 x M701DA	ratings at electric
MPCP2(M701)	1981	426 600 kW	6610 Btu	51.6%	6974 kJ	****	284 200 kW	142 400 kW	2 x M701DA	generator terminals with
MPCP3(M701)	1981	645 000 kW	6585 Btu	51.8%	6947 kJ	****	426 300 kW	218 700 kW	3 x M701DA	inlet and exhaust losses
MPCP1(M701F)	1992	464 500 kW	5735 Btu	59.5%	6050 kJ	****	307 200 kW	157 300 kW	1 x M701F4	all heat rates LHV natural gas
MPCP2(M701F)	1992	932 100 kW	5716 Btu	59.7%	6030 kJ	****	614 400 kW	317 700 kW	2 x M701F4	
MPCP1(M701G)	1997	498 000 kW	5755 Btu	59.3%	6071 kJ	****	325 700 kW	172 300 kW	1 x M701G2	
MPCP2(M701G)	1997	999 400 kW	5735 Btu	59.5%	6051 kJ	****	651 400 kW	348 000 kW	2 x M701G2	
Mitsubishi Heavy Industries (60 Hz)										
MPCP1(M501)	1981	167 400 kW	6635 Btu	51.4%	7000 kJ	****	112 100 kW	55 300 kW	1 x M501DA	ratings at electric
MPCP2(M501)	1981	336 200 kW	6610 Btu	51.6%	6974 kJ	****	224 200 kW	112 000 kW	2 x M501DA	generator terminals with
MPCP3(M501)	1981	506 200 kW	6585 Btu	51.8%	6947 kJ	****	336 300 kW	169 900 kW	3 x M501DA	inlet and exhaust losses
MPCP1(M501F)	1994	285 100 kW	5976 Btu	57.1%	6305 kJ	****	182 700 kW	102 400 kW	1 x M501F3	all heat rates LHV natural gas
MPCP2(M501F)	1994	572 200 kW	5955 Btu	57.3%	6283 kJ	****	365 400 kW	206 800 kW	2 x M501F3	
MPCP1(M501G)	1995	398 900 kW	5843 Btu	58.4%	6165 kJ	****	264 400 kW	134 500 kW	1 x M501G1	
MPCP2(M501G)	1995	800 500 kW	5823 Btu	58.6%	6144 kJ	****	528 800 kW	271 700 kW	2 x M501G1	
MPCP1(M501H)	2001	403 000 kW	5689 Btu	60.0%	6000 kJ	****	****	****	1 x M501H	steam-cooled rotor

Model	Year	Net Plant Output	Heat Rate Btu/kWh	Net Plant Efficiency	Heat Rate kJ/kWh	Condenser Vacuum (Hg)	Gas Turbine Power	Steam Turbine Power	No. & Type Gas Turbine	Comments
Mitsui Engineering & Shipbuilding (50/60 Hz)										
MACS70	1997	8 500 kW	8 385 Btu	40.7%	8 846 kJ	****	6 560 kW	1 940 kW	1 x MSC70	
MACS90	1997	11 730 kW	8 406 Btu	40.6%	8 868 kJ	****	8 910 kW	2 820 kW	1 x MSC90	
MACS100	1997	13 250 kW	8 185 Btu	41.7%	8 635 kJ	****	9 930 kW	3 320 kW	1 x MSC100	
NK - Engines (50/60 Hz)										
NK-37	1993	66 840 kW	7246 Btu	47.1%	7643 kJ	****	47 200 kW	19 640 kW	2 x NK-37	
Pratt & Whitney Power Systems (50/60 Hz)										
FT8 PowerPac	1990	32 910 kW	6865 Btu	49.7%	7243 kJ	****	24 737 kW	8 755 kW	1 x FT8	all with dual pressure HRSGs
FT8 TwinPac	1990	66 745 kW	6770 Btu	50.4%	7143 kJ	****	49 828 kW	18 020 kW	2 x FT8	and 1.0 psia condenser
FT8-3 PowerPac	1990	36 570 kW	6750 Btu	50.6%	7122 kJ	****	27 220 kW	10 006 kW	1 x FT8-3	
FT8-3 TwinPac	1990	74 185 kW	6655 Btu	51.3%	7022 kJ	****	54 840 kW	20 597 kW	2 x FT8-3	
Rolls-Royce (50/60 Hz)										
RB211-G62 DLE	1993	37 725 kW	6801 Btu	50.2%	7175 kJ	****	26 716 kW	12 045 kW	1 x RB211	4/10" losses all models
2 x RB211-G62	1993	75 480 kW	6801 Btu	50.2%	7175 kJ	****	53 432 kW	24 118 kW	2 x RB211	
RB211-GT62 DLE	1999	39 760 kW	6639 Btu	51.4%	7005 kJ	****	28 626 kW	12 205 kW	1 x RB211	
2 x RB211-GT62	1999	79 540 kW	6639 Btu	51.4%	7005 kJ	****	57 252 kW	24 439 kW	2 x RB211	
RB211-GT61 DLE	2000	42 640 kW	6464 Btu	52.8%	6820 kJ	****	31 171 kW	12 593 kW	1 x RB211	
2 x RB211-GT61	2000	85 300 kW	6464 Btu	52.8%	6820 kJ	****	62 342 kW	25 215 kW	2 x RB211	
Rolls-Royce (50 Hz)										
Trent 60 DLE	1996	64 232 kW	6480 Btu	52.7%	6837 kJ	****	50 068 kW	15 261 kW	1 x Trent	4/10" losses, 2P steam
Trent 60 DLE	1996	89 482 kW	6798 Btu	50.2%	7172 kJ	****	50 068 kW	41 348 kW	1 x Trent	duct fired to 1380F
2 x Trent 60 DLE	1996	129 216 kW	6442 Btu	53.0%	6797 kJ	****	100 136 kW	31 277 kW	2 x Trent	4/10" losses, 2P steam
Trent 60 WLE	2001	72 670 kW	6784 Btu	50.3%	7157 kJ	****	58 000 kW	15 893 kW	1 x Trent	NOx water injected
Trent 60 WLE	2001	102 828 kW	7019 Btu	48.6%	7405 kJ	****	58 000 kW	47 043 kW	1 x Trent	duct fired to 1380F
2 x Trent 60 WLE	2001	146 035 kW	6751 Btu	50.5%	7123 kJ	****	116 000 kW	32 495 kW	2 x Trent	4/10" losses, 2P steam
Rolls-Royce (60 Hz)										
Trent 60 DLE	1996	64 601 kW	6497 Btu	52.5%	6855 kJ	****	50 492 kW	15 211 kW	1 x Trent	4/10" losses, 2P steam
Trent 60 DLE	1996	90 326 kW	6816 Btu	50.1%	7191 kJ	****	50 492 kW	41 791 kW	1 x Trent	duct fired to 1380F
2 x Trent 60 DLE	1996	129 899 kW	6462 Btu	52.8%	6818 kJ	****	100 984 kW	31 115 kW	2 x Trent	4/10" losses, 2P steam
Trent 60 WLE	2001	72 898 kW	6743 Btu	50.6%	7114 kJ	****	58 000 kW	16 127 kW	1 x Trent	NOx water injected
Trent 60 WLE	2001	101 719 kW	6989 Btu	48.8%	7374 kJ	****	58 000 kW	45 901 kW	1 x Trent	duct fired to 1380F
2 x Trent 60 WLE	2001	146 441 kW	6712 Btu	50.8%	7082 kJ	****	116 000 kW	32 919 kW	2 x Trent	4/10" losses, 2P steam

Model	Year	Net Plant Output	Heat Rate Btu/kWh	Net Plant Efficiency	Heat Rate kJ/kWh	Condenser Vacuum (Hg)	Gas Turbine Power	Steam Turbine Power	No. & Type Gas Turbine	Comments
Siemens Power Generation (50/60 Hz)										
SCC-600 1x1	1981	36 100 kW	6810 Btu	50.1%	7185 kJ	****	24 000 kW	12 550 kW	1 x SGT-600	dual pressure HRSG
SCC-600 2x1	1981	73 150 kW	6730 Btu	50.7%	7100 kJ	****	48 000 kW	26 000 kW	2 x SGT-600	dual pressure HRSG
SCC-700 1x1	1998	41 280 kW	6674 Btu	51.1%	7041 kJ	****	28 400 kW	12 880 kW	1 x SGT-700	dual pressure HRSG
SCC-700 2x1	1998	83 630 kW	6588 Btu	51.8%	6950 kJ	****	56 800 kW	26 830 kW	2 x SGT-700	dual pressure HRSG
SCC-800 1x1	1998	66 500 kW	6353 Btu	53.7%	6703 kJ	****	46 000 kW	21 400 kW	1 x SGT-800	dual pressure HRSG
SCC-800 2x1	1998	135 000 kW	6273 Btu	54.4%	6618 kJ	****	92 000 kW	44 400 kW	2 x SGT-800	dual pressure HRSG
SCC-900 1x1	1982	71 500 kW	7140 Btu	47.8%	7530 kJ	****	48 000 kW	25 000 kW	1 x SGT-900	dual pressure, no reheat
SCC-900 2x1	1982	143 500 kW	7110 Btu	48.0%	7500 kJ	****	96 000 kW	50 500 kW	2 x SGT-900	dual pressure, no reheat
SCC-1000F single shaft	1996	100 800 kW	6487 Btu	52.6%	6844 kJ	****	****	****	1 x SGT-1000F	dual pressure, no reheat
SCC-1000F 2x1	1996	201 200 kW	6501 Btu	52.5%	6858 kJ	****	131 400 kW	74 000 kW	2 x SGT-1000F	dual pressure, no reheat
Siemens Power Generation (50 Hz)										
SCC5-2000E 1x1	1981	251 000 kW	6535 Btu	52.2%	6895 kJ	****	163 800 kW	91 100 kW	1 x SGT5-2000E	dual pressure, no reheat
SCC5-2000E 2x1	1981	505 000 kW	6502 Btu	52.5%	6860 kJ	****	327 600 kW	184 900 kW	2 x SGT5-2000E	dual pressure, no reheat
SCC5-3000E single shaft	1997	290 000 kW	6036 Btu	56.5%	6368 kJ	****	****	****	1 x SGT5-3000E	triple pressure, reheat, 41000 EOH maint Interval
SCC5-3000E 2x1	1997	576 000 kW	6056 Btu	56.3%	6389 kJ	****	370 400 kW	215 300 kW	2 x SGT5-3000E	triple pressure, reheat, 41000 EOH maint Interval
SCC5-4000F single shaft	1995	416 000 kW	5859 Btu	58.2%	6182 kJ	****	****	****	1 x SGT5-4000F	triple pressure, reheat
SCC5-4000F 2x1	1995	832 000 kW	5860 Btu	58.2%	6183 kJ	****	557 400 kW	288 700 kW	2 x SGT5-4000F	triple pressure, reheat
Siemens Power Generation (60 Hz)										
SCC6-3000E 1X1	1993	173 000 kW	6760 Btu	50.5%	7130 kJ	****	117 000 kW	58 500 kW	1 x SGT6-3000E	dual pressure, no reheat
SCC6-3000E 2X1	1993	346 900 kW	6740 Btu	50.6%	7110 kJ	****	234 200 kW	118 000 kW	2 x SGT6-3000E	dual pressure, no reheat
SCC6-5000F 1X1	1989	295 700 kW	5990 Btu	57.0%	6320 kJ	****	196 400 kW	105 300 kW	1 x SGT6-5000F	triple pressure, reheat
SCC6-5000F 2X1	1989	598 000 kW	5950 Btu	57.3%	6280 kJ	****	392 800 kW	217 400 kW	2 x SGT6-5000F	triple pressure, reheat
SCC6-6000G single shaft	1994	397 100 kW	5803 Btu	58.8%	6123 kJ	****	****	****	1 x SGT6-6000G	triple pressure, reheat
SCC6-6000G 2x1	1994	794 300 kW	5803 Btu	58.8%	6123 kJ	****	525 200 kW	281 200 kW	2 x SGT6-6000G	triple pressure, reheat
Solar Turbines (50/60 Hz)										
STAC 60	1993	7 300 kW	8620 Btu	39.6%	9095 kJ	****	5 500 kW	1 800 kW	1 x Taurus 60	single pressure, saturated steam
STAC 70	1994	9 480 kW	8180 Btu	41.7%	8630 kJ	****	7 520 kW	1 960 kW	1 x Taurus 70	ISO rating, STAC system
STAC 100	1994	13 770 kW	8380 Btu	41.0%	8789 kJ	****	10 690 kW	3 080 kW	1 x Mars 100	is designed based on
STAC 130	1998	17 724 kW	8000 Btu	42.7%	8440 kJ	****	14 000 kW	3 724 kW	1 x Titan 130	process steam requirements

Model	Year	Net Plant Output	Heat Rate Btu/kWh	Net Plant Efficiency	Heat Rate kJ/kWh	Condenser Vacuum (Hg)	Gas Turbine Power	Steam Turbine Power	No. & Type Gas Turbine	Comments
Zorya-Mashproekt (50 Hz)										
UGT 10CC1	1998	13 000 kW	7450 Btu	45.8%	7860 kJ	****	9 500 kW	3 500 kW	1 x UGT10000	
UGT 10CC2	1998	26 500 kW	7310 Btu	46.7%	7710 kJ	****	19 000 kW	7 500 kW	2 x UGT10000	
UGT 15CC1	1998	21 200 kW	7690 Btu	44.4%	8110 kJ	****	16 000 kW	5 200 kW	1 x UGT15000	
UGT 15CC2	1988	42 800 kW	7620 Btu	44.8%	8035 kJ	****	32 000 kW	10 800 kW	2 x UGT15000	
UGT 25CC1	1993	33 000 kW	7390 Btu	46.2%	7790 kJ	****	25 000 kW	8 000 kW	1 x UGT25000	
UGT 25CC2	1993	67 200 kW	7260 Btu	47.0%	7660 kJ	****	50 000 kW	17 200 kW	2 x UGT25000	

Simple Cycle Ratings

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Model	Year	ISO Base Rating	Heat Rate Btu/kWh	Efficiency	Pressure Ratio	Flow lb/sec	Turbine Speed	Exhaust Temp	Approx Weight	Approx L x W x H	Comments
Alstom (50 Hz)											
GT8C2	1998	56 300 kW	10 065 Btu	33.9%	17.6	433.0 lb	6219 rpm	946 F	368 166 lb	38 x 17 x 16 ft	gearbox losses included
GT11N2	1993	113 600 kW	10 247 Btu	33.3%	16.0	880.0 lb	3610 rpm	977 F	418 871 lb	31 x 18 x 33 ft	with dry low NOx combustor
GT13E2	1993	179 900 kW	9 247 Btu	36.9%	16.4	1241.0 lb	3000 rpm	950 F	747 354 lb	35 x 21 x 18 ft	with dry low NOx combustor
GT26	1994	288 300 kW	8 956 Btu	38.1%	33.9	1430.0 lb	3000 rpm	1141 F	815 697 lb	40 x 16 x 18 ft	with air quench cooler
GT26	1994	289 139 kW	8 716 Btu	39.1%	33.4	1410.0 lb	3000 rpm	1139 F	815 697 lb	40 x 16 x 18 ft	with once through cooler
Alstom (60 Hz)											
GT8C2	1998	56 200 kW	10 098 Btu	33.8%	17.6	433.0 lb	6204 rpm	946 F	368 166 lb	38 x 17 x 16 ft	gearbox losses included
GT11N2	1993	115 400 kW	10 065 Btu	33.9%	15.5	880.0 lb	3600 rpm	977 F	418 871 lb	31 x 18 x 33 ft	with dry low NOx combustor
GT24	1994	188 200 kW	9 247 Btu	36.9%	32.0	988.0 lb	3600 rpm	1126 F	507 055 lb	35 x 13 x 15 ft	with air quench cooler
GT24	1994	188 782 kW	8 956 Btu	38.1%	32.0	972.0 lb	3600 rpm	1125 F	507 055 lb	35 x 13 x 15 ft	with once through cooler
Ansaldo Energia											
V64.3A	1996	77 000kW	9 487 Btu	36.0%	17.1	470.0 lb	3000/3600	1087 F	242 500 lb	36 x 13 x 16 ft	V64.3A includes gear ox
V94.2	1981	166 000 kW	9 899 Btu	34.5%	11.8	1171.0 lb	3000 rpm	1011 F	650 400 lb	46 x 41 x 28 ft	all weights include auxiliaries
V94.2K	1981	170 000 kW	9 357 Btu	36.5%	12.0	1190.0 lb	3000 rpm	1013 F	650 400 lb	46 x 41 x 28 ft	
V94.3A	1995	285 000 kW	8 624 Btu	39.6%	17.7	1521.0 lb	3000 rpm	1062 F	727 500 lb	43 x 20 x 26 ft	
Aviadvigatel											
GTU-2.5P	1995	2 550 kW	16 175 Btu	21.1%	5.9	56.4 lb	5500/3000	682 F	83 995 lb	43 x 10 x 9 ft	includes gearbox and generator
GTU-4P	1997	4 130 kW	14 220 Btu	24.0%	7.3	65.7 lb	5500/3000	777 F	89 506 lb	43 x 10 x 9 ft	includes gearbox and generator
GTU-6P	2002	6 140 kW	13 077 Btu	26.1%	8.5	71.9 lb	6925/3000	918 F	100 529 lb	43 x 10 x 9 ft	includes gearbox and generator
GTU-12PER	2004	12 400 kW	10 373 Btu	32.9%	16.1	101.2 lb	6500/3000	919 F	198 920 lb	68 x 10 x 9 ft	includes gearbox and generator
GTE-16PA	2005	16 300 kW	9 614 Btu	35.5%	19.9	124.2 lb	3000 rpm	892 F	220 660 lb	68 x 10 x 9 ft	includes generator
GTU-16PER	2004	16 400 kW	9 807 Btu	34.8%	19.5	123.7 lb	5300/3000	923 F	229 784 lb	68 x 10 x 9 ft	includes gearbox and generator
GTU-25PER	2004	22 900 kW	9 249 Btu	36.9%	28.0	166.4 lb	5000/3000	885 F	328 490 lb	82 x 15 x 15 ft	includes gearbox and generator
Bharat Heavy Electricals											
PG5371(PA)	1988	26 300 kW	11 990 Btu	28.5%	10.5	270.0 lb	5100 rpm	909 F	185 220 lb	38 x 11 x 12 ft	all ratings on natural gas
PG6581(B)	2000	42 100 kW	10 642 Btu	32.1%	12.2	315.0 lb	5163 rpm	1011 F	200 665 lb	49 x 11 x 12 ft	
PG6591(C)	2004	42 300 kW	9 400 Btu	36.3%	19.0	258.0 lb	7100 rpm	1065 F	****	****	
PG6111(FA)	2003	75 900 kW	9 755 Btu	35.0%	15.8	447.0 lb	5254 rpm	1119 F	231 525 lb	****	
PG9171(E)	1994	126 100 kW	10 100 Btu	33.8%	12.6	903.0 lb	3000 rpm	1008 F	617 400 lb	66 x 15 x 16 ft	

Model	Year	ISO Base Rating	Heat Rate Btu/kWh	Efficiency	Pressure Ratio	Flow lb/sec	Turbine Speed	Exhaust Temp	Approx Weight	Approx L x W x H	Comments
Bharat Heavy Electricals continued											
V94.2	1997	157 000 kW	9 920 Btu	34.4%	11.1	1132.0 lb	3000 rpm	1004 F	650 475 lb	46 x 41 x 28 ft	
PG9351(FA)	1996	255 600 kW	9 250 Btu	36.9%	16.5	1428.0 lb	3000 rpm	1116 F	595 350 lb	74 x 16 x 18 ft	
PG9371(FB)	2004	279 200 kW	9 015 Btu	37.9%	18.5	1404.0 lb.	3000 rpm	1164 F	****	****	
Centrax Gas Turbine											
CX501 KB3	1993	2 691 kW	13 642 Btu	25.1%	8.0	28.3 lb	12857 rpm	1050 F	66 138 lb	30 x 9 x 10 ft	
CX501 KB5	1992	3 947 kW	11 745 Btu	29.1%	10.2	34.7 lb	14571 rpm	1031 F	70 547 lb	30 x 9 x 10 ft	
CX501 KN5	1992	4 495 kW	11 053 Btu	30.9%	10.7	36.2 lb	14571 rpm	1021 F	70 547 lb	30 x 9 x 10 ft	nozzle steam injected
CX501 KH5	1992	6 344 kW	8 551 Btu	39.9%	12.3	40.5 lb	14571 rpm	971 F	77 160 lb	30 x 9 x 10 ft	case steam injected
CX501 KB7	1993	5 333 kW	10 647 Btu	32.1%	13.5	46.4 lb	14571 rpm	930 F	70 547 lb	30 x 9 x 10 ft	
CX501 KN7	1993	5 766 kW	10 194 Btu	33.5%	14.0	47.8 lb	14571 rpm	906 F	70 547 lb	30 x 9 x 10 ft	nozzle steam injected
Dresser-Rand											
KG2-3E	1989	1 895 kW	21 543 Btu	16.7%	4.7	33.0 lb	18800 rpm	1020 F	38 580 lb	22 x 7 x 8 ft	D-R gas turbine
Vectra 30G	2007	22 767 kW	9 421 Btu	36.2%	17.9	151.2 lb	6200 rpm	1017 F	88 200 lb	30 x 14 x 15 ft	LM2500 gas gen, SAC
DR-61G	1981	23 394 kW	9 280 Btu	36.8%	18.2	153.1 lb	3600 rpm	992 F	88 200 lb	30 x 14 x 15 ft	LM2500 gas turb, SAC 60-Hz
Vectra 40G	1998	30 460 kW	8 773 Btu	38.9%	22.4	190.2 lb	6200 rpm	979 F	88 200 lb	30 x 14 x 15 ft	LM2500+ gas gen, SAC
DR-61GP	1996	30 742 kW	8 821 Btu	38.7%	22.5	192.2 lb	3600 rpm	959 F	88 200 lb	30 x 14 x 15 ft	LM2500+ gas turb, SAC 60-Hz
Vectra 40G4	2007	32 905 kW	8 722 Btu	39.1%	23.3	196.4 lb	6200 rpm	1007 F	88 200 lb	30 x 14 x 15 ft	LM2500+G4 gas gen, SAC
DR-61GPP	2005	33 175 kW	8 811 Btu	38.7%	23.0	201.8 lb	3600 rpm	978 F	88 200 lb	30 x 14 x 15 ft	LM2500+G4 gas turb, SAC 60-Hz
DR-63G	1994	42 857 kW	8 192 Btu	41.6%	28.2	278.5 lb	3600 rpm	839 F	83 800 lb	27 x 14 x 19 ft	LM6000, 60-Hz, SAC or DLE
Ebara											
ST6L-795	1986	678 kW	13 826 Btu	24.7%	7.4	7.1 lb	33000 rpm	1092\ F	229 lb	4 x 1 x 2 ft	
ST6L-813	1978	848 kW	13 099 Btu	26.1%	8.5	8.6 lb	33000 rpm	1051 F	300 lb	4 x 2 x 2 ft	
ST18A	1995	1 961 kW	11 237 Btu	30.4%	14.0	17.6 lb	18900 rpm	990 F	772 lb	5 x 2 x 3 ft	
ST40	1999	4 039 kW	10 310 Btu	33.1%	16.9	30.6 lb	14875 rpm	1011 F	1 157 lb	6 x 2 x 3 ft	
SwiftPac 4	****	3 880 kW	10 735 Btu	31.8%	16.9	30.6 lb	14875 rpm	1011 F	****	****	
FT8 PowerPac	1990	25 490 kW	8 950 Btu	38.1%	19.3	187.0 lb	3000/3600	855 F	****	****	
FT8 TwinPac	1990	51 350 kW	8 890 Btu	38.4%	19.3	374.0 lb	3000/3600	855 F	****	****	
SwiftPac 25	****	25 455 kW	8 960 Btu	38.1%	19.5	186.9 lb	3000/3600	856 F	****	****	transportable
SwiftPac 50	****	51 235 kW	8 905 Btu	38.3%	19.5	373.8 lb	3000/3600	856 F	****	****	transportable
FT8-3 PowerPac	1990	27 970 kW	8 900 Btu	38.3%	20.2	193.0 lb	3000/3600	893 F	****	****	
FT8-3 TwinPac	1990	56 340 kW	8 840 Btu	38.6%	20.2	386.0 lb	3000/3600	893 F	****	****	

Model	Year	ISO Base Rating	Heat Rate Btu/kWh	Efficiency	Pressure Ratio	Flow lb/sec	Turbine Speed	Exhaust Temp	Approx Weight	Approx L x W x H	Comments
GE Energy Aeroderivative (50 Hz)											
LM2000PS	2000	18 363 kW	10 094 Btu	33.8%	16.0	145.9 lb	3000 rpm	866 F	210 000 lb	57 x 9 x 10 ft	water injected
LM2000PJ	2000	17 855 kW	9 888 Btu	34.5%	16.0	140.2 lb	3000 rpm	925 F	210 000 lb	57 x 9 x 10 ft	DLE
LM2500PE	1981	22 346 kW	9 630 Btu	35.4%	18.0	153.6 lb	3000 rpm	1001 F	250 000 lb	57 x 9 x 10 ft	dry
LM2500PE	1981	23 060 kW	10 041 Btu	34.0%	18.0	157.8 lb	3000 rpm	963 F	250 000 lb	57 x 9 x 10 ft	water injected
LM2500PJ	1995	21 818 kW	9 655 Btu	35.3%	18.0	151.6 lb	3000 rpm	995 F	250 000 lb	57 x 9 x 10 ft	DLE
LM2500PH	1981	26 510 kW	8 679 Btu	39.3%	19.4	167.6 lb	3000 rpm	929 F	250 000 lb	57 x 9 x 10 ft	water injected
LM2500+ RC	2005	36 024 kW	9 263 Btu	36.8%	23.0	213.0 lb	3000 rpm	945 F	250 000 lb	65 x 10 x 23 ft	water injected
LM2500+ RD	2005	32 881 kW	8 949 Btu	38.1%	23.0	201.0 lb	3000 rpm	977 F	250 000 lb	65 x 10 x 23 ft	DLE
LM6000PC	1997	43 339 kW	8 571 Btu	39.8%	30.0	284.7 lb	3000 rpm	803 F	673 370 lb	65 x 14 x 15 ft	water injected
LM6000PC Sprint	1998	50 836 kW	8 478 Btu	40.2%	32.3	300.1 lb	3000 rpm	835 F	673 370 lb	65 x 14 x 15 ft	water injected
LM6000PD	1997	42 732 kW	8 222 Btu	41.5%	30.0	277.1 lb	3000 rpm	844 F	673 370 lb	65 x 14 x 15 ft	DLE
LM6000PD liquid	2005	40 999 kW	8 345 Btu	40.4%	29.5	272.1 lb	3000 rpm	852 F	673 370 lb	65 x 14 x 15 ft	distillate fuel
LM6000PD Sprint	2000	47 505 kW	8 198 Btu	41.6%	32.0	293.1 lb	3000 rpm	835 F	673 370 lb	65 x 14 x 15 ft	DLE
LM6000PF	2006	42 732 kW	8 222 Btu	41.5%	30.0	277.1 lb	3000 rpm	844 F	673 370 lb	65 x 14 x 15 ft	DLE, 15 ppm NOx
LM6000PF Sprint	2006	48 040 kW	8 188 Btu	41.7%	32.1	293.6 b	3000 rpm	840 F	673 370 lb	65 x 14 x 15 ft	DLE
LMS100PA	2006	102 998 kW	7 777 Btu	43.9%	41.0	469.9 lb	3000 rpm	765 F	TBD	130 x 20 x 54 ft	water injected
LMS100PB	TBD	98 440 kW	7 563 Btu	45.1%	40.0	456.0 lb	3000 rpm	783 F	TBD	130 x 20 x 54 ft	DLE
GE Energy Aeroderivative (60 Hz)											
LM2000PS	2000	18 412 kW	9 874 Btu	34.6%	15.6	142.7 lb	3600 rpm	860 F	210 000 lb	57 x 9 x 10 ft	water injected
LM2000PJ	2000	17 657 kW	9 707 Btu	35.2%	15.6	136.1 lb	3600 rpm	918 F	210 000 lb	57 x 9 x 10 ft	DLE
LM2500PE	1981	23 292 kW	9 315 Btu	36.6%	19.1	153.1 lb	3600 rpm	992 F	250 000 lb	57 x 9 x 10 ft	dry
LM2500PE	1981	24 049 kW	9 717 Btu	35.1%	19.1	157.4 lb	3600 rpm	955 F	250 000 lb	57 x 9 x 10 ft	water injected
LM2500PJ	1995	22 719 kW	9 345 Btu	36.5%	19.1	151.0 lb	3600 rpm	987 F	250 000 lb	57 x 9 x 10 ft	DLE
LM2500PH	1981	27 765 kW	8 391 Btu	40.7%	19.4	167.1 lb	3600 rpm	922 F	250 000 lb	57 x 9 x 10 ft	water injected
LM2500+ RC	2005	36 333 kW	9 184 Btu	37.2%	23.0	213.0 lb	3600 rpm	945 F	250 000 lb	65 x 10 x 10 ft	water injected
LM2500+ RD	2005	33 165 kW	8 774 Btu	38.9%	23.0	201.0 lb	3600 rpm	977 F	250 000 lb	65 x 10 x 10 ft	DLE
LM6000PC	1997	43 843 kW	8 519 Btu	40.1%	29.8	283.2 lb	3600 rpm	810 F	532 080 lb	56 x 14 x 15 ft	water injected
LM6000PC Sprint	1998	50 526 kW	8 458 Btu	40.3%	31.9	296.9 lb	3600 rpm	838 F	532 080 lb	56 x 14 x 15 ft	water injected
LM6000PD	1997	43 068 kW	8 173 Btu	41.7%	29.8	274.8 lb	3600 rpm	851 F	532 080 lb	56 x 14 x 15 ft	DLE
LM6000PD liquid	2005	40 712 kW	8 315 Btu	41.0%	29.8	268.2 lb	3600 rpm	856 F	532 080 lb	57 x 15 x 16 ft	distillate fuel
LM6000PD Sprint	2000	47 383 kW	8 162 Btu	41.8%	31.7	290.0 lb	3600 rpm	838 F	532 080 lb	56 x 14 x 15 ft	DLE

Model	Year	ISO Base Rating	Heat Rate Btu/kWh	Efficiency	Pressure Ratio	Flow lb/sec	Turbine Speed	Exhaust Temp	Approx Weight	Approx L x W x H	Comments
GE Energy Aeroderivative (60 Hz) continued											
LM6000PF	2006	43 068 kW	8 173 Btu	41.7%	29.8	274.8 lb	3600 rpm	851 F	532 080 lb	56 x 14 x 15 ft	DLE, 15 ppm NOx
LM6000PF Sprint	2006	48 092 kW	8 151 Btu	41.9%	31.9	290.8 lb	3600 rpm	846 F	532 080 lb	56 x 14 x 15 ft	DLE
LMS100PA	2006	103 045 kW	7 773 Btu	43.9%	41.0	469.9 lb	3600 rpm	763 F	TBD	130 x 20 x 54 ft	water injected
LMS100PB	TBD	98 396 kW	7 566 Btu	45.1%	40.0	456.0 lb	3600 rpm	763 F	TBD	130 x 20 x 54 ft	DLE
GE Energy Heavy Duty											
PG6581(B)	1999	42 100 kW	10 642 Btu	32.1%	12.2	311.0 lb	5163 rpm	1018 F	700 000 lb	123 x 24 x 34 ft	all are packaged power plants
PG6591C (50Hz)	2003	45 400 kW	9 315 Btu	36.5%	19.6	269.0 lb	7100 rpm	1078 F	775 000 lb	82 x 28 x 41 ft	50 Hz
PG6591C (60Hz)	2003	45 300 kW	9 340 Btu	36.5%	19.6	270.0 lb	7100 rpm	1078 F	775 000 lb	82 x 28 x 41 ft	60 Hz
PG6111(FA) (50Hz)	2003	77 100 kW	9 760 Btu	35.5%	15.6	467.0 lb	5231 rpm	1117 F	800 000 lb	95 x 66 x 34 ft	50 Hz
PG6111(FA) (60Hz)	2003	77 100 kW	9 795 Btu	35.4%	15.7	467.0 lb	5254 rpm	1118 F	800 000 lb	95 x 66 x 34 ft	60 Hz
PG7121(EA)	1984	85 100 kW	10 430 Btu	32.7%	12.7	648.0 lb	3600 rpm	997 F	1 070 000 lb	132 x 71 x 31 ft	ratings include inlet & exhaust
PG7241(FA)	1994	171 700 kW	9 360 Btu	36.5%	16.0	981.0 lb	3600 rpm	1114 F	1 642 000 lb	180 x 75 x 31 ft	losses & shaft driven auxiliaries
PG7251(FB)*	1999	184 400 kW	9 215 Btu	37.0%	18.4	1000.0 lb	3600 rpm	1155 F	1 642 000 lb	180 x 75 x 31 ft	*for combined cycle use only
PG9171(E)	1992	126 100 kW	10 100 Btu	33.8%	12.6	922.0 lb	3000 rpm	1009 F	1 900 000 lb	115 x 77 x 39 ft	
PG9351(FA)	1996	255 600 kW	9 250 Btu	36.9%	17.0	1413.0 lb	3000 rpm	1116 F	2 400 000 lb	112 x 25 x 50 ft	
PG9371(FB)*	2002	287 400 kW	8 985 Btu	38.0%	18.3	1453.0 lb	3000 rpm	1182 F	2 400 000 lb	112 x 25 x 50 ft	*for combined cycle use only
GE Energy Oil & Gas											
GE10-1	2000	11 250 kW	10 892 Btu	31.4%	15.5	104.7 lb	11000 rpm	900 F	74 970 lb	39 x 8 x 26 ft	DLE, size w/ GT enclosure
PGT16	1989	13 720 kW	9 760 Btu	35.0%	20.2	104.3 lb	7900 rpm	919 F	41 895 lb	27 x 11 x 12 ft	size w/o GT enclosure
PGT20	2002	17 464 kW	9 706 Btu	35.2%	15.7	137.7 lb	6500 rpm	887 F	83 020 lb	30 x 11 x 11 ft	size w/o GT enclosure
PGT25	1981	22 417 kW	9 404 Btu	36.3%	17.9	151.9 lb	6500 rpm	976 F	83 020 lb	30 x 11 x 11 ft	size w/o GT enclosure
PGT25+	1996	30 226 kW	8 612 Btu	39.6%	21.5	185.9 lb	6100 rpm	931 F	67 805 lb	21 x 13 x 13 ft	size w/o GT enclosure
PGT25+G4	2005	32 760 kW	8 594 Btu	39.7%	24.4	196.0 lb	6100 rpm	950 F	68 025 lb	21 x 13 x 13 ft	size w/o GT enclosure
LM6000PD	1994	42 336 kW	8 305 Btu	41.1%	29.3	277.9 lb	3600 rpm	840 F	68 355 lb	31 x 14 x 14 ft	size w/o GT enclosure, DLE
LMS100	2005	98 196 kW	7 582 Btu	45.0%	40.0	456.0 lb	3600 rpm	782 F	TBD	130 x 20 x 54 ft	size w/o GT enclosure, DLE
MS5001	1987	26 830 kW	12 028 Btu	28.4%	10.5	276.1 lb	5094 rpm	901 F	192 785 lb	38 x 10 x 12 ft	size w/o GT enclosure
MS5002E	2003	31 100 kW	9 751 Btu	35.0%	17.0	225.0 lb	5714 rpm	952 F	151 045 lb	56 x 13 x 13 ft	introductory rating
MS6001B	1978	42 100 kW	10 647 Btu	32.1%	12.2	311.0 lb	5163 rpm	1026 F	211 644 lb	51 x 10 x 12 ft	size w/o GT enclosure
MS7001EA	1984	85 400 kW	10 419 Btu	32.7%	12.6	643.0 lb	3600 rpm	998 F	266 759 lb	37 x 11 x 12 ft	size w/o GT enclosure
MS9001E	1976	126 100 kW	10 097 Btu	33.8%	12.6	921.0 lb	3000 rpm	1009 F	479 505 lb	51 x 45 x 16 ft	size w/o GT enclosure

Model	Year	ISO Base Rating	Heat Rate Btu/kWh	Efficiency	Pressure Ratio	Flow lb/sec	Turbine Speed	Exhaust Temp	Approx Weight	Approx L x W x H	Comments
Hitachi											
H-15	1990	15 000 kW	10 598 Btu	32.2%	14.7	115.0 lb	9710 rpm	1031 F	429 000 lb	82 x 19 x 36 ft	all ratings on natural gas fuel
H-25	1988	27 500 kW	10 097 Btu	33.8%	14.7	194.0 lb	7280 rpm	1031 F	561 000 lb	115 x 19 x 36 ft	with inlet and exhaust losses
PG5371(PA)	1987	26 300 kW	11 990 Btu	28.5%	10.5	270.0 lb	5100 rpm	909 F	570 000 lb	115 x 19 x 36 ft	& shaft-driven auxiliaries
PG6561(B)	1996	39 620 kW	10 710 Btu	31.9%	12.0	318.0 lb	5123 rpm	989 F	700 000 lb	123 x 24 x 34 ft	
PG6101(FA)	1993	70 140 kW	9 980 Btu	34.2%	15.0	433.0 lb	5247 rpm	1107 F	****	120 x 20 x 34 ft	
PG7121(EA)	1987	85 400 kW	10 420 Btu	32.8%	12.6	658.0 lb	3600 rpm	998 F	1 070 000 lb	132 x 71 x 31 ft	
PG7241(FA)	1994	171 700 kW	9 360 Btu	36.5%	15.5	952.0 lb	3600 rpm	1119 F	1 642 000 lb	180 x 75 x 31 ft	
PG9171(E)	1987	123 400 kW	10 100 Btu	33.8%	12.3	890.0 lb	3000 rpm	1001 F	1 900 000 lb	115 x 77 x 39 ft	
PG9331(FA)	1995	243 000 kW	9 360 Btu	36.5%	14.8	1422.0 lb	3000 rpm	1106 F	2 400 000 lb	112 x 25 x 50 ft	
Hitachi Zosen											
GT10	2006	4 130 kW	11 582 Btu	29.5%	10.4	34.3 lb	14200 rpm	1050 F	1 270 lb	7 x 3 x 3 ft	R-R 501-KB5S, gas fuel nozzle steam injected
GT13	2006	5 600 kW	10 646 Btu	32.1%	14.3	47.0 lb	14600 rpm	940 F	1 691 lb	9 x 4 x 3 ft	R-R 501-KB7S, gas fuel nozzle steam injected
VHP6	2006	6 260 kW	8 847 Btu	38.6%	12.5	40.0 lb	14600 rpm	991 F	1 270 lb	8 x 3 x 3 ft	R-R 501-KH5, gas fuel
IHI Power Systems											
IM270	1996	2 000 kW	13 880 Btu	24.6%	12.2	21.3 lb	20300 rpm	1013 F	4 409 lb	8 x 3 x 3 ft	dry low NOx
IM400	1982	4 100 kW	12 540 Btu	27.2%	10.9	35.1 lb	14580 rpm	1076 F	1 279 lb	7 x 3 x 3 ft	RR 501-KB5S 50/60Hz
IM400	1992	5 460 kW	11 640 Btu	29.3%	13.5	44.8 lb	14580 rpm	951 F	1 691 lb	9 x 4 x 4 ft	RR 501-KB7 50/60Hz
IM400 IHI-FLECS	1996	6 230 kW	9 570 Btu	35.7%	12.4	40.1 lb	14580 rpm	1029 F	1 171 lb	8 x 3 x 3 ft	RR 501-KH5
LM1600PA	1988	13 900 kW	10 130 Btu	33.7%	22.3	103.6 lb	7000 rpm	914 F	6 658 lb	14 x 9 x 7 ft	
LM2500PE	1976	21 900 kW	10 290 Btu	33.2%	20.0	154.3 lb	3000 rpm	986 F	7 815 lb	15 x 6 x 6 ft	50Hz
LM2500PE	1976	22 800 kW	9 960 Btu	34.3%	20.0	154.3 lb	3600 rpm	968 F	7 815 lb	15 x 6 x 6 ft	60Hz
LM2500PK	1998	28 440 kW	9 150 Btu	37.3%	23.0	181.2 lb	3000 rpm	952 F	8 485 lb	16 x 6 x 6 ft	50Hz
LM2500PK	1998	28 500 kW	8 660 Btu	39.4%	23.0	176.1 lb	3600 rpm	937 F	8 485 lb	16 x 6 x 6 ft	60Hz
LM2500RB	2006	31 970 kW	8 720 Btu	39.2%	23.0	193.9 lb	6100 rpm	958 F	31 228 lb	19 x 8 x 9 ft	50Hz
LM6000PC	1997	42 197 kW	8 330 Btu	41.0%	29.4	275.0 lb	3000 rpm	853 F	15 498 lb	16 x 7 x 7 ft	50Hz
LM6000PC	1997	42 623 kW	8 250 Btu	41.4%	29.4	275.0 lb	3600 rpm	853 F	15 498 lb	16 x 7 x 7 ft	60Hz
LM6000PC Sprint	1997	46 070 kW	8 423 Btu	40.5%	30.0	287.9 lb	3000 rpm	833 F	15 498 lb	16 x 7 x 7 ft	50Hz
LM6000PC Sprint	1997	46 370 kW	8 345 Btu	40.9%	30.0	287.0 lb	3600 rpm	835 F	15 498 lb	16 x 7 x 7 ft	60Hz
LM6000PD	1997	41 124 kW	8 390 Btu	40.7%	29.4	273.2 lb	3000 rpm	840 F	19 158 lb	16 x 7 x 7 ft	50Hz, DLE model
LM6000PD	1997	41 540 kW	8 306 Btu	41.1%	29.4	273.2 lb	3600 rpm	840 F	19 158 lb	16 x 7 x 7 ft	60Hz, DLE model
LM6000PD Sprint	1997	45 480 kW	8 424 Btu	40.5%	30.0	288.1 lb	3000 rpm	842 F	19 158 lb	16 x 7 x 7 ft	50Hz
LM6000PD Sprint	1997	45 770 kW	8 345 Btu	40.9%	30.0	286.8 lb	3600 rpm	842 F	19 158 lb	16 x 7 x 7 ft	60Hz

Model	Year	ISO Base Rating	Heat Rate Btu/kWh	Efficiency	Pressure Ratio	Flow lb/sec	Turbine Speed	Exhaust Temp	Approx Weight	Approx L x W x H	Comments
IHI Power Systems continued											
STIG-LM1600	1991	16 900 kW	8 607 Btu	39.7%	25.1	116.0 lb	7000 rpm	878 F	****	****	with 20,100 pph steam inj
STIG-LM2500	1986	26 650 kW	8 650 Btu	39.5%	19.7	168.0 lb	3000 rpm	929 F	****	****	with 50,000 pph steam inj - 50Hz
STIG-LM2500	1986	27 990 kW	8 360 Btu	40.8%	20.0	168.0 lb	3600 rpm	922 F	****	****	with 50,000 pph steam inj - 60Hz
Iskra Energetika											
GTES-4	1999	4 100 kW	14 132 Btu	24.2%	7.1	65.0 lb	5500/3000	792 F	352 734 lb	82 x 21 x 25 ft	PMZ GTU-4P
GTES-6	2001	6 200 kW	12 782 Btu	26.7%	8.7	73.9 lb	5500/3000	892 F	352 734 lb	82 x 21 x 25 ft	PMZ GTU-6P
GTES-12	2001	12 000 kW	10 242 Btu	33.3%	15.8	103.8 lb	6500/3000	878 F	573 192 lb	75 x 41 x 34 ft	PMZ GTU-12P
GTES-16	2001	16 000 kW	9 787 Btu	34.9%	19.9	125.9 lb	5500/3000	900 F	573 192 lb	82 x 41 x 34 ft	PMZ GTU-16P
Kawasaki Heavy Industries											
S2A-01	1979	648 kW	17 208 Btu	19.8%	8.5	11.2 lb	1500/1800	885 F	3 263 lb	7 x 4 x 4 ft	weights and dimensions incl. reduction gearbox, fuel/lube
M1A-13X	2001	1 424 kW	14 389 Btu	23.7%	9.6	17.4 lb	1500/1800	977 F	8 697 lb	10 x 4 x 10 ft	oil and starting systems,
M1A-13	1989	1 474 kW	14 086 Btu	24.2%	9.4	17.7 lb	1500/1800	968 F	7 209 lb	8 x 5 x 7 ft	except M7A-01, M7A-01S,
M1A-13D	1995	1 475 kW	14 229 Btu	24.0%	9.5	17.5 lb	1500/1800	986 F	7 518 lb	8 x 4 x 7 ft	and M7A-02.
M1T-13	1989	2 903 kW	14 305 Btu	23.9%	9.4	35.5 lb	1500/1800	968 F	13 668 lb	8 x 7 x 6 ft	all output at electric generator
M1T-13D	1995	2 907 kW	14 439 Btu	23.6%	9.5	35.1 lb	1500/1800	986 F	13 801 lb	8 x 7 x 7 ft	terminals with generator effic. of 95% exc. 98% for M7A-01,
M7A-01	1993	5 512 kW	11 530 Btu	29.6%	12.7	48.0 lb	1500/1800	1013 F	9 921 lb	12 x 5 x 6 ft	M7A-01S, and M7A-02.
M7A-01S	1996	6 545 kW	10 237 Btu	33.3%	12.7	48.9 lb	1500/1800	981 F	10 362 lb	12 x 5 x 6 ft	M1A-13D, M1T-13D, M7A-01D,
M7A-02	1997	6 912 kW	11 190 Btu	30.5%	15.9	59.5 lb	1500/1800	972 F	11 023 lb	12 x 5 x 6 ft	M7A-02D with dry-low NOx comb. M1A-13X with Xonon comb.
M7A-01D	1993	5 381 kW	11 648 Btu	29.3%	12.7	48.0 lb	1500/1800	1008 F	10 362 lb	12 x 5 x 6 ft	
M7A-02D	1997	6 721 kW	11 264 Btu	30.3%	15.9	59.5 lb	1500/1800	955 F	11 464 lb	12 x 5 x 6 ft	
M7A-03D	2006	7 439 kW	10 290 Btu	33.1%	15.9	59.5 lb	1500/1800	948 F	11 658 lb	14 x 5 x 6 ft	
L20A	2001	17 640 kW	9 948 Btu	34.3%	18.0	127.2 lb	3000/3600	1013 F	30 864 lb	22 x 7 x 9 ft	
MAN Turbo											
THM1203A	1979	5 760 kW	15 184 Btu	22.5%	8.0	79.0 lb	7550 rpm	959 F	165 375 lb	49 x 9 x 16 ft	
THM1304-9	1999	8 640 kW	12 341 Btu	27.7%	9.6	99.0 lb	8600 rpm	918 F	169 785 lb	52 x 9 x 17 ft	
THM1304-10	1980	9 320 kW	12 170 Btu	28.0%	10.0	100.0 lb	8600 rpm	932 F	169 785 lb	52 x 9 x 17 ft	
THM1304-11	1999	10 760 kW	11 459 Btu	29.8%	10.8	108.0 lb	8600 rpm	941 F	169 785 lb	52 x 12 x 21 ft	
THM1304-12	2004	11 520 kW	11 165 Btu	30.6%	11.0	108.0 lb	8600 rpm	959 F	169 785 lb	52 x 12 x 21 ft	
THM1304-14	2005	12 680 kW	11 000 Btu	31.0%	11.0	108.0 lb	8600 rpm	1013 F	169 785 lb	52 x 12 x 21 ft	
FT8 PowerPac	1990	25 490 kW	8 950 Btu	38.1%	19.3	187.0 lb	3000/3600	855 F	330 750 lb	66 x 15 x 12 ft	
FT8 TwinPac	1990	51 350 kW	8 890 Btu	38.4%	19.3	374.0 lb	3000/3600	855 F	551 250 lb	115 x 15 x 12 ft	

Model	Year	ISO Base Rating	Heat Rate Btu/kWh	Efficiency	Pressure Ratio	Flow lb/sec	Turbine Speed	Exhaust Temp	Approx Weight	Approx L x W x H	Comments
Mitsubishi Heavy Industries											
MF-61	1989	5 925 kW	11 910 Btu	28.7%	15.0	60.0 lb	13800 rpm	925 F	21 605 lb	12 x 8 x 10 ft	all ratings on natural gas
MF-111	1985	14 570 kW	11 020 Btu	31.0%	15.0	121.0 lb	9660 rpm	986 F	48 501 lb	18 x 9 x 8 ft	with inlet and exhaust losses
MFT-8	1994	26 780 kW	8 820 Btu	38.7%	21.0	190.0 lb	5000 rpm	867 F	14 771 lb	23 x 8 x 8 ft	shaft output
MF-221	1994	30 000 kW	10 670 Btu	32.0%	15.0	238.0 lb	7200 rpm	991 F	110 229 lb	25 x 12 x 11 ft	
M501DA	1980	113 950 kW	9 780 Btu	34.9%	14.0	763.0 lb	3600 rpm	1009 F	319 665 lb	38 x 19 x 14 ft	
M501F3	1989	185 400 kW	9 230 Btu	37.0%	16.0	1011.0 lb	3600 rpm	1136 F	429 894 lb	46 x 15 x 15 ft	
M501G1	1997	267 500 kW	8 730 Btu	39.1%	20.0	1320.0 lb	3600 rpm	1113 F	551 146 lb	50 x 15 x 16 ft	
M701DA	1981	144 090 kW	9 810 Btu	34.8%	14.0	972.0 lb	3000 rpm	1008 F	440 917 lb	41 x 17 x 17 ft	
M701F4	1992	312 100 kW	8 683 Btu	39.3%	18.0	1549.0 lb	3000 rpm	1106\ F	922 633 lb	57 x 19 x 19 ft	
M701G2	1997	334 000 kW	8 630 Btu	39.5%	21.0	1625.0 lb	3000 rpm	1089 F	925 926 lb	60 x 20 x 20 ft	
Mitsui Engineering & Shipbuilding											
SB5	1987	1 080 kW	13 390 Btu	25.5%	10.0	11.0 lb	26600 rpm	918 F	2 205 lb	6 x 5 x 3 ft	
SB15	1986	2 720 kW	13 330 Btu	25.6%	10.0	32.0 lb	13070 rpm	916 F	14 109 lb	10 x 5 x 10 ft	
SB30E	1995	7 330 kW	12 200 Btu	28.0%	12.5	72.5 lb	11380 rpm	936 F	41 446 lb	16 x 8 x 12 ft	
SB60-2	1981	12 490kW	11 530Btu	29.6%	12.1	122.0 lb	5680 rpm	853 F	120 591 lb	24 x 11 x 15 ft	two shaft design
SB60-1	1988	13 570kW	11 490Btu	29.7%	13.2	131.0lb	6780 rpm	918 F	114 638 lb	23 x 11 x 15 ft	one shaft design
SB120	1985	23 000kW	11 190Btu	30.5%	11.7	225.0lb	5070 rpm	887 F	198 413 lb	31 x 14 x 20 ft	
MSC40	1970	3 520kW	12 240Btu	27.9%	9.7	41.0lb	1500/1800	819 F	59 524 lb	29 x 8 x 10 ft	Centaur 40
MSC50	1985	4 350kW	11 675Btu	29.2%	10.3	41.9lb	1500/1800	934 F	59 524 lb	29 x 8 x 10 ft	Centaur 50
MSC60	1989	5 000kW	11 250Btu	30.3%	11.7	47.1lb	1500/1800	898 F	59 524 lb	29 x 8 x 10 ft	Taurus 60
MSC70	1994	6 840 kW	10 570 Btu	32.3%	15.0	56.2 lb	1500/1800	894 F	116 843 lb	41 x 9 x 11 ft	Taurus 70
MSC90	1987	9 290 kW	10 765 Btu	31.7%	16.2	86.4 lb	1500/1800	867 F	149 912 lb	48 x 9 x 11 ft	Mars 90
MSC100	1989	10 690 kW	10 505 Btu	32.5%	17.1	91.8 lb	1500/1800	910 F	149 912 lb	48 x 9 x 11 ft	Mars 100
Motor Sich - Progress (50/60 Hz)											
TV3-137	1999	1 100 kW	13 655 Btu	25.0%	7.5	16.1 lb	15000 rpm	790 F	639 lb	7 x 2 x 2 ft	natural gas fuel
AI-20DME	1991	2 500 kW	14 224 Btu	24.0%	9.0	42.7 lb	12300 rpm	968 F	2 646 lb	11 x 3 x 4 ft	dual fuel
GTE-6.3/MS	1997	6 300 kW	11 012 Btu	31.0%	15.3	70.4 lb	8560 rpm	808 F	3 241 lb	13 x 4 x 4 ft	gas fuel
GTE-8/MS	2001	8 000 kW	10 735 Btu	31.8%	17.5	81.1 lb	8560 rpm	846 F	3 241 lb	13 x 4 x 4 ft	gas fuel
MTU Friedrichshafen											
LM1600-PA	1989	13 820 kW	9 577 Btu	35.6%	21.5	103.0 lb	7000/1500	910 F	7 550 lb	15 x 8 x 7 ft	all with 3.5% gearbox and
LM2500 PE	1973	22 460 kW	9 417 Btu	36.2%	18.8	152.0 lb	3600/1500	974 F	10 300 lb	21 x 7 x 7 ft	generator loss
LM2500 PH STIG	1986	27 630 kW	8 450 Btu	40.4%	20.2	167.0 lb	3600/1500	926 F	10 500 lb	21 x 7 x 7 ft	
LM2500+ (PK)	1998	28 070 kW	9 022 Btu	37.8%	22.2	183.0 lb	3600/1500	950 F	11 500 lb	22 x 7 x 7 ft	
NK - Engines											
NK-143	1996	10 000 kW	10 340 Btu	33.0%	11.3	87.5 lb	3000/3600	***	6 835 lb	15 x 5 x 5 ft	
NK-39	1995	16 000 kW	8 981 Btu	38.0%	25.9	120.0 lb	3000/3600	829 F	15 900 lb	19 x 7 x 7 ft	
NK-37	1993	25 000 kW	9 376 Btu	36.4%	23.1	223.0 lb	3000/3600	797 F	21 790 lb	17 x 7 x 7 ft	

Model	Year	ISO Base Rating	Heat Rate Btu/kWh	Efficiency	Pressure Ratio	Flow lb/sec	Turbine Speed	Exhaust Temp	Approx Weight	Approx L x W x H	Comments
OPRA Optimal Radial Turbine											
OP16-3A	2004	1 910 kW	12 732 Btu	26.9%	6.7	19.2 lb	26000 rpm	1032 F	3 968 lb	8 x 4 x 5 ft	
OP16-3B (DLE)	2004	1 910 kW	12 732 Btu	26.9%	6.7	19.2 lb	26000 rpm	1032 F	3 968 lb	8 x 4 x 5 ft	
Orenda Aerospace											
OGT2500	1994	2 670 kW	12 780 Btu	26.7%	12.0	33.1 lb	1500/1800	860 F	5 513 lb	10 x 4 x 7 ft	weights, dimensions engine only
GT4000SI	1994	4 050 kW	10 065 Btu	33.9%	12.0	37.5 lb	3000/3600	842 F	5 513 lb	10 x 4 x 7 ft	
GT6000	1994	6 500 kW	11 187 Btu	30.5%	14.0	68.3 lb	3000/3600	788 F	9 923 lb	15 x 6 x 6 ft	weights, dimensions engine only
GT15000	1996	16 300 kW	9 977 Btu	34.2%	19.7	158.7 lb	3000/3600	770 F	28 224 lb	20 x 7 x 8 ft	weights, dimensions engine only
GT16000BF	1991	15 500 kW	11 090 Btu	30.8%	13.0	212.0 lb	3000/3600	662 F	35 280 lb	19 x 9 x 10 ft	diesel, bio oil, heavy oil, ethanol
GT25000	1996	25 500 kW	9 639 Btu	35.4%	21.0	198.2 lb	3000/3600	914 F	35 280 lb	21 x 8 x 9 ft	weights, dimensions engine only
Pratt & Whitney Power Systems											
ST6L-795	1986	678 kW	13 826 Btu	24.7%	7.4	7.1 lb	33000 rpm	1092 F	229 lb	4 x 1 x 2 ft	
ST6L-813	1978	848 kW	13 099 Btu	26.1%	8.5	8.6 lb	33000 rpm	1051 F	300 lb	4 x 2 x 2 ft	
ST18A	1995	1 961 kW	11 237 Btu	30.4%	14.0	17.6 lb	18900 rpm	990 F	772 lb	5 x 2 x 3 ft	
ST40	1999	4 039 kW	10 310 Btu	33.1%	16.9	30.6 lb	14875 rpm	1011 F	1 157 lb	6 x 2 x 3 ft	
SwiftPac 4	2003	3 880 kW	10 735Btu	31.8%	16.9	30.6 lb	14875 rpm	1011 F	****	****	
MobilePac	2005	24 957 kW	9 035Btu	37.8%	19.3	187.0 lb	3000/3600	855 F	****	****	
FT8 PowerPac	1990	25 490 kW	8 950 Btu	38.1%	19.3	187.0 lb	3000/3600	855 F	****	****	
FT8 TwinPac	1990	51 350 kW	8 890 Btu	38.4%	19.3	374.0 lb	3000/3600	855 F	****	****	
SwiftPac 25	2003	25 455 kW	8 960 Btu	38.1%	19.5	186.9 lb	3000/3600	856 F	****	****	transportable
SwiftPac 50	2003	51 235 kW	8 905 Btu	38.3%	19.5	373.8 lb	3000/3600	856 F	****	****	transportable
FT8-3 PowerPac	1990	27 970 kW	8 900 Btu	38.3%	20.2	193.0 lb	3000/3600	893 F	****	****	
FT8-3 TwinPac	1990	56 340 kW	8 840 Btu	38.6%	20.2	386.0 lb	3000/3600	893 F	****	****	
Rolls-Royce											
501-KB5S	1990	3 897 kW	11 747 Btu	29.0%	10.3	33.9 lb	14200 rpm	1040 F	****	****	ratings at sea level, 15 deg C
501-KB7S	1992	5 245 kW	10 848 Btu	31.5%	13.9	46.6 lb	14600 rpm	928 F	****	****	no external pressure losses
501-KH5	1982	6 447 kW	8 509 Btu	40.1%	12.5	40.6 lb	14600 rpm	986 F	****	****	case steam injected 2.73 kg/sec
RB211-G62 DLE	1993	27 520 kW	9 415 Btu	36.2%	20.8	202.0 lb	4800 rpm	932 F	****	****	steam injection
RB211-GT62 DLE	1999	29 500 kW	9 055 Btu	37.7%	21.5	211.0 lb	4800 rpm	920 F	****	****	
RB211-GT61 DLE	2000	32 120 kW	8 680 Btu	39.3%	21.5	208.0 lb	4850 rpm	938 F	****	****	
Trent 60 DLE	1996	51 504 kW	8 104 Btu	42.1%	33.0	334.0 lb	3000 rpm	832 F	****	****	
Trent 60 DLE	1996	51 685 kW	8 138 Btu	41.9%	34.0	341.0 lb	3600 rpm	825 F	****	****	
Trent 60 WLE	2001	58 000 kW	8 346 Btu	40.9%	36.0	365.0 lb	3000 rpm	794 F	****	****	water injected
Trent 60 WLE	2001	58 000 kW	8 336 Btu	40.9%	35.0	358.0 lb	3600 rpm	805 F	****	****	water injected

Model	Year	ISO Base Rating	Heat Rate Btu/kWh	Efficiency	Pressure Ratio	Flow lb/sec	Turbine Speed	Exhaust Temp	Approx Weight	Approx L x W x H	Comments
Siemens Power Generation											
SGT-100	1989	4 350 kW	11 370 Btu	30.0%	13.0	39.0 lb	16500 rpm	981 F	78 175 lb	33 x 8 x 11 ft	
SGT-100	1989	4 700 kW	11 309 Btu	30.2%	14.1	42.0 lb	17384 rpm	975 F	78 175 lb	33 x 8 x 11 ft	
SGT-100	1997	5 050 kW	11 294 Btu	30.2%	14.3	43.0 lb	17384 rpm	1015 F	78 175 lb	33 x 8 x 11 ft	
SGT-100	1998	5 250 kW	11 203 Btu	30.5%	14.8	46.0 lb	17384 rpm	986 F	78 175 lb	33 x 8 x 11 ft	
SGT-200	1981	6 750 kW	10 824 Btu	31.5%	12.3	65.0 lb	11053 rpm	871 F	124 000 lb	41 x 8 x 11 ft	
SGT-300	1995	7 900 kW	10 937 Btu	31.2%	13.8	66.0 lb	14010 rpm	999 F	126 000 lb	40 x 8 x 12 ft	
SGT-400	1997	12 900 kW	9 817 Btu	34.8%	16.9	87.0 lb	9500 rpm	1031 F	165 000 lb	61 x 9 x 13 ft	
SGT-500	1968	17 000 kW	10 600 Btu	32.2%	12.0	203.5 lb	3000/3600	707 F	331 000 lb	68 x 16 x 13 ft	50/60 Hz
SGT-600	1981	24 770 kW	9 985 Btu	34.2%	14.0	177.3 lb	7700 rpm	1009F	335 000 lb	68 x 15 x 17 ft	50/60 Hz
SGT-700	1999	29 060 kW	9 480 Btu	36.0%	18.0	201.0 lb	6500 rpm	964F	353 000 lb	68 x 15 x 18 ft	50/60 Hz
SGT-800	1998	45 000 kW	9 224 Btu	37.0%	19.3	287.0 lb	6600 rpm	1001F	379 000 lb	56 x 15 x 13 ft	50/60 Hz
SGT-800	2007	47 000 kW	9 100 Btu	37.5%	20.0	290.0 lb	6600 rpm	1012F	379 000 lb	56 x 15 x 13 ft	50/60 Hz
SGT-900	1982	49 500 kW	10 450 Btu	32.7%	15.3	386.0 lb	5425 rpm	957F	276 000 lb	50 x 12 x 14 ft	50/60 Hz, W251B11/12
SGT-1000F	1996	67 700 kW	9 730 Btu	35.1%	15.8	422.0 lb	5400 rpm	1081 F	242 500 lb	36 x 13 x 16 ft	50/60 Hz, V64.3A
SGT6-3000E	1993	120 500 kW	9 840 Btu	34.7%	14.2	849.0 lb	3600 rpm	986 F	310 000 lb	34 x 12 x 14 ft	W501D5A
SGT5-2000E	1981	168 000 kW	9 825 Btu	34.7%	11.7	1170.0 lb	3000 rpm	998 F	650 360 lb	46 x 41 x 28 ft	V94.2
SGT6-5000F	1989	202 000 kW	8 955 Btu	38.1%	17.4	1120.0 lb	3600 rpm	1073 F	425 000 lb	33 x 13 x 15 ft	W501F
SGT5-3000E	1997	191 000 kW	9 283 Btu	36.8%	13.3	1129.0 lb	3000 rpm	1068 F	727 520 lb	43 x 20 x 26 ft	V94.2A, 41000 EOH Maint Interval
SGT6-6000G	1994	267 500 kW	8 715 Btu	39.2%	19.9	1284.0 lb	3600 rpm	1135 F	600 000 lb	36 x 14 x 15 ft	W501G
SGT5-4000F	1995	286 600 kW	8 638 Btu	39.5%	17.9	1520.0 lb	3000 rpm	1071 F	727 520 lb	43 x 20 x 26 ft	V94.3A
Solar Turbines											
Saturn 20	1985	1 210 kW	14 025 Btu	24.3%	6.8	14.4 lb	22516 rpm	940 F	22 000 lb	18 x 6 x 7 ft	
Centaur 40	1992	3 515 kW	12 240 Btu	27.9%	9.8	41.9 lb	14944 rpm	830 F	52 370 lb	32 x 8 x 9 ft	
Centaur 50	1993	4 600 kW	11 630 Btu	29.3%	10.6	42.1 lb	14944 rpm	950 F	59 700 lb	32 x 8 x 9 ft	
Mercury 50	1997	4 600 kW	8 863 Btu	38.5%	9.9	39.0 lb	14944 rpm	710 F	129 700 lb	37 x 10 x 12 ft	
Taurus 60	1993	5 670 kW	11 225 Btu	31.5%	12.5	48.0 lb	14951 rpm	950 F	66 900 lb	32 x 8 x 9 ft	
Taurus 65	2005	6 300 kW	10 375 Btu	32.9%	15.1	46.5 lb	14951 rpm	1021 F	72 700 lb	32 x 8 x 10 ft	
Taurus 70	1994	7 520 kW	10 100 Btu	33.8%	16.1	59.4 lb	15200 rpm	905 F	125 405 lb	37 x 9 x 9 ft	
Mars 100	1994	10 690 kW	10 520 Btu	32.4%	17.4	91.7 lb	10780 rpm	910 F	160 000 lb	48 x 9 x 12 ft	
Titan 130	1998	15 000 kW	9 695 Btu	38.9%	16.1	109.8 lb	11220 rpm	925 F	162 409 lb	46 x 11 x 11 ft	
Titan 130 Mobile	2005	15 000 kW	9 695 Btu	35.2%	17.0	109.8 lb	11220 rpm	925 F	147 599 lb	46 x 11 x 11 ft	

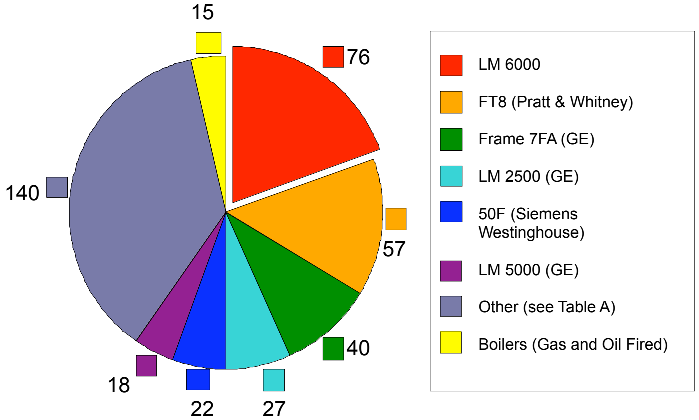
Model	Year	ISO Base Rating	Heat Rate Btu/kWh	Efficiency	Pressure Ratio	Flow lb/sec	Turbine Speed	Exhaust Temp	Approx Weight	Approx L x W x H	Comments
Turbomach											
TBM-S20	1985	1 204 kW	14 025 Btu	24.3%	6.7	14.4 lb	1500/1800	942 F	44 092 lb	20 x 6 x 9 ft	Saturn 20
TBM-C40	1992	3 515 kW	12 244 Btu	27.8%	9.7	41.9 lb	1500/1800	829 F	88 184 lb	39 x 7 x 11 ft	Centaur 40
TBM-C50	1993	4 600 kW	11 628 Btu	29.3%	10.6	42.1 lb	1500/1800	949 F	97 003 lb	39 x 7 x 11 ft	Centaur 50
TBM-M50	1997	4 600 kW	8 863 Btu	38.5%	9.9	39.3 lb	1500/1800	705 F	110 231 lb	42 x 10 x 11 ft	Mercury 50
TBM-T60	1993	5 670 kW	10 832 Btu	31.5%	12.5	48.0 lb	1500/1800	951 F	99 208 lb	39 x 7 x 11 ft	Taurus 60
TBM-T65	2005	6 300 kW	10 375 Btu	32.9%	15.0	46.5 lb	1500/1800	1021 F	123 459 lb	36 x 7 x 11 ft	Taurus 65
TBM-T70	1994	7 520 kW	10 098 Btu	33.8%	16.0	59.4 lb	1500/1800	906 F	149 914 lb	39 x 10 x 10 ft	Taurus 70
TBM-M100	1994	10 685 kW	10 514 Btu	32.4%	17.4	92.1 lb	1500/1800	908 F	185 188 lb	49 x 10 x 10 ft	Mars 100
TBM-T130	1998	15 000 kW	9 695 Btu	35.2%	16.0	109.8 lb	1500/1800	925 F	196 211 lb	51 x 10 x 10 ft	Titan 130
Vericor											
VPS1	1974	500 kW	16 467 Btu	20.7%	10.5	7.9 lb	1500/1800	908 F	20 000 lb	14 x 9 x 14 ft	
VPS3	1978	3 148 kW	12 553 Btu	28.3%	8.7	28.3 lb	15400 rpm	1108 F	70 000 lb	25 x 9 x 20 ft	
VPS4	1999	3 519 kW	11 907 Btu	30.4%	9.9	30.4 lb	15400 rpm	1076 F	70 000 lb	25 x 9 x 20 ft	
Zorya-Mashproekt											
UGT 2500	1992	2 850 kW	11 975 Btu	28.5%	12.0	36.4 lb	1800/3000	860 F	3 300 lb	10 x 4 x 6 ft	
UGT 6000	1978	6 360 kW	10 835 Btu	31.5%	13.5	67.2 lb	3000 rpm	797 F	7 720 lb	10 x 5 x 6 ft	
UGT 8000	2006	9 000 kW	10 150 Btu	33.6%	17.9	77.2 lb	3000 rpm	896 F	****	****	
UGT 10000	1998	10 300 kW	9 670 Btu	35.3%	19.0	79.4 lb	3000/3600	914 F	9 920 lb	12 x 6 x 6 ft	gearbox losses included
UGT 16000	1980	15 900 kW	10 870 Btu	31.4%	12.5	211.6 lb	3000/3600	662 F	35 270 lb	19 x 9 x 10 ft	
UGT 15000	1988	16 900 kW	9 750 Btu	35.0%	19.5	156.5 lb	3000/3600	788 F	19 840 lb	16 x 9 x 9 ft	
UGT 15000 STIG	1995	25 000 kW	8 130 Btu	42.0%	17.9	160.3 lb	3000/3600	824 F	429 900 lb	82 x 43 x 39 ft	with inlet and exhaust losses
UGT 25000	1993	26 200 kW	9 400 Btu	36.3%	20.5	192.9 lb	3000/3600	905 F	30 860 lb	21 x 8 x 9 ft	

Oxidation Catalyst – Power Generation

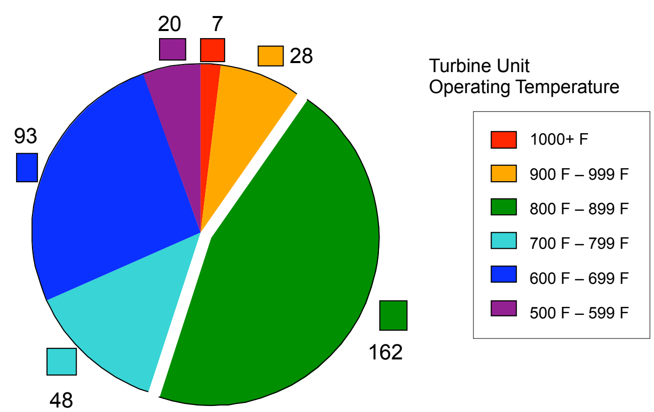
BASF is the #1 oxidation catalyst supplier in the world. We have serviced the Power Generation industry for over 15 years with 400 units operating or under construction (refer to Figure 1 and Table A). Our experience encompasses virtually every make, model, and turbine configuration (see Figure 2).

BASF customers value our experience and do not worry about the performance of their oxidation catalyst. In the power generation industry, the stakes are too high to be shut down – for any reason. Even a short outage can be devastating. Lost revenue can pay for catalyst many times over.

Over 400 Units Operating or Under Construction



Extensive Simple and Combined Cycle Operating Experience



Manufacturer	Model	Units
ABB	GT24	14
Pratt & Whitney	FT8 Twin Pac (2 CT/Unit)	13
GE	10	12
Mitsubishi	501G	9
Westinghouse	501AA	6
GE	LM6000 Sprint	5
Westinghouse	191	4
GE	Frame 7	4
GE	LM2500 (2 CTs/Unit)	4
Westinghouse	251	3
Westinghouse	501G	3
GE	Frame 7E	3
GE	Frame 7EA	3
GE	Frame 7FB	3
ABB	GT10	3
GE	LM1600	3
RR	RB211	3
Solar	Taurus 60	3
Siemens	V84.2	3
Siemens Westinghouse	501G	2
BBC	8	2
Solar	Centaur 50	2
GE	Frame 6	2
GE	Frame 6B	2
Solar	Mars	2
ABB	10B	1
ABB	11N2	1
Westinghouse	251B12	1
Westinghouse	501 D5A	1
Solar	Centaur	1
GE	Frame 7F	1
GE	Frame 9	1
Pratt & Whitney	FT4A9	1
Mannesman	GHH FT8	1
GE	LM1500	1
Solar	Taurus 70	1
Siemens	V84.3A	1
Make/Model Unknown		23

BF-8358, 02/2007

The Chemical Company

BASF is extremely proud of our low cost and technologically superior oxidation catalyst. Our catalysts perform well beyond the warranty period, which makes them an excellent value (refer to Figure 3). Almost all of the Powergen oxidation catalysts that we have supplied are still running. More than 50 units are six to ten years old and 30+ units are over ten years old. No one else in the industry even comes close to this durability.

BASF Catalysts Perform Well Beyond the Warranty

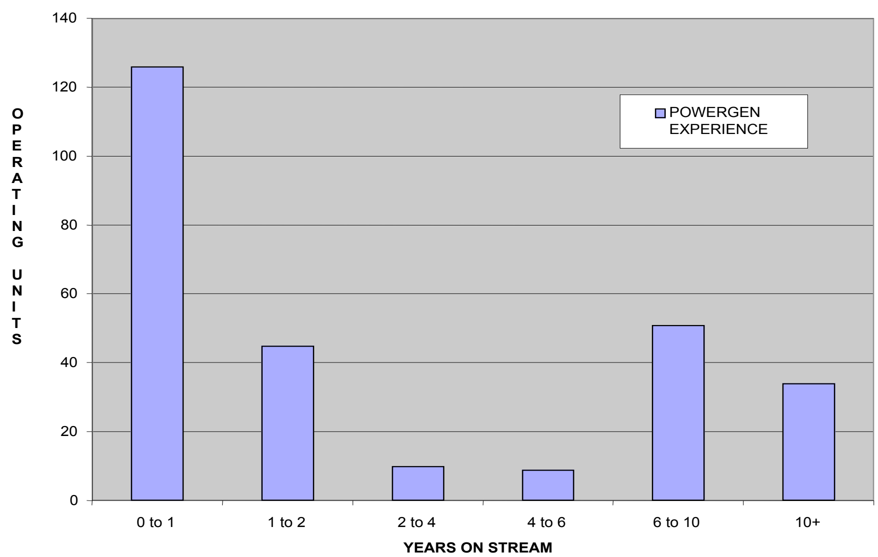


Figure 3 – Catalyst

Other BASF Powergen Experience

- Highest CO removal efficiency – 98%+
- Most VOC experience
- HAPs conversion data
- >99% warranty compliance
- 100% on-time delivery

If you need more detailed information, or have a question about oxidation catalyst, please contact us:

BASF Catalysts LLC
101 Wood Avenue
Iselin, NJ 08830
Telephone: 732-205-5077
Toll-free: 800-631-9505
Fax: 732-205-6146
Web site: www.basf-catalysts.com

Exhibit 20

	StartupDate	SiteLocation	TurbineMfg	Applications	IdenticalUnits	Temperature	Flow	COConv.	VOCConv.	Fuel
1					3	932	59	50.00%		NG/Oil
2	10/1/1986	New Mexico	RR	RB211	3	645	139	90.00%		
3	11/1/1987	Illinois	GE	LM2500	1	519	160	42.00%		
4	12/1/1987	California	GE	Frame 6	2	902	305	90.00%		
5	6/1/1988	California	GE	LM5000	1	750	351	90.00%		
6	6/1/1988	California	Westinghouse	251	1	710	375	82.00%		
7	7/1/1988	California	GE	LM2500	1	936	152	80.00%		
8	7/1/1988	California	GE	LM2500	2	720	154	80.00%		
9	9/1/1988	California	GE	LM2500	1	858	150	83.00%		
10	2/1/1989	California	GE	Frame 7	1	535	695	80.00%		
11	2/1/1989	California	GE	LM2500	6	890	162	82.00%		
12	2/1/1989	California		Boiler	2	533	33	90.00%		
13	3/1/1989	New Jersey	GE	LM2500	1	820	172	80.00%		
14	3/1/1989	California	GE	Frame 7E	1	990	671	85.00%		
15	5/1/1989	California	GE	LM5000	1		300	90.00%		
16	6/1/1989	California	GE	LM2500	1	920	149	84.00%		
17	6/1/1989	California	GE	LM2500	1		148	90.00%		
18	7/1/1989	New York	GE	LM2500	2		148	90.00%		
19	9/1/1989	California	GE	LM5000	1	792	303	80.00%		
20	2/1/1990	California	GE	LM5000	1	760	350	60.00%		
21	6/1/1990	Texas	Westinghouse	191	2	775	267	85.00%		
22	7/1/1990	California	GE	LM2500	1	920	149	84.00%		
23	8/1/1990	Texas	Westinghouse	191	2	775	267	85.00%		
24	12/1/1990	California	GE	LM5000	1	900	333	82.00%		
25	1/1/1991	New Jersey	GE	Frame 7	2	580	750	75.00%		
26	2/1/1991	California	GE	LM5000	1	760	350	80.00%		
27	6/1/1991	California	GE	LM5000	1	760	350	80.00%		
28	7/1/1991	Pennsylvania	GE	LM5000	2	546	286	90.00%		
29	9/1/1991	New York	GE	LM5000	2	550	286	90.00%		
30	9/1/1991	New York	GE	LM5000	1		300	90.00%		
31	10/1/1991	Nevada	GE	LM2500	6	589	148	90.00%		
32	11/1/1991	California	GE	LM5000	1	760	350	80.00%		
33	1/1/1992	California	BBC	8	2	930	410	90.00%		
34	4/1/1992	California	GE	LM5000	1	660	306	80.00%		
35	6/1/1992	California	GE	LM1600	2	959	107	90.00%		
36	8/1/1992	Texas	RR		1	1100	259	95.00%		
37	12/1/1992	New Jersey	Westinghouse	251	2	590	422	90.00%		
38	3/1/1993	Washington	GE	Frame 7	1	625	669	80.00%		
39	5/1/1993	California	GE	LM2500	1	900	157	80.00%		
40	7/1/1993	California	GE	Frame 7E	2	971	687	92.00%		
41	11/1/1993	New Mexico	ABB	10B	1	983	154	87.00%		
42	11/1/1993	New York	GE	Frame 7EA	2	705	663	90.00%		
43	3/1/1994	New Jersey	Pratt & Whitney	FT8 Twin Pac (2 CT/Unit	4	678	427	90.00%		
44	4/1/1994	Texas	Solar	Mars	1	980	85	95.00%		
45	7/1/1994	California	GE	LM2500	2		153	90.00%		
46	8/1/1994	California			1	680	91.5	90.00%		
47	8/1/1994	Switzerland	ABB		1	900	60	80.00%		
48	8/1/1994	Massachusetts	ABB	GT10	1	879	184	98.00%		
49	8/1/1994	California	GE	LM6000	1		303	90.00%		
50	8/1/1994	California		Boiler	2	470	12.9	90.00%		
51	4/1/1995	California	GE	LM5000	1	750	342	88.00%		
52	4/1/1995	California	GE	LM5000	1	750	342	88.00%		
53	4/1/1995	California	GE	LM5000	1	880	350	80.00%		
54	6/1/1995	New Jersey		Boiler	2	700	66	90.00%		
55	7/1/1995	New Jersey	Solar	Centaur	1	980	37	91.00%		
56	8/1/1995	New York	GE	LM5000	1		300	90.00%		
57	8/1/1995	California	GE	LM6000	2	560	343	90.00%		
58	8/1/1995	Michigan	GE	Frame 7EA	1	876	673	80.00%		
59	8/1/1995	New Jersey	GE	LM1600	1			90.00%		
60	11/1/1995	California	Pratt & Whitney	FT4A9	1	860	314	80.00%		
61	12/1/1995	New York	Siemens	V84.2	2	1027	750	98.00%		
62	1/1/1996	Colorado	GE	LM6000	1	620	247	80.00%		
63	3/1/1996	California	GE	LM6000	1	938	290	90.00%		
64	4/1/1996	California	GE	LM2500	1	604	162	92.00%		
65	7/1/1996	Minnesota	Westinghouse	501F	1	655	1079	90.00%		
66	8/1/1996	Austria	Mannesman	GHH FT8	1	878	197	70.00%		
67	1/1/1997	Washington	GE	Frame 7F	1	965	1062	82.00%		
68	3/1/1997	Virginia	Westinghouse	251B12	1	700	431	91.00%		
69	3/1/1997	Pennsylvania	Westinghouse	501 D5A	1	1107	931	90.00%		

70	3/1/1997	California	Siemens	V84.2	1	635	782	90.00%		
71	9/1/1998	Massachusetts	ABB	11N2	1	637	888	80.00%		
72	12/1/1998	Scotland	ABB	GT10	1	952	189	95.00%		
73	1/1/1999	Massachusetts	Solar	Centaur 50	1	910	46	80.00%		
74	6/1/1999	Italy	GE	Frame 9	1	660	956	85.00%		
75	10/1/1999	Nevada	Westinghouse	501F	2	600	996	85.00%		
76	10/1/1999	Massachusetts	ABB	GT24	1	633	935	80.00%		
77	10/1/1999	Texas	GE	Frame 6B	2	1019	347	75.00%		
78	12/1/1999	Massachusetts	Westinghouse	501G	1	633	1472	90.00%		
79	3/1/2000	Ohio	Pratt & Whitney	FT8	8	898	214	90.00%		NG
80	6/1/2000	Connecticut	ABB	GT24	3	640	930	80.40%		NG/Distilate Oil
81	7/1/2000	California	Pratt & Whitney	FT8	1	775	73	60.00%		
82	10/1/2000	California	Solar	Centaur 50	1	921	42	88.00%		NG/Propane
83	12/1/2000	Unknown	Pratt & Whitney	FT8	18	898	214	90.00%		NG
84	12/1/2000	Illinois	Pratt & Whitney	FT8	12	898	214	90.00%		NG
85	12/1/2000	West Virginia	Pratt & Whitney	FT8	2	898	214	90.00%		NG
86	3/1/2001	California	Siemens	501F	2	665	1010	89.30%		NG
87	4/1/2001	Texas			1	775	268	85.00%		
88	4/1/2001	Pennsylvania	Westinghouse	501G	2	649	1417	80.00%		NG/Distilate Oil
89	4/1/2001	New Jersey	GE	Frame 7FA	1	759	1073	82.30%		NG/LS-Diesel
90	4/1/2001	West Virginia			6	998	656	50.00%		NG
91	4/1/2001	West Virginia	Pratt & Whitney	FT8	12	898	214	90.00%		NG
92	5/1/2001	California	GE	Frame 7FA	2	1025	1053	62.70%	36.00%	NG
93	6/1/2001	California	Pratt & Whitney	FT8 Twin Pac (2 CT/Unit	1	750	390	80.00%		NG
94	6/1/2001	California	Pratt & Whitney	FT8 Twin Pac (2 CT/Unit	1	750	390	80.00%		NG
95	6/1/2001	New York	GE	LM6000	11	840	292	93.30%		NG
96	6/1/2001	Washington	Pratt & Whitney	FT8 Twin Pac (2 CT/Unit	2	804	471	87.50%		NG
97	6/1/2001	Nevada	Westinghouse	501AA	6	840	814	90.00%		NG
98	6/1/2001	California	Pratt & Whitney	FT8 Twin Pac (2 CT/Unit	1	750	390	80.00%		NG
99	6/1/2001	California	Pratt & Whitney	FT8 Twin Pac (2 CT/Unit	1	750	390	80.00%		NG
100	6/1/2001	California	Pratt & Whitney	FT8 Twin Pac (2 CT/Unit	2	750	390	80.00%		NG
101	6/1/2001	Oregon	Pratt & Whitney	FT8	4	898	214	90.00%		NG
102	6/1/2001	N/A	GE	LM1500	1	850	114			NG/Oil
103	6/1/2001	California	Pratt & Whitney	FT8 Twin Pac (2 CT/Unit	1	750	390	80.00%		NG
104	6/1/2001		Pratt & Whitney	FT8	8	898	214	90.00%		NG
105	6/1/2001	Kansas	Siemens	V84.3A	1	735	1047	51.50%		NG
106	6/1/2001	Idaho	GE	Frame 7FA	1	654	1001	30.00%		NG
107	6/1/2001	Florida	Westinghouse	501F	2	623	1098	90.00%		NG/Oil
108	6/1/2001	California	GE	LM6000	3	858	292	90.00%		NG
109	7/1/2001	California		Boiler	2	730	509	95.00%		NG
110	8/1/2001	California	GE	LM6000	2	750	342	92.00%		NG
111	8/1/2001	Massachusetts	Mitsubishi	501G	4	711	1454	86.60%		NG
112	8/1/2001	Massachusetts	Mitsubishi	501G	2	711	1454	86.60%		NG
113	9/1/2001	Washington	GE	10	4	860	111	80.00%		NG
114	9/1/2001	Arizona	Solar	Taurus 70	1	971	56	60.00%		NG
115	9/1/2001	Connecticut	GE	LM6000 Sprint	5	853	292	90.00%		NG
116	9/1/2001	Massachusetts	ABB	GT24	2	633	910	83.80%		NG
117	9/1/2001	Washington	Solar	Mars	1	860	100	90.00%		NG
118	9/1/2001	Washington	GE	LM2500 (2 CTs/Unit)	4	840	376	90.00%		NG/#2 Oil
119	9/1/2001	California	GE	LM6000	6	840	292	90.00%		NG
120	10/1/2001	Connecticut	ABB	GT24	2	653	938	80.00%		NG/Distilate Oil
121	10/1/2001	California	GE	10	8	850	110	82.60%		NG
122	10/1/2001	California	GE	LM6000	1	750	342	92.00%	30.00%	NG
123	10/1/2001	California	ABB	GT24	4	626	902	90.10%		NG
124	10/1/2001	Utah	GE	LM6000	4	840	278	82.10%		NG
125	11/1/2001	California			1	790	580	80.00%		NG
126	11/1/2001	California	Solar	Taurus 60	1	904	51	92.00%		NG
127	11/1/2001	Texas		Boiler	1	800	64	80.00%		NG
128	11/1/2001	Texas		Boiler	2	672	65	80.00%		NG
129	11/1/2001	New Jersey	GE	Frame 7FA	3	656	1103	73.30%	25.00%	NG
130	11/1/2001	Massachusetts	ABB	GT24	2	626	896	80.30%		NG
131	11/1/2001	California	GE	LM6000	1	750	342	92.00%	30.00%	NG
132	12/1/2001	Colorado	GE	LM6000	2	569	266	75.00%		NG

133	12/1/2001	New Jersey	GE	Frame 7FA	2	664	1072	80.00%		NG
134	12/1/2001	California	Solar	Taurus 60	2	729	50	88.00%		NG
135	12/1/2001	New Jersey		Boiler	4	800	101	90.00%		NG/Refinery Gas
136	1/1/2002	New York			4	856	327	0.00%		NG
137	1/1/2002	Nevada	GE	Frame 7FA	2	665	972	77.30%		NG
138	1/1/2002	Arizona	GE	Frame 7FA	1	654	1003	63.90%		NG
139	1/1/2002	Colorado	GE	Frame 7FA	2	662	1039	76.60%		NG
140	2/1/2002	New Jersey	GE	Frame 7FA	4	674	1078	84.40%		NG
141	2/1/2002	Wisconsin	GE	LM6000	1	739	263	96.00%		NG
142	3/1/2002	California	GE	LM6000	4	885	313	90.00%		NG
143	3/1/2002	Arizona	GE	LM6000	10	842	329	90.00%		NG
144	3/1/2002	New Jersey	GE	LM6000	2	842	329	90.00%		NG/Oil
145	3/1/2002	New Jersey	GE	LM6000	4	842	329	90.00%		NG
146	3/1/2002	New Jersey	GE	LM6000	4	842	329	90.00%		NG
147	3/1/2002	Illinois	GE	LM6000	12	842	329	90.00%		NG
148	3/1/2002	California	GE	LM6000	3	750	342	92.00%		NG
149	4/1/2002		Pratt & Whitney	FT4A9	1	850	266	98.50%		NG
150	4/1/2002		Pratt & Whitney	FT4A9	1	850	531	94.00%		NG
151	4/1/2002	Arizona	Siemens Westinghouse	501F	3	667	1308	76.00%		NG
152	4/1/2002	Washington	GE	Frame 7FA	1	921	1036	71.60%		NG
153	5/1/2002	Arizona	GE	LM6000	1	845	281	80.00%		NG/Oil
154	5/1/2002	California	Solar	Centaur 50	1	725	37	81.20%		NG/Oil
155	5/1/2002	Washington	GE	Frame 7FA	1	644	1013	86.80%		NG
156	5/1/2002	California	GE	LM6000	1	750	342	92.00%		NG
157	5/1/2002	Washington	GE	LM6000	4	858	312	90.00%		NG
158	6/1/2002	Arizona	GE	Frame 7FA	8	670	1060	80.00%		NG
159	6/1/2002	California	GE	Frame 7EA	2	850	824	86.00%		NG
160	6/1/2002	California	GE	LM6000	1	860	291	85.00%		NG
161	6/1/2002		GE	10	4	850	110	70.00%		NG
162	6/1/2002	Arizona	Westinghouse	501F	2	690	1005	85.00%		NG
163	6/1/2002	Arizona	Westinghouse	501F	2	690	1005	85.00%		NG
164	6/1/2002	New York	GE	Frame 7FA	2	661	1050	90.00%		NG
165	6/1/2002	Texas	Siemens Westinghouse	501G	2	682	1468	77.50%		NG
166	7/1/2002	Maryland	ABB	GT10	1	739	189	96.90%		NG/Oil
167	7/1/2002	California	GE	Frame 7FA	2	649	934	80.00%	50.00%	NG
168	8/1/2002	Pennsylvania	Siemens Westinghouse	501F	2	667	1101	65.80%		NG
169	8/1/2002	California			1	1018	297	88.90%		NG
170	9/1/2002	California	GE	LM6000	1	750	342	92.00%		NG
171	9/1/2002				2	1065	984	68.30%		NG
172	9/30/2002		GE	LM6000	12	842	329	90.00%		NG
173	10/1/2002		GE	LM6000	4	829	301	85.70%		NG
174	12/1/2002	Nevada			2	675	1111	84.10%		NG
175	12/1/2002	Washington			2	675	1111	86.50%		NG
176	12/1/2002	Pennsylvania			2	669	1018	67.00%		NG
177	12/1/2002	Pennsylvania			2	669	1018	67.00%		NG
178	1/1/2003	Arizona	Siemens Westinghouse	501F	2	647	1033	90.00%		NG
179	1/1/2003	Michigan	Mitsubishi	501G	3	961	1346	71.20%		NG
180	4/1/2003	New York	GE	Frame 7FA	1	779	914	80.00%		NG
181	5/1/2003	Arizona	GE	Frame 7FA	4	683	1040	81.90%		NG
182	5/1/2003	New Jersey	GE	Frame 7FB	3	637	1061	80.50%		NG
183	6/1/2003				2	698	1188	83.80%		NG
184	10/1/2003	California	GE	Frame 7FA	3	645	1049	48.50%		NG/Oil
185	12/1/2003	Ohio	Siemens Westinghouse	501F	2	696	1004	75.00%		NG
					449					

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Oxidation Catalyst Experience
Power Generation

Application	Startup	# of Units	Temp °F	Flow (#/s)	% CO Conversion	% VOC Conversion	Fuel
RR RB211	Oct-86	3	645	139	90		
GE LM2500	Nov-87	1	519	160	42		
GE Frame 6	Dec-87	2	902	305	90		
Westinghouse 251	Jun-88	1	710	375	82		
GE LM5000	Jun-88	1	750	351	90		
GE LM2500	Jul-88	2	720	154	80		
GE LM2500	Jul-88	1	936	152	80		
GE LM2500	Sep-88	1	858	150	83		
GE LM2500	Feb-89	6	890	162	82		
GE Frame 7	Feb-89	1	535	695	80		
Boiler	Feb-89	2	533	33	90		
GE Frame 7E	Mar-89	1	990	671	85		
GE LM2500	Mar-89	1	820	172	80		
GE LM5000	May-89	1		300	90		
GE LM2500	Jun-89	1		148	90		
GE LM2500	Jun-89	1	920	149	84		
GE LM2500	Jul-89	2		148	90		
GE LM5000	Sep-89	1	792	303	80		
GE LM5000	Feb-90	1	760	350	60		
Westinghouse 191	Jun-90	2	775	267	85		
GE LM2500	Jul-90	1	920	149	84		
Westinghouse 191	Aug-90	2	775	267	85		
GE LM5000	Dec-90	1	900	333	82		
GE Frame 7	Jan-91	2	580	750	75		
GE LM5000	Feb-91	1	760	350	80		
GE LM5000	Jun-91	1	760	350	80		
GE LM5000	Jul-91	2	546	286	90		
GE LM5000	Sep-91	2	550	286	90		
GE LM5000	Sep-91	1		300	90		
GE LM2500	Oct-91	6	589	148	90		
GE LM5000	Nov-91	1	760	350	80		
BBC-8	Jan-92	2	930	410	90		
GE LM5000	Apr-92	1	660	306	80		
GE LM1600	Jun-92	2	959	107	90		
RR	Aug-92	1	1100	259	95		
Westinghouse 251	Dec-92	2	590	422	90		
GE Frame 7	Mar-93	1	625	669	80		
GE LM2500	May-93	1	900	157	80		
GE Frame 7E	Jul-93	2	971	687	92		
ABB 10B	Nov-93	1	983	154	87		
GE Frame 7EA	Nov-93	2	705	663	90		
P&W FT8 Twin Pac (2 CT/Unit)	Mar-94	4	678	427	90		
Solar Mars	Apr-94	1	980	85	95		
GE LM2500	Jul-94	2		153	90		
ABB	Aug-94	1	900	60	80		
Turbine	Aug-94	1	680	91.5	90		
Boiler	Aug-94	2	470	12.9	90		
ABB GT 10	Aug-94	1	879	184	98		
GE LM6000	Aug-94	1		303	90		
GE LM5000	Apr-95	1	880	350	80		
GE LM5000	Apr-95	1	750	342	88		
GE LM5000	Apr-95	1	750	342	88		
Boiler	Jun-95	2	700	66	90		
Solar Centaur	Jul-95	1	980	37	91		

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Oxidation Catalyst Experience
Power Generation

Application	Startup	# of Units	Temp °F	Flow (#/s)	% CO Conversion	% VOC Conversion	Fuel
GE LM6000	Aug-95	2	560	343	90		
GE Frame 7EA	Aug-95	1	876	673	80		
GE LM1600	Aug-95	1			90		
GE LM5000	Aug-95	1		300	90		
P&W FT4A9	Nov-95	1	860	314	80		
Siemens V84.2	Dec-95	2	1027	750	98		
GE LM6000	Jan-96	1	620	247	80		
GE LM6000	Mar-96	1	938	290	90		
GE LM2500	Apr-96	1	604	162	92		
Westinghouse 501F	Jul-96	1	655	1079	90		
MAN GHH FT8	Aug-96	1	878	197	70		
GE Frame 7F	Jan-97	1	965	1062	82		
Westinghouse 501 D5A	Mar-97	1	1107	931	90		
Siemens V84.2	Mar-97	1	635	782	90		
Westinghouse 251B12	Mar-97	1	700	431	91		
ABB 11N2	Sep-98	1	637	888	80		
ABB GT10	Dec-98	1	952	189	95		
Solar CENTAUR 50	Jan-99	1	910	46	80		
GE Frame 9	Jun-99	1	660	956	85		
ABB GT 24	Oct-99	1	633	935	80		
GE Frame 6B	Oct-99	2	1019	347	75		
Westinghouse 501F	Oct-99	2	600	996	85		
Westinghouse 501G	Dec-99	1	633	1472	90		
P&W FT8	Mar-00	8	898	214	90		NG
ABB GT24	Jun-00	3	640	930	80.4		NG/Distilate Oil
P&W FT8	Jul-00	1	775	73	60		
Centaur 50	Oct-00	1	921	42	88		NG/Propane
P&W FT8	Dec-00	12	898	214	90		NG
P&W FT8	Dec-00	2	898	214	90		NG
P&W FT8	Dec-00	18	898	214	90		NG
Siemens 501F	Mar-01	2	665	1010	89.3		NG
GE 7FA	Apr-01	1	759	1073	82.3		NG/LS-Diesel
Westinghouse 501G	Apr-01	2	649	1417	80		NG/Distilate Oil
	Apr-01	6	998	656	50		NG
P&W FT8	Apr-01	12	898	214	90		NG
GE 7FA	May-01	2	1025	1053	62.7	36	NG
GE 7FA	Jun-01	1	654	1001	30		NG
GE LM6000	Jun-01	11	840	292	93.3		NG
Westinghouse 501AA	Jun-01	6	840	814	90		NG
P&W FT8 Twin Pac (2 CT/Unit)	Jun-01	2	804	471	87.5		NG
Westinghouse 501F	Jun-01	2	623	1098	90		NG/Oil
GE LM6000	Jun-01	3	858	292	90		NG
P&W FT8 Twin Pac(2 CTs/Unit)	Jun-01	1	750	390	80		NG
P&W FT8 Twin Pac(2 CTs/Unit)	Jun-01	1	750	390	80		NG
P&W FT8 Twin Pac(2 CTs/Unit)	Jun-01	1	750	390	80		NG
P&W FT8 Twin Pac(2 CTs/Unit)	Jun-01	2	750	390	80		NG
P&W FT8 Twin Pac(2 CTs/Unit)	Jun-01	1	750	390	80		NG
P&W FT8 Twin Pac(2 CTs/Unit)	Jun-01	1	750	390	80		NG
P&W FT8	Jun-01	4	898	214	90		NG
GE LM1500	Jun-01	1	850	114			NG/Oil
Siemens V84.3A	Jun-01	1	735	1047	51.5		NG
Boiler	Jul-01	2	730	509	95		NG
GE LM6000	Aug-01	2	750	342	92		NG
Mitsubishi 501G	Aug-01	4	711	1454	86.6		NG
Mitsubishi 501G	Aug-01	2	711	1454	86.6		NG

Oxidation Catalyst Experience
Power Generation

Application	Startup	# of Units	Temp °F	Flow (#/s)	% CO Conversion	% VOC Conversion	Fuel
ABB GT24	Sep-01	2	633	910	83.8		NG
GE LM6000 Sprint	Sep-01	5	853	292	90		NG
GE LM2500 (2 CTs/Unit)	Sep-01	4	840	376	90		NG/#2 Oil
GE LM6000	Sep-01	6	840	292	90		NG
GE 10	Sep-01	4	860	111	80		NG
Solar Mars	Sep-01	1	860	100	90		NG
Solar Taurus 70	Sep-01	1	971	56	60		NG
ABB GT24	Oct-01	2	653	938	80		NG/Distilate Oil
GE LM6000	Oct-01	4	840	278	82.1		NG
GE LM6000	Oct-01	1	750	342	92	30	NG
ABB GT24	Oct-01	4	626	902	90.1		NG
GE 10	Oct-01	8	850	110	82.6		NG
LP Boiler	Nov-01	2	672	65	80		NG
HP Boiler	Nov-01	1	800	64	80		NG
ABB GT24	Nov-01	2	626	896	80.3		NG
ABB GT10	Nov-01	1	739	189	96.9		NG/Oil
GE 7FA	Nov-01	3	656	1103	73.3	25	NG
GE LM6000	Nov-01	1	750	342	92	30	NG
	Nov-01	1	790	580	80		NG
Solar Taurus 60	Nov-01	1	904	51	92		NG
GE LM6000	Dec-01	4	858	312	90		NG
GE LM6000	Dec-01	1	739	263	96		NG
GE 7FA	Dec-01	2	664	1072	73.9		NG
Boiler	Dec-01	4	800	101	90		NG/Refinery Gas
Solar Taurus 60	Dec-01	2	729	50	80		NG
GE LM6000	Dec-01	2	569	266	75		NG
GE LM6000	Jan-02	3	750	342	92		NG
GE LM6000	Jan-02	1	750	342	92		NG
GE 7FA	Jan-02	1	654	1003	63.9		NG
GE 7FA	Jan-02	2	665	972	77.3		NG
GE 7FA	Jan-02	2	662	1039	76.6		NG
	Jan-02	4	856	327	0		NG
GE LM6000	Feb-02	1	750	342	92		NG
GE 7FA	Feb-02	4	674	1078	84.4		NG
GE LM6000	Mar-02	12	842	329	90		NG/Oil
GE LM6000	Mar-02	8	842	329	90		NG/Oil
GE LM6000	Mar-02	10	842	329	90		NG/Oil
	Mar-02	2	669	1018	65.7		NG
GE LM6000	Mar-02	4	885	313	90		NG
Siemens Westinghouse 501F	Apr-02	3	667	1308	76		NG
GE 7FA	Apr-02	1	921	1036	71.6		NG
	Apr-02	2	669	1018	65.7		NG
GE 7FA	May-02	1	644	1013	86.8		NG
GE 7FA	Jun-02	8	670	1060	80		NG
GE 7FA	Jun-02	2	661	1050	90		NG
Siemens Westinghouse 501G	Jun-02	2	682	1468	77.5		NG
Westinghouse 501F	Jun-02	2	690	1005	85		NG
Westinghouse 501F	Jun-02	2	690	1005	85		NG
GE 7FA	Jul-02	2	649	934	80	50	NG
	Jul-02	2	675	1111	86.1		NG
Siemens Westinghouse 501F	Aug-02	2	667	1101	65.8		NG
	Aug-02	1	1018	297	88.9		NG
	Aug-02	2	675	1111	84.1		NG
Mitsubishi 501G	Jan-03	3	961	1346	71.2		NG
Siemens Westinghouse 501F	Jan-03	2	647	1033	90		NG

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Oxidation Catalyst Experience
Power Generation

Application	Startup	# of Units	Temp °F	Flow (#/s)	% CO Conversion	% VOC Conversion	Fuel
GE 7FA	Apr-03	1	779	914	80		NG
GE 7FA	May-03	4	683	1040	81.9		NG
GE 7FB	May-03	3	637	1061	80.5		NG
GE 7FA	Oct-03	3	645	1049	48.5		NG/Oil
Siemens Westinghouse 501F	Dec-03	2	696	1004	75		NG
	Total Units	**404**					

Exhibit 21

The Use of Oxidation Catalysts for Controlling Emissions from Gas Turbines: A Historical Perspective with a View Towards the Future

Engelhard Corporation

Mike Durilla, Fred Booth, Ken Burns, William Hizny

POWER-GEN International 2001

December 12, 2001

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Change the nature of things.

PRESENTATION OUTLINE

- Overview
- The Technology
- The Market
- Future Projections
- Summary

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OVERVIEW

- An oxidation catalyst is used to reduce CO (carbon monoxide) emissions from gas turbines
  - Catalyst converts CO to harmless CO_2 (carbon dioxide)
- Since 1986, there are over 277 operating installations of oxidation catalyst on gas turbines
- All installations have met emissions warranties
- Virtually maintenance free
  - Catalyst service and/or replacement has not been required.
- Limited catalyst issues
  - Plugging from insulation
  - Phosphorous from gas pipeline on one installation
- Oxidation catalyst effectively reduces aldehyde (formaldehyde) emissions, which may be a future issue

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THE TECHNOLOGY

- Virtually all carbon in the fuel is combusted to CO_2
- Incomplete combustion results with some carbon going to CO
- The oxidation catalyst oxidizes the CO to CO_2

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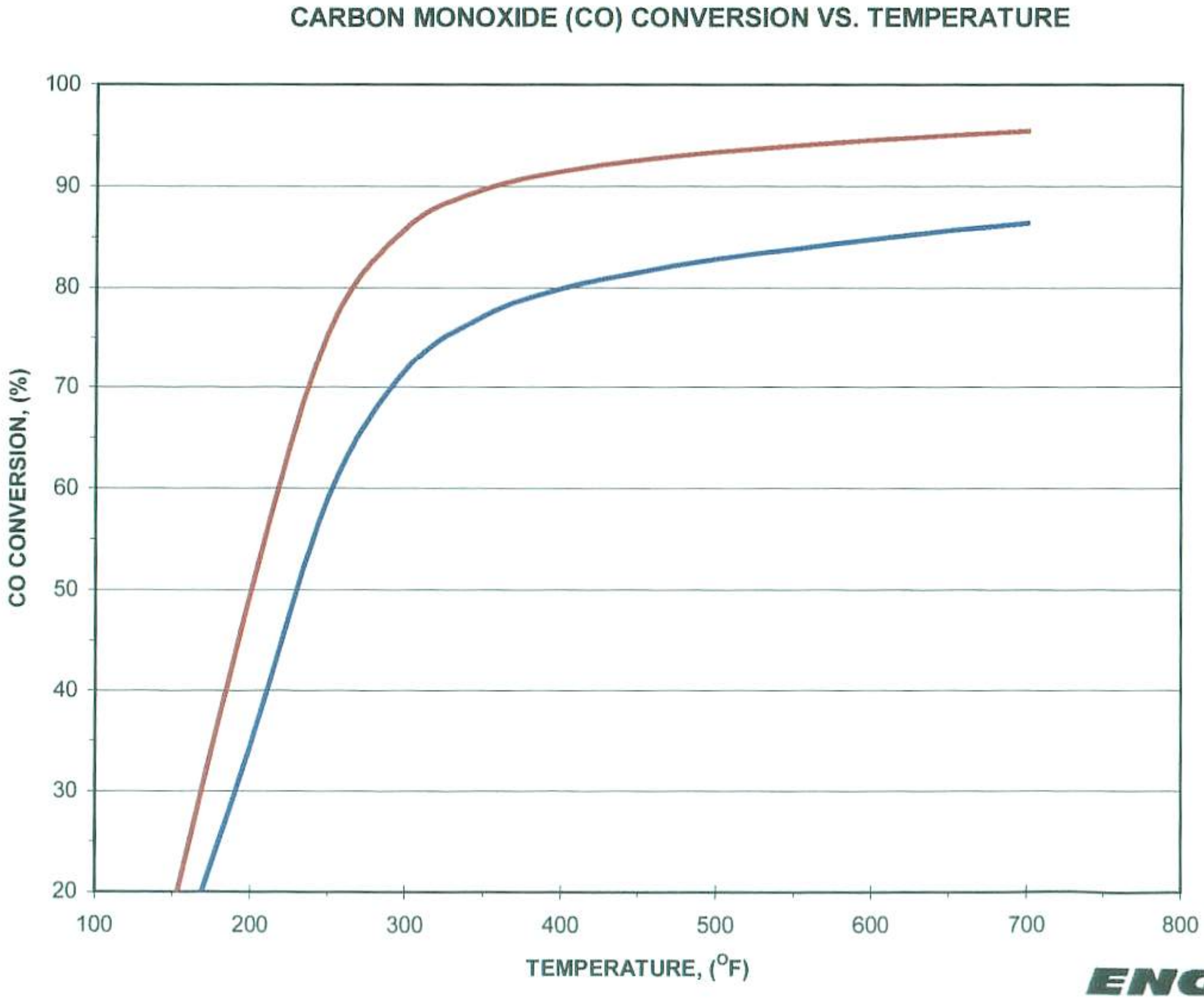
CO CONVERSION CURVE



NOTE:

CO CONVERSION REPRESENTED AT TYPICAL GAS TURBINE CONDITIONS FOR TWO DIFFERENT OXIDATION CATALYST BED DESIGNS

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FACTORS AFFECTING CATALYST LIFE

- Thermal stability of the catalyst
  - Not an issue. Catalyst can operate at 1300°F continuously
  - Thermal degradation of catalyst has not been observed on any field installation
- Contamination or fouling of the catalyst
  - Insulation from duct liners
  - Phosphorous contamination (Corrosion inhibitor from natural gas pipeline)

DURABILITY CONCERNS WHEN THE PRODUCT WAS FIRST INTRODUCED IN THE 1980'S

- Contamination from lubricating oils
  - Specifically phosphorous
  - Proven not to be an issue
- Gas turbine steam / water injection
  - Contamination from water solids and additives
  - Proven not to be an issue
- Steam / water leaks from HRSG tubes
  - Additives in steam
  - Proven not to be an issue
- Ambient air contamination
  - Salt air (chlorine is a catalyst poison)
  - Dust particulates
  - Proven not to be an issue

UNBURNED HYDROCARBONS (UHC'S)

- Also referred to as Volatile Organic Compounds (VOC's) or Reactive Organic Compounds (ROG's)
- Many species; each with unique conversion curve
- Lighter (low carbon number) and saturated compounds are the most difficult to convert
  - Methane is the most difficult
  - Aldehydes (formaldehyde) convert as easily as CO

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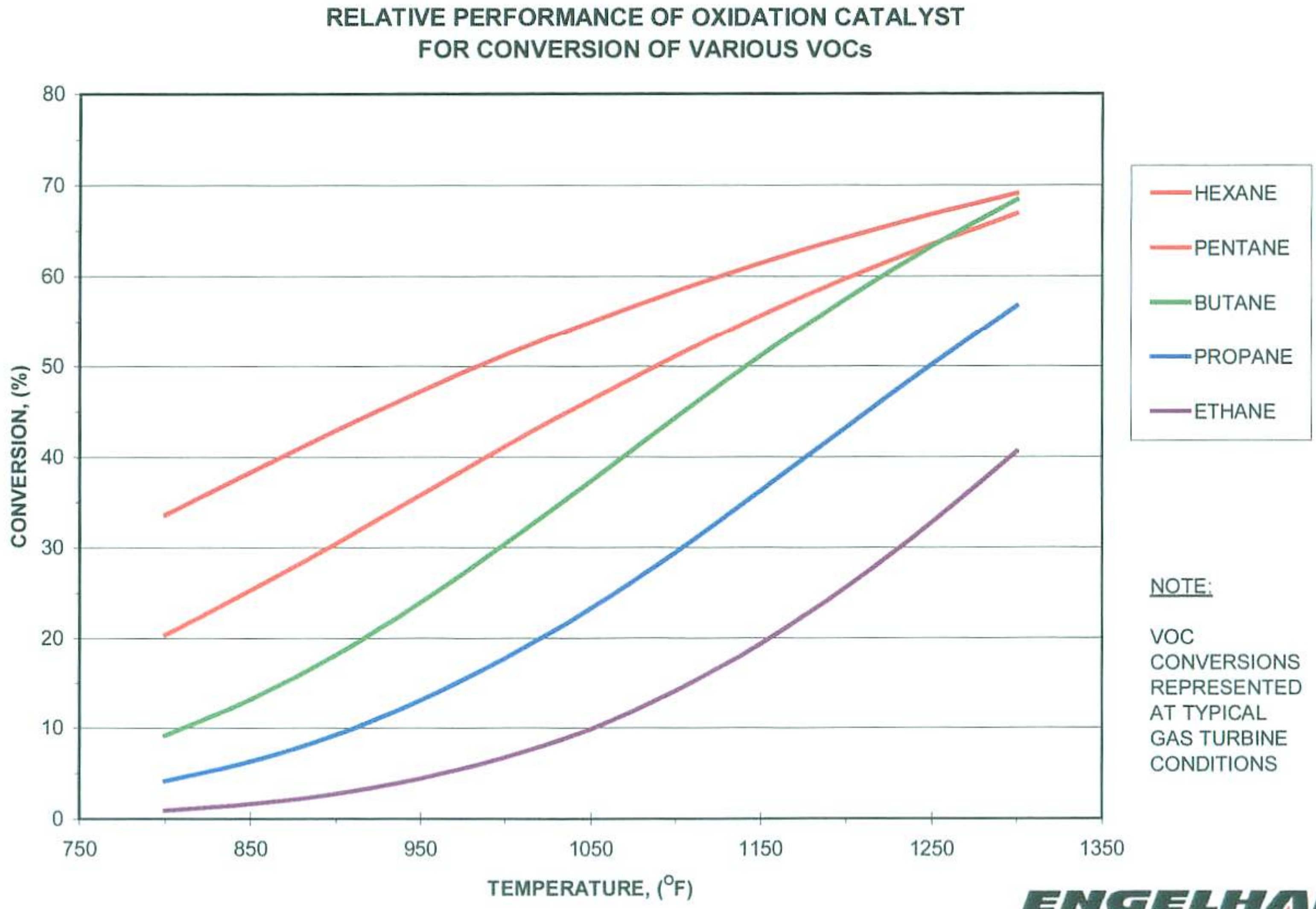
HYDROCARBON CONVERSION CURVE



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EVOLUTION OF OXIDATION CATALYST DESIGNS FOR THE GAS TURBINE MARKET

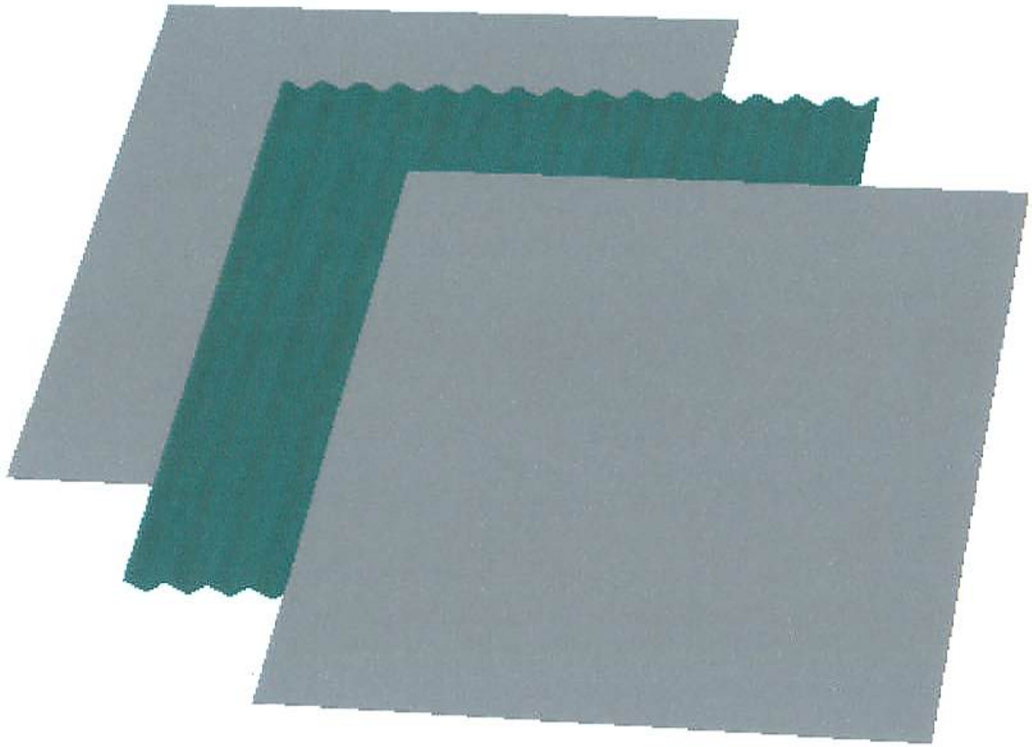
- Initially, catalyst supports were either metal or ceramic honeycombs - metal supports are used by all suppliers
- Initial designs were based almost exclusively on parallel straight channels; technology improvements have led to non-parallel channel patterns
- Catalyst formulations have been predominately precious metal, but formulations have been varied depending on:
  - Oxidation performance requirements and constraints
  - Operating temperature window

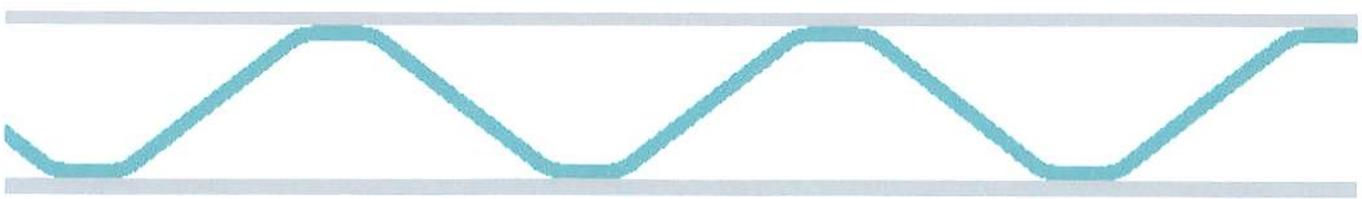
OXIDATION CATALYST SUBSTRATES: "METAL" VS "CERAMIC"

- Metal substrate
  - Lower pressure drop
  - Higher surface area
  - More variable CPSI
  - Greater substrate flexibility:
    - Straight
    - Skew
    - Herringbone
  - Greater design flexibility

- Ceramic substrate
  - Automotive catalyst derivative
  - Broad history of washing

STRAIGHT METAL FOIL SUBSTRATE





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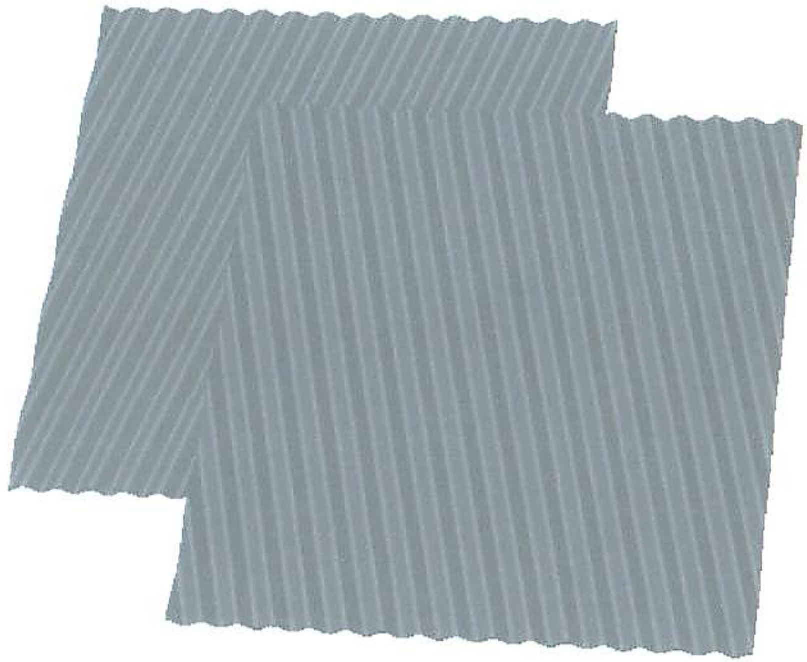
SKEW METAL FOIL SUBSTRATE



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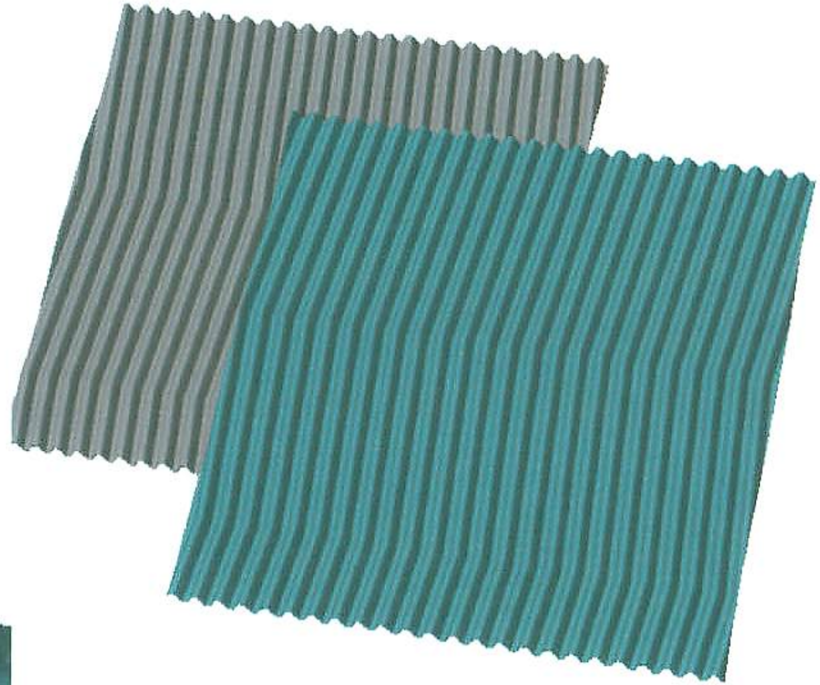
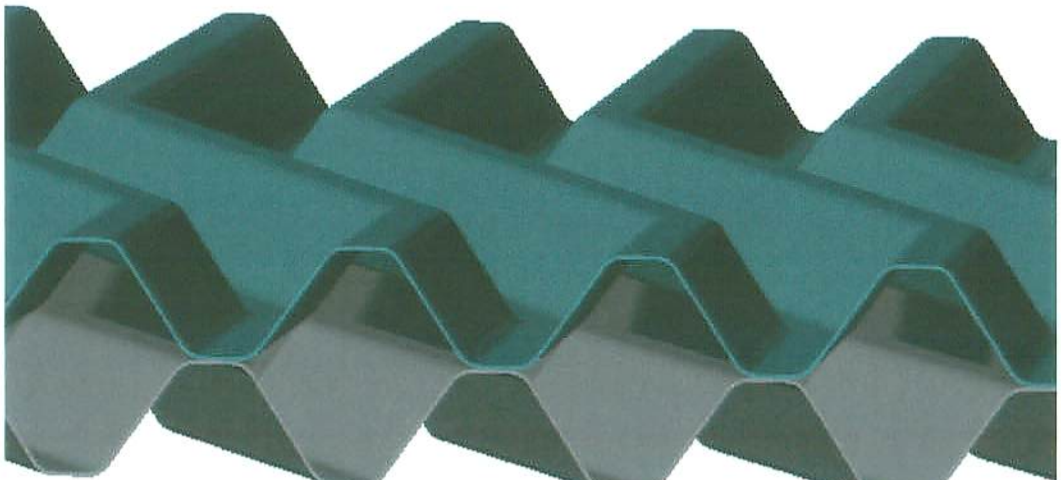
HERRINGBONE METAL FOIL SUBSTRATE





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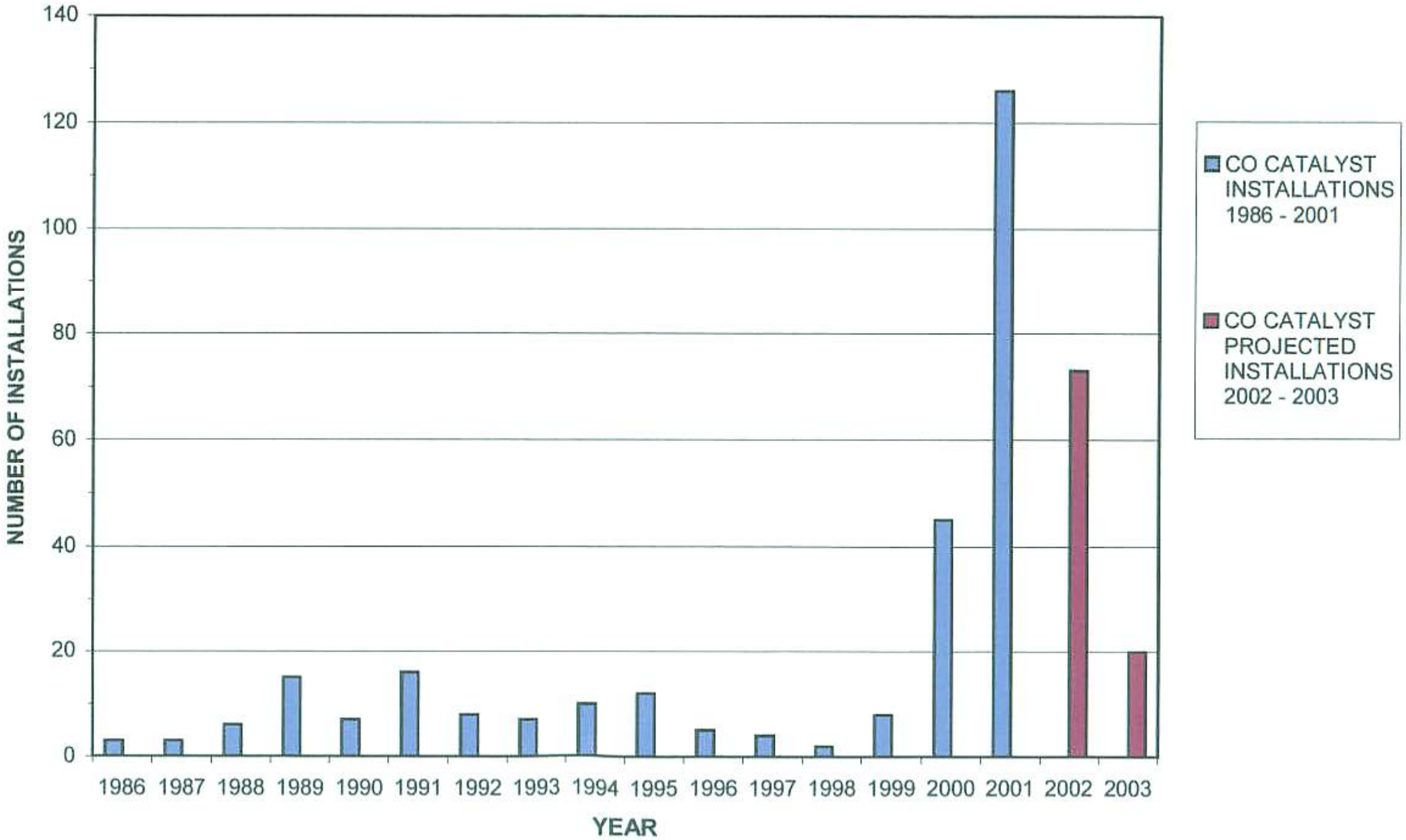
"A SUPPLIER'S PERSPECTIVE OF THE MARKET"

- 1978 Public Utilities Regulatory Act spurred the use of gas turbine cogeneration power plant installations
- California initially was the strongest market, other areas of the country have followed
- The market has expanded with increasing requirements for CO catalyst
- Applications on all size turbines (> 1 MW)
- Conversion requirements at 80% and 90%, with as high as 98%

TOTAL MARKET GROWTH:
OXIDATION CATALYST FOR THE GAS TURBINE MARKET

DISTRIBUTION OF CO CATALYST INSTALLATIONS ON GAS TURBINES OVER TIME



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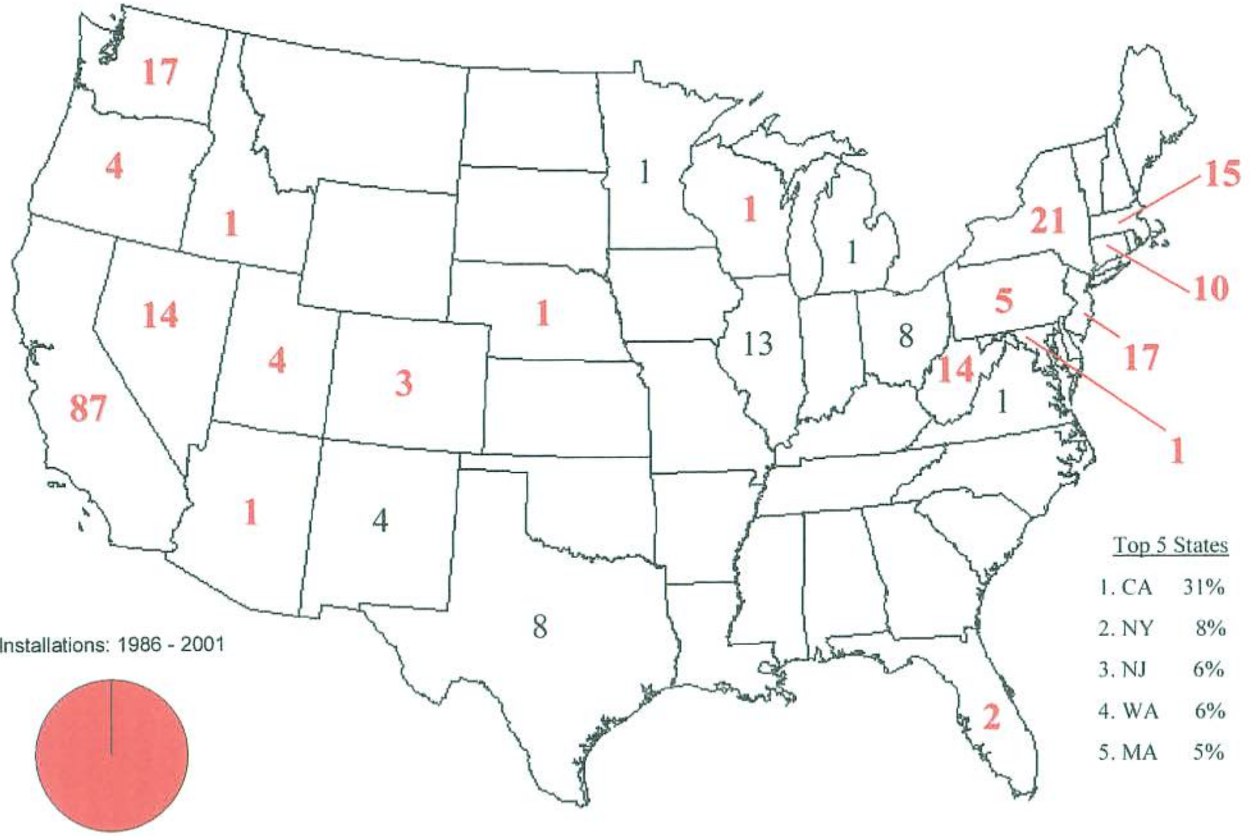
EVOLUTION OF THE U.S. MARKET: 1986 - 2001
OXIDATION CATALYST FOR THE GAS TURBINE MARKET



Top 5 States

1. CA 31%
2. NY 8%
3. NJ 6%
4. WA 6%
5. MA 5%

Installations: 1986 - 2001

1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003

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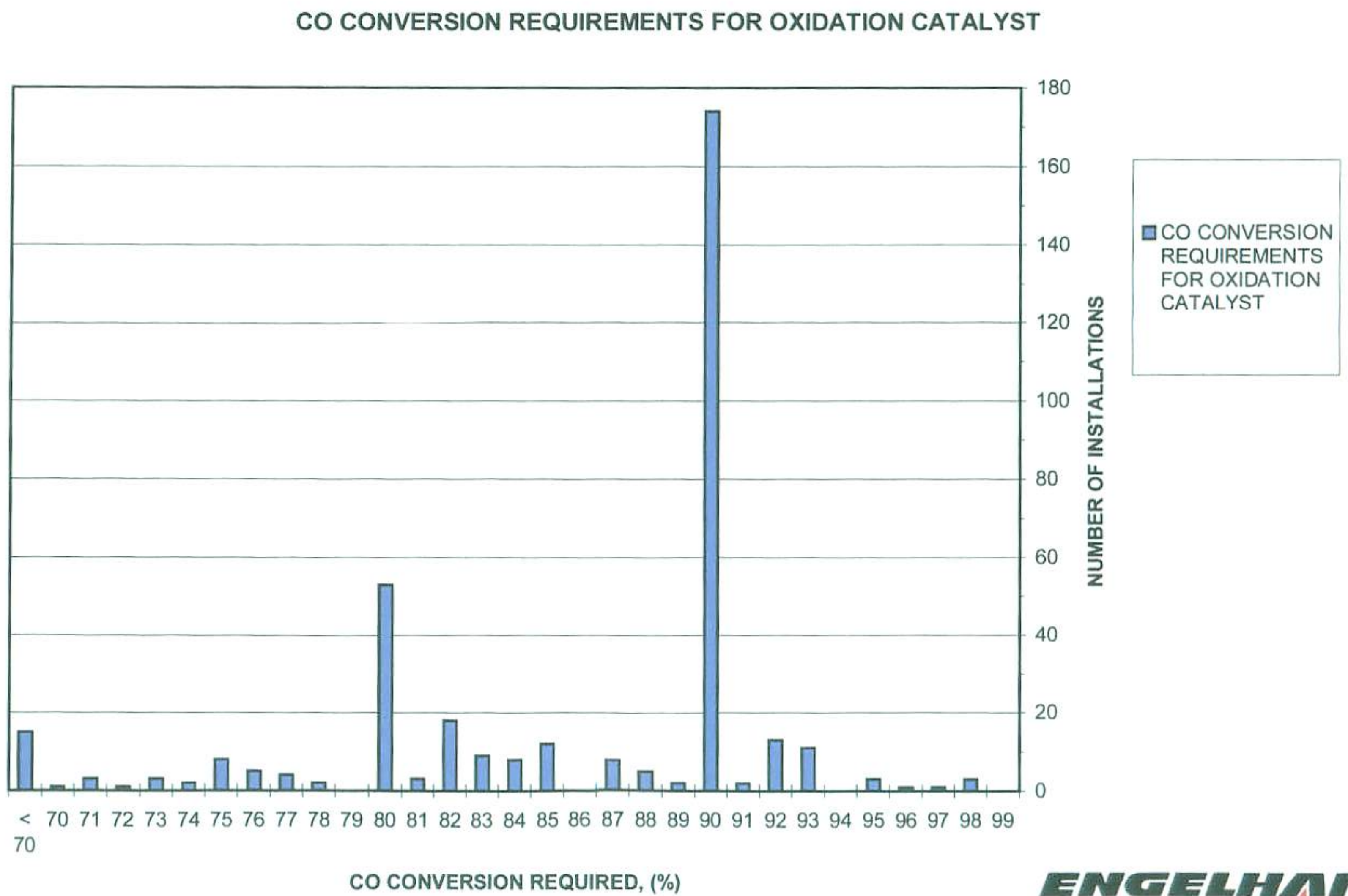
CO CONVERSION DISTRIBUTION AMONG GAS TURBINE MARKET



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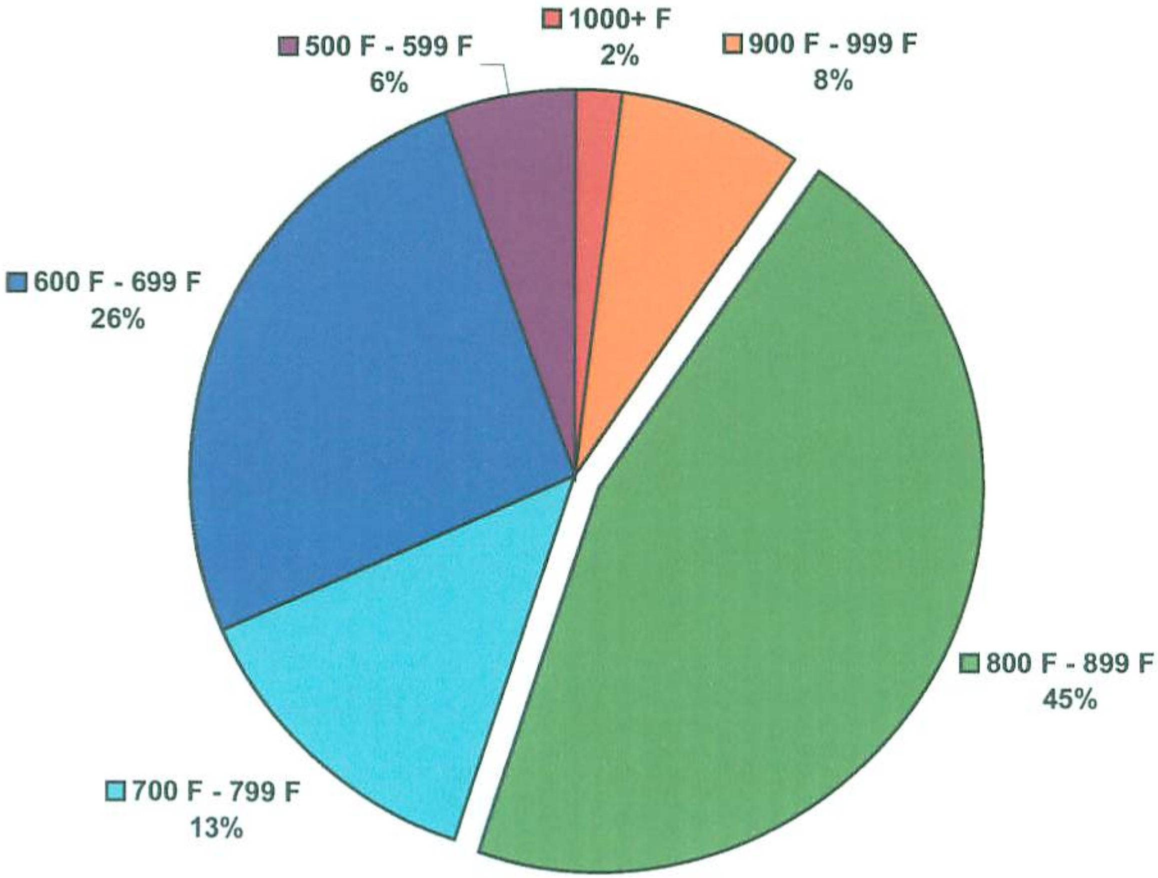
TEMPERATURE DISTRIBUTION AMONG GAS TURBINE MARKET

DISTRIBUTION OF CO CATALYST INSTALLATIONS AMONG
GAS TURBINE EXHAUST TEMPERATURES



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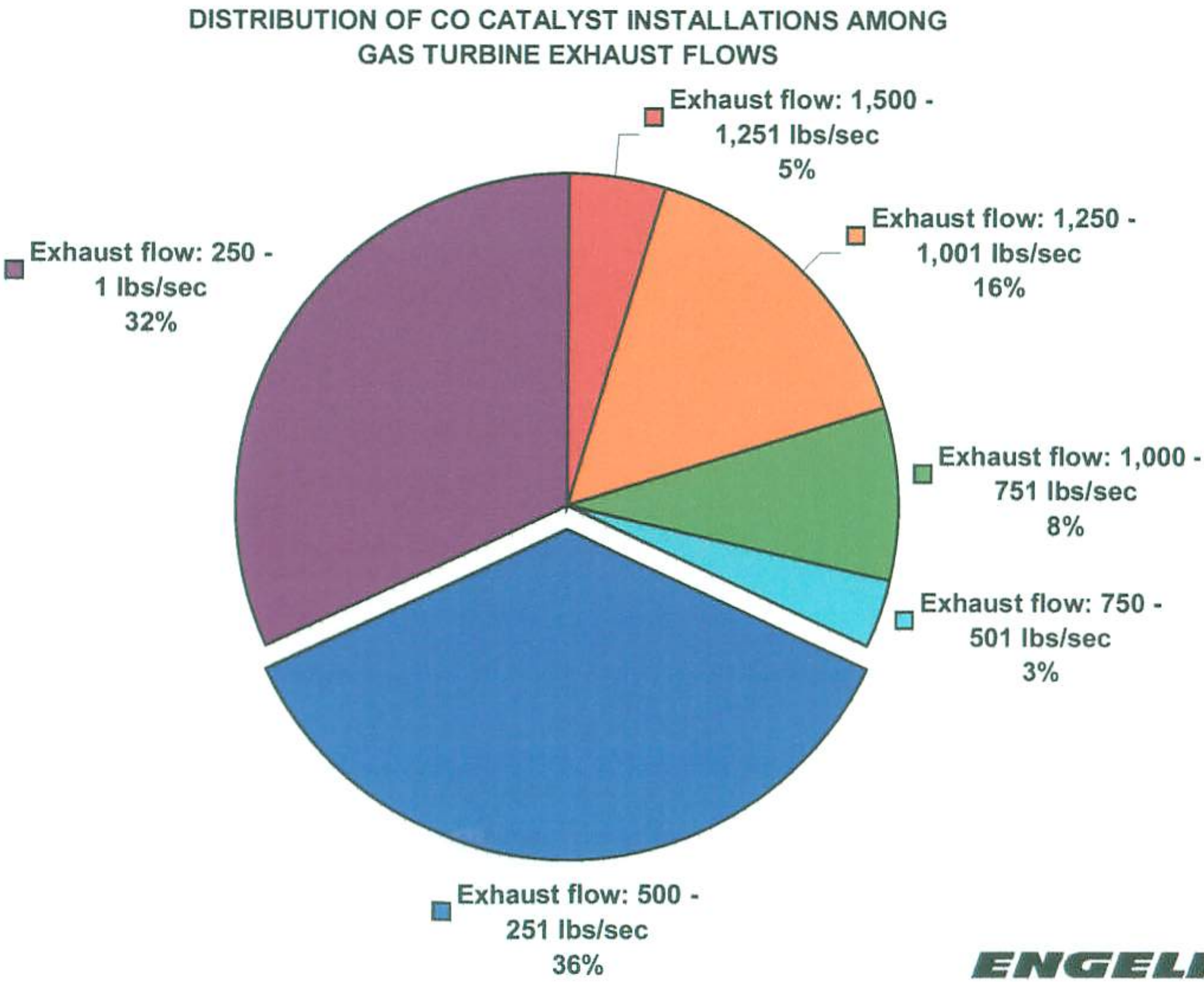
EXHAUST FLOW DISTRIBUTION AMONG GAS TURBINE MARKET



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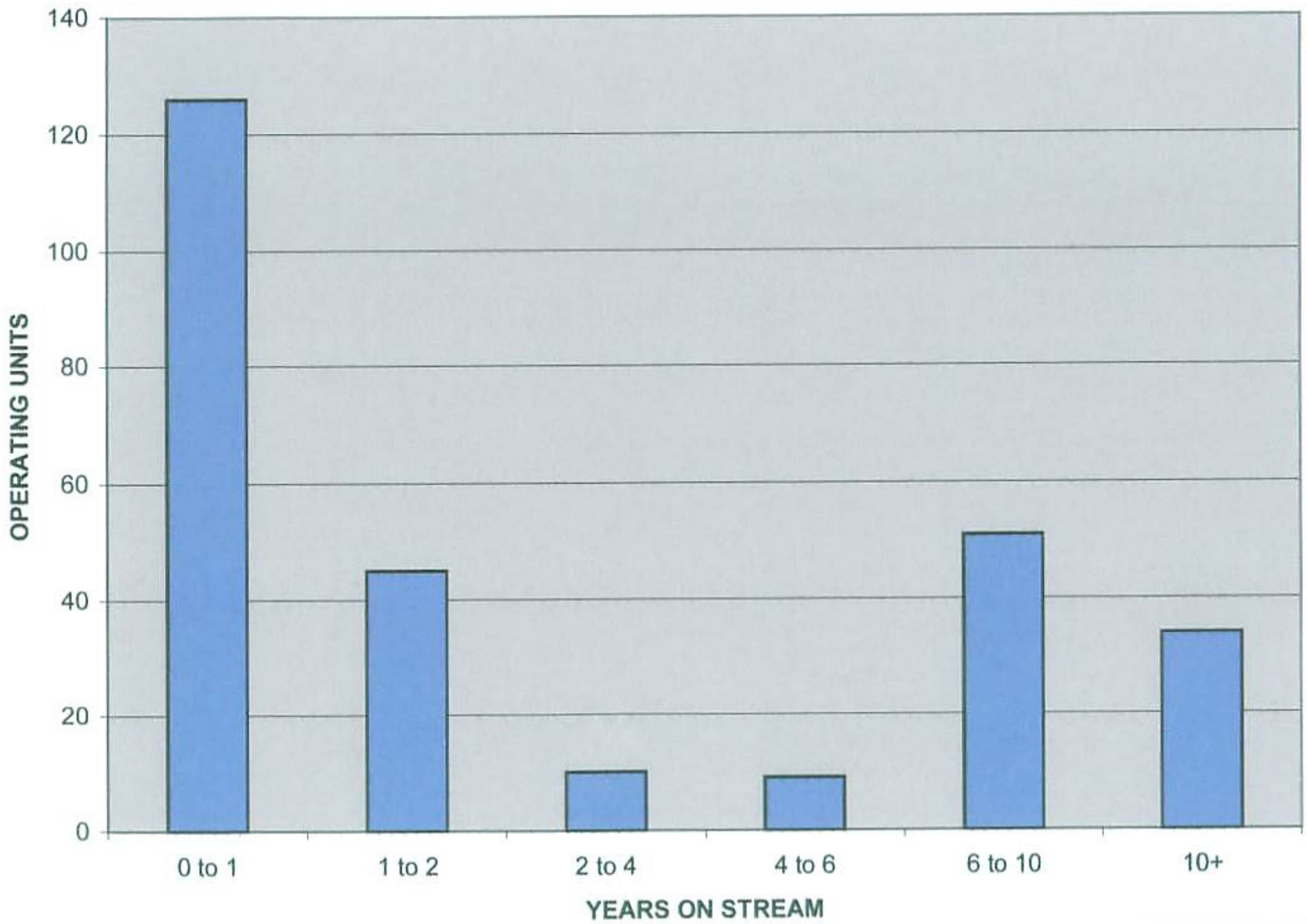
TIME ON STREAM DISTRIBUTION AMONG GAS TURBINE MARKET

Engelhard Catalysts Perform Well Beyond the Warranty



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FUTURE PROJECTIONS

- Further developments in catalyst design
  - More conversion per catalyst volume
  - More conversion per pressure drop
  - Greater conversion at lower temperatures
  - Lower cost

FUTURE PROJECTIONS, continued

- Increasing percent of turbines being installed will use CO catalyst
- Potential requirements for control of aldehyde (formaldehyde) emissions
- Use of oxidation catalyst to control ammonia slip emissions from SCR catalyst systems on HRSG applications.
- Use of oxidation catalysts in conjunction with SCR catalysts to reach lower emission limits of NOx and ammonia
  - May be more cost effective than simply enlarging the SCR

SUMMARY

- CO oxidation catalysts for gas turbines:
  - An extensively proven technology
  - Minimal field service issues (virtually maintenance free)
  - Very long catalyst life
  - Increasing market penetration
  - Potential to control aldehyde and ammonia emissions

ADDITIONAL SLIDES

SAMPLE SCR - OXIDATION CATALYST INSTALLATION

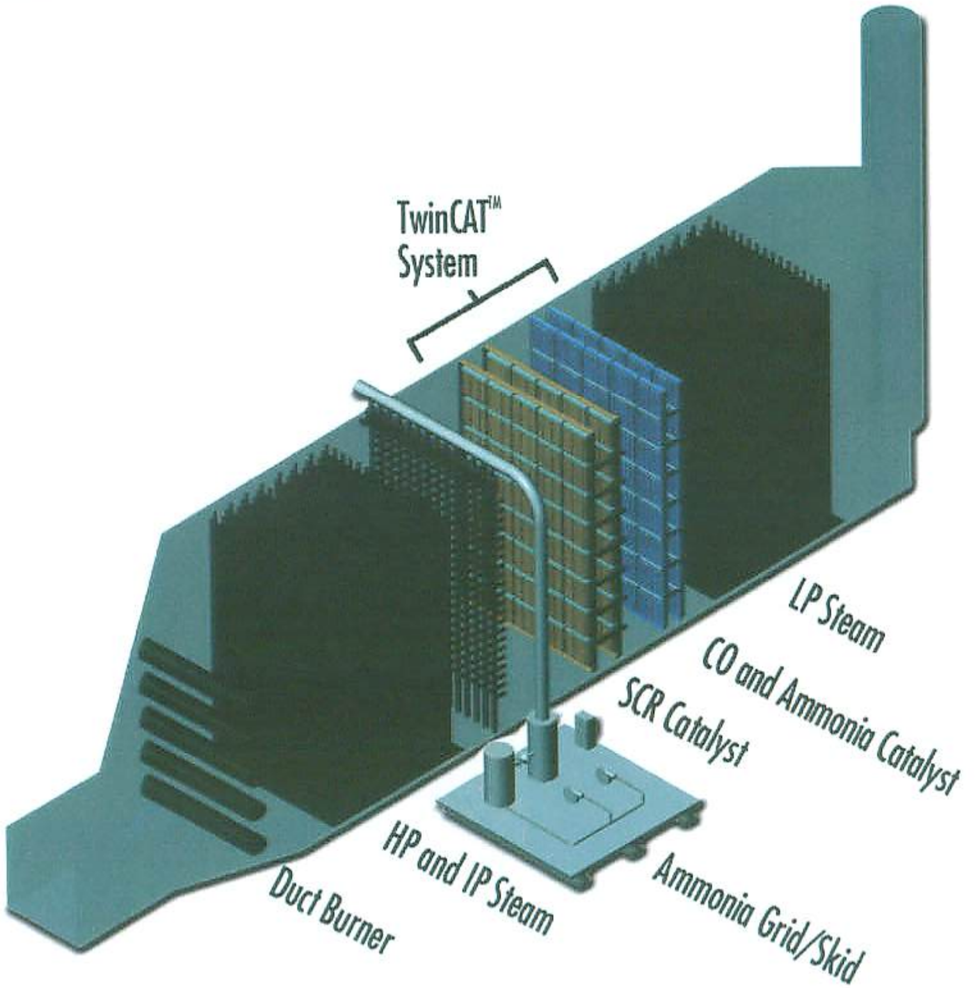

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Exhibit 22

CALIFORNIA ENERGY COMMISSION - ENERGY FACILITY STATUS

Power Plant Projects Filed Since 1996, Updated: 1/9/2009

(Note: Does not include projects filed but were withdrawn before they were approved.)

Color Key

Color	Meaning
Green	Operational Status
Yellow	Approved
Light green	In Review
Gray	On-line date is expected to be delayed beyond the date shown
Orange	Not Approved/Denied
Light cyan	Expected and disclosed
Purple	Expected but undisclosed
Pink	On hold, suspended. According to developers, the new on-line date will be determined when the markets are favorable and/or financing available.
Red	Cancelled, withdrawn, not built, license expired.

	Projects On Line (Arranged By Online Date)	**Docket Number**	**Status**	**Capacity (MW)**	**Const. Completed (%)**	**Location**	**Date Approved**	**Const. Start Date**	**Original OnLine Date**	**Current / Actual Online Date**
	Sunrise Simple Cycle - Texaco & Edison Mission E.	1998-AFC-04	Operational	320	100	Kern	12/06/2000	12/07/2000	07/01	06/27/2001
	Sutter - Calpine	1997-AFC-02	Operational	540	100	Sutter	04/14/1999	07/01/1999	07/01	07/02/2001
	Los Medanos - Calpine	1998-AFC-01	Operational	555	100	Contra Costa	08/17/1999	09/17/1999	07/01	07/09/2001
	Wildflower Larkspur - Intergen	*2001-EP-01*	*Operational*	*90*	*100*	*San Diego*	*04/04/2001*	*04/05/2001*	*07/01*	*07/16/2001*
	Wildflower Indigo - Intergen	*2001-EP-02*	*Operational*	*135*	*100*	*Riverside*	*04/04/2001*	*04/05/2001*	*07/01*	*09/10/2001*
	Drews - Alliance	*2001-EP-05*	*Operational*	*40*	*100*	*San Bernardino*	*04/25/2001*	*04/26/2001*	*09/01*	*08/15/2001*
	Hanford - GWF	*2001-EP-07*	*Operational*	*95*	*100*	*Kings*	*05/10/2001*	*05/11/2001*	*09/01*	*09/01/2001*
	Century - Alliance	*2001-EP-04*	*Operational*	*40*	*100*	*San Bernardino*	*04/25/2001*	*04/26/2001*	*09/01*	*09/15/2001*
	Escondido - Calpeak	*2001-EP-10*	*Operational*	*50*	*100*	*San Diego*	*06/06/2001*	*06/07/2001*	*09/01*	*09/30/2001*
	Border - Calpeak	*2001-EP-14*	*Operational*	*50*	*100*	*San Diego*	*07/11/2001*	*07/12/2001*	*09/01*	*10/26/2001*
			Subtotal On Line 2001	*1,914*						
	King City - Calpine	*2001-EP-06*	*Operational*	*50*	*100*	*Monterey*	*05/02/2001*	*05/03/2001*	*09/01*	*01/14/2002*
	Gilroy I - Calpine	*2001-EP-08*	*Operational*	*135*	*100*	*Santa Clara*	*05/21/2001*	*05/22/2001*	*09/01*	*02/20/2002*
	Delta - Calpine	1998-AFC-03	Operational	887	100	Contra Costa	02/09/2000	04/01/2000	07/02	05/10/2002
	Henrietta Peaker - GWF	2001-AFC-18	Operational	96	100	Kings	03/05/2002	03/08/2002	06/02	07/01/2002
	Moss Landing - L.S. Power	1999-AFC-04	Operational	1,060	100	Monterey	10/25/2000	11/28/2000	06/02	07/11/2002
1a	Huntington Beach Unit 3 - AES	2000-AFC-13	Operational	225	100	Orange	05/10/2001	05/31/2001	11/01	07/31/2002
2a	Valero Cogen - Valero	2001-AFC-05	Operational	51	100	Solano	10/31/2001	11/05/2001	06/02	10/18/2002
			Subtotal On Line 2002	*2,504*						
	La Paloma - Complete Energy Holdings	1998-AFC-02	Operational	1,124	100	Kern	10/06/1999	01/01/2000	03/02	03/07/2003
	Los Esteros Simple Cycle - Calpine	2001-AFC-12	Operational	180	100	Santa Clara	02/07/2002	07/08/2002	05/03	03/07/2003
	Los Esteros Simple Cycle recertification - Calpine	2003-AFC-02	Operational	0	100	Santa Clara	03/16/2005	07/08/2002	05/03	03/07/2003
	High Desert - Constellation	1997-AFC-01	Operational	830	100	San Bernardino	05/03/2000	05/01/2001	07/03	04/22/2003
	Tracy Peaker - GWF	2001-AFC-16	Operational	169	100	San Joaquin	07/17/2002	07/22/2002	04/03	06/01/2003
	Sunrise Comb. Cycle Amendment - Texaco & Edison Mission E.	1998-AFC-04C	Operational	265	100	Kern	11/19/2001	12/21/2001	06/03	06/01/2003
	Woodland II - Modesto Irrigation District	2001-SPPE-01	Operational	80	100	Stanislaus	09/19/2001	02/21/2002	05/03	06/06/2003
	Blythe I - FPL	1999-AFC-08	Operational	520	100	Riverside	03/21/2001	04/27/2001	04/03	07/15/2003
	Elk Hills - Sempra & Oxy	1999-AFC-01	Operational	500	100	Kern	12/06/2000	06/08/2001	12/02	07/24/2003
1b	Huntington Beach Unit 4 - AES	2000-AFC-13	Operational	225	100	Orange	05/10/2001	05/31/2001	11/01	08/07/2003
			Subtotal On Line 2003	*3,893*						
	Donald Von Raesfeld Power Plant (Pico) - Silicon Valley Power	2002-AFC-03	Operational	147	100	Santa Clara	09/09/2003	09/10/2003	12/04	03/24/2005
	Pastoria - Calpine	1999-AFC-07	Operational	750	100	Kern	12/20/2000	10/03/2001	01/03	07/05/2005
	Metcalf - Calpine	1999-AFC-03	Operational	600	100	Santa Clara	09/24/2001	01/15/2002	07/03	05/27/2005
	Kings River - Kings River Cons. Dist.	2003-SPPE-02	Operational	97	100	Fresno	05/19/2004	11/01/2004	05/05	09/19/2005
	Magnolia - So. Ca. Power Producers	2001-AFC-06	Operational	328	100	Los Angeles	03/05/2003	07/21/2003	05/05	09/22/2005
	Malburg - City of Vernon	2001-AFC-25	Operational	134	100	Los Angeles	05/20/2003	09/11/2003	11/05	10/17/2005
3a	Mountainview Unit 3 - SCE	2000-AFC-02	Operational	528	100	San Bernardino	03/21/2001	09/01/2001	06/03	12/09/2005
			Subtotal On Line 2005	*2,584*						
3b	Mountainview Unit 4 - SCE	2000-AFC-02	Operational	528	100	San Bernardino	03/21/2001	09/01/2001	06/03	01/19/2006
	Cosumnes - SMUD	2001-AFC-19	Operational	500	100	Sacramento	09/09/2003	10/31/2003	06/05	02/24/2006
	Walnut - Turlock Irr. Dist.	2002-AFC-04	Operational	250	100	Stanislaus	02/18/2004	03/15/2004	04/06	02/28/2006
	Palomar Escondido - SDG&E	2001-AFC-24	Operational	546	100	San Diego	08/06/2003	06/01/2004	03/06	04/01/2006
	Riverside En. Res. Cntr. Units 1 & 2 - City of Riverside	2004-SPPE-01	Operational	96	100	Riverside	12/15/2004	02/23/2005	11/05	06/01/2006
	Ripon - Modesto Irrigation Dist	2003-SPPE-01	Operational	95	100	San Joaquin	02/04/2004	04/01/2005	04/05	06/21/2006
			Subtotal On Line 2006	*2,015*						
	Bottle Rock Geothermal Restart	1979-AFC-4C	Operational	17	100	Lake	12/13/2006	12/19/2006	06/07	10/01/2007
	Roseville Combined Cycle - Roseville Electric	2003-AFC-01	Operational	160	100	Placer	04/13/2005	08/18/2005	12/07	11/07/2007
			Subtotal On Line 2007	*177*						
	Niland Peaker - IID	2006-SPPE-1	Operational	93	100	Imperial	10/11/2006	6/25/2007	06/08	05/29/2008
			Subtotal On Line 2008	*93*						
			ON-LINE TOTAL	**13,180**						

	Approved / Under Construction (Arranged By Online Date)	**Docket Number**	**Status**	**Capacity (MW)**	**Const. Completed (%)**	**Location**	**Date Approved**	**Const. Start Date**	**Original OnLine Date**	**Current / Actual Online Date**
1	Inland Empire - GE	2001-AFC-17	Under Construction	800	**92** Unit 2 delayed	Riverside	12/17/2003	8/26/2005	12/05	unit 1: **1/09** unit 2: 7/09

CALIFORNIA ENERGY COMMISSION - ENERGY FACILITY STATUS

Power Plant Projects Filed Since 1996, Updated: 1/9/2009

(Note: Does not include projects filed but were withdrawn before they were approved.)

Color Key

Operational Status	Expected and disclosed
Approved	Expected but undisclosed
In Review	On hold, suspended. According to developers, the new on-line date
On-line date is expected to be delayed beyond the date shown	will be determined when the markets are favorable and/or financing available.
Not Approved/Denied	Cancelled, withdrawn, not built, license expired.

2	Gateway - PG&E	2000-AFC-01	Under Construction	530	96	Contra Costa	5/30/2001	8/30/2001 Resumed: 2/2007	08/03	**3/2009**
3	Starwood Midway - Starwood Power	2006-AFC-10	Under Construction	120	**30**	Fresno	1/16/2008	9/23/2008	06/09	05/09
4	EIF Panoche - Energy Investors Fund	2006-AFC-5	Under Construction	400	64	Fresno	12/19/2007	2/15/2008	11/09	08/09
5	Otay Mesa - Calpine	1999-AFC-05	Under Construction	590	74	San Diego	4/18/2001	5/01/2007	07/03	10/09
6	Humboldt Power Plant - PG&E	2006-AFC-7	Under Construction	163	4	Humboldt	9/24/2008	10/11/2008	09/09	04/10
7	Colusa Generation Station - PG&E	2006-AFC-9	Under Construction	660	**10**	Colusa	4/23/2008	7/28/2008	06/10	10/10
			Under Construction Subtotal	***3,263***						

	Approved / Not Under Construction (Arranged By Online Date)	**Docket Number**	**Status**	**Capacity (MW)**	**Const. Completed (%)**	**Location**	**Date Approved**	**Const. Start Date**	**Original OnLine Date**	**Current / Actual Online Date**
	Blythe I Transmission Line - FPL	1999-AFC-8C	**Pre-Construction**	0	0	Riverside	10/11/2006	2/09	06/07	**2010**
	Victorville Hybrid Gas-Solar - City of Victorville	2007-AFC-1	**Pre-Construction**	563	0	San Bernardino	7/16/2008	4/09	8/10	**10/10**
	Russell City - Calpine & GE	2001-AFC-07	On Hold	600	0	Alameda	10/03/2007	9/09	12/04	06/12
	El Centro Unit 3 Repower - IID	2006-SPPE-2	On Hold	85	0	Imperial	01/03/2007	On Hold	05/09	On Hold
	Morro Bay - L.S. Power	2000-AFC-12	On Hold	1,200	0	San Luis Obispo	08/02/2004 Note: Commis-sion decision not finalized pending NPDS permit	On Hold	On Hold	On Hold
	Tesla - FPL	2001-AFC-21	On Hold	1,120	0	Alameda	06/16/2004	On Hold	On Hold	On Hold
	El Segundo Repower - NRG	2000-AFC-14	On Hold	630	0	Los Angeles	02/02/2005	On Hold Pending Dry Coooling Amendment	On Hold	On Hold
	Los Esteros Combined Cycle - Calpine	2003-AFC-02	On Hold	140	0	Santa Clara	10/11/2006	On Holdt	On Hold	On Hold
	Pastoria Simple Cycle Addition - Calpine	2005-AFC-1	On Hold	160		Kern	12/18/2006	On Hold	06/07	On Hold
	Walnut Creek Peaker - Edison Mission E.	2005-AFC-02	On Hold	500	0	Los Angeles	02/27/2008	9/09	On Hold	On Hold
	San Joaquin Valley - Calpine	2001-AFC-22	On Hold	1,087	0	Fresno	01/14/2004	On Hold	01/06	On Hold
	East Altamont - Calpine	2001-AFC-04	On Hold	1,100	0	Alameda	08/20/2003	8/11	07/05	On Hold
	Salton Sea - Cal Energy	2002-AFC-02	On Hold	215	0	Imperial	12/17/2003	On Hold	01/06	On Hold
	SF Reliability Project - CCSF	2004-AFC-01	On Hold	145	0	San Francisco	10/03/2006	On Hold	06/06	On Hold
	Blythe II - Caithness	2002-AFC-01	On Hold	520	0	Riverside	12/14/2005	On Hold	On Hold	On Hold
			Approved and available for construction.	**8,065**						
A	Three Mountain - Covanta	1999-AFC-02	Not Built and License Expired	500	0	Shasta	05/16/2001	On Hold	12/03	Not Built and License Expired
B	Western Midway Sunset - Edison Mission Energy	1999-AFC-09	Not Built and License Expired	500	0	Kern	03/21/2001	On Hold	07/03	Not Built and License Expired
C	United Golden Gate - El Paso	2000-AFC-05	Not Built and License Expired	51	0	San Mateo	03/07/2001	On Hold	07/01	Not Built and License Expired
D	*Pegasus Energy - Delta Power*	*2001-EP-09*	*Cancelled*	*181*	*0*	*San Bernardino*	*06/06/2001*	*Cancelled*	*Cancelled*	*Cancelled*
E	*Chula Vista 2 - Ramco*	*2001-EP-03*	*Cancelled*	*62*	*0*	*San Diego*	*06/13/2001*	*Cancelled*	*Cancelled*	*Cancelled*
F	Hanford Energy Park - GWF	2000-SPPE-01	Cancelled	99	0	Kings	04/11/2001	Cancelled	Cancelled	Cancelled
G	Valero Cogen - Valero	2001-AFC-05	Not Built and License Expired	51	37	Solano	10/31/2001	02/01/2007	12/02	Not Built and License Expired
			Total Cancelled or License Expired	**1,444**						
			Not Under Construction Subtotal	*9,509*						

APPROVED TOTAL 25,952

Projects Not Approved (Arranged By Decision Date)	**Docket Number**	**Process**	**Capacity (MW)**	**Project Type**	**Location**	**Date Filed**	**Decision Date**		

CALIFORNIA ENERGY COMMISSION - ENERGY FACILITY STATUS

Power Plant Projects Filed Since 1996, Updated: 1/9/2009

(Note: Does not include projects filed but were withdrawn before they were approved.)

Color Key

Operational Status	Expected and disclosed
Approved	Expected but undisclosed
In Review	On hold, suspended. According to developers, the new on-line date will be determined when the markets are favorable and/or financing available.
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Not Approved/Denied	Cancelled, withdrawn, not built, license expired.

Eastshore - Tierra Energy	**2006-AFC-6**	**12-mo AFC**	**116**	**Brownfield**	**Alameda**	**09/22/2006**	**10/08/2008**		

NOT APPROVED TOTAL 116

	Projects In Review (Arranged By Estimated Decision Date)	Docket Number	Process	Capacity (MW)	Project Type	Location	Date Filed	Estimated Decision Date		Estimated On-line Date
1	El Segundo Amendment - NRG	2000-AFC-14C	Dry Cooling Amendment	[See 00-AFC-14]	Replacement	Los Angeles	6/19/2007	1/09		06/10
2	Orange Grove AFC - J Power USA	2008-AFC-4	12-mo AFC	96	Greenfield	San Diego	6/20/2008	1/09		Unknown
3	Riverside En. Res. Cntr. Units 3 & 4 - City of Riverside	2008-SPPE-1	SPPE	96	Expansion	Riverside	3/19/2008	1/09		12/09
4	Sentinel Peaker - CPV	2007-AFC-3	12-mo AFC	850	Greenfield	Riverside	6/26/2007	1/09		05/10
5	MMC Chula Vista Replacement - MMC Energy, Inc.	2007-AFC-4	12-mo AFC	100	Replacement	San Diego	8/10/2007	2/09		12/09
6	Carlsbad - NRG	2007-AFC-6	12-mo AFC	558	Brownfield	San Diego	9/14/2007	3/09		07/10
7	San Gabriel - Reliant	2007-AFC-2	12-mo AFC	656	Expansion	San Bernardino	4/13/2007	3/09		Unknown
8	Highgrove Peaker - AES	2006-AFC-2	12-mo AFC	300	Expansion	San Bernardino	5/25/2006	4/09		Unknown
9	Sun Valley Peaker - Edison Mission	2005-AFC-03	12-mo AFC	500	Greenfield	Riverside	12/01/2005	4/09		Unknown
10	Southeast Region Energy Project formerly Vernon - City of Vernon	2006-AFC-4	12-mo AFC	943	Brownfield	Los Angeles	6/30/2006	4/09		Unknown
11	Community Power Plant - Kings River Conservation Dist.	2007-AFC-7	12-mo AFC	565	Greenfield	Fresno	9/27/2007	4/09		06/11
12	Carrizo Solar Farm - Ausra	2007-AFC-8	12-mo AFC	177	Greenfield	San Luis Obispo	10/25/2007	4/09		05/10
13	Canyon Power Plant - City of Anaheim	2007-AFC-9	12-mo AFC	200	Brownfield	Orange	12/28/2007	4/09		06/10
14	Ivanpah Solar - Brightsource	2007-AFC-5	12-mo AFC	400	Greenfield	San Bernardino	8/30/2007	5/09		02/11
15	Avenal Energy - Avenal Power Center, LLC	2008-AFC-1	12-mo AFC	600	Greenfield	Kings	2/21/2008	5/09		Unknown
16	Beacon Solar Energy Project - Beacon Solar LLC	2008-AFC-2	12-mo AFC	250	Greenfield	Kern	3/14/2008	5/09		10/11
17	SES Solar Two - SES Solar Two LLC/Stirling Energy	2008-AFC-5	12-mo AFC	750	Greenfield	Imperial	6/30/2008	6/09		Unknown
18	Tracy Combined Cycle - GWF	2008-AFC-7	12-mo AFC	169	Expansion	San Joaquin	7/18/2008	9/09		3/11
19	Marsh Landing Generating Station	2008-AFC-3	12-mo AFC	930	Brownfield	Contra Costa	5/30/2008	10/09		Unknown
20	Willow Pass - Mirant	2008-AFC-6	12-mo AFC	550	Brownfield	Contra Costa	6/30/2008	10/09		7/12
21	Hybrid Gas-solar - City of Palmdale	2008-AFC-9	12-mo AFC	617	Greenfield	Los Angeles	8/4/2008	10/09		2013
22	Lodi Energy Center - NCPA	2008-AFC-10	12-mo AFC	255	Brownfield	San Joaquin	9/10/2008	11/09		2012
23	Hanford Combined-Cycle Power Plant (Hanford Energy Peaker Project Expansion) - GWF Energy LLC	01-EP-7C	Major Amendment	55	Expansion Amendment	Kings	10/1/2008	10/09		?
24	CPV Vaca-Station - Competitive Power Ventures Inc.	2008-AFC-11	12-mo AFC	660	Greenfield	Solano	11/18/2008	11/09		?
25	San Joaquin Solar 1 & 2 (solar thermal & biomass hybrid) - San Joaquin Solar	2008-AFC-12	12-mo AFC	106.8	Greenfield	Fresno	11/26/2008	12/09		5/2011
26	SES Solar One - SES Solar One LLC/Stirling Energy	2008-AFC-13	12-mo AFC	850	Greenfield	San Bernardino	12/2/2008	12/09		2014

CALIFORNIA ENERGY COMMISSION - ENERGY FACILITY STATUS

Power Plant Projects Filed Since 1996, Updated: 1/9/2009

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Color Key

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	Approved		Expected but undisclosed
	In Review		On hold, suspended. According to developers, the new on-line date will be determined when the markets are favorable and/or financing available.
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	Not Approved/Denied		Cancelled, withdrawn, not built, license expired.

Clean Hydrogen Power Project - BP Arco & Edison Mission Energy	2008-AFC-8	12-mo AFC	[390]	Brownfield	Kern	7/31/2008	Suspended During Review		Suspended During Review

UNDER REVIEW TOTAL 11,233.8

Projects Anounced (Aranged by Estimated Filing Date)		**Process**	**Capacity (MW)**	**Project Type**	**Location**	**Estimated Filing Date**			
eSolar 1 - eSolar Inc.		12-mo AFC	84	Greenfield	Los Angeles	1/09			
eSolar 2 - eSolar Inc.		12-mo AFC	66	Greenfield	Los Angeles	1/09			
Mojave - Solel		12-mo AFC	553	Greenfield	San Bernardino	2009			

ANNOUNCED TOTAL 703.0

Projects Planned (Aranged by Estimated Filing Date)		**Process**	**Capacity (MW)**	**Project Type**	**Location**	**Estimated Filing Date**			
Peaker 1		12-mo AFC	700		Unknown	Unknown			
Peaker 2		12-mo AFC	200		Unknown	Unknown			
Combined Cycle		12-mo AFC	575		Unknown	Unknown			
Combined Cycle		12-mo AFC	575		Unknown	Unknown			
Peaker Expansion 4		12-mo AFC	120		Unknown	Unknown			
Solar Thermal 3		12-mo AFC	160		Unknown	Unknown			
Solar Thermal 4		12-mo AFC	230		Unknown	Unknown			
Solar Thermal 5		12-mo AFC	230		Unknown	Unknown			
Solar Thermal 6		12-mo AFC	250		Unknown	Unknown			
Solar Thermal 7		12-mo AFC	250		Unknown	Unknown			
Solar Thermal 8		12-mo AFC	250		Unknown	Unknown			

PLANNED TOTAL 3,540

NOTES:

Bold text in table identifies a change from the previous report.
* Estimated on-line date if construction is not delayed.
** Estimated on-line date if approved & constructed as proposed.
Projects in italics and an "EP" Docket Number are emergency peakers
Megawatts in [ ] are not included in totals.
{1} 1021 MW replaced with 1200 MW for a net increase of 179 MW
{2} Project approved but replaced by Hanford-GWF (01-EP-7).
{3} 30 MW organic rankine cycle amendment approved 5/11/05.
{4} 130 MW amendment approved 6/22/05.

DEFINITIONS:

Greenfield	Undeveloped
Brownfield	Developed site
Expansion	New unit at existing site, no loss of existing generation
Repower	Modification of existing equipment
Replacement	Demolition of old plant and construction of new plant
On Hold	Applicant has suspended work
Suspended	Committee has suspended the proceeding

Exhibit 23

The California ENERGY COMMISSION

Home » sitingcases » **alphabetical**

Alphabetical List of Power Plant Projects Filed Since 1996

- Avenal Energy Project - Avenal Power Center, LLC
- Beacon Solar Energy Project
- Blythe - Blythe Energy LLC
- Blythe II Combined Cycle - Blythe Energy LLC
- Blythe Transmission Line - Blythe Energy LLC
- Border - Calpeak (Emergency Peaker)
- Bottle Rock Geothermal - U.S. Renewables Group (Repower)
- Bullard Energy Center (BEC)
- Canyon Power Plant
- Carlsbad Energy Center - NRG
- Carrizo Energy Solar Farm
- Century - Alliance (Emergency Peaker)
- Chevron Richmond Power Plant Replacement Project - Chevron USA, Inc.
- Chula Vista Energy Upgrade Project - MMC Energy, Inc.
- City of Vernon Malburg Generating Station
- Colusa Generating Station (CGS)
- Community Power - Kings River Conservation District
- CPV Vacaville Station
- Delta - Calpine
- Drews - Alliance (Emergency Peaker)
- East Altamont - Calpine
- Eastshore Power Project - Tierra Energy
- El Centro Unit 3 Repower Project - Imperial Irrigation District (IID)
- El Segundo Repower - Dynegy/NRG
- El Segundo - Dry Cooling Amendment Proceeding
- Elk Hills - Sempra & Oxy
- Escondido - Calpeak (Emergency Peaker)
- Gateway Generating Station (formerly Contra Costa) Power Plant Project
- Gilroy I, Units 1,2 & 3 - Calpine (Emergency Peaker)
- Hanford - GWF (Emergency Peaker)
- Hanford Combined Cycle Power Project -
- Magnolia - SoCal Power Authority
- Malburg Generating Station - City of Vernon
- Marsh Landing Generating Station
- Metcalf - Metcalf Energy Center LLC
- Modesto Irrigation District - Ripon, Simple Cycle
- Morro Bay - Duke
- Moss Landing Unit 1 & 2 - Duke
- Mountainview - SCE
- Niland Gas Turbine Plant (SPPE)
- Orange Grove Energy, Simple Cycle
- Otay Mesa - Calpine
- Palmdale Solar-Gas Hybrid - City of Palmdale
- Palomar Escondido - Sempra
- Panoche Energy Center - Energy Investors Fund
- Pastoria - Calpine
- Pastoria Expansion Project (Pastoria 2) - Pastoria Energy LLC
- Riverside Energy Resource Center - City of Riverside Public Utilities
- Riverside Energy Resource Center Units 3 & 4 **(Expansion Project)** - City of Riverside
- Roseville Energy Park - City of Roseville
- Russell City - Calpine
- Russell City **Amendment** - Calpine
- Salton Sea Geothermal
- San Francisco Electric Reliability Project - City of San Francisco
- San Gabriel Generating Station - Reliant Energy
- San Joaquin Solar 1 & 2 - San Joaquin Solar LLC
- San Joaquin Valley Energy Center - Calpine
- Sentinel Energy Project - CPV Sentinel, LLC
- SMUD Combined Cycle Phase 1
- Solar One Power Project - SES Solar One LLC
- Solar Two Power Project - SES Solar

GWF (Major Amendment)
- Henrietta Peaker - GWF
- Henrietta Combined Cycle Power Project - GWF (Major Amendment)
- High Desert - High Desert Power Project LLC
- Highgrove - AES
- Humboldt Bay Generating Station - PG&E
- Huntington Beach Unit 3 & 4 - AES
- Hydrogen Energy California - Hydrogen Energy International LLC
- Inland Empire Combined Cycle - Calpine
- Ivanpah Solar Electric Generating System
- King City - Calpine (Emergency Peaker)
- Kings River Peaker - Kings River Conservation District
- La Paloma - PG&E Natl. Units 1, 2, 3 & 4
- Lodi Energy Center - Northern California Power Authority
- Los Esteros - Calpine
- Los Esteros PHASE 2 - Calpine
- Los Medanos (Pittsburg) - Calpine

Two LLC
- Southeast Regional Energy Center (Formerly City of Vernon)
- South Bay Combined Cycle - L.S. Power
- Starwood Power - Starwood Power-Midway LLC
- Sunrise - Texaco & Edison Mission E.
- Sun Valley Energy Project - Edison Mission Energy
- Sutter - Calpine
- Tesla Combined Cycle - FPL
- Tracy Peaker - GWF
- Tracy Combined-Cycle Power Plant - GWF Energy, LLC (Project Expansion)
- Vaca Station - CPV Vacaville
- Valero Cogeneration Unit 1 & 2
- Vernon Combined Cycle - City of Vernon
- Victorville 2 Solar-Gas Hybrid Power Project - City of Victorville
- Von Raesfeld (Formerly Pico Power) Combined Cycle - Silicon Valley Power
- Walnut Creek Energy Park (City of Industry) - Edison Mission Energy
- Walnut Energy Center - Turlock Irrigation District
- Wildflower Indigo - Intergen (Emergency Peaker)
- Wildflower Larkspur - Intergen (Emergency Peaker)
- Willow Pass Generating Station - Mirant
- Woodland II Combined Cycle - Modesto Irrigation District

Withdrawn Projects List

Exhibit 24

Final
Determination of Compliance

Metcalf Energy Center

Bay Area Air Quality Management District
Application 27215

August 24, 2000

Dennis Jang, P.E.
Air Quality Engineer

Contents

15. The combined heat input rate to each power train consisting of a Gas Turbine and its associated HRSG (S-1 & S-2 and S-3 & S-4) shall not exceed 49,908 MM BTU per calendar day. (PSD for PM_{10})

16. The combined cumulative heat input rate for the Gas Turbines (S-1 & S-3) and the HRSGs (S-2 & S-4) shall not exceed 35,274,060 MM BTU per year. (Offsets)

17. The HRSG duct burners (S-2 and S-4) shall not be fired unless its associated Gas Turbine (S-1 and S-3, respectively) is in operation. (BACT for NO_x)

18. S-1 Gas Turbine and S-2 HRSG shall be abated by the properly operated and properly maintained A-1 Selective Catalytic Reduction (SCR) System whenever fuel is combusted at those sources and the A-1 catalyst bed has reached minimum operating temperature. (BACT for NO_x)

19. S-3 Gas Turbine and S-4 HRSG shall be abated by the properly operated and properly maintained A-2 Selective Catalytic Reduction (SCR) System whenever fuel is combusted at those sources and the A-2 catalyst bed has reached minimum operating temperature. (BACT for NO_x)

20. The Gas Turbines (S-1 & S-3) and HRSGs (S-2 & S-4) shall comply with requirements (a) through (h) under all operating scenarios, including duct burner firing mode and steam injection power augmentation mode. Requirements (a) through (h) do not apply during a gas turbine start-up or shutdown. (BACT, PSD, and Toxic Risk Management Policy)

    (a) Nitrogen oxide mass emissions (calculated as NO_2) at P-1 (the combined exhaust point for the S-1 Gas Turbine and the S-2 HRSG after abatement by A-1 SCR System) shall not exceed 19.2 pounds per hour or 0.00904 lb/MM BTU (HHV) of natural gas fired. Nitrogen oxide mass emissions (calculated as NO_2) at P-2 (the combined exhaust point for the S-3 Gas Turbine and the S-4 HRSG after abatement by A-3 SCR System) shall not exceed 19.2 pounds per hour or 0.00904 lb/MM BTU (HHV) of natural gas fired. (PSD for NO_x)

    (b) The nitrogen oxide emission concentration at emission points P-1 and P-2 each shall not exceed 2.5 ppmv, on a dry basis, corrected to 15% O_2, averaged over any 1-hour period. (BACT for NO_x)

    (c) Carbon monoxide mass emissions at P-1 and P-2 each shall not exceed 0.0132 lb/MM BTU (HHV) of natural gas fired or 28.07 pounds per hour, averaged over any rolling 3-hour period. (PSD for CO)

    (d) The carbon monoxide emission concentration at P-1 and P-2 each shall not exceed 6.0 ppmv, on a dry basis, corrected to 15% O_2, when the heat input to the combustion turbine exceeds 1700 MM BTU/hr (HHV), averaged over any rolling 3-hour period. If compliance source test results and continuous emission monitoring data indicate that a lower CO emission concentration level can be achieved on a consistent basis (with a suitable complaince margin) over the entire range of turbine operating conditions, including duct firing and power steam augmentation operations, and over the entire range of ambient conditions, the District will reduce this limit to a level not lower than 4.0 ppmv, on a dry basis, corrected to 15% O_2. If this limit is reduced, the corresponding mass emission rate limit specified in condition 20(c) shall also be modified to reflect this reduction. (BACT for CO)

(e) Ammonia (NH_3) emission concentrations at P-1 and P-2 each shall not exceed 5 ppmv, on a dry basis, corrected to 15% O_2, averaged over any rolling 3-hour period. This ammonia emission concentration shall be verified by the continuous recording of the ammonia injection rate to A-1 and A-2 SCR Systems. The correlation between the gas turbine and HRSG heat input rates, A-1 and A-2 SCR System ammonia injection rates, and corresponding ammonia emission concentration at emission points P-1 and P-2 shall be determined in accordance with permit condition 30. (TRMP for NH_3)

(f) Precursor organic compound (POC) mass emissions (as CH_4) at P-1 and P-2 each shall not exceed 2.7 pounds per hour or 0.00126 lb/MM BTU of natural gas fired. (BACT)

(g) Sulfur dioxide (SO_2) mass emissions at P-1 and P-2 each shall not exceed 1.28 pounds per hour or 0.0006 lb/MM BTU of natural gas fired. (BACT)

(h) Particulate matter (PM_{10}) mass emissions at P-1 and P-2 each shall not exceed 9 pounds per hour or 0.00452 lb PM_{10}/MM BTU of natural gas fired when HRSG duct burners are not in operation. Particulate matter (PM_{10}) mass emissions at P-1 and P-2 each shall not exceed 12 pounds per hour or 0.00565 lb PM_{10}/MM BTU of natural gas fired when HRSG duct burners are in operation. (BACT)

21. The regulated air pollutant mass emission rates from each of the Gas Turbines (S-1 and S-3) during a start-up or a shutdown shall not exceed the limits established below. (PSD)

	Start-Up (lb/start-up)	Start-Up (lb/hr)	Shutdown (lb/shutdown)
Oxides of Nitrogen (as NO_2)	240	80	18
Carbon Monoxide (CO)	2,514	902	43.8
Precursor Organic Compounds (as CH_4)	48	16	5

22. The Gas Turbines (S-1 and S-3) shall not be in start-up mode simultaneously. (PSD)

23. The heat recovery steam generators (S-2 & S-4) and associated ducting shall be designed and constructed such that an oxidation catalyst can be readily installed and properly operated if

Exhibit 25

CALIFORNIA
ENERGY
COMMISSION

THE METCALF ENERGY CENTER

Application For Certification 99-AFC-3
Santa Clara County

COMMISSION DECISION

SEPTEMBER 2001
P800-01-023

Gray Davis, *Governor*

THE METCALF ENERGY CENTER

Application For Certification 99-AFC-3
Santa Clara County

CALIFORNIA
ENERGY
COMMISSION

COMMISSION DECISION

SEPTEMBER 2001
P800-01-023

Gray Davis, *Governor*

CALIFORNIA ENERGY COMMISSION

1516 9th Street
Sacramento, CA 98814

www.energy.ca.gov/sitingcases/metcalf

The Metcalf Energy Center Committee

ROBERT A. LAURIE, Commissioner
Presiding Committee Member

WILLIAM J. KEESE, Chairman
Associate Committee Member

Hearing Office

STANLEY VALKOSKY
Chief Hearing Officer

Verification: As part of the monthly Air Quality Reports, the owner/operator shall indicate the date of any violation of this Condition including quantitative information on the severity of the violation.

AQ-55 The project owner shall install an oxidation catalyst to control VOC emissions.

Verification: As part of the final design plans, specifications, and drawings, the project owner shall submit to the District and the CPM for review and approval the final selection and design details of the combustion equipment, including all emission control systems.

Exhibit 26

COMMONWEALTH OF MASSACHUSETTS
EXECUTIVE OFFICE OF ENVIRONMENTAL AFFAIRS
DEPARTMENT OF ENVIRONMENTAL PROTECTION
Metropolitan Boston – Northeast Regional Office

ARGEO PAUL CELLUCCI
Governor

JANE SWIFT
Lieutenant Governor

BOB DURAND
Secretary

LAUREN A. LISS
Commissioner

March 10, 2000

Mr. George Wilson
Sithe Edgar Development, LLC
173 Alford Street
Charlestown, MA 02129

RE: **WEYMOUTH** - Metropolitan
Boston/Northeast Region
PROPOSED CONDITIONAL
MAJOR COMPREHENSIVE PLAN APPROVAL
310 CMR 7.00: APPENDIX A
310 CMR 7.02(2)
Prevention of Significant Deterioration Permit
40 CFR 52.21
Transmittal No. W004896
Application No. MBR-99-COM-018

Dear Mr. Wilson:

The Department of Environmental Protection (the "Department"), Northeast Regional Office (NERO), Bureau of Waste Prevention, has reviewed the Major Comprehensive Plan Application for the proposed 775 megawatt (MW) combined cycle electric generating facility and auxiliary combustion equipment to be located at 1 Bridge Street in Weymouth, Massachusetts. The submittal bears the seal and signature of Dale T. Raczynski, Massachusetts P.E. Number 36207.

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

This letter combines and includes: the proposed 310 CMR 7.02(2) Comprehensive Plan Approval, the proposed 310 CMR 7.00: APPENDIX A: Emission Offsets and Nonattainment Review Approval, and the proposed Code of Federal Regulations, Title 40, Part 52.21 Prevention of Significant Deterioration (PSD) Permit. These proposed actions are subject to a public comment period and a public hearing 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 PROPOSED CONDITIONAL APPROVAL/PSD Permit will allow for commencement of construction of the facility and its operation, and provides information on the project description, emission control systems, facility emission limits, continuous emission monitors, record keeping, reporting and testing requirements.

This facility is also subject to the requirements of the Massachusetts Environmental Policy Act (MEPA) Massachusetts General Laws (M.G.L.) Chapter 30, Sections 61-62H. On September 16, 1999, the Secretary of the Executive Office of Environmental Affairs issued a certificate that the Final Environmental Impact Report (FEIR) (EOEA #11726) adequately complied with the MEPA and its regulations.

On February 11, 1999, the Energy Facility Siting Board issued approval under M.G.L. Chapter 164, §69J of Sithe Edgar Development's Petition to construct and operate the facility. In accordance with that statute, the Department may issue a Plan Approval/Permit for the facility to be constructed.

This PROPOSED CONDITIONAL APPROVAL/PSD Permit 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 subject facility to be installed and operated.

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

If you have any questions concerning this matter, please feel free to contact Mr. Marc Altobelli at (978) 661-7642.

Sincerely,

Edward Braczyk
Environmental Engineer
Bureau of Waste Prevention

James E. Belsky
Regional Permit Chief
Bureau of Waste Prevention

Marc Altobelli
Environmental Engineer
Bureau of Waste Prevention

cc: see Attachment List

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I. FACILITY DESCRIPTION

A. Site Description

The Fore River Station site, formerly the Boston Edison Edgar site, consists of approximately 57 acres of land situated on a peninsula along the bank of the Weymouth Fore River in Weymouth, Massachusetts. The existing Edgar Station includes two 12 MW simple cycle combustion turbines (Edgar Units J1 and J2) used for peaking power only. Each combustion turbine fires No. 2 fuel oil with a maximum sulfur content of 0.3 weight percent as the only fuel of use. The Fore River Station site is bounded by the Weymouth Fore River to the west, and south, Bridge Street (Route 3A) to the north, and Monatiquot Street to the east.

The neighboring community consists of a mix of industrial, commercial, and residential properties. The nearest residential area is located approximately 50 feet east of the property fence line.

B. Project Description

Sithe Edgar Development LLC (the "Applicant") proposes to design, construct and operate a new combined-cycle electric generating facility within the boundaries of the existing Fore River Station site in Weymouth, Massachusetts. The Project is referred to as the Fore River Station Project. The Project will be configured as a new main power block generating 775 MW of electric power.

Fore River Station Unit 1(A and B) will include two Mitsubishi Heavy Industries (MHI) Model 501G combustion turbine generators (CTGs) each including a Heat Recovery Steam Generator (HRSG). The new power block will be equipped with one steam turbine generator (STG). Each CTG will have a nominal generating capacity of approximately 250 MW. The hot exhaust gases from each CTG will pass through a HRSG, which will use the heat from these gases to produce steam. These exhaust gases also contain sufficient oxygen to allow the placement of supplemental firing burners in the ducts just upstream of the HRSG equipment. Each HRSG will house an oxidation catalyst for carbon monoxide (CO) control, followed by an ammonia (NH_3) injection grid and selective catalytic reduction (SCR) catalyst for control of nitrogen oxides (NO_X). The steam produced by each HRSG will be fed into a single condensing STG. The STG will have a nominal generating capacity of approximately 275 MW. An air-cooled condenser will be used to condense the steam.

Each MHI 501G turbine will have a maximum energy input at -12ºF ambient of 2,676 Million British Thermal Units per hour (MMBtu/hr), HHV (higher heating value) during natural gas firing. Each supplementary natural gas-fired HRSG will have a maximum energy input of 279 MMBtu/hr (HHV) at -12ºF. Each MHI 501G turbine and supplementary-fired HRSG in combination will have a maximum energy input (at -12ºF ambient) of 2955 MMBtu/hr, HHV during natural gas firing.

During oil firing, each MHI 501G turbine will have a maximum energy input at -12ºF ambient of 2,734 MMBtu/hr, (HHV) at a water to fuel ratio of 0.4 to 1. Each MHI 501G oil-fired turbine and supplementary natural gas-fired HRSG in combination will have a maximum energy input (at -12ºF ambient) of 3,001 MMBtu/hr (HHV).

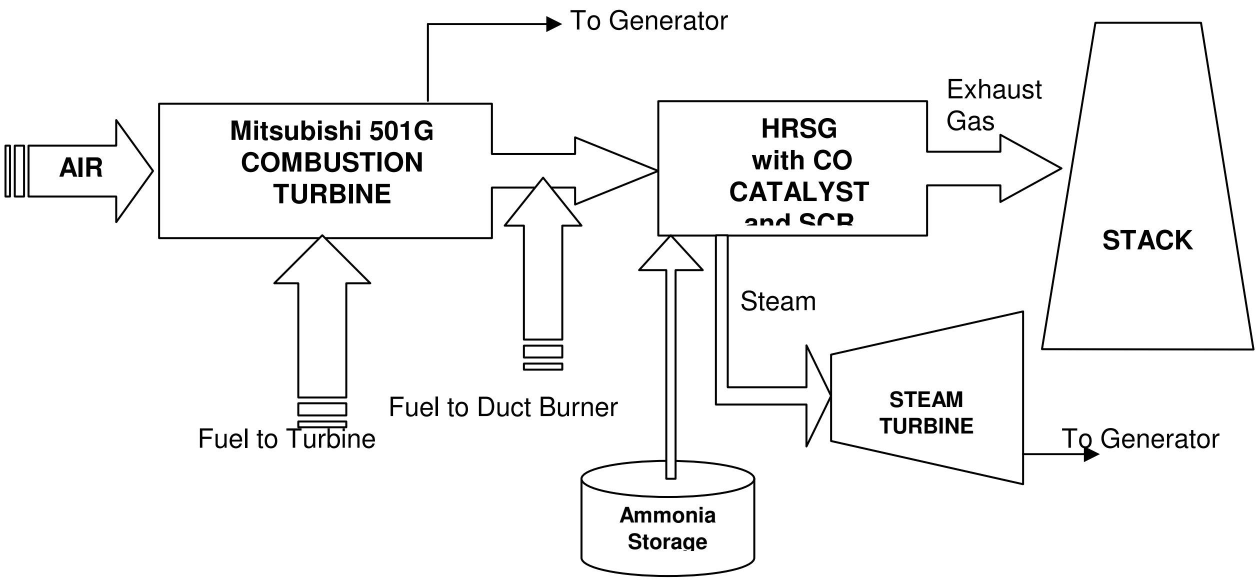
The entire CTG/HRSG facility will use natural gas (with a sulfur content that does not exceed 0.8 grains per 100 cubic feet) as the primary fuel of use. Transportation distillate fuel oil with a sulfur content that does not exceed 0.05 percent by weight will be fired at a maximum annual rate of 29,074,350 gallons per 12-month rolling period when operating at 100% rated capacity and at a temperature of -12^{0}F ambient. 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.

Other auxiliary equipment includes aqueous ammonia storage tanks, a continuous emissions monitoring system (CEMS), a new auxiliary boiler and a new emergency diesel generator.

The new auxiliary boiler shall be designated as Fore River Unit AB and will provide steam for plant startup when both CTGs are off line. This boiler will fire natural gas (with a sulfur content that does not exceed 0.8 grains per 100 cubic feet) as the primary fuel of use and transportation distillate fuel as a back-up fuel. The auxiliary boiler will have a maximum energy input of 96 MMBtu/hr HHV. This boiler shall be limited to 48,000 MMBtu per 12-month rolling period, corresponding to the equivalent of 500 full load operating hours. This boiler shall be limited to 9,600 MMBtu per month (See Section III (H)).

The new emergency generator, 1,500 kilowatts (kW) or 15.4 MMBtu/hr, HHV, shall be designated as Fore River Unit EDG1 and is required for facility backup power to support shut down operations if no power is available from the utility grid. The emergency diesel generator will fire transportation diesel fuel oil with a sulfur content that does not exceed 0.05 percent by weight and shall be limited to a fuel consumption of 16,500 gallons based on 150 hours of operation per 12-month rolling period.

The exhaust gases from the proposed facility shall be emitted from three new flues located in a common concrete shell, with the stack having a height of 255 feet above ground level. The auxiliary boiler shall utilize one flue and the other two flues shall provide dedicated service for the exhaust of the CTG/HRSG units. Each CTG/HRSG flue will have an inside exit diameter of 20.5 feet, which will provide for a maximum exit velocity of 84.7 feet per second at an exit stack temperature of 311ºF. The auxiliary boiler flue will have an inside exit diameter of 4 feet, which will provide for a maximum exit velocity of 35.0 feet per second at an exit stack temperature of 300ºF. The emergency diesel generator will be equipped with a steel stack with two flues, having a height of 25 feet above ground level. Each stack flue will have an inside exit diameter of 1.0 foot which will provide for a maximum exit velocity of 134 feet per second at an exit stack temperature of 900ºF.



II. EMISSIONS

The operation of the turbine combustors and the auxiliary boiler on natural gas and back-up transportation distillate oil (as well as the emergency diesel generators on transportation distillate oil) will result in emissions to the ambient air of the following criteria air pollutants: Particulate Matter (PM/PM_{10}), Sulfur Dioxide (SO_2), Carbon Monoxide (CO), Nitrogen Oxides (NO_x), and Volatile Organic Compounds (VOC). During firing of the primary fuel, natural gas, the turbine combustors will be a source of emissions of three (3) air toxics: ammonia (NH_3), formaldehyde (CH_2O), and sulfuric acid mist (H_2SO_4). During firing of the back-up fuel, transportation distillate oil, the turbine combustors will also be a source of emissions of several air toxics. Please refer to pages 40 and 41 of this document for a complete listing.

III. EMISSION LIMITS

A. Air pollutant 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 Tables 1 and 2 below.

Table 1: Short Term Emission Limits for Proposed Facility Per Emission Unit				
Pollutant	Each Combustion Turbine(1,2)		Auxiliary Boiler (4) Natural Gas/Fuel Oil	Emergency Diesel Generator(5)
	Natural Gas	Fuel Oil		
NO_x	21.8 lbs/hr	65.7 lbs/hr	3.4 / 9.6 lbs/hr	37.44 lbs/hr
CO	13.3 lbs/hr	46.5 lbs/hr	7.7 lbs/hr	3.05 lbs/hr
VOC (unfired)	3.8 lbs/hr	26.0 lbs/hr	0.8/ 0.384 lbs/hr	1.16 lbs/hr
VOC (duct-fired)	6.4 lbs/hr	28.4 lbs/hr	NA	NA
SO_2	6.4 lbs/hr	143.5 lbs/hr	0.3/ 5.01 lbs/hr	0.95 lbs/hr
PM	32.5 lbs/hr	139.6 lbs/hr	0.7/ 7.7 lbs/hr	0.87 lbs/hr
NH_3(3)	8.0 lbs/hr	8.6 lbs/hr	NA	NA
NO_x	0.0074 lbs/MMBtu	0.0233 lbs/MMBtu	0.035/ 0.10 lbs/MMBtu	6.55 gm/bhp-hr
CO	0.0045 lbs/MMBtu	0.0166 lbs/MMBtu	0.08 lbs/MMBtu	0.53 gm/bhp-hr
VOC (unfired)	0.0013 lbs/MMBtu	0.0095 lbs/MMBtu	0.008/ 0.004 lbs/MMBtu	0.20 gm/bhp-hr
VOC (duct-fired)	0.0022 lbs/MMBtu	0.0095 lbs/MMBtu	NA	NA
SO_2	0.0023 lbs/MMBtu	0.0522 lbs/MMBtu	0.0029/ 0.0522 lbs/MMBtu	0.17 gm/bhp-hr
PM	0.011 lbs/MMBtu	0.05 lbs/MMBtu	0.007/ 0.08 lbs/MMBtu	0.15 gm/bhp-hr
NH_3(3)	0.0027 lbs/MMBtu	0.0029 lbs/MMBtu	NA	NA
NO_x	2.0 ppmvd @15% O_2	6.0 ppmvd @15%O_2	NA	NA
CO	2.0 ppmvd @ 15% O_2	7.0 ppmvd @15%O_2	100 ppmvd @ 3% O_2	NA
VOC (unfired)	1.0 ppmvd @ 15% O_2	7.0 ppmvd @15%O_2	NA	NA
VOC (duct-fired)	1.7 ppmvd @ 15% O_2	7.0 ppmvd @15%O_2	NA	NA
SO_2	NA	NA	NA	NA
PM	NA	NA	NA	NA
NH_3	2.0 ppmvd @ 15% O_2(3) (7)	2.0 ppmvd @ 15%O_2(3) (7)	NA	NA
Opacity	<5%, except 5 to < 10% for ≤ 2 minutes during any one hour	< 10%, except 10 to < 15% for ≤ 2 minutes during any one hour		
Smoke	310 CMR 7.06(1)(a)			

Table 2: Long Term Emission Limits For Proposed Facility	
Pollutant	**Proposed Facility[(6)] (tons per 12-month rolling period)**
NO_x	218
CO	296
VOC	71.5
SO_2	154
PM	352
NH_3[(3)]	67

Tables 1 & 2 Key:

NO_x	= oxides of nitrogen
CO	= carbon monoxide
VOC	= volatile organic compounds
SO_2	= sulfur dioxide
PM	= particulate matter
NH_3	= ammonia
lbs/hr	= pounds per hour
lb/MMBtu	= pound per million British Thermal Units
gm/bhp-hr	= grams per brake horsepower hour
ppmvd@15%O_2	= parts per million, dry volume basis corrected to 15 percent oxygen
ppmvd@3%O_2	= parts per million, dry volume basis corrected to 3 percent oxygen
NA	= not applicable
%	= percent
<	= less than
≤	= less than or equal to

Tables 1 & 2 Notes:

1. Emission limits are one-hour block averages and do not apply during start-up/shutdown, fuel transfers, and equipment cleaning. Start-ups, shutdowns, and fuel transfers shall not last longer than 3 hours (See Proviso X.2.).

2. Emission rates are for burning natural gas or transportation distillate fuel oil in one combustion turbine and based on 100% load and -12°F ambient while supplemental duct firing. These constitute worst case emissions.

3. Based on maximum ammonia (NH_3) slip (from SCR) of 2.0 ppmvd @15% O_2 (excluding start-up, shutdown, and fuel transfer periods).

4. Emission limits for the auxiliary boiler are one-hour block averages and apply over the normal operating range up to 100% load.

5. Emission limits for the emergency diesel generator are one-hour block averages and apply over the normal operating range up to 100% load.

6. Proposed facility emissions include the two CTG/HRSG pair with supplemental duct firing burners (designated as Fore River Unit 1), the auxiliary boiler (designated as Fore River Unit AB), and an emergency diesel generator (designated as Fore River Unit EDG1). Emissions for the combustion turbines are based upon 8,040 hours of natural gas firing at 100% duct-fired load at an annual average inlet temperature of 51^{o}F ambient, 720 hours of transportation distillate fuel oil with a sulfur content that does not exceed 0.05 percent by weight firing at 100% duct-fired load at an inlet temperature of -12^{o}F ambient and includes combustion turbine start-up emissions (see Application Transmittal No. W004896). Emissions for the auxiliary boiler are based on a 48,000 MMBtu per year restriction and 500 hours of operation. The auxiliary boiler shall be restricted to a total fuel consumption of 48 million cubic feet of natural gas based on a heat input of 1,000 BTU per cubic foot of natural gas or 355,555 gallons of transportation distillate fuel oil with a sulfur content that does not exceed 0.05 percent by weight based on a heat input of 135,000 BTU per gallon of fuel oil, the combined consumption of which shall not exceed the total of 48,000 MMBtu per 12-month rolling period. Emissions for the emergency diesel generator are based on restricted operation of 150 hours or while firing 16,500 gallons per 12-month rolling period of transportation diesel fuel oil having a sulfur content that does not exceed 0.05% by weight. The proposed facility emissions are determined as equal to the total combustion turbine emissions due to the fact that neither the auxiliary boiler nor emergency diesel generator will operate concurrently with combustion turbine operation. Auxiliary boiler operation will only be required for start-up and only in the event that no other combustion turbine is in operation or if steam is not available from some other on-site steam source. The emergency diesel generator will only operate as required to shutdown Unit 1 (A and B) and only in the event that power to achieve shutdown is not available from the electric power grid.

7. For the duration of the optimization program identified in Section X. 3 and XIII.7 the ammonia emission limit shall be State enforceable only. Thereafter, the ammonia emission limit will be federally enforceable.

B. The Applicant shall ensure that the proposed facility shall comply with all emission limits contained in Table 1 above.

C. The Applicant shall ensure that the subject facility does not exceed the annual emissions limits in Table 2 above, based on a 12-month rolling period.

D. The Applicant shall burn natural gas as the primary fuel in the CTGs, the supplemental firing burners (natural gas only firing), and the auxiliary boiler, and shall ensure that the sulfur content of the natural gas to be used at the subject facility does not exceed 0.8 grains per 100 cubic feet.

E. The Applicant shall burn no more than 29,074,350 gallons of transportation distillate fuel oil per twelve-month rolling total in the CTGs (equivalent to no more than 720 hours per year). The sulfur content of the transportation distillate fuel oil to be used at the subject facility shall not exceed 0.05 percent by weight. The Applicant shall not burn transportation distillate fuel oil in the CTGs and the auxiliary boiler during the time period May 1 through September 30 inclusive of any calendar year, except during initial compliance testing, initial plant demonstration and performance testing, periodic readiness testing, in the event of the unavailability of natural gas, or in the case of a variance obtained from the Department to operate during an emergency.

F. The Department and the Applicant have entered into a memorandum of understanding (MOU) concerning the use of zero ammonia technology (ZAT) for the control of nitrogen oxides. A copy of the MOU is included here as Attachment C. For the first five years of operation of the facility, there shall be an interim emission rate for ammonia of 2.0 ppmvd

@ 15% O_2 one-hour block average. Pursuant to the MOU, the emission rate for ammonia after the first five years of operation shall be zero unless the Department extends the interim 2.0 ppm ammonia limit. During the five year period it will be determined whether a ZAT must be installed in the facility. The MOU provides a methodology for making the determination, including a consideration of availability, reliability, comparable costs and the impact on other permits and approvals. A determination of the comparative costs of retrofitting the facility to a ZAT will be made by an independent consultant.

G. The Applicant shall not operate the existing jet turbines when the new facility is operating on transportation distillate fuel oil.

H. The Applicant shall restrict the operation of the subject 96 MMBtu/hr auxiliary boiler to a total BTU cap of no more than 48,000 MMBtu per 12 month rolling period based upon 500 hours of operation while firing natural gas as the primary fuel of use and firing transportation diesel fuel oil having a sulfur content that does not exceed 0.05% by weight as the back-up fuel.

I. The Applicant shall restrict the operation of the 1500 KW (15.4 MMBtu/hr) emergency diesel generator to a total fuel consumption of no more than 16,500 gallons of fuel oil per 12 month rolling period based upon 150 hours of operation per unit while firing transportation diesel fuel oil having a sulfur content that does not exceed 0.05% by weight only, inclusive of periodic readiness testing and emergency use.

IV. ACCIDENTAL RELEASE MODELING OF AQUEOUS AMMONIA

Aqueous ammonia will be used as the reducing agent in the SCR system. A solution of aqueous ammonia (≤ 19.5% by weight solution) will be stored onsite. A 90,000-gallon double walled steel tank will be provided for on-site storage of ammonia. The tank will be equipped with leak detection and an ammonia vapor treatment system. The vapor treatment system will consist of a continuous water quench designed to absorb all ammonia vapor off the tanks. The system will have a ventilation pipe less than 4 inches in diameter. The tanks will be surrounded by concrete berms or fencing to prevent accidental contact with vehicles or other equipment. A catastrophic release from the inner wall of each tank would be contained within its outer wall. The tank vapor treatment system will continue to function even if the aqueous ammonia accumulates within the outer tank wall. Ammonia would be released to the atmosphere through the ventilation pipe only if a rupture of the primary (internal) tank wall were to occur coupled with a loss of power to the ammonia vapor filtration system.

The vaporization and dispersion of the ammonia was modeled to the nearest receptors at the nearest fence line, property boundary line, and public road to the ammonia storage tank. Specific computer dispersion modelling documents that maximum predicted concentrations of ammonia were below the Immediately Dangerous to Life or Health (IDLH) thresholds developed by the National Institute for Occupational Safety and Health (NIOSH) at all receptors.

V. EMISSION OFFSETS AND NONATTAINMENT REVIEW

The entire Commonwealth of Massachusetts is designated "serious" Nonattainment for the pollutant ozone (O_3). Nonattainment review applies to any Applicant with potential emissions of Nitrogen Oxides (NO_x) and/or Volatile Organic Compounds (VOC) from a facility that is at or above the "major source" threshold criterion of 50 tons per year, as well as to "major modifications" at existing "major" facilities, as defined in 310 CMR 7.00: Appendix A. A "major modification" is defined as an increase of 25 or more tpy of nonattainment precursor pollutants at an existing "major" source. NO_x and VOC emissions are precursors to the formation of ozone and "major" NO_x and VOC emitters are regulated pursuant to Appendix A. Applicable requirements for any proposed new major stationary source of nonattainment pollutants require the source to meet Lowest Achievable Emission Rate (LAER) and obtain emission offsets.

Several recent developments have directly impacted the Emission Offsets and Nonattainment review process as required by Appendix A. On May 14, 1999, the D.C. Circuit Court of Appeals remanded the 8-hour ozone standard to the U.S. Environmental Protection Agency (U.S. EPA) to develop an acceptable basis for the standard (American Trucking Associations v. U.S. EPA). However, the standard was not vacated. Then on June 9, 1999, the U.S. EPA determined that the 1-hour ozone standard no longer applies to the eastern portion of the Commonwealth of Massachusetts (including Weymouth). These developments temporarily placed Nonattainment New Source Review (NSR) (310 CMR 7.00: Appendix A) in abeyance.

On October 22, 1999, the Department issued an Emergency Amendment to Appendix A through the emergency promulgation provisions at M.G.L. c.30A Sections 2 and 3. These provisions authorize the Department to immediately adopt, prior to notice and public hearing, regulations which are necessary for the preservation of the public health, safety or general welfare, where the Department finds that observance of the requirements of notice and public comment would be contrary to the public interest. The Regulation adoption reinstates the Appendix A requirements. Regulation 310 CMR 7.00 Appendix A sets offset requirements for major sources, or major modifications thereat, of NOx and VOC at a minimum ratio of 1.2 to 1.

The Applicant has proposed maximum potential NOx and VOC emissions from Fore River Station Unit 1 (A and B), AB and EDG1 of 218 and 70 tons per year, respectively. The Fore River Station Project is thus a "major source" with respect to NOx and VOC emissions.

Since the Project is a major source for NOx and VOC, NOx and VOC offsets are required. 310 CMR 7.00: Appendix B(3) requires that applicants must obtain 5% more ERCs than the number of ERCs needed for offsets. This 5% must be held as a set aside and neither sold nor used. Offsets must be from the same nonattainment area or from another nonattainment area of equal or more severe nonattainment classification if emissions from this other area contribute to ozone nonattainment in the area where the new project will be constructed. At this time, the total number of offsets needed are (218) times (1.26) = 275 tpy of NOx and (71.5) times (1.26) = 90.1 tpy of VOC.

The Applicant has proposed NOx emission limits of 2.0 ppmvd at 15% O_2 for natural gas firing and 6.0 ppmvd at 15% O_2 while combusting transportation distillate fuel oil (with a sulfur content that does not exceed 0.05 percent by weight), both at one hour block averages. The Applicant has proposed VOC emission limits of 1.0 ppmvd at 15% O_2 for natural gas firing without duct firing, and 1.7 ppmvd at 15% O_2 for natural gas firing with duct firing, both at one hour block averages. The Applicant has proposed a VOC limit of 7.0 ppmvd at 15% O_2 while combusting transportation distillate fuel oil (with a sulfur content that does not exceed 0.05 percent by weight) at a one hour block average. The Department has verified and concurs with the Applicant's LAER analysis as presented in its Major Comprehensive Plan Application (MBR-99-COM-018, Transmittal W004896) that these proposed NOx and VOC limits constitute NOx and VOC LAER for the project.

The NOx and VOC offset requirements for this facility under Appendix A can be met by withdrawing Massachusetts Department-certified NOx and VOC 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 and VOC offsets created by qualifying activities in certain other states provided that the Department has executed a memorandum of understanding or some other mutually acceptable agreement with the other state(s). The offsets created in the other state must be real, surplus, permanent, quantifiable, and federally enforceable.

Sithe Edgar Development, LLC will use NO_X Rate Based ERCs from reduction in NO_X emissions from their Mystic Station. Sithe Edgar Development, LLC has an agreement with BASF to obtain 24.8 tpy of certified VOC offsets for application to the Fore River Project. These VOC offsets are from the total of 154 tpy of Rate Bank VOC ERCs certified by the Department on May 8, 1996 (Approval No. MBR-94-ERC-011) for the VOC reductions at the BASF Bedford, MA facility. Sithe has also acquired 56.6 tpy of certified Rate Bank VOC ERCs from Lightolier Corporation (Approval No. 4P95217), and 8.7 tpy of certified Rate Bank VOC ERCs from Avery Dennison Company (Approval No. MBR-94-ERC-006, MBR-95-ERC-001) for application to the Fore River Station Project.

All NOx and VOC ERCs have been obtained for the proposed Fore River Station Development Project in order to fulfill the requirement for offsets as required by 310 CMR 7.00 Appendices A and B. The appropriate quantity of NOx and VOC ERCs must be surrendered by the Applicant to the Department prior to the commencement of operation of the facility.

VI. NEW SOURCE PERFORMANCE STANDARDS (NSPS)

The subject facility is considered to be an electric utility stationary gas turbine since more than one third of its net electrical output will be sold to a utility. The New Source Performance Standards (NSPS) for gas turbines, 40 CFR 60 Subpart GG of the Code of Federal Regulations, is applicable to this facility. The NSPS restricts NO_x emissions to a nominal value of 75 ppmvd corrected to 15% O_2 (approximately equivalent to 0.3 lb/MMBTU) for an electric utility gas turbine of 100 MMBTU/hr or greater energy input. The Applicant shall ensure that the subject facility complies with this limit through the use of dry low-NO_x combustion technology in conjunction with SCR add-on NO_x control technology to control NO_x emissions to 2.0 ppmvd corrected to 15% O_2 during natural gas firing and 6.0 ppmvd corrected to 15% O_2 during transportation distillate fuel oil firing (with a sulfur content that does not exceed 0.05 percent by weight), well below the NSPS limit.

The NSPS for gas turbines also limits SO_2 emissions to 150 ppmvd corrected to 15% O_2 and restricts fuel sulfur to 0.8 percent by weight. The Project will meet this criteria by combusting natural gas as the primary fuel and transportation distillate fuel oil (with a sulfur content that does not exceed 0.05 percent by weight) as the back-up fuel, both of which have a fuel sulfur content well below the NSPS limit. The maximum flue gas SO_2 concentration will be 0.0522 lb/MMBtu, well below the NSPS standard.

For the supplemental duct firing HRSG burners, NSPS 40 CFR 60 Subpart Da applies, since the duct burners are rated at more than 250 MMBtu/hr apiece. Subpart Da limits NO_x to 0.2 lb/MMBtu and 1.6 lb/MW-hr gross energy output, limits PM to 0.03 lb/MMBtu, and limits SO_2 to 0.20 lb/MMBtu. The duct burners for the Project, which will operate on natural gas only, are limited herein to emissions of 0.0074 lb/MMBtu and 0.05 lb/MW-hr (after controls) for NO_x, 0.011 lb/MMBtu for PM, and 0.0029 lb/MMBtu for SO_2. The proposed emission limits, contained in Table 1 above, are well below the Subpart Da limits.

The new auxiliary boiler (96 MMBtu/hr) meets the definition of an "affected" facility under the NSPS, 40 CFR 60 Subpart Dc (Small Industrial Commercial Institutional Steam Generating Units). Subpart Dc limits the sulfur content of oil to 0.5 lb/MMBtu or 0.5% by weight and the opacity to 20% with one 6-minute period of no greater than 27% opacity allowed. Fuel sulfur content for the transportation distillate fuel oil (with a sulfur content that does not exceed 0.05 percent by weight), is well below the NSPS limit.

There are no NSPS requirements for internal combustion engines applicable to the proposed emergency diesel generators.

VII. COMPARATIVE BACT ANALYSIS

The Applicant is required to evaluate Best Available Control Technology (BACT) as it applies to emissions of Nitrogen Oxides (NO_x), Volatile Organic Compounds (VOC) (state BACT only), Particulate Matter (PM), Sulfur Dioxide, and Carbon Monoxide (CO). Nitrogen Oxides and VOC are also subject to Lowest Achievable Emission Rate (LAER) since NO_x and VOC are Ozone precursors. BACT is defined as the optimum level of control applied to pollutant emissions based upon consideration of technical, economic, and environmental factors.

The first step in a BACT analysis is to determine for the emission source, the most stringent control available for a similar or identical source or source category. The proposed facility must utilize BACT to control the emissions of the pollutants listed in Table 3 below. The

Department has verified and concurs with the following Comparative BACT Analysis (as referenced in the Applicant's Major Comprehensive Application and the Supplemental BACT Analysis, dated February 15, 2000).

Table 3: Comparative LAER/BACT Analysis

Control Technology	Emission Rate	LAER/ BACT?	Costs	Reason
NO_x				
SCONOx & Dry Low NOx Combustor with Water Injection during Oil Firing	2.0 ppmvd (natural gas), 6.0+ ppmvd (oil)	Yes for natural gas firing, LAER can be achieved by this method, but it is not the chosen option. It is unknown if LAER can be achieved by this method during oil firing.	$$$$	SCONOx provides additional collateral environmental benefits because it does not use ammonia (NH_3), however, there are collateral environmental and energy costs associated with using SCONOx, such as significant quantities of water are needed and there is additional energy drain. In addition, an economic analysis demonstrates that SCONOx is estimated to be about four times more expensive than SCR. Because there is insufficient information available to quantify all the collateral environmental impacts, then, based upon the economic analysis portion of the top-down BACT process, currently available data, and the tenets and procedures of the BACT process, the Department has concluded that the SCR system is the more cost-effective means to achieve the BACT/LAER emission rates for NOx.
Selective Catalytic Reduction & Dry Low NOx Combustor with Water Injection during Oil Firing	2.0 ppmvd (natural gas), 6.0 ppmvd (oil)	Yes	$$$	method chosen to achieve BACT/LAER (see above)
Dry Low NOx Combustor (DLN) with Water Injection during Oil Firing	50 ppmvd (natural gas), 90 ppmvd (oil)	No	$	more stringent control has been chosen
Water Injection on turbine without DLN	50+ ppmvd (natural gas), 90+ ppmvd (oil)	No	$	more stringent control has been chosen

Table 3: Comparative LAER/BACT Analysis				
Control Technology	**Emission Rate**	**LAER/ BACT?**	**Costs**	**Reason**
SO_2				
Fuel: Natural Gas with 720 hours of oil firing per year	0.0023 lb/MMBtu	Yes	$	Is top BACT case
Low Sulfur Content (0.05% S) Transportation Diesel	0.052 lb/MMBtu	No for primary fuel, Yes for backup fuel	**$**	more stringent control has been chosen for primary fuel, backup fuel limited to 720 hours per year operation.
Oil-Firing (1 – 2% S) with Flue Gas Desulfurization	0.052+ lb/MMBtu	No	$$$	more stringent control has been chosen
PM				
Fuel: Natural Gas with 720 hours of oil firing	0.011 lb/MMBtu	Yes	$	Is top BACT case
Low Sulfur Content (0.05% S) Transportation Diesel	0.05 lb/MMBtu	No, for primary fuel, Yes for backup fuel.	$	more stringent control has been chosen for primary fuel, backup fuel limited to 720 hours per year operation.
Oil-firing (1 – 2% S) with Electrostatic Precipitators	0.05+ lb/MMBtu	no	$$$	more stringent control has been chosen
Oil-firing (1 – 2% S) with Wet Scrubber	0.05+ lb/MMBtu	no	$$$	more stringent control has been chosen
Oil-firing (1 – 2% S) with Fabric Filter Collector	0.05+ lb/MMBtu	no	$$$	more stringent control has been chosen
CO				
CO Oxidation Catalyst (89%+ efficient during natural gas firing, 86% efficient during oil firing)	2 ppmvd (natural gas), 7 ppmvd (oil)	yes	$$$	Is top BACT case
CO Oxidation Catalyst (85% efficient)	2.7 ppmvd (natural gas), 7.5 ppmvd (oil)	no	$$	more stringent control has been chosen
CO Oxidation Catalyst (70% efficient)	5.4 ppmvd (natural gas), 15 ppmvd (oil)	no	$$	more stringent control has been chosen

Table 3: Comparative LAER/BACT Analysis				
Control Technology	**Emission Rate**	**LAER/ BACT?**	**Costs**	**Reason**
Combustion Controls	18 ppmvd (natural gas), 50 ppmvd (oil)	no	$	more stringent control has been chosen
VOC				
Combustion Controls & Oxidation Catalyst	1.0 ppmvd (turbine only- natural gas),1.7 ppmvd (turbine with duct firing- natural gas), 7 ppmvd (oil firing with or without duct firing)	yes	$$$	Is top LAER/BACT case (some VOC control is expected from the CO oxidation catalyst as a secondary benefit)
Combustion Controls	1/1.7/7+ ppmvd	no	$	more stringent control

Table 3 Key:

NO_x	= oxides of nitrogen
CO	= carbon monoxide
VOC	= volatile organic compounds
SO_2	= sulfur dioxide
PM	= particulate matter
NH_3	= ammonia
S	= sulfur
lb/MMBtu	= pound per million British Thermal Units
ppmvd@15%O_2	= parts per million, dry volume basis corrected to 15 percent oxygen
LAER	= lowest achievable emission rate
BACT	= best available control technology
%	= percent
$	= least expensive (relative to control technologies for that specific pollutant)
$$	= moderately expensive (relative to control technologies for that specific pollutant)
$$$	= fairly expensive (relative to control technologies for that specific pollutant)
$$$$	= very expensive (relative to control technologies for that specific pollutant)

VIII. TITLE IV SULFUR DIOXIDE ALLOWANCES AND MONITORING

According to 40 CFR Part 72, the subject facility 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 Phase II application for the subject facility must be submitted to the Department 24 months before the commencement of operation.

The Acid Rain Program effects reductions of sulfur dioxide (SO_2) from existing power plants by allocating SO_2 allowances to existing power plants and by requiring new plants to purchase SO_2 allowances to offset their SO_2 potential to emit. The Applicant shall secure SO_2 allowances for the proposed facility.

The Applicant will be required to have a Designated Representative (DR) and to install a Continuous Emissions Monitoring System (CEMS) to service the subject facility. The DR is the Applicant's facility representative responsible for submitting required permits, compliance plans, emissions monitoring reports, offset plans, and compliance certification, and is responsible for the requirements specified in 40 CFR Part 75 for monitoring and/or reporting SO_2, NO_x and CO_2 emissions as well as opacity and heat input at the proposed facility. As an option, natural gas and oil fired facilities may conduct fuel quality and fuel flow monitoring in place of SO_2 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.

The Applicant will also be required to submit a complete, electronic, up-to-date monitoring plan no later than 45 days prior to initial certification test as required by 40 CFR 75.62.

IX. NOISE
(State-Only Requirement)

Daytime and nighttime noise measurements were taken at eight locations around the site. The noise measurements consisted of both A-weighted sound pressure levels and octave band sound pressure levels. A-weighted sound levels emphasize the middle frequency sounds and de-emphasize lower and higher frequency sounds, and are reported in decibels designated as “dBA”. The A-weighted sound pressure levels were recorded for each of the four categories most commonly used to describe ambient noise environments: L_{90}, L_{50}, L_{10}, and L_{eq}. The L_{90} level represents the sound level exceeded 90 percent of the time and is used by the Department for the regulation of noise emissions.

In general, background (L_{90}) levels (in dBA) averaged from 35 to 42 during nighttime hours and from 40 to 55 during daytime hours.

1. The facility shall be designed, constructed, operated and maintained such that at all times:

   a) Other than as approved herein, no sound emissions shall occur that cause a condition of air pollution or exceeds the levels in the Department’s Policy 90-001; and

b) Other than approved herein, sound emissions shall not exceed the levels set forth in Table 3 at the locations as identified in said Table 3.

2. Facility personnel shall identify and evaluate all plant equipment that may cause a noise condition. Sources of noise include, but are not limited to: transformers, the air-cooled condenser, the heat recovery steam generators, the combustion turbines, natural gas compressors, main exhaust stack, and building ventilation systems.

3. The Applicant shall perform the following measures or equivalent alternative measures as noise mitigation and as indicated in (and in addition to) the Applicant's Response, dated February 14, 2000, to the Department's request for additional information with regard to noise mitigation:

a) Enclosure of the following noise-producing components of the Project within an acoustically-designed building: the gas turbines, steam turbines, electric generators, HRSGs, the high pressure and auxiliary boiler feedwater pumps, plant and instrument air compressors, and the auxiliary boiler;

b) Install low noise air-cooled condensers utilizing slower fans, additional blades, and additional surface area over the standard base model;

c) Install enhanced noise suppressants for the combustion turbine air inlets and exhausts;

d) Procure and install quiet-design transformers;

e) Install low noise closed cooling water coolers utilizing slower fans, additional blades, and additional surface area over the standard base model;

f) Install silencers on all vents including those that would or may be activated during start-up and shut down sequences.

g) Install all natural gas compressor equipment within an acoustically designed building.

h) Install lagging or enclosures on all metering equipment, such as valves and associated exposed pipes, to assure the reduction of noise from these sources.

i) Install glycol coolers at the south end of the ACC, at a point furthest away from residential neighborhoods

4. Department Noise Policy 90-0901 limits increases over the existing L_{90} background level to

10 dBA. Additionally, "pure tone" sounds, defined as any octave band level which exceeds the levels in adjacent octave bands by 3 dBA or more, are also prohibited. The Applicant, at a minimum, shall ensure that the subject facility complies with said Policy.

5. The allowable noise levels generated from the operation of the subject facility by the Applicant are summarized in Table 3 of this PROPOSED CONDITIONAL APPROVAL/PSD Permit. Further, based on the noise frequency distribution, no combination of noise sources shall result in a "pure tone condition," as previously defined.

Table 3: Allowable Noise Impacts

LOCATION	AMBIENT (L_{90},dBA)[1]	AMBIENT & PLANT (L_{90},dBA)	CHANGE (dBA)[2]
R-1 Monatiquot Street	41	47	+6
R-2 Idlewell	35	36	+1
R-3 East Braintree	37	38	+1
R-4 Quincy, W	37	38	+1
R-5 Quincy Point	42	43	+1
R-6 Germantown	39	40	+1
R-7 East Property Fence Line	41	48	+7

Table 3 Notes:

1. The lowest background levels observed during either nighttime or daytime where the noise level is exceeded 90 percent of the time (L_{90}) which is the level regulated by the Massachusetts DEP Noise Policy.

2. The Massachusetts DEP Noise Policy limits new noise increases to no more than 10 dBA over the L_{90} ambient levels. Tonal sounds, defined as any octave band level, which exceeds the levels in adjacent octave bands by 3 dBA or more are not allowed.

6. The Applicant shall conduct a noise survey in accordance with Department procedures/guidelines within 180 days of the facility start-up to verify compliance with the allowable noise impacts specified in Table 3 of this PROPOSED CONDITIONAL APPROVAL/PSD Permit. The Applicant shall provide the Department with a written report describing the results of said noise survey, within 60 days of its completion.

X. SPECIAL CONDITIONS

1. The Applicant shall submit to the Department, in accordance with the provisions of Regulation 310 CMR 7.02(2)(a), plans and specifications for the exhaust stack, combustion turbine generator set, the SCR control system (including the ammonia handling and storage system), the CO catalyst control system, facility plans, the Continuous Emissions Monitor System (CEMS) and the Continuous Opacity Monitoring System (COMS) once the specific information has been determined, but in any case not later than 30 days prior to commencement of construction/installation of each component of the subject facility.

2. The Applicant shall not allow the gas turbines at the subject facility to operate at less than 75% power, excluding start-ups and shutdowns and fuel transfers. Operation below 75% power is limited to no more than 3 hours duration for each start up, shutdown, and fuel transfer or for a duration that may be otherwise practical to achieve start-up from a cold, warm or hot turbine condition.

3. Upon the commencement of facility operation, there will be a 12-month NH3 optimization/minimization program. The program will allow the Applicant to identify and take appropriate measures designed to attain and maintain the ammonia emission limit of 2.0 ppmvd @15% O2 during all operating time (excluding start up, shut down and fuel transfer periods). Appropriate measures include a reasonable additional capital investment and/or increase in operating and maintenance expenditures.

4. The Applicant shall ensure that the SCR control equipment for each subject turbine generator is operational whenever the turbine exhaust temperature attains 558 ^{o}F at the SCR unit during natural gas firing and 608 ^{o}F during fuel oil firing. The above temperature points correspond approximately to 50% combustion turbine power during natural gas and fuel oil firing.

5. The Applicant shall maintain in the proposed facility control room, properly maintained operable, portable ammonia detectors for use during an ammonia spill, or other emergency situation involving ammonia, at the proposed facility.

6. The Applicant shall ensure that the subject ammonia storage tanks shall be equipped with high and low level audible alarm monitors.

7. The Applicant shall maintain an adequate supply of spare parts on-site to maintain the on-line availability and data capture requirements for the subject CEMS and COMS equipment servicing the proposed facility.

8. Within one year of commencement of operation, the Applicant shall file an Operating Permit application with the Department, pursuant to Regulation 310 CMR 7.00: Appendix C for the proposed facility.

9. The Applicant shall ensure that the proposed facility complies with all applicable operational standards contained in 40 CFR Part 72 and 75, 40 CFR 60, 310 CMR 7.27, and 310 CMR 7.28.11 The Applicant shall submit Standard Operating and Maintenance

Procedures (SOMP) for the entire facility to the Department no later than 30 days prior to commencement of operation of the proposed facility. Thereafter, the Applicant shall submit updated versions of the SOMP to the Department no later than 30 days prior to the occurrence of a significant change. The Department must approve of significant changes to the SOMP prior to the SOMP becoming effective. The updated SOMP shall supersede prior versions of the SOMP.

11. The Applicant shall examine and propose, as part of the final emissions test results report, a surrogate methodology or parametric monitoring for PM based on initial compliance test results.

12. The Applicant shall conduct initial compliance tests for "hot start", "warm start", "cold start", shut down, and fuel transfer periods as defined in the Applicant's Major Comprehensive Plan Application (MBR-99-COM-018, Transmittal W004896). Emission data generated from this testing shall be made available for review by the Department prior to determining and approving the maximum allowable emission rate limits (lb/hr, lb/MMBtu, ppmvd), including Opacity limits, for these periods of time. The Department shall incorporate the emission limits into the Final Approval for the facility upon issuance and such limits shall be considered enforceable. The above testing shall be for all pollutants listed in Table 1.

    The Applicant shall submit information for Department review that demonstrates that the emissions generated from the facility during these periods of time do not cause or contribute to an exceedance of applicable National Ambient Air Quality Standards (NAAQS) and Significant Impact Levels (SIL's) for SO_2 , PM_{10}, NO_2, CO or the Threshold Effects Exposure Limits (TELs) for air toxics. This information shall be submitted to the Department as part of the final emissions test results report.

XI. MONITORING AND RECORDING REQUIREMENTS

1. The Applicant shall install, calibrate, test and operate a Data Acquisition and Handling System(s) (DAHS), CEMS, and COMS to measure and record the following emissions from the subject facility:

    a) Oxygen (O_2)
    b) Oxides of Nitrogen (NO_x)
    c) Carbon Monoxide (CO)
    d) Opacity
    e) Ammonia (NH_3)

2. The Applicant shall ensure continuous monitoring and compliance with PM limits utilizing the parametric monitoring methodology developed during the initial compliance test.

3. The Applicant shall ensure that all emission monitors and recording equipment servicing

the proposed facility comply with Department approved performance and location specifications, and conform with the EPA monitoring specifications at 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.

4. The Applicant shall ensure that the proposed facility complies with all the applicable monitoring requirements contained in 40 CFR Parts 72 and 75 (Acid Rain Program), 310 CMR 7.27 (NO_x Allowance Program), and 310 CMR 7.28 (NO_x Allowance Trading Program).

5. The Applicant shall equip the CEMS and COMS with audible and visible alarms to activate whenever emissions from the proposed facility exceed the limits established in Table 1 of this PROPOSED CONDITIONAL APPROVAL/PSD Permit.

6. The Applicant shall operate each CEMS and COMS servicing the proposed facility at all times except for periods of CEMS and COMS calibration checks, zero and span adjustments, preventive maintenance, and periods of unavoidable malfunction.

7. The Applicant shall obtain and record emission data from each CEMS and COMS servicing the proposed facility for at least 75% of the emission unit's operating hours per day, except for periods of CEMS and COMS calibration checks, zero and span adjustments, and maintenance, for at least 75% of the emission unit operating hours per month, and for at least 95% of the emission unit's operating hours per quarter.

8. All periods of excess emissions at the proposed facility, even if attributable to an emergency/malfunction, start up/shutdown or equipment cleaning, shall be quantified and included by the Applicant in the determination of annual emissions and compliance with the annual emission limits as stated in Table 2 of this PROPOSED CONDITIONAL APPROVAL/PSD Permit. (**"Excess Emissions"** are defined as emissions, which are in excess of the short term emissions as stipulated in Table 1.). An exceedance of emission limits in Table 1 due to an emergency or malfunction shall not be deemed a federally permitted release as that term is used in 42 U.S.C. Section 9601(10).

9. The Applicant shall use and maintain its CEMS and COMS servicing the proposed facility as "direct-compliance" monitors to measure NO_x, CO, O_2, NH_3, and Opacity. "Direct-compliance" monitors generate data that legally documents the compliance status of a source.

10. Whenever any gas turbine is operating below 75% load, the VOC emissions shall be considered as occurring at the rate determined in the initial stack test for start up conditions.

11. If either of the proposed gas turbines is operating at 75% 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 PROPOSED CONDITIONAL APPROVAL/PSD Permit subject to correlation as contained

in Proviso X.12 below.

12. If either of the proposed gas turbines is operating at 75% 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: $VOC_{actual}=VOC_{LIMIT}$ x (CO_{actual}/CO_{limit}), pending the outcome of the initial compliance testing after which a VOC/CO correlation curve for each turbine will be developed and used for VOC compliance determination purposes.

13. The Applicant shall install and operate a continuous monitoring system to record the transportation diesel fuel oil (with a sulfur content that does not exceed 0.05 percent by weight) consumption and the ratio of water-to-fuel oil being fired in the combustion turbine.

14. The Applicant 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 proposed facility, in accordance with 40 CFR Part 60, Subparts GG 60.334(b)(2), Da, or Dc.

15. The Applicant shall monitor and record the Sulfur and Nitrogen content in the transportation diesel fuel oil (with a sulfur content that does not exceed 0.05 percent by weight) on each occasion that the oil is transferred to the bulk storage tank pursuant to 40CFR Part 60, Subparts GG 60.334(b)(2), Da, Dc, and Part 75, or pursuant to any alternative fuel monitoring schedule issued for the proposed facility, in accordance with 40 CFR Part 60, Subparts GG 60.334(b)(2), Da, or Dc.

16. The Applicant shall install and operate a continuous monitor and alarm system to monitor the temperature at the inlet to the SCR and CO catalysts servicing the proposed facility.

17. A quality control/quality assurance (QA/QC) program must be developed for the long-term operation of the CEMS and COMS servicing the proposed facility which conforms to 40 CFR Part 60, Appendix F, all applicable portions of 40 CFR Parts 72 and 75, 310 CMR 7.27 (NO_x Allowance Program) and 310 CMR 7.28 (NO_x Allowance Trading Program).

    The QA/QC program must be submitted in writing, and reviewed and approved in writing by the Department at least 30 days prior to commencement of facility operation. Any subsequent changes to the program shall be approved by the Department.

18. The Applicant shall monitor and record all required parameters for the proposed auxiliary boiler pursuant to the requirements contained in 310 CMR 7.19(5) (Medium Size Boilers).

XII. RECORD KEEPING REQUIREMENTS

1. A record keeping system for the proposed facility shall be established and maintained on site by the Applicant. All such records shall be maintained up-to-date such that year-to-date

information is readily available for Department examination upon request and shall be kept on-site for a minimum of five (5) years. Record keeping shall, at a minimum, include:

a) Compliance records sufficient to demonstrate that emissions from the proposed facility have not exceeded what is allowed by this PROPOSED CONDITIONAL APPROVAL/PSD Permit. Such records may include, but are not limited to, fuel usage rates, emissions test results, monitoring equipment data and reports.

b) Maintenance: A record of routine maintenance activities performed on the proposed emission units 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 proposed emission units control 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 proposed equipment was returned to compliance.

2. The Applicant shall maintain a file for the Certification of Analysis, verified by a qualified laboratory, of the sulfur and nitrogen content of each fuel oil delivery. The Applicant shall maintain records on natural gas consumed by the subject facility 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).

3. The Applicant shall maintain on-site for five (5) years all permanent records of output from all continuous monitors for flue gas emissions, fuel consumption, water-to-fuel ratios, SCR and CO control system inlet temperatures, and turbines inlet and ambient temperatures, and shall make these records available to the Department upon request.

4. The Applicant shall maintain a log to record problems, upsets or failures associated with the subject emission control systems, DAHS, CEMS, COMS, or ammonia handling system.

5. The Applicant shall comply with all applicable record keeping requirements regarding the subject facility contained in 40 CFR Parts 72 and 75, 40 CFR 60, 310 CMR 7.27, and 310 CMR 7.28.

6. The Applicant shall make available to the Department for inspection, upon request, the most recent five years of records as contained in Provisos XI 1., 2., 3., 4., and 5..

XIII. REPORTING REQUIREMENTS

1. All notifications and reporting required by this PROPOSED CONDITIONAL APPROVAL/PSD Permit shall be made to the attention of:

   Department of Environmental Protection/Bureau of Waste Prevention
   205A Lowell Street
   Wilmington, Massachusetts 01887
   ATTN: James Belsky, Permit Chief
   Phone: 978.661.7600
   Fax: 978.661.7615

2. The Applicant must notify the Department by telephone or fax as soon as possible, but in any case no later than three (3) business days after the occurrence of any upsets or malfunctions to the proposed facility equipment, air pollution control equipment, or monitoring equipment which result in an excess emission to the air and/or a condition of air pollution.

3. The Applicant shall notify the Department immediately by telephone or fax and within three (3) working days, in writing, of any upset or malfunction to the ammonia handling or delivery systems at the proposed facility. The Applicant also must comply with all notification procedures required under M.G.L. c. 21 E for any release or threat of release of ammonia.

4. The Applicant shall submit a quarterly report to the Department. The report shall be submitted by the 30th of the following month after the end of each quarter and shall contain at least the following information:

   a) The facility CEMS and COMS excess emission data, in a format acceptable to the Department.

   b) For each period of all excess emissions or excursions from allowable operating conditions for the proposed facility, the Applicant shall list the duration, cause, the response taken, and the amount of excess emissions. Periods of excess emissions shall include periods of start-up, shutdown, fuel transfer, malfunction, emergency, equipment cleaning, and upsets or failures associated with the emission control system or CEMS or COMS. (**"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. **"Emergency"** means any situation arising from sudden and reasonably unforeseeable events beyond the control of this source, including acts of God, which situation would require immediate corrective action to restore normal operation, and that causes the source to exceed a technology based limitation under the Approval, 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.)

c) Each period during which there was any firing of transportation diesel fuel oil (with a sulfur content that does not exceed 0.05 percent by weight). The period shall include the date of oil firing, the amount of oil fired, and the reasons for and duration of firing. This report shall summarize year-to-date the number of hours of transportation diesel fuel oil use and the total amount of transportation diesel fuel oil burned.

d) A tabulation of periods of operation (dispatch) of the proposed facility.

5. The Applicant shall ensure that the subject facility complies with all applicable reporting requirements contained in 40 CFR Parts 72 and 75, 40 CFR 60, 310 CMR 7.27, and 310 CMR 7.28.

6. In accordance with 310 CMR 7.12(7), the Applicant shall ensure that the proposed facility registers 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.

7. The Applicant shall submit to the Department no later than 13 months after the commencement of operation of the subject facility an ammonia optimization/minimization program report prepared by a qualified independent third-party that shall contain:

a) a summary of the record of deviations from the ammonia emission limit;

b) an evaluation of the reasons for deviations from the ammonia limit;

c) recommendations on all appropriate measures designed to eliminate or mitigate NH_3 deviations and to meet the 2.0 ppmvd@15% O_2 NH_3 emission limit on a 1-hour basis, including a description of all capital investments which have been or will be made to modify or substitute for existing control equipment or changes to operation and maintenance procedures (with a description of the cost, timeline and emission reduction to be achieved by each option);

d) recommendations on any modifications to this CONDITIONAL APPROVAL/PSD Permit that are necessary to implement the identified appropriate measures.

XIV. TESTING REQUIREMENTS

1. The Applicant shall ensure that the proposed facility shall be constructed to accommodate the emissions (compliance) testing requirements contained herein. All emissions testing shall be conducted in accordance with the Department's "Guidelines for Source Emissions Testing" and in accordance with the Environmental Protection Agency reference test methods as specified in 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. The Applicant shall conduct initial compliance tests must be conducted within 180 days after initial start up of the proposed facility.

3. The Applicant must obtain written Department approval of an emissions test protocol. The protocol shall include detailed description of sampling port locations, sampling equipment, sampling and analytical procedures, and operating conditions for any such emissions testing. It must be submitted to the Department at least 90 days prior to commencement of testing of the facility.

4. The Applicant shall ensure that a final emissions test results report is submitted to the Department within 60 days of completion of the emissions testing program.

5. The Applicant shall conduct initial compliance tests to demonstrate compliance with the emission limits (lb/hr, lb/MMBtu, ppmvd as applicable, and opacity) of the proposed combustion turbines and the auxiliary boiler as specified in Table 1 for the pollutants listed below. Sulfuric Acid Mist testing shall be included for the combustion turbines when firing of transportation diesel fuel oil (with a sulfur content that does not exceed 0.05 percent by weight). Testing for these pollutants for the combustion turbines will be conducted at four (4) representative steady state loads (but not less than 75% of rated base load), except for PM which will be conducted at 100% of rated base load only. The auxiliary boiler will be tested for NO_x and CO at 100% of rated base load.

Natural Gas Firing	**Transportation Distillate Oil Firing**
Nitrogen Oxides (NO_x)	Nitrogen Oxides (NO_x)

Carbon Monoxide (CO)	Carbon Monoxide (CO)
Volatile Organic Compounds (VOC)	Volatile Organic Compounds (VOC)
Particulate Matter (PM) and Opacity	Particulate Matter (PM) and Opacity
Ammonia (NH_3)	Ammonia (NH_3)
	Sulfuric Acid Mist

6. The Applicant's emissions testing for VOC for the proposed facility shall include VOC testing for the duration of a start up, in order to determine the total mass emissions of VOC during start up conditions. The Applicant shall determine VOC compliance by the VOC/CO correlation curve that will be developed during the same time period as the Project's ammonia optimization/minimization program.

7. In accordance with 310 CMR 7.04(4)(a), the Applicant shall have the proposed units 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 proposed equipment.

8. In accordance with 310 CMR 7.13 the Department may require additional emission testing of the proposed facility at any time to ascertain compliance with the Department's Regulations or any proviso(s) contained in this PROPOSED CONDITIONAL APPROVAL/PSD Permit.

9. The Applicant shall comply with all applicable testing requirements contained in 40 CFR Parts 72 and 75, 40 CFR 60, 310 CMR 7.27, and 310 CMR 7.28 regarding the proposed facility.

XV. GENERAL REQUIREMENTS

1. The Applicant shall properly train all personnel to operate the proposed facility and control equipment in accordance with vendor specifications. All persons responsible for the operation of the proposed 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. Refresher training shall be given by the Applicant to facility personnel at least once annually.

2. All requirements of this PROPOSED CONDITIONAL APPROVAL/PSD Permit which apply to the Applicant shall apply to all subsequent owners and/or operators of the facility.

3. The Applicant shall maintain the standard operating and maintenance procedures for the subject ammonia handling systems in a convenient location (e.g., control room/technical library) and make them readily available to all employees.

4. The Applicant 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.

5. The Applicant shall ensure that the proposed facility complies with the requirements of Regulation 310 CMR 7.27(7) and 310 CMR 7.28 in the NO_x Allowance Program and NO_x Allowance Trading Program by the submission of an Emission Control Plan within 6 months of issuance of a CONDITIONAL APPROVAL/PSD Permit. In addition, the facility must submit a monitoring plan, and install, operate and certify the emission monitoring systems required by 310 CMR 7.27(11) within 90 days after the date the unit commences operations.

6. Within 60 days of start up of the proposed facility, the roadways servicing said facility shall be paved and maintained free of deposits that could result in excessive dust emissions.

7. SUSPENSION - This PROPOSED CONDITIONAL APPROVAL/PSD Permit 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.

8. OTHER REGULATIONS - This PROPOSED CONDITIONAL APPROVAL/PSD Permit 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 PROPOSED CONDITIONAL APPROVAL/PSD Permit imply compliance with any other applicable federal, state or local regulations now or in the future.

9. DUST AND ODOR - The proposed 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 Regulations 310 CMR 7.01 and 7.09.

10. ASBESTOS - Should asbestos remediation/removal be required as a result of this PROPOSED CONDITIONAL APPROVAL/PSD Permit, such asbestos remediation/removal shall be done in accordance with Regulation 310 CMR 7.15 and 310 CMR 4.00.

11. MODIFICATIONS - Any proposed increase in emissions above the limits contained in this PROPOSED CONDITIONAL APPROVAL/PSD Permit must first be approved in writing by the Department pursuant to 310 CMR 7.02. In addition, any emissions increase may subject the facility to additional regulatory requirements.

12. 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.

13. The proposed facility shall be constructed and operated in strict accordance with the APPROVAL/PSD Permit herein. Should there be any differences between the Applicant's Major Comprehensive Plan Application (MBR-99-COM-018, Transmittal W004896) and this APPROVAL/PSD Permit, this APPROVAL/PSD Permit shall govern.

XVI. CONSTRUCTION REQUIREMENTS

During the construction phase of the proposed facility, the Applicant shall ensure that facility personnel take all reasonable precautions (noted below) to minimize air pollution episodes (dust, odor, and noise):

1. Facility personnel shall exercise care in operating any noise generating equipment (including mobile power equipment, power tools, etc.) at all times to minimize noise.

2. Construction vehicles transporting loose aggregate to or from the facility shall be covered and shall use leak tight containers.

3. During construction open storage areas, piles of soil, loose aggregate, etc. shall be covered or watered down as necessary to minimize dust emissions.

4. Any spillage of loose aggregate and dirt deposits on any public roadway, leading to or from the proposed facility shall be removed by the next business day or sooner, if necessary. (A mobile 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.

XVII. DETERMINATION OF PSD APPLICABILITY AND PSD PERMIT

I. Background

The federal government under the jurisdiction of the Environmental Protection Agency (EPA) established National Ambient Air Quality Standards (NAAQS) for six air contaminants, known as criteria pollutants, for the protection of public health and welfare. These criteria pollutants are Sulfur Dioxide (SO_2), Particulate Matter having a diameter of 10 microns or less (PM_{10}), Nitrogen Oxides (NO_x), Carbon Monoxide (CO), Ozone (O_3), and Lead (Pb).

The state government under the jurisdiction of the Department of Environmental Protection (the Department) has adopted these ambient air quality standards for the Commonwealth of Massachusetts as stated under 310 CMR 6.00 of the Air Pollution Control Regulations. One of the basic goals of federal and state air regulations is to ensure that ambient air quality, including the impact of existing and new sources, complies with ambient standards.

Towards this end, EPA classified all areas of the country as "attainment", "nonattainment", or "unclassified" with respect to the NAAQS.

New major sources of regulated air pollutants or major modifications to existing major sources of regulated air pollutants that are located in areas classified as either "attainment" or "unclassified" are subject to Prevention of Significant Deterioration ("PSD") regulations promulgated under 40 CFR Section 52.21. Pursuant to 40 CFR 52.21(b)(1)(I)(a.) of the PSD Regulations, an attainment pollutant source is considered "major" if it has the potential to emit 100 tons per year (tpy) or more of any pollutant and is listed as one of the 28 designated PSD stationary source categories; or if it is an unlisted source and has the potential to emit 250 tons per year (tpy) or more of any pollutant regulated under the Clean Air Act.

Effective July 1, 1982, the PSD program was implemented by the Department in accordance with the Department's "Procedures for Implementing Federal Prevention of Significant Deterioration Regulations". On July 23, 1999, Sithe Edgar Development LLC ("the Permittee") submitted to the Department an application for a Prevention of Significant Deterioration (PSD) Permit to construct and operate a new 775 megawatt (MW) combined-cycle combustion turbine electric power generation facility at Fore River Station in Weymouth, Massachusetts. This proposed facility is one of the 28 designated PSD stationary source categories, namely a fossil fuel fired steam electric plant of more than 250 million Btu/hr heat input. Fore River Station is an existing major source of regulated air pollutants.

II. General Information

A. PSD Applicability Determination & Attainment Status

The Permittee is proposing to build a combined-cycle combustion turbine electric power generation facility in Weymouth, Massachusetts. The proposed facility will be located in an area which is in either "attainment" or "unclassified" for Sulfur Dioxide (SO_2), Nitrogen Dioxide (NO_x), Carbon Monoxide (CO), Lead (Pb), and total Particulate Matter (PM), which includes PM that does not exceed 10 microns in size (referred to as PM_{10}). Therefore, the proposed facility will be located in a PSD area for these pollutants. The proposed facility would be categorized as a major modification to an existing major source if emissions were to increase by greater than the following significant PSD pollutant emission rates: 40 tpy of SO_2, 40 tpy of NO_x, 100 tpy of CO, 0.6 tpy of Pb, 25 tpy of PM, 15 tpy of PM_{10}, 7 tpy of Sulfuric Acid (H_2SO_4), or varied emission rates of miscellaneous PSD pollutants.

The proposed facility will have a net increase in emissions above PSD significance levels for SO_2, NO_x, CO, PM, $PM_{10,}$ and $H_2SO_{4.}$ Therefore, PSD review will be required for these pollutants (see 40 CFR 52.51 (b)(23)). The estimated emissions of lead (Pb) as well as other miscellaneous PSD pollutants are not expected to rise above PSD significance levels, therefore, PSD review will not be required for these pollutants.

For information and regulatory requirements concerning Nonattainment New Source Review (NSR), please see Section V of this document.

Table 1 shows the potential maximum annual emissions from the proposed facility, the potential maximum annual emissions from the existing facility and the net emission increases with respect to PSD significance levels for the various pollutants.

Table 1: Fore River Station PSD Pollutant Applicability Evaluation					
Pollutant	**Potential Maximum Annual Emissions from New Equipment (tpy)(1)(2)**	**Potential Maximum Annual Emissions from Existing Equipment (tpy)**	**Net Emission Increase (tpy)**	**PSD Significant Emission Rate (tpy)**	**PSD Review Required?**
NO_X	218	644	+218	40	Yes
SO_2	154	554	154	40	Yes
CO	296	387	+296	100	Yes
PM	352	196	+352	25	Yes
PM_{10}	352	196	+352	15	Yes
Sulfuric Acid Mist	99	8.3	+99	7	Yes
Lead	0.25	0.0007	+0.25	0.6	No
Other PSD Pollutants(3)	None Expected	None Expected	None Expected	Varies	No

Table 1 Notes:

(1) Based on 8040 hours of natural gas operation at 51^0F , 720 hours of oil operation at -12^0F

(2) The auxiliary boiler (NO_x emissions less than 3 tpy as shown in Appendix B of the submitted application) will not operate concurrently with the turbines except during startup and will not affect potential emissions. The emergency generator will operate only to shut down the facility if no power is available from the utility grid. The auxiliary boiler and emergency generator emissions, estimated in Appendix B of the submitted application, will not impact the project's potential emissions.

(3) Other PSD include vinyl chloride, asbestos, fluorides, hydrogen sulfide, and reduced sulfur compounds.

NO_x = oxides of nitrogen
CO = carbon monoxide
PM = particulate matter
SO_2 = sulfur dioxide
PM_{10} = particulate matter less than 10 microns in aerodynamic diameter
tpy = tons per twelve month rolling calendar period

B. Site Information

The proposed facility will be constructed on the existing 57 acre Fore River Station site located in Weymouth, Massachusetts. The City of Weymouth is located in Norfolk County in the southeast area of the Commonwealth of Massachusetts. The Fore River Station site is located approximately 10 miles southeast of downtown Boston. The site is now principally occupied by two 12 MW simple cycle combustion turbines. These two combustion turbines are used for peaking power only and utilize No. 2 distillate oil (with a sulfur content that does not exceed 0.3 percent by weight) as the only fuel of use. The site will provide convenient access to both the interstate natural gas pipeline system and to the New England electric power transmission grid.

The site area consists of a mix of industrial, commercial, and residential properties. The nearest residential area is located approximately 50 feet east from the fence line. The site is bordered by Monatiquot Street to the east, the Weymouth Fore River to the west and south, and Bridge Street (Route 3A) to the north.

The topography within 2 to 3 miles surrounding the Project site is relatively flat except for several isolated hills. The closest hills include King Oak Hill to the southeast, Baker Hill to the east, Weymouth Great Hill to the east-northeast, Quincy Great Hill to the north-northeast, Forbes Hill to the west-northwest, and Penns Hill to the west-southwest. The topography in the more distant region to the west and south of the Project site is generally hilly. The proposed facility will be located at an elevation of 21 feet above mean sea level. The closest elevation above the stack top of the proposed facility is Rattlesnake Hill on the northeastern edge of the Blue Hill Reservation, approximately 3.7 miles to the west-southwest to the site.

C. Operation Information

The Permittee is proposing to develop, construct and operate a new natural gas-fired, with back up No. 2 transportation distillate oil (with a sulfur content that does not exceed 0.05 percent by weight), combined-cycle electric power generation facility at Fore River Station. The proposed facility will be designed to provide a total nominal electric power output rating of 775 MW to Massachusetts utility companies. The proposed facility will include major equipment comprised of two combustion turbines, two respective heat recovery steam generators (HRSGs) with supplemental duct firing, and one steam turbine. The proposed facility will be configured as one main power block, which will contain two combustion turbine units, each generating 250 MW of electric power. The power block will be arranged in a two-on-one configuration: two combustion turbines, two supplementary-fired HRSGs, and a single steam turbine with a nominal generating capacity of approximately 275 MW. In addition, the Permittee is proposing to install a natural gas-fired with back-up No. 2 transportation distillate oil auxiliary boiler and a diesel oil-fired generator to support emergency conditions.

The existing Fore River Station includes two 12 MW simple cycle combustion turbines used for peaking power only. Each combustion turbine fires No. 2 fuel oil with a maximum sulfur content of 0.3 weight percent as the only fuel of use. The existing Fore River Station peaking units comprised of Edgar Units J1 and J2 will continue to operate as peaking units. These peaking units shall not operate when the proposed facility is operating on back-up oil.

III. Additional Regulatory Air Pollution Requirements

A. Federal

The electric generating facility is subject to the Federal New Source Performance Standards (NSPS), 40 CFR Part 60 Subpart GG, Standards of Performance for Stationary Gas Turbines, which sets SO_2 and NO_x emission limitations and specifies certain monitoring and reporting requirements. The facility will have emission rates, which are significantly less than the NSPS rate. The Department has the responsibility to enforce the NSPS regulations that affect stationary gas turbines.

B. State

The Commonwealth of Massachusetts, Department of Environmental Protection has a number of emission limitations and other air pollution control requirements as set forth in the DEP Air Pollution Control Regulations (310 CMR 7.00) that apply to the combined cycle electric generating facility. The requirements are summarized below.

1) Section 7.01 - General Regulations to Prevent Air Pollution: General Prohibition of Causing a Condition of Air Pollution

2) Section 7.02(2) - Plan Approval and Emission Limitations: requires pre-construction review of plans, specifications, standard operating procedures and standard maintenance procedures, a BACT determination and Department approval in writing.

3) Section 7.04 - Fuel Utilization Facilities ("FUF"): requires pre-construction review of certain sized fuel utilization facilities.

4) Section 7.06 - Visible Emissions: The emissions of smoke from a stationary source must be controlled by the application of modern technology, but in no case shall exceed opacity and smoke as specified in the regulation.

5) Section 7.09 - Dust and Odor, Construction and Demolition: The generation of dust or odor may not cause or contribute to a condition of air pollution.

6) Section 7.10 - Noise: The generator of noise may not cause or contribute to a condition of

air pollution.

7) Section 7.13 - Stack Testing: Requires stack testing if the Department has determined that such testing is necessary.

8) Section 7.14 - Monitoring Devices and Reports: Allows the Department to require sources to install, maintain and use monitoring devices of a design and installation approved by the Department and requires periodic reports on emissions.

9) Section 7.27 and Section 7.28 - NO_x Allowance Program and NO_x Allowance Trading Program: Requires a monitoring plan and certification of the CEMS and establishes the requirements and guidelines for NO_x allowances and trading.

10) Air Toxics Policy - The Department has established ambient guidelines for over 100 air toxic pollutants. The Permittee's compliance with these guidelines is addressed in Section V. Ambient Air Quality Impact Analysis, F. Air Toxics Analysis.

11) Operating Permit - Within one year of commencement of operation, the facility must file an application for an operating permit pursuant to Regulation 310 CMR 7.00, Appendix C.

12) 310 CMR 7.00, Appendix A, Emission Offset & Nonattainment Review - which requires certain size facilities to comply with offsetting of emissions and use of lowest achievable emission rate technology.

C. Nonattainment Issues

The Weymouth area has been designated Nonattainment for Ozone only. For information and regulatory requirements concerning Nonattainment NSR, please see Section V of this document.

IV. Control Technology Review

The proposed combined-cycle electric generating facility is required to evaluate Best Available Control Technology (BACT) as it applies to emissions of Sulfur Dioxide (SO_2), Nitrogen Oxides (NO_x), Carbon Monoxide (CO), Particulate Matter (PM/PM_{10}), and Sulfuric Acid Mist (H_2SO_4) (Nitrogen Oxides are also subject to Lowest Achievable Emission Rate (LAER) since NO_x is an Ozone precursor – See pages 11 and 12 of this PROPOSED CONDITIONAL APPROVAL/PSD Permit). BACT is defined as the optimum level of control applied to pollutant emissions based upon consideration of technical, economic, and environmental factors.

The first step in a BACT analysis is to determine for the emission source, the most stringent control available for a similar or identical source or source category. The Department has verified and concurs with the Permittee’s BACT analysis as presented in its Major

Comprehensive Plan Application (MBR-99-COM-018, Transmittal W004896). The proposed combined-cycle electric generating facility must utilize BACT to control the emissions of the following pollutants.

A. Sulfur Dioxide (SO_2)

The control technologies for SO_2 emissions include flue gas desulfurization and fuel type. The Permittee has proposed an emission rate for SO_2 of 0.0023 pounds per million British thermal units (lbs/MMBtu) input when firing natural gas and 0.0522 lbs/MMBtu input when firing transportation distillate fuel oil (with a sulfur content that does not exceed 0.05 percent by weight). The Department has concluded that use of natural gas, which contains negligible sulfur, as the primary fuel and transportation distillate fuel oil as the back-up fuel is regarded as BACT for SO_2 and additional SO_2 emission controls are not required

B. Nitrogen Oxides (NO_x)

In order to reduce the NO_x emissions, the Permittee proposes to utilize the NO_x control techniques dry low NO_x combustion, water injection for NO_x control on oil and Selective Catalytic Reduction (SCR) in the heat recovery steam generator (HRSG) to achieve a NO_x emission rate of 2.0 ppmvd at 15% O_2 when firing natural gas and 6.0 ppmvd at 15% O_2 when firing transportation distillate fuel oil (with a sulfur content that does not exceed 0.05 percent by weight). These NO_x emission rates are more stringent than the 75 ppm NO_x emission rate for combustion turbines contained in Subpart GG of the New Source Performance Standards. The Department has concluded that these emission rates are BACT (as well as LAER) for NO_x and that additional NO_x emission controls are not required.

C. Particulate Matter (PM/PM_{10})

The control technologies for PM/PM_{10} emissions include fabric filter collector, electrostatic precipitators, and wet scrubbers and fuel type. The Permittee has proposed an emission rate for PM/PM_{10} of 0.011 lbs/MMBtu input when firing natural gas and 0.050 lbs/MMBtu input when firing transportation distillate fuel oil (with a sulfur content that does not exceed 0.05 percent by weight). The Department has concluded that use of natural gas, essentially ash free, as the primary fuel and transportation distillate fuel oil as the back-up fuel is regarded as BACT for PM/PM_{10} and that additional PM/PM_{10} emission controls are not required.

D. Carbon Monoxide (CO)

CO emissions are formed due to incomplete combustion of the fuel in the combustion process. Control methods that reduce CO are combustion controls (less stringent) and catalytic oxidation (most stringent). The Permittee proposes the use of an 89% efficient oxidation catalyst as BACT to limit CO emissions to 2.0 ppmvd at 15% O_2 when firing natural gas. The Permittee proposes the oxidation catalyst as BACT to limit CO emissions to 7.0 ppmvd at 15% O_2 when firing transportation distillate fuel oil (with a sulfur content that does not exceed 0.05 percent by weight). The Department has concluded that these emission rates are BACT for CO and that additional CO emission controls are not required. The use of higher CO removal efficiency catalyst would lead to higher emissions of sulfuric acid mist and PM_{10} due to higher conversion of SO_2 and downstream reaction of SO_3 with ammonia slip from the NO_x SCR system.

E. Sulfuric Acid Mist (H_2SO_4)

H_2SO_4 emissions are formed due to sulfur in the fuel that oxidizes to SO_3 and then combines with H_2O to form H_2SO_4. The Permittee has proposed an emission limitation for H_2SO_4 of 0.0016 lb/MMBtu input when firing natural gas and 0.032 lbs/MMBtu input when firing transportation distillate fuel oil (with a sulfur content that does not exceed 0.05 percent by weight). The Department has concluded that the use of natural gas, which contains negligible sulfur, as the primary fuel and transportation distillate fuel oil as the back-up fuel is regarded as BACT for H_2SO_4 and that additional H_2SO_4 emission controls are not required.

V. Air Impact Analysis

A. General Conditions

An air quality impact analysis was performed to assess Project air quality concentrations against applicable State and Federal standards. This modeling was based on EPA's SCREEN3, Industrial Source Complex Short Term (ISCST3), and CTSCREEN models using terrain data from USGS topographic maps. In addition, the Offshore and Coastal Dispersion Model (OCD) was used to assess potential coastal fumigation effects on plume dispersion. Results for the load conditions that produced the highest predicted concentrations were then compared to significant impact levels (SILs) or ambient air quality standards/PSD increments.

The modeling included the use of EPA recommended ISCST3 (Industrial Source Complex Short Term Version 3) model in the refined mode with hourly meteorological data. The meteorological data that was used consisted of five years of surface observations (1991-1995) collected by the National Weather Service at Logan Airport and one year of Clean Harbor's meteorological data (11/1/88-10/31/89). Modeling was performed for a single stack containing two flues, which is 255 feet tall. The SCREEN3 model was used as an initial analysis for simple and intermediate/complex terrain receptors. The refined modeling techniques included the use of ISCST3 model for simple terrain and CTSCREEN for intermediate and complex terrain. The predicted concentrations are based on the combustion turbine operating under maximum operating conditions. Table 2 presents the maximum predicted concentrations for the new combined cycle units at Fore River Station. Details of the modeling analysis are presented in the PSD/NSR application and the Major Comprehensive Plan Application. The proposed combined cycle units are predicted to have maximum predicted concentrations below SILs for all pollutants and averaging periods. The OCD model also predicted concentrations below the SILs. The maximum concentrations in Table 2 below are based on 8040 hours of operation burning natural gas at 100% load @ -12^{0}F and 720 hours burning fuel oil at 100% load @ -12^{0}F.

Table 2: Maximum Predicted Concentrations for New Combined Cycle Units Criteria

Pollutants					
Pollutant	**Averaging Time**	**Significant Impact Level (ug/m^3)**	**Class II PSD Increment (ug/m^3)**	**NAAQS (ug/m^3)**	**Maximum Concentrations (ug/m^3)**
SO_2	3-HOUR 24-HOUR ANNUAL	25 5 1	512 91 20	1,300 365 80	15.07(2) 3.23(2) 0.20(1)
PM_{10}	24-HOUR ANNUAL	5 1	30 17	150 50	3.14(2) 0.50(1)
NO_2	ANNUAL	1	25	100	0.31(1)
CO	1-HOUR 8-HOUR	2,000 500	No PSD increment established	40,000 10,000	4.31(1) 3.02(1)

Table 2 Notes:

1 = SCREEN3
2 = CTSCREEN
NO_2 = nitrogen dioxide
CO = carbon monoxide
SO_2 = sulfur dioxide
PM_{10} = particulate matter less than 10 microns in aerodynamic diameter
ug/m^3 = micrograms per cubic meter

B. Class I Area Impact Analysis

The nearest Class I area is the Lye Brook National Wilderness area in southern Vermont. This area is to the northwest at a distance of approximately 188 kilometers. Predicted concentrations for each pollutant are well below significant impact levels in this area. The maximum significance levels were not exceeded and the facility will not significantly impact the nearest Class I area.

C. Visibility Impairment Analysis

The Fore River Station Project is located about 188 kilometers to the southeast of the PSD Class I Lye Brook Wilderness Area in southern Vermont and 206 kilometers to the south of the PSD Class I Presidential Range areas in New Hampshire. A visibility impairment analysis, using the VISCREEN model, was performed in order to determine the affect of pollutants on altering the color of the sky or contrast of terrain features with the horizon. Under worst case operations, the visibility impacts were well below screening level thresholds at all these Class I areas.

D. Growth Analysis

The Permittee will provide electricity to the utility grid to satisfy general electric demand. There is not expected to be any appreciable industrial, commercial, or residential growth that would occur as a direct result of this Project due to the self sufficient nature of the proposed facility and the modest number of permanent employees required in plant operations. Therefore, there will be negligible growth-related air pollution impacts from the proposed Project.

E. Cumulative Impacts with the Major Sources in the vicinity of the Proposed Plant

A formal source interaction analysis for the proposed combined cycle units is not required since the maximum predicted concentrations are less than the SILs in all cases. However, based on comments received in the MEPA process, a cumulative impact assessment was performed to demonstrate that combined impacts of the new combined cycle units plus impacts from the existing Edgar Station units, plus the impacts of potential major sources in the vicinity (a 10 mile radii of the proposed Fore River Station) of the plant, plus background, do not exceed applicable air quality standards. This cumulative impact analysis was performed with the ISCST3 model with both 1991-1995 Boston meteorological data and one year of Clean Harbors data.

The results of the cumulative impact analysis show maximum cumulative impacts are below the applicable ambient air quality standards for all air pollutants and averaging periods.

F. Air Toxics Analysis

The Permittee also conducted dispersion modeling for pollutant emissions from the new combined cycle units for non-criteria air pollutants (i.e. applicable metals, metal oxides, ammonia, phosphoric acid, sulfuric acid, and formaldehyde). This analysis was also performed with the ISCST3 model for simple terrain with 1991-1995 meteorological data, and the CTSCREEN model for intermediate /complex terrain. The 24-hour average concentrations were computed for both oil firing and natural gas firing scenarios. The annual average concentrations were computed assuming 8040 hours of operation on natural gas and 720 hours of operation on oil.

A summary of maximum predicted concentrations and the Department's guideline levels is provided in Table 3. The 24-hour concentrations presented represent the maximum of the oil firing or gas firing scenario. All the 24-hour average concentrations presented in Table 3 are based on oil firing, except for formaldehyde.

Table 3: Maximum Predicted Concentrations for New Combined Cycle Units Air Toxics			
Pollutant	**Averaging Time**	**Department Guideline Level (ug/m^3)**	**Maximum Concentrations (ug/m^3)[1]**

Table 3: Maximum Predicted Concentrations for New Combined Cycle Units Air Toxics			
Pollutant	**Averaging Time**	**Department Guideline Level (ug/m^3)**	**Maximum Concentrations (ug/m^3)[1]**
Ammonia	24-HOUR ANNUAL	100 100	0.19 0.05
Sulfuric Acid	24-HOUR ANNUAL	2.72 2.72	1.98 0.06
Formaldehyde	24-HOUR ANNUAL	0.33 0.08	0.02 0.01
Antimony	24-HOUR ANNUAL	2.0 1.0	1.48E-03 2.42E-05
Arsenic	24-HOUR ANNUAL	5.00E-04 2.00E-04	1.65E-04 3.58E-06
Beryllium	24-HOUR ANNUAL	1.00E-03 4.00E-04	2.23E-05 3.63E-07
Cadmium	24-HOUR ANNUAL	3.00E-03 1.00E-03	2.63E-04 1.96E-05
Chromium	24-HOUR ANNUAL	1.36 0.68	3.51E-04 5.72E-06
Hexavalent Chromium	24-HOUR ANNUAL	3.00E-03 1.00E-04	6.30E-05 2.48E-05
Copper	24-HOUR ANNUAL	0.54 0.54	8.77E-02 1.43E-03
Lead	24-HOUR ANNUAL	0.14 0.07	3.66E-03 3.52E-04
Mercury	24-HOUR ANNUAL	0.14 0.07	5.85E-05 8.97E-06
Nickel	24-HOUR ANNUAL	0.27 0.18	3.49E-04 5.68E-06
Nickel Oxide	24-HOUR ANNUAL	0.27 0.01	4.45E-04 7.26E-06
Phosphoric Acid	24-HOUR ANNUAL	0.27 0.27	6.48E-02 1.06E-03

Table 3: Maximum Predicted Concentrations for New Combined Cycle Units Air Toxics			
Pollutant	**Averaging Time**	**Department Guideline Level (ug/m^3)**	**Maximum Concentrations (ug/m^3)^1**
Selenium	24-HOUR ANNUAL	0.54 0.54	3.58E-03 5.83E-05
Vanadium	24-HOUR ANNUAL	0.27 0.27	2.97E-04 4.84E-06
Vanadium Pentoxide	24-HOUR ANNUAL	0.14 0.03	1.06E-03 1.73E-05

Table 3 Notes:

1- ISCST3 was used for the 24-hour natural gas concentrations; CTSCREEN was used for the 24-hour and annual oil concentrations.
2- Annual average assumes 8040 hours of operation burning natural gas at 100% load @ -12^{0}F and 720 hours burning fuel oil at 100% load @ -12^{0}F.
3- All toxic emission rates are based on AP-42 5/95, except that arsenic, chromium, hexavalent chromium, nickel and nickel oxide are based on lab analysis of the fuel, and formaldehyde is based on AP-42, 5/98 emission factor.
ug/m^3 = micrograms per cubic meter

VI. Vegetation And Soils

1. PSD regulations require analysis of air quality impacts on sensitive vegetation types, with significant commercial or recreational value, or sensitive types of soil.

2. Most of the designated vegetation screening levels are equivalent to or exceed NAAQS and/or PSD increments, so that satisfaction of NAAQS and PSD increments assures compliance with sensitive vegetation screening levels.

3. For SO_2, 3-hour and annual sensitive vegetation screening levels are more stringent than comparable NAAQS standards, and there is a 1-hour screening level for SO_2 for which there is no NAAQS equivalent. Maximum 1-hour, 3-hour, and annual SO_2 concentrations from the new units were added to background levels and compared to the vegetation sensitivity concentrations. The 1-hour, 3-hour, and annual vegetation sensitivity threshold values are 917 ug/m^3, 786 ug/m^3, and 18 ug/m^3, respectively. The maximum 1-hour, 3-hour, and annual average concentrations from the proposed new combined cycle units are 13.22 ug/m^3, 15.10 ug/m^3, and 0.20 ug/m^3, respectively which are well below the sensitive vegetation screening level thresholds.

When cumulative impacts with background and the existing Fore River Station are considered, an exceedance is predicted to occur for the annual averaging period. This exceedance is largely due to the existing background ambient concentration. The background level of 23.6 ug/m^3, which is already above the annual sensitivity threshold, was conservatively obtained from the Kenmore Square monitoring location in Boston. This monitoring location is an urban location where higher levels of SO_2 are expected, than at the more suburban/rural coastal environment of Weymouth. The project contribution to the annual SO_2 concentration is less than 0.1%. The usage of natural gas as the primary fuel and transportation distillate fuel oil as the back-up fuel is the best available control for SO_2 emissions from the new combined cycle units at Fore River Station.

XVIII. SECTION 61 FINDINGS

The Applicant's Environmental Impact Report (EIR) has been carefully considered prior to action on their plan application approval request. The Department, in issuing this PROPOSED CONDITIONAL APPROVAL/PSD Permit, requires the Applicant to use all feasible means and measures to avoid or minimize adverse environmental impacts. Measures the Department deems necessary to mitigate or prevent harm to the environment are included in the conditions of this PROPOSED CONDITIONAL APPROVAL/PSD Permit. The Department has made its decision under applicable law based on a balancing, where appropriate, of environmental and socioeconomic objectives, as mandated by 301 CMR 11.01(4).

Pursuant to M.G.L. Chapter 30 Section 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 September 16, 1999 (EOEA #11726) the Department's Section 61 Findings on the Fore River Development Project determining that all feasible measures have been taken to avoid or minimize impacts to the environment are presented here as follows.

Introduction

This Section 61 Finding has been prepared in compliance with the requirements of Massachusetts General Laws Chapter 30, Section 61. Chapter 30 Section 61 requires state agencies and authorities to review, evaluate and determine impacts on the natural environment of all projects or activities conducted or permitted by them, and to undertake all feasible means and measures to minimize and prevent damage to the environment. In making a determination, agencies are required to issue a "Section 61 Finding" describing project impacts, and certifying that all feasible mitigation measures have been taken.

The Section 61 Finding is associated with the construction of the Fore River Station, a 775 MW natural gas fired combined cycle power plant to be developed and operated by Sithe Edgar Development, LLC (Sithe). The project is proposed to be located on the site of the former Edgar Station, a 57-acre property on the Weymouth Fore River on the Weymouth/Quincy town line in Massachusetts.

History of MEPA Review

Sithe submitted an Environmental Notification Form for the Fore River Station Project to the MEPA Unit on July 15, 1998. The project was noticed in the Environmental Monitor on July 22, 1998. The Secretary of Environmental Affairs issued a Certificate on the ENF on August 21, 1998. The Secretary determined that the project required a Draft Environmental Impact Report (DEIR) and provided the scope of the DEIR.

The DEIR was filed with the Secretary on February 15, 1999. It was noticed in the Environmental Monitor on February 23, 1999. The Secretary of Environmental Affairs issued a Certificate on the DEIR on April 8, 1999.

The Final Environmental Impact Report (FEIR) was filed on August 2, 1999. It was noticed in the Environmental Monitor on August 10, 1999. On September 16, 1999, the Secretary of Environmental Affairs issued a Certificate stating that the FEIR adequately and properly complies with the Massachusetts Environmental Policy Act and with its implementing regulations.

A List of State Permits

The Fore River Station project requires a number of state permits that trigger review under the Massachusetts Environmental Policy Act. The issuing authorities must comply with MGL C. 30, Section 61 to ensure that the proponent has described the impacts and proposed mitigation to minimize and prevent damage to the environment. A list of the state permits required by the project was provided in Section 2.4, Table 2-1 of the FEIR.

Project Mitigation Measures

In this Section 61 Finding, individual mitigation measures that will be undertaken by Sithe both during construction and the operational life of the Project are discussed. These measures are anticipated to reduce or eliminate many of the potential environmental impacts of the Project.

Attachment A is a table summarizing the potential environmental impacts associated with the Project, the mitigation measures which will be undertaken to address each, and a statement of assumed financial responsibility for each.

Attachment B is a summary of the implementation schedule for mitigation measures associated with construction activities.

Attachment C is a summary of the implementation schedule for mitigation measures associated with operation of the Project. Note that all of these measures will remain in force through the life of the Project.

Overview of Project Impacts

Potential impacts from the Fore River Station project are defined as either construction or post-construction and grouped by issue areas. The issue areas are:

- Air Quality
- Noise
- Visual
- Wetlands / Dredging
- Water Use
- Wastewater Discharge
- Stormwater
- Cultural
- Traffic
- Hazardous Materials
- Construction

Project impacts are summarized by issue area below. The potential environmental effects of each impact are described, followed by the proposed mitigation measures that will offset potential impacts

Air Quality

Air impacts are primarily limited to the operation of the Fore River Station during post-construction. Dust control during construction is discussed under Construction Impacts, below.
The Fore River Station will generate air emissions during fuel combustion to produce energy. Nitrogen Oxides (NO_x) are formed in the turbine combustion chamber primarily as a result of the reaction between nitrogen and oxygen (O_2) (oxidation). During oil firing, NO_x is also formed by oxidation of fuel-bound nitrogen (fuel NO_x). Volatile Organic Compounds (VOC) emitted from combustion turbines are products of incomplete combustion of the fuel. Sulfur dioxide (SO_2) is formed by the reaction of sulfur found in fuel with oxygen from the combustion air. Emissions of particulate matter (PM and PM_{10}) result from trace quantities of non-combustibles in the fuel or combustion air or from formation of ammonium sulfates post combustion. Carbon Monoxide (CO) emitted from combustion turbines is a product of incomplete combustion of the fuel.

The Massachusetts Department of Environmental Protection (DEP) and the U.S. Environmental Protection Agency (EPA) have promulgated air quality regulations that establish ambient air quality standards and emission limits. These regulations include: (1) Non-Attainment New Source Review (NSR), (2) Prevention of Significant Deterioration (PSD), (3) National Ambient Air Quality Standards (NAAQS) and (4) New Source Performance Standards (NSPS) for criteria pollutants.

Application of these regulatory requirements is through the DEP Air Plan Approval process.

Mitigation

Natural gas and low-sulfur distillate oil

Through the use of clean-burning natural gas, low sulfur distillate oil as a secondary fuel and advanced combustion and pollution control technologies, including a dry low-NO_x combustor, water injection, a Selective Catalytic Reduction System (SCR) and a CO oxidation catalyst, emissions will be controlled to extremely low levels. In addition, the project will acquire emissions offsets as required for Non-Attainment NSR.

Use of LAER and BACT

Dry low-NO_x combustion limits NO_x formation by lowering flame temperatures through fuel/air optimization. The facility will control NO_x emissions during natural gas firing with dry low-NO_x combustion in combination with SCR. Water injection and SCR will control NO_x emissions during oil firing. Water injection acts as a heat sink in the turbine combustor, further limiting peak flame temperatures and resultant NO_x formation. The use of a dry low-NO_x combustor, with water injection during operation on oil, in combination with SCR technology, achieves LAER for NO_x emissions.

Due to the nature of the state-of-the-art dry low-NO_x combustion system (minimal excess air at flame), the combustion turbine generates VOC at a higher rate than a combustion turbine that utilizes water or steam injection for NO_x control. However, levels of VOC emissions will be maintained at very low levels with substantial savings in water consumption with the control process utilized on this project. Combustion controls and the primary use of clean burning natural gas are the measures taken to minimize VOC emissions. Use of a CO catalyst achieves BACT for CO.

Clean burning natural gas has only trace quantities of SO_2. The use of natural gas as the primary fuel and low sulfur distillate oil as the secondary fuel achieves BACT for SO_2. Particulate matter (PM_{10}) emissions are also minimized by use of clean burning natural gas as the primary fuel and low sulfur oil as a secondary fuel.

In order to comply with the requirements of Non-Attainment NSR for NO_x and VOC, the Fore River Station Project will be required to acquire NO_x and VOC offsets at a minimum ratio of 1.26 to 1.0.

The amount of NO_x and VOC offsets required for the facility is 275 and 90.1 tons per year respectively. Sithe is currently formulating plans to obtain the required NO_x and VOC offsets.

The NO_x offsets will be obtained by curtailing use or adding controls to some of Sithe's existing facilities in Massachusetts. NO_x offsets will most likely be obtained from the emission credits generated by the Sithe Mystic Station Air Quality Implementation Plan (AQIP). With respect to VOC, offsets will be obtained in the following manner: 24.8 tpy from BASF (certified in DEP Approval No. MBR-94-ERC-011); 56.6 tpy from Lightolier (Approval No. 4P95217); and 8.7 tpy from Avery Dennison (Approval No. . MBR-94-ERC-006, MBR-95-ERC-001).

Noise

Noise impacts are associated with construction and post-construction. Construction impacts are discussed below. The operation of the Fore River Station will increase noise levels by 6 dBa over ambient conditions at the nearest residential receptor (Monatiquot Street). Sources of noise during operation include combustion turbines, natural gas compressor, natural gas meters, transformers, glycol coolers, and air-cooled condenser (ACC).

Air is drawn into combustion turbine equipment from the outdoors, used in the gas turbine combustion process, expanded through a power turbine and exhausted through the heat recovery steam generators (HRSGs) before being released from the 255-foot high dual flue stack. A compressor is needed to process natural gas to fuel the combustion turbines. The metering equipment includes various meters and valves, which have the potential of high frequency (hissing) sounds at nearby locations. There will be three main transformers, one for each generator, which will produce a small level of noise. The glycol coolers, sometimes called fin/fan coolers, provide cooling for the combustion turbine lubrication system. The primary source of ACC noise is the fans.

<u>Mitigation</u>

The Fore River Station noise mitigation design includes the following or equivalent alternative measures to achieve the allowable noise impacts below.

a) Enclosure of the following noise-producing components of the Project within an acoustically-designed building: the gas turbines, steam turbines, electric generators, HRSGs, the high pressure and auxiliary boiler feedwater pumps, plant and instrument air compressors, and the auxiliary boiler.

b) Install low noise ACC utilizing slower fans, additional blades, and additional surface area over the standard base model.

c) Install enhanced noise suppressants for the combustion turbine air inlets and exhausts.

d) Procure and install quiet-design transformers.

e) Install low noise closed cooling water coolers utilizing slower fans, additional blades, and additional surface area over the standard base model.

f) Install silencers on all vents including those that would or may be activated during start-up and shut down sequences.

g) Install all natural gas compressor equipment within an acoustically designed building.

h) Install lagging or enclosures on all metering equipment, such as valves and associated exposed pipes, to assure the reduction of noise from these sources.

i) Install glycol coolers at the south end of the ACC, at a point furthest away from residential neighborhoods

Fore River Station Allowable Noise Impacts

Receptor Location	**Ambient L_{90}, dBA**	**Ambient & Plant L_{90} dBA**	**Nighttime Increase, dBA**
R-1 Monatiquot Street, E	41	47	+6
R-2 Idlewell	35	36	+1
R-3 East Braintree	37	38	+1
Quincy, W	37	38	+1
Quincy Point	42	43	+1
Germantown	39	40	+1
Property Fence Line, E	41	48	+7

Sithe will conduct a noise survey within 180 days of the facility start-up to verify compliance with the allowable noise impacts specified in the above table. Sithe will provide the Department with a written report describing the results of said noise survey, within 60 days of its completion.

Furthermore, Sithe will assure that the following mitigation measures are incorporated in the project construction and operation:

- Trucks accessing site will comply with federal regulations limiting noise from trucks.

- Construction equipment sound muffling devices will be in good repair.

- Pile driving will occur only during daytime as defined in local codes. When practical, major construction activities will be limited to daytime.

- Project engineering will incorporate best available noise control technology.

In addition to the normal construction activities, steam and air blows will occur in the final phases of construction. These processes use high pressure steam or air to clean plant piping prior to operation. The testing process will utilize "silent blows," which are continuous releases of steam or air that have been treated to reduce noise.

Estimated noise mitigation costs total $15,840,000: $8,039,000 to reduce increases to 10 dBA at the nearest residential receptor (the Department's Noise Policy Guideline), and an additional $7,801,000 to reduce increases yet further, to 6 dBA at the nearest residential receptor.

Visual

The tallest facility structure will be the plant's stack, which will be 255 feet high. Excepting the stack, the tallest structure will be 102 feet high.

<u>Mitigation</u>

In project layout and design, Sithe has sought to minimize the visual impact of the Fore River Station. Every effort has been made to make visual improvements to the site, to please as large a segment of the population as possible. In general, the site will be much cleaner and better maintained than the current site.

Elements of project design

The existing brick building is being removed and will be replaced with a modern facility. The Fore River Station's powerhouse design height will be 102 feet high, compared to 155 feet for the highest part of existing Edgar Station. The exterior will be insulated metal siding. Sithe's preferred color scheme is white with blue trim; Sithe will finalize this choice in discussions with Weymouth officials.

The project will have one multi -flue stack, rather than individual stacks. The height of the single stack will be 255' a.g.l., compared to the five 250' stacks that served Edgar Station.

Landscaping and public areas

Significant improvements will be made to landscape and revegetate areas of the project site. Landscaping along the western shore of the property will be conducted where possible to screen the building and improve the view of the site from the water. Landscaping will also be proposed south of the air-cooled condenser for the same reason, where it will not interfere with air flow to the air-cooled condenser. Sithe will also provide landscaping along the eastern (Monatiquot Street) edge of the site. Landscaping elements will include a combination of low vegetation (above the MWRA sewer easement) with higher vegetation, berm, fencing and/or trees to the west, shielding the neighborhood from the Fore River Station. Additional landscaping will be provided to the north and east of the powerhouse, and north of Route 3A along a proposed Kings Cove public access area.

Wetlands / Dredging

The Fore River Station will require direct alteration through dredging of approximately 2 acres of nearshore land under the ocean, in the Designated Port Area (DPA) immediately west of the Edgar Station, to accommodate a fuel oil barge pier. Piles will be driven into the seabed to secure barges that dock at the pier. Piles will also be installed in an area north of the Fore River Bridge within the footprint of the existing northern pier to handle the construction barge that will deliver large components of the plant to the project site during construction. Pile driving will result in only temporary impacts that will be mitigated as discussed below. There will also be limited filling of an area landward of the existing bulkhead south of the Edgar Station that currently floods at high tide. An area of Land Subject to Coastal Storm Flowage will be filled to accommodate the ACC, a detention pond, and ancillary facilities. Some stabilization and repair of the existing bulkhead will also take place to provide security to the shoreline. Finally, the existing discharge flume, a remnant structure of the Edgar Station's cooling system, will be filled to improve structural stability, worker safety, and landscaping aesthetics of the site. Because the bottom of the discharge flume is below extreme low water, it comprises a manmade feature of land under the ocean encompassing approximately 15,000 s.f.

Most of the project site within 200 feet of the Weymouth Fore River is formerly-filled tidelands, licensed by DEP under Chapter 91. Three small portions of the site within 200 feet of the Weymouth Fore River were upland, and thus may comprise Riverfront Area (within a DPA). Two of these three areas are previously developed (Edgar Station and pier).

<u>Mitigation</u>

The Fore River Station project will avoid, minimize, and mitigate impacts to the wetland resource areas identified within the project site that are presumed significant to the protection of the interests of the Massachusetts Wetlands Protection Act (MWPA). The Fore River Station will also comply with the State's Stormwater Policy as implemented and regulated through the MWPA and its regulations, and will meet performance standards for Riverfront Area. Since the Fore River Station is located within a DPA, Land Under the Ocean is the only resource identified within the site that is presumed significant to the any of the interests of the MWPA.

Elimination of once-through cooling

A major change from former Edgar Station has been the elimination of once-through cooling, in favor of an ACC. This has reduced potential direct wetland impacts considerably, reducing filling of coastal beach and land subject to coastal storm flowage. Dredging also has been greatly reduced, from 56,150 cy to 28,000 cy.
Work within Bank and 100-foot buffer

To assure that construction-related impacts to the Weymouth Fore River are minimized, all work performed within the bank area and its 100-foot buffer zone will be performed according to the Order of Conditions issued by the Weymouth Conservation Commission.

Potential dewatering activities

Any dewatering activities at the Project site will be performed in accordance with good construction practice per approval by the Weymouth Conservation Commission.

Construction and Operational Stormwater Pollution Prevention Plan (SWPPP)

Sithe will develop and implement a construction and operational SWPPP which will include a commitment to conduct construction and operational activities in accordance with appropriate Best Management Practices (BMPs) intended to prevent stormwater contamination.

Chapter 91 Licensure

Sithe will obtain a Chapter 91 waterway license, and will comply with the terms of that license throughout the operational life of the Project.

Shellfish seeding program

To mitigate any potential impacts from dredging the 2.1 acre area of DPA for the fuel oil barge pier, the applicant will fund a one time shellfish seeding program in Weymouth nearshore waters. The program will be implemented by the Weymouth Shellfish Warden and in consultation with MA Division of Marine Fisheries (MA DMF). An area for seeding will be selected from beds currently harvested by master diggers. Potential seeding areas include Kings Cove, Wessagusset, and the Back River. Seed will be purchased by the applicant from a MA DMF approved shellfish hatchery to ensure that disease free seed is used.

Dredging mitigation

Mitigation measures will be employed during dredging operations and work around the bulkheads. All dredging operations will be conducted from the upland or from a floating barge using either a mechanical clamshell bucket dredge or a hydraulic dredge that will minimize turbidity within the water column. The top and most silty sediment will be dredged using a hydraulic dredge to decrease turbidity. A clamshell will be employed to dredge the more sandy sediments. During clamshell dredging, silt curtains will be employed to localize sedimentation. Dredge activities will be scheduled to avoid sensitive life periods of critical fish species. Installation of piles and bulkhead sheeting will be completed from the upland when possible. Otherwise it will be conducted from a floating barge. All pile driving will be conducted with a vibrating hammer to reduce turbidity within the water column. Fill activities will be conducted behind a cofferdam to avoid increased turbidity within the water column. These mitigation measures will prevent impacts to adjacent habitats during dredging, pile driving, and work around the bulkheads.

At the request of MA Division of Marine Fisheries, there will be no dredging between February 1 and September 15.

Riverfront areas

All work in Riverfront Area will meet performance standards, in conformity with an Order of Conditions issued by the Weymouth Conservation Commission.

Nearshore upland areas adjacent to the ocean will be revegetated with native woody species to provide wildlife habitat not currently available. Revegetation will be concentrated at the two public access areas at Lovell's Grove and Kings Cove, and south of the ACC.

Watershed wetlands restoration plan

Although not proposed as direct mitigation for any potential project impacts, it is important to note that the applicant will also implement a Watershed Wetlands Restoration Plan for the entire Weymouth Back River Watershed and for the portions of Weymouth located in the Fore River Watershed. The purpose of the study is to identify wetland and habitat restoration opportunities and produce a prioritized list of for the future implementation of restoration projects.

Water Use

The Fore River Station requires a reliable source of freshwater for process and potable water uses. As stated in the FEIR, Sithe has continued to work to reduce water requirements. Under normal or "base case" conditions, the plant will use an estimated 46,214 gallons per day (gpd) for HRSG make-up, demineralizer regeneration, equipment washdowns and potable uses (drinking water, showers). Under evaporative cooling conditions, use of freshwater increases to an estimated 105,724 gpd, of which 62,831 gpd is evaporated to the atmosphere. Lastly, during oil firing, water injection is required in order to control the combustion temperature thus limiting NO_x formation to acceptable levels. At full load oil firing, limited to 720 hours per year, the plant will use an estimated 482,200 gpd.

Make-up water for the plant process and sanitary water system will be obtained from the City of Quincy pursuant to the MWRA Straddle Policy. The City of Quincy is a member community of the MWRA system. On an average day the MWRA reservoir system provides 9.7 million gallons per day (mgd) of potable water to Quincy for subsequent distribution to the City's businesses, institutions and 84,000 residents. Peak usage is 13.4 mgd (1997 usage). The MWRA can currently supply the City of Quincy with 20 mgd with an expected increase to 32 mgd in 2004. On December 15, 1999, the MWRA Board of Directors voted final approval of Sithe's application under the MWRA Straddle Policy.

<u>Mitigation</u>

Water conservation and recyling

The Fore River Station has been designed with intensive internal levels of water treatment and recycling, to minimize water use as well as wastewater generation. Water conservation measures will be implemented at the Fore River Station to minimize water demand. The measures proposed include:

1. Dry Low NOx combustors are used rather than water injection during natural gas operation.

2. HRSG blowdown is recycled during normal operation.

3. Flash steam from the high pressure and intermediate pressure continuous blowdown tank is routed to the low pressure drum for recovery rather than to the atmosphere.

4. Steam and condensate system samples are recovered and recycled rather than sent to the waste system.

5. During periods of combustion turbine oil firing when demineralized water requirements increase sharply, offsite regenerated demineralizers will normally be used to provide demineralized water to the combustion turbine, minimizing the quantity of water required for regeneration needs.

6. The combustion turbine inlet evaporative cooler blowdown will be recycled. During periods of combustion turbine evaporative inlet cooling, the makeup water to the coolers shall normally be provided by offsite regenerated demineralizers thus allowing the blowdown from the coolers to be recycled to the main cycle demineralizer system without loss of demineralized water quality, and minimize use of water for regeneration of the main cycle dimineralizer system during recycle of the cooler blowdown.

7. ACC enables use of precoat condensate polishers, rather than deep bed polishers (reducing wastewater generation).

Wastewater Discharge

Process wastewater that can no longer be recycled will be pretreated and discharged, together with sanitary wastewater, to the Weymouth sewer system. Wastewater will be conveyed via an existing 10" PVC sewer pipe to the MWRA system at the existing King's Cove siphon, from where it will be conveyed to the new Nut Island headworks, and then to the Deer Island Treatment Plant.
Under the base case, plant wastewater discharge will be 39,983 gpd. Under the evaporative cooling case, wastewater will be 42,858 gpd. Under the oil-fired case, wastewater will be 42,718gpd. These figures include sanitary wastewater of 625 gpd.

<u>Mitigation</u>

Wastewater reduction through water conservation and recycling

Water conservation and recycling measures (described above) have been reflected in reduced discharge rates. Annualized average wastewater discharge will be 40,229 gpd, reduced from 48,174 gpd in the DEIR.

Wastewater pretreatment

All wastewater will be treated to meet MWRA Pretreatment Standards. All wastewater will be quality tested prior to release to assure that it meets the minimum standards established by the MWRA.

Use of Treatment Equipment

Demineralizer regeneration wastewater will be neutralized in a holding tank. Wastewater from the process drains will be routed through an oil-water separation system. Oil collected in the oil-water separator will be hauled off site for management at a licensed facility.

I/I removal

Peak flows are 42,858 gpd. Sithe will fund the removal by Weymouth of infiltration/inflow at a 7:1 ratio, as discussed between the Weymouth Department of Public Works and DEP, Northeast Region.

Stormwater

Stormwater from the Fore River Station is discharged to the Weymouth Fore River.

Mitigation

Compliance with state Stormwater Management Policy

The Fore River Station design includes pre-redevelopment and new post-redevelopment stormwater management systems that meet the requirements for the NPDES General Construction Permit and the state Stormwater Management Policy for redevelopment projects. The stormwater management design will minimize pollutants in stormwater discharge, and will attenuate peak stormwater runoff discharge rates.

Stormwater management during construction

During construction, mitigation will be taken to manage stormwater runoff and erosion and sedimentation within the Fore River Station site. A Stormwater Pollution Prevention Plan will be prepared incorporating best management practices for stormwater management during construction. Silt fences and/or hay bales will be located along the downslope sides of the construction area adjacent to the Weymouth Fore River, around unstabilized fill areas, around excavated materials which are temporarily stockpiled and around any area where erosion may be a problem. Disturbed portions of the site where construction activity will cease temporarily for 21 days or more will be stabilized with temporary seed, mulch or geotextiles. Stockpiles will be located as far away from the Weymouth Fore River as is practical. Runoff water will be intercepted and directed from work areas to appropriate sediment traps or a sediment basin. Sediment traps will be used in situations requiring minimal amounts of dewatering. Inlets to active catch basins will be protected from sedimentation by hay bales.

During construction, all potential contaminants will be stored, handled and disposed of so that accidental releases to the environment are avoided. Spill prevention and control measures will be described in detail in a Spill Prevention, Control and Countermeasure Plan (SPCC) that will be prepared for construction and will include measures to prevent spills, provide emergency response measures and training of all construction personnel. All erosion and sediment control measures will be maintained in effective operating condition. Regular inspections of the controls will be conducted and documented. Additional specific measures will be implemented as required in the Order of Conditions to be issued by the Weymouth Conservation Commission. Permanent site stabilization (e.g. planting and seeding) will be undertaken upon completion of the site clean-up, regrading, backfilling and topsoil replacement. After the entire site is permanently stabilized, to the satisfaction of the Conservation Commission Administrator, temporary erosion and sediment control measures will be removed.

Stormwater management during operation

During the operation of the Fore River Station mitigation measures will be taken to manage stormwater runoff within the Fore River Station site. 80% total suspended solids (TSS) will be removed from all stormwater discharges from impervious surfaces within the Fore River Station site. Stormwater from the impervious areas within the site will be piped to one of two detention ponds for treatment prior to being released to the discharge outfalls. Both detention ponds will be impervious to prevent water from leaching into the subsoil. Deep sump catch basins will be utilized upstream of the detention basins.

An Operation and Maintenance Plan will be prepared for the stormwater management system that will incorporate Best Management Practices (BMPs). BMPs will include such actions as periodic sweeping of all parking and roadway areas, semi-annual inspections and cleaning of catch basins, and designated snow storage areas.

Cultural

Edgar Station is considered a significant building for architectural and historical reasons as discussed in the EIR. In order to construct the Fore River Station, and to comply with state law, Edgar Station and its associated buildings must be demolished.

<u>Mitigation</u>

Mitigation provided per two Memoranda of Agreement

Sithe consulted with the Massachusetts Historical Commission (MHC) regarding alternatives to demolition of the Edgar Station complex. As a result of this consultation, Sithe agreed to undertake measures to mitigate the adverse impact of the demolition of the Edgar Energy Station. Mitigation measures are included in an MOA (Appendix E of the FEIR) which has been reviewed by the MHC, and will be executed by the MHC, acting as State Historic Preservation Officer, and by U.S. Army Corps of Engineers. In addition, further mitigation activities requested by the Weymouth Historical Commission are outlined in a separate MOA (Appendix D to the FEIR) between Sithe, the Weymouth Historical Commission, and the Weymouth Board of Selectmen.

Photographic recordation of the interior and exterior of the turbine building, switch house, gatehouse, and other extant structures according to Historic American Engineering Record (HAER) standards has been conducted. Copies have been submitted to the MHC and the Weymouth Historical Commission.

Ongoing historic mitigation

Sithe will provide on-site public access to a landscaped area that will memorialize Lovell's Grove, a popular 19th century picnic and promenade spot which once existed at the site. This area will include a memorial, which provides a brief history of the grove. Sithe will sponsor the printing of an illustrated brochure which describes the history of the Edgar Station site and of other historically significant sites along the Fore and Back Rivers. Sithe will make the existing gatehouse, which will be retained, available for the use of the Weymouth Historical Commission to display brochures and other historical materials concerning the Edgar Station site. Sithe will consider assisting the Weymouth Historical Commission and the Town in preserving specific open space along Weymouth's historic waterfront for public access. Sithe will assist the Weymouth Historical Commission in printing an illustrated booklet which summarizes the Historic American Engineering Record (HAER) report for the general public. Sithe will also consult with the Weymouth Historical Commission and the Weymouth Board of Selectmen on final designs for the new Sithe facility to ensure compatibility with the surrounding landscape and buildings.

Traffic

Traffic to and from the Fore River Station will increase over existing conditions as a result of the redevelopment of the project site. Construction workers in the peak month will total 685 per day. Power plant operation traffic will increase marginally with the Fore River Station employing up to 25 workers. Concurrent activities at the site include the construction by the Massachusetts Highway Department (MHD) of the temporary Fore River Bridge, and construction by MWRA of Braintree-Weymouth Relief Interceptor facilities.

Mitigation

Construction traffic mitigation

By opening the passageway under the Route 3A viaduct, Sithe will maintain right-in, right-out access from the site. Further, a member of the construction management team will be designated as Transportation Coordinator so coordination of traffic and transit support measures will be specifically part of that person's job description. This job description will include interaction and coordination with other construction projects. The coordinator will also establish liaison with traffic officials in Weymouth and Quincy so that information can be transmitted between them as appropriate.

As reported in the FEIR the following elements will be implemented between Sithe, MHD and MWRA:

Maintenance of continuous traffic access beneath Route 3A viaduct to permit right-off, right-on access to all projects.

Provision of flagman control should construction operations require temporary suspension of traffic flow beneath Route 3A viaduct.

The above activities will be planned and executed through a hierarchy of planning and coordination meetings:

Monthly owners meetings. Review schedules and projected activities. Identify any problems, develop solutions. Identify plan for use of shared land.

Weekly Site Manager meetings. Review day-to-day activities and coordination. Notify neighborhood of anticipated activities or problems. Coordinate with Weymouth and Quincy police, fire, traffic, and public works departments, and with bridge tenders.

Daily Site Manager communication. Routine communication to keep all components of construction coordination program functioning smoothly.
MWRA has concurred in these recommendations, and agreed that MWRA and contractor representatives will attend and participate in the planning and coordination meetings.
The location of the construction barge access to north of the bridge means that bridge openings will not be required during delivery of major equipment components by barge to the site.

Hazardous Materials

Hazardous substances are in the ground on-site as a result of past uses during the operation of the Edgar Station. In addition, the proposed Fore River Station will be using some hazardous substances necessary for the production of energy and long-term maintenance of the facility infrastructure.

<u>Mitigation</u>

The Fore River Station site's long-term use for electric power generation and the nature of the fuels used have resulted in some hazardous substances being present on portions of the property. Over the past ten years several investigations of the site have been conducted and reported. Sithe has engaged in a program to ensure the appropriate remediation of existing conditions at the Fore River Station site.

Asbestos remediation

The Restructuring Act of 1997 required Sithe to remove unused structures from the Fore River site. Removal of these structures necessarily first required removal of asbestos. Under contract to a licensed asbestos abatement and building demolition contractor, and abatement of asbestos in the existing facilities has been completed. Following asbestos abatement, demolition commenced and is now under way, as required by state law.

Compliance with MCP

As a part of the Project, Sithe will assure that contaminated soils at the Project site receive appropriate remediation in accordance with the Massachusetts Contingency Plan (MCP.). Utilizing the services of a Licensed Site Professional Sithe has also investigating past contamination in a number of areas of the site. Where public access is being provided, risk assessments establish that no unacceptable risk to human health exists in light of the Company's redevelopment plan which includes placement of crushed stone, paving and landscaping. Other areas of the site, which are zoned for industrial use, will meet all applicable cleanup standards.

A plan will be prepared to address the potential for construction worker exposure to hazardous substances at the site. Contractor training and construction management oversight will also be implemented to minimize any risks associated with the low levels of contamination present in some areas of the site.

Operational usage of hazardous substances

Sithe will also transport, use and store several hazardous substances for the operation of the Fore River Station facility. These substances will include distillate fuel oil, aqueous ammonia, and additional chemicals for plant operation such as strong acid and caustic base, water treatment chemicals and maintenance materials. These hazardous substances will be properly stored within the project site in above-ground storage facilities that will have appropriate secondary containment. Delivery and unloading of the substances will be conducted by trained personnel using spill prevention equipment. The required training and spill prevention and response plans will be prepared by Sithe and kept on-site.

Sithe will develop a hazardous materials emergency response plan and retain an emergency response contractor to assure that hazardous materials incidents during both construction and the operational life of the Project are addressed in a thorough and appropriate manner.

Construction

Construction of the Fore River Station project will involve site preparation and earthmoving activities, foundation work, waterfront construction, placement of major equipment and structural steel erection, infrastructure construction and testing and start-up.

Mitigation

Air quality during construction

To mitigate fugitive air particles within the site and surrounding area, standard dust control measures will be employed, including water sprays when necessary to reduce the amount of airborne dust whenever construction activities require exposure of bare soil. In addition, site roadways will receive periodic sweeping. Truck traffic will be minimized to the extent practical by utilizing barges. A tire wash will be set up at the exit of the site.

Construction noise mitigation

To minimize noise disturbances to the community, construction hours for noisy activities will be limited. As noted above, silent steam will be utilized for final pre-operational cleaning of plant piping. To ensure that noise associated with construction equipment is minimized, Sithe will ensure that the construction contractor chosen to complete the Project inspects sound muffling devices on construction equipment to make sure they are in good repair. Trucks accessing the site will comply with federal regulations limiting noise from trucks. In order to reduce the amount of construction related noise caused by pile driving activities, pile driving will occur only during daytime hours.

Construction mitigation to wetland resources

To minimize and avoid impacts to aquatic resources, all in water construction will be scheduled to avoid impacts to fisheries during sensitive life periods. Dredging and pile driving activities will be conducted from the upland or a floating barge using a clamshell bucket dredge and vibrating hammer to minimize increased turbidity levels within the water column. Any temporary increases in turbidity within the water column will be limited by using a siltation curtain around all active dredge operations and pile driving activities.

To manage stormwater runoff and erosion and sedimentation within the Fore River Station site, the project will implement mitigation measures as discussed above.

Sithe will develop and implement a construction SWPPP that will include a commitment to conduct construction activities in accordance with appropriate Best Management Practices (BMPs) intended to prevent stormwater contamination.

All construction activities will be coordinated with the MWRA and the MHD.

Funding Responsibility

Sithe has committed to funding all of the mitigation measures discussed in these Section 61 findings.

Implementation Schedule (Construction)

A schedule for implementation of the mitigation measures associated with construction is included with this document as Attachment B.

Implementation Schedule (Operation)

A schedule for implementation of the mitigation measures associated with operation of the facility is included with this document as Attachment C.

SUMMARY SECTION 61 FINDINGS

Based upon the Environmental Impact Reports and the review of the record, the Department finds that the implementation of the requirements of its permits and the measures described above constitute all feasible measures to avoid damage to the environment and will minimize and mitigate damage to the environment to the maximum extent practicable, within the subject of the required permits.

ATTACHMENT A – TABLE OF MITIGATION MEASURES AND RESPONSIBILITY

EIR Category	Impact	Mitigation	Funding Responsibility	Timing
Air Quality	Construction air quality	Reduce construction dust by water sprays, street sweeping.	Sithe	Construction
	Operational air quality	Use of clean-burning natural gas as fuel.	Sithe	Operation
		Use of low sulfur distillate oil as a back-up fuel	Sithe	Operation
		Use of advanced combustion and pollution control technologies including dry low-NO_X combustors, SCR and oxidation catalysts that represent LAER and BACT.	Sithe	Operation
		Acquisition of offsets at 1.26:1 for VOC emissions	Sithe	Construction
Noise	Construction noise	Trucks accessing site must comply with federal regulations limiting noise from trucks.	Sithe	Construction
		Construction equipment sound muffling devices will be in	Sithe	Construction

EIR Category	Impact	Mitigation	Funding Responsibility	Timing
		good repair.		
		Pile driving will occur only during daytime. When practical, major construction activities will be limited to daytime.	Sithe	Construction
		Use of silent steam blows to clean piping.	Sithe	Construction
	Operational noise	Project engineering will incorporate best available noise control technology to ensure that the Project will not cause greater than 6 dBA (L_{90}) increase in noise at nearest residence.	Sithe	Operation
Visual	Visual Impact	The facility will be 102' high, compared with 174' maximum building height of Edgar Station.	Sithe	Operation
		Only one new stack shell rather than two separate new stacks will be constructed. Stack height will be 255 feet (one stack), compared with five (5) 250-foot stacks that served former Edgar Station	Sithe	Design
		Color scheme determined in consultation with Weymouth officials.	Sithe	Operation
Water Use and Quality	Impacts on Water Consumption	Dry low NOx combustors during natural gas operation. Recycle HRSG blowdown during normal operation. Recycle flash steam. Recycle steam and condensate system samples. Normally regenerate demineralizers offsite during oil firing and evaporative cooling	Sithe	Operation

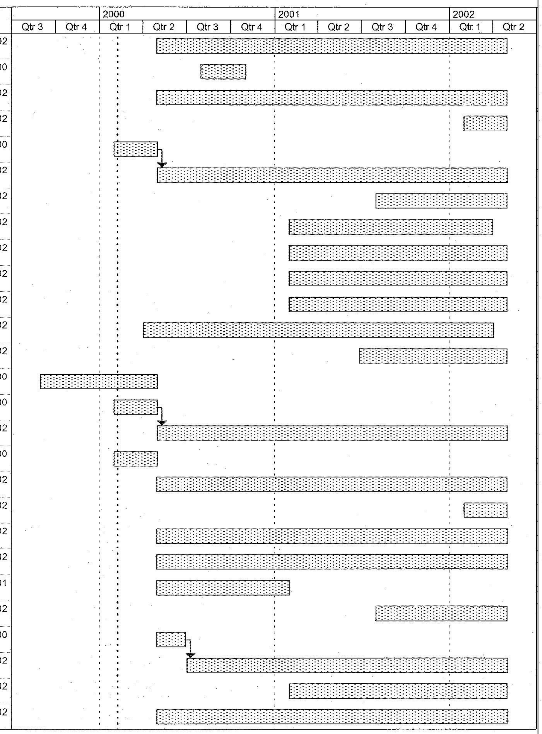
EIR Category	Impact	Mitigation	Funding Responsibility	Timing
		Use precoat condensate polishers. Recycle combustion turbine inlet evaporative cooler blowdown.		
	Wastewater generation	Use water conservation and recycling to minimize wastewater generation.	Sithe	Operation
	Wastewater discharge	Portions of wastewater will be treated and recycled as make-up to the raw water supply. Remaining wastewater will be discharged to municipal sewer system after proper treatment so that streams meet industrial pretreatment standards of the MWRA.	Sithe	Operation
		Fund removal by Weymouth of I/I at 7:1ratio	Sithe	Construction
		Provide secondary containment for all hazardous material storage areas and tanks.	Sithe	Operation
		Test water in containment areas prior to discharge to ensure discharge requirements are met.	Sithe	Operation
		Use treatment equipment to neutralize wastewater from demineralizer regeneration system and to separate oil in process area drains.	Sithe	Operation
Wetlands and Dredging	Potential impacts on wetland resources	Work within bank and 100-foot buffer zone will be performed according to Order of Conditions issued by Weymouth Conservation Commission.	Sithe	Construction
	Thermal impacts on	Utilize Air-cooled condenser	Sithe	Operation

EIR Category	Impact	Mitigation	Funding Responsibility	Timing
	Weymouth Fore River, entrainment and impingingement of fish	rather than once-through cooling		
	Impacts of dredging	Employ silt curtains and clamshell or hydraulic dredging. Fund shellfish seeding program. No dredging between 2/1 and 9/15.	Sithe	Construction
Stormwater	Stormwater runoff	After project completion, stormwater will be treated prior to discharge to the Weymouth Fore River in accordance with DEP Stormwater Management Guidelines.	Sithe	Operation
		Develop and implement SWPPP for construction.	Raytheon	Construction
		Develop and implement SWPPP for operation.	Sithe	Operation
Waterways, Tidelands and Public Access	Potential tidelands impacts	Provide public access areas as provided in Ch. 91 permit.	Sithe	Prior to construction
Hazardous Substances	Impacts of substances during construction	Remediate site contamination in accordance with the MCP.	Sithe	Prior to and during construction
		Prepare plan to address potential for construction worker exposure to hazardous substances at site.	Sithe	Construction
		Provide training and construction management oversight to ensure plan implementation.	Sithe	Construction
	Impacts of substances during operation	Hazardous substance storage vessels and areas will be equipped with secondary	Sithe	Operation

EIR Category	Impact	Mitigation	Funding Responsibility	Timing
		containment to prevent releases from spills.		
		Aqueous ammonia storage tanks will be contained with a double wall design in accordance with API specifications.	Sithe	Operation
		Emergency response procedures and an emergency response contractor will be in place.	Sithe	Operation
Cultural	Demolition of Edgar Station	Photo-recordation program. Lovell's Grove restoration. Gatehouse restoration, and illustrative brochure	Sithe	Construction and operation
Construction Management	Construction Activities	Erosion and sediment control devices and dust reducing measures will be in place to prevent effects on wetlands and waterbodies.	Raytheon	Construction
		Ensure contractor compliance with terms and conditions of environmental permits.	Sithe	Construction
Traffic	Traffic Impacts	Maintain right-in, right-out traffic access	Sithe	Construction
		Coordinate construction period traffic with MWRA and MHD	Sithe, MWRA, MHD	Construction

Attachment B: Implementation Schedule (Construction)

ID	Task Name	Duration	Start	Finish
1	Noise-Control Construction Equipment Noise	523 days	Mon 5/1/00	Wed 5/1/02
2	Noise-Conduct Time Limited Pile Driving	67 days	Tue 8/1/00	Wed 11/1/00
3	Noise-Limit Major Construction Activities To Daytime	523 days	Mon 5/1/00	Wed 5/1/02
4	Silent Steam Blows	64 days	Fri 2/1/02	Wed 5/1/02
5	Stormwater-Develop Construction SWPPP	65 days	Tue 2/1/00	Mon 5/1/00
6	Stormwater-Implement Construction SWPPP	523 days	Tue 5/2/00	Thu 5/2/02
7	Visual-Build Double Flue Stacks	196 days	Wed 8/1/01	Wed 5/1/02
8	Water Supply Conservation-Install Air Cooled Condensers	303 days	Thu 2/1/01	Mon 4/1/02
9	Water Supply Conservation-Install Dry Low Nox Combustors	325 days	Thu 2/1/01	Wed 5/1/02
10	Wastewater- Install Treatment System To Neutralize Wastewater from Demineralizer System	325 days	Thu 2/1/01	Wed 5/1/02
11	Wastewater-Install Oil/Water Separator(s) To Service Process Area Drains	325 days	Thu 2/1/01	Wed 5/1/02
12	Fund removal of I/I at 7:1	523 days	Mon 4/3/00	Wed 4/3/02
13	Soils-Install AST Secondary Containment	220 days	Thu 6/28/01	Wed 5/1/02
14	Soils-Conduct Remediation at Site In Accordance With MCP	174 days	Wed 9/1/99	Mon 5/1/00
15	Hazmat-Develop Hazardous Materials Response Plan	65 days	Tue 2/1/00	Mon 5/1/00
16	Hazmat-Implement Hazardous Materials Response Plan	523 days	Tue 5/2/00	Thu 5/2/02
17	Hazmat-Conduct Hazardous Materials Safety Training For Construction Workers	65 days	Tue 2/1/00	Mon 5/1/00
18	Hazmat-Assure Secondary Containment Of Construction Related Hazardous Materials	523 days	Mon 5/1/00	Wed 5/1/02
19	Hazmat-Install Double Walled Ammonia Tanks	64 days	Fri 2/1/02	Wed 5/1/02
20	Riverfront-Assure Compliance with Weymouth CC OOC	524 days	Mon 5/1/00	Thu 5/2/02
21	Riverfront-Conduct Dewatering in Compliance With Weymouth CC OOC.	524 days	Mon 5/1/00	Thu 5/2/02
22	Riverfront-Install Erosion Control Devices	199 days	Mon 5/1/00	Thu 2/1/01
23	Mitigate impacts of dredging and pier installation	196 days	Wed 8/1/01	Wed 5/1/02
24	Air-Install Dust Control Devices	44 days	Mon 5/1/00	Thu 6/29/00
25	Air-Implement Dust Control Measures (Water Sprays)	479 days	Mon 7/3/00	Thu 5/2/02
26	Cultural - provide historic mitigation	325 days	Thu 2/1/01	Wed 5/1/02
27	Implement Traffic Mitigation and Coordination with MWRA, MHD	524 days	Mon 5/1/00	Thu 5/2/02

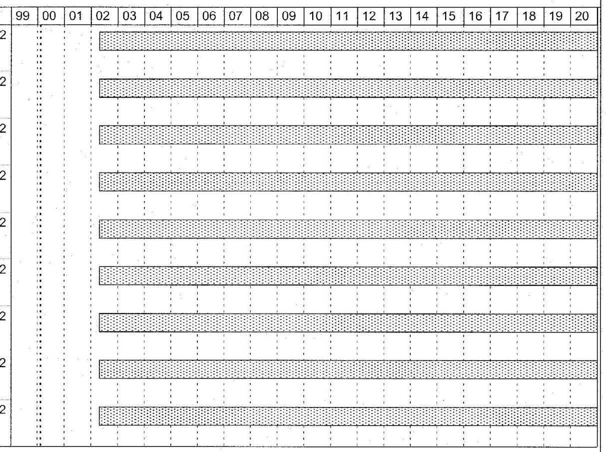


Fore River Station
Contruction Related Mitigation
Implementation Schedule

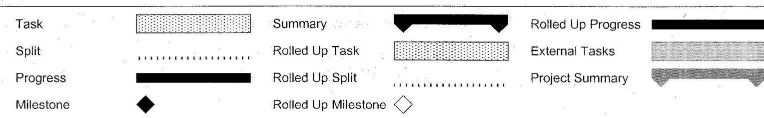
Task, Split, Progress, Milestone, Summary, Rolled Up Task, Rolled Up Split, Rolled Up Milestone, Rolled Up Progress, External Tasks, Project Summary

Attachment C: Implementation Schedule (Operation)

ID	Task Name	Duration	Start
1	Air-Fire ProjectWith Natural Gas, with very low sulfur distillate oil as secondary fuel	5218 days	Wed 5/1/02
2	Air-Operate Project With Dry Low-Nox/SCR/Oxidation Catalyst, with steam injection during oil firing	5218 days	Wed 5/1/02
3	Stormwater-Maintain Effective Stormwater Treatment per Stormwater Management Policy	5218 days	Wed 5/1/02
4	Stormwater-Develop and Comply With Operational SWPPP	5218 days	Wed 5/1/02
5	Wastewater-Reduce Generation Through Water Conservation	5218 days	Wed 5/1/02
6	Wastewater-Maintain Recycling Protocol and Infrastructure (Steam Blowdown)	5218 days	Wed 5/1/02
7	Wastewater-Maintain Monitoring Protocol and Treat as Needed	5218 days	Wed 5/1/02
8	Wastewater-Obtain the Services of a Contractor For Offsite Demineralizer Regeneration	5218 days	Wed 5/1/02
9	Hazmat-Retain Hazardous Materials Emerency Response Contractor	5218 days	Wed 5/1/02



Fore River Station
Operational Remediation
Implementation Schedule



Note: Finish dates noted on this chart are not intended to imply that operational remediation measures will be abandoned after twenty years. All operational remediation will remain in place through the life of the project.

XIX. ZERO AMMONIA TECHNOLOGY MEMORANDUM OF UNDERSTANDING

MEMORANDUM OF UNDERSTANDING BETWEEN THE DEPARTMENT OF ENVIRONMENTAL PROTECTION ("DEP") AND SITHE EDGAR DEVELOPMENT LLC ("SED") FORE RIVER STATION, WEYMOUTH, MASSACHUSETTS REGARDING ACHIEVING A ZERO EMISSION RATE FOR AMMONIA TR#W004896

The parties agree as follows:

1. DEP proposes to issue a draft air permit for the SED Power Plant in Weymouth, MA (the "Facility") that establishes an emission limit of 0 ppm of ammonia.

2. The permit will further provide that the Facility is approved to emit up to 2 ppm of ammonia, subject to optimization testing, for a period of not more than five years from the date of commencement of operations; provided that the 2 ppm ammonia emission standard will remain in effect after that anniversary unless DEP determines, in accordance with the process and criteria set out below, that there is a compatible zero ammonia air pollution control technology (ZAT) available to be installed at the Facility.

3. No later than four years after commencement of operations SED will commence and subsequently submit to the DEP an evaluation of available ZATs to determine if any such technology is compatible to be installed in the Facility. The evaluation should:

(a) review all ZATs that have been demonstrated to meet the Facility's final permit's NOx limit;

(b) provide facts and analysis regarding the extent to which each ZAT qualified under 3(a) meets the criteria set forth at 5 (a)-(d);

(c) incorporate the independent financial analysis set forth at 5(e) for each ZAT that meets the criteria set forth at 5(a)-(d); and

(d) compare the scope and extent of pollution reduction and prevention of each ZAT that meets the criteria set forth at 5 (a)-(e).

4. The parties anticipate that the evaluation should be submitted to DEP within 90 days of its commencement absent unavoidable delay. SED will supplement the evaluation upon DEP's request for reasonably available additional information or analysis. The fourth year anniversary date for commencing the evaluation was established based on the parties' assumption regarding the facility's major maintenance schedule. Upon agreement of the parties the commencement date may be modified.

5. A ZAT will be considered compatible if it meets the following criteria:

(a) The ZAT is commercially available for turbines 100 megawatts or larger.

(b) The ZAT meets all other emission and performance standards established by the permit(s) or such other enforceable emission limits in effect as of the ZAT installation date.

(c) The ZAT is guaranteed to perform with an equivalent or better level of reliability, availability and performance characteristics than was guaranteed for the technology installed at the commencement of operations, Selective Catalytic Reduction (SCR), provided that differences in emission rates will not be considered if the ZAT meets the criteria set forth in 5(b). A copy of the SCR guarantee will be provided to DEP.

(d) The installation, operation and maintenance of the proposed ZAT is consistent with the terms and conditions of the applicable state, town or federal permits or approvals, or other enforceable agreements between SED and a public entity in effect at the time the final permit is issued, that are necessary for the continued operation of the Facility, including but not limited to the City of Quincy's current limits on the Facility's consumption of water and generation of hazardous waste. If a permit, approval or agreement in effect when the evaluation is conducted may require modification to conform with a ZAT's requirements, SED shall use its best efforts to secure such modification unless it is reasonably likely that an appropriate modification could not be obtained. SED may consult with the Department prior to submission of the evaluation on the reasonable likelihood of obtaining a modification and SED's intended course of action.

(e) The installation, operation and maintenance of the ZAT are determined to be comparable to the cost of continued operation and maintenance of the SCR. The costs will be considered comparable if the cost for ZAT is not more than 5% greater than the cost for SCR. An independent third party expert jointly selected by the parties will make the determination of cost comparability in accordance with the general principles and methodology agreed to by the parties and attached hereto. The expert will be retained by SED but will be jointly managed by and be equally independent from both parties. Both parties agree to accept the cost comparability determination of the independent expert.

6. In the event that more than one ZAT meets the criteria set forth in paragraph 5, the technology that achieves the greatest degree of pollution reduction and prevention will be the preferred ZAT selected for installation.

7. The evaluation shall not consider the revision of any final permit emission standards other than ammonia except to the extent that performance of the preferred ZAT reduces other than non-ammonia emissions.

8. The DEP shall determine in accordance with the criteria set forth above whether the evaluation demonstrates that no ZAT is compatible. The written determination will set forth the facts and analysis upon which DEP based the determination. If DEP determines that the

evaluation did not adequately demonstrate that a compatible ZAT is not available, the provisions allowing for a 2 ppm ammonia emission rate will be void and a 0 ammonia emission rate shall become the enforceable permit limit effective on the fifth anniversary of the commencement of Facility's operations date, or within a reasonable period agreed to by the parties and consistent with the Consultant's Analysis, not to exceed 180 days from the final determination, whichever is later. The effective date may be extended by the Department to allow for unanticipated delays in the installation or testing of the selected ZAT.

9. The Department shall prepare a draft compatibility determination, which shall be made available for comment. SED shall have a right to appeal DEP's final compatibility determination pursuant to M.G.L, c. 30A, s. 11. Pending the resolution of an appeal the facility will be permitted to continue to emit 2 ppm of ammonia or such other rate established through optimization testing as provided for in the final permit.

10. Notwithstanding any provision herein, SED may at any time voluntarily install a ZAT in accordance with the provisions of DEP's regulations and the final permit.

11. This Memorandum of Understanding, or applicable provisions thereof, will be incorporated in the Facility's draft and final air permit.

DEPARTMENT OF ENVIRONMENTAL PROTECTION

By: ____
Date:

SITHE EDGAR DEVELOPMENT LLC

By: ____
Date:

PRINCIPLES AND METHODOLOGY FOR DETERMINATION OF COST COMPARABILITY OF NOx REDUCTION TECHNOLOGY

SITHE EDGAR DEVELOPMENT LLC ("SED") and the Massachusetts Department of Environmental Protection ("DEP") have agreed that an independent third party expert jointly selected by SED and DEP and retained by SED will perform an analysis (the "Analysis") of the cost comparability of NOx reduction technologies and will abide by the results of the analysis. DEP will approve the installation of selective catalytic reduction ("SCR") in the SED Weymouth facility (the "Facility") for the commencement of operations. Four years from the commencement of operation of the Facility, a study will be performed to determine whether an available zero ammonia technology ("ZAT") should be installed in the facility as an alternative NOx technology. A portion of that study is a comparison of the costs of continuing to maintain and operate the SCR system to the costs of installing and operating a ZAT system. ZAT shall include SCONOx and any other technology that provides NOx reduction equal to or better than the 2.0 ppm emissions limitation in the plan approval for the facility with no use of ammonia.

1. <u>Consultant</u>. A consultant ("the Consultant") shall be hired to perform an independent financial Analysis comparing the life cycle cost of certain NOx reduction technologies.

2. <u>Time of Performance</u>. The Analysis shall commence four years from the commencement of operation at the Facility and be completed within 90 days, unless extended by SED and DEP. Such extension shall not be unreasonably denied should delays occur that are beyond the control of the Consultant.

3. <u>Technologies to be Analyzed</u>. The Consultant shall analyze SCR which shall be installed and operated in the Facility for the commencement of operations and any ZAT designated by SED and DEP and which SED and DEP agree is available, including, but not limited to SCONOx.

4. <u>Qualifications of the Consultant</u>. The Consultant and its personnel performing the Analysis shall be independent, as defined below, regularly engaged in the business of valuing technology and specifically qualified with respect to:

   (a) demonstrated experience valuing and comparing the relative costs of alternative technologies;
   (b) familiarity with applicable environmental laws and regulations as well as regulatory processes;
   (c) experience with pertinent engineering and construction cost categories; and
   (d) experience with valuing fixed assets for sale or liquidation useful to determining salvage value.

5. <u>Independence of the Consultant</u>. The Consultant shall not be an affiliate of SED or any of its affiliates. Partners, principals and employees of the Consultant who shall work on this engagement shall have no current or contemplated future financial interest in SED. The Consultant's professionals performing the Analysis shall not be working on any DEP project

involving this analysis at the time of engagement. The Consultant shall not earn a contingent fee for performing the scope of work described herein. The Consultant shall not be engaged in the production, sale or installation of the pollution control technologies or have any current or contemplated financial interest in any of the technologies being analyzed.

6. Scope of Work. The Analysis will evaluate and compare the costs of maintaining and operating the SCR equipment installed in the Facility to the costs of installing, maintaining and operating ZATs.

7. Basis of Comparison and Analysis. The Consultant shall prepare the Analysis by comparing the present value of future cash costs directly attributable to the installed SCR and ZATs mutually agreed upon by SEP and DEP. The Consultant shall include all relevant cash costs in its Analysis of the NOx reduction technologies. All costs related to the installation, operation and maintenance of the technologies from the date of the Analysis through the remaining life of the facility will be considered, including but not be limited to: construction planning, design, permitting and execution; process engineering, labor, materials and equipment associated with installation and retrofit activities; plant sequencing, phasing and shut down requirements; lost business and opportunity costs; repair and maintenance; insurance; federal, state and local taxes; performance indemnification; salvage value of SCR; sale of by-products; ammonia delivery, injection, and storage systems; costs of material necessary for operation, including but not limited to ammonia; testing specifically related to the operation of either technology; and disposal cost of by-products. If the Consultant is unable to establish a single cost for a whole or part of the cost analysis and instead provides a cost range, then the cost selected for comparison will be the most likely within the range; provided that if there is no cost that is the most likely cost the mid point of the range will be used as the cost basis. In determining the allocation of costs to either technology, the Consultant shall assume that SED will take all reasonable steps to incur and allocate costs to minimize the cost of ZAT installation.

   The Consultant shall submit a draft list of the specific cost categories and other considerations and assumptions to SED and DEP for comment prior to commencing the Analysis.

   The Analysis shall be carried out over a period of time the Consultant considers appropriate, but not less than fifteen years as the remaining life of the Facility. The Consultant shall estimate a discount rate to evaluate the technologies, after consultation with SED and DEP and obtaining other sources of information it deems appropriate, that consistently reflects the business and financial risks of the Facility. Other considerations or assumptions that may be addressed in the Analyses include, but are not limited to, comparable scale and timing of installation.

   The Analysis shall state the Consultant's conclusion with respect to the relative cost of the SCR system and the ZAT. The report of the Analysis shall make the relevant costs easy to understand and will clearly distinguish factual assumptions from judgment. The Report of the Analysis shall be made available to SED and DEP at the same time.

8. Matters to be Relied upon and Management's Responsibility. The Consultant shall rely upon information provided by SED which SED will represent is accurate to the best of its knowledge and not in conflict with other information known to it. SED shall state this understanding in a representation letter to be dated the last day of the Consultant's work on the Analysis and prior to the issuance of the Consultant's report. Items which the Consultant may rely upon as accurate will include, but may not be limited to: information obtained from interviews with management; plant financials and operating records; technology performance documents or assessments; power purchase agreements; other material contracts; and fixed asset records.

   The Consultant shall require representations, including performance representations from SED or from suppliers of the ZATs being analyzed. Further, once requested by the Consultant, SED shall provide the Consultant the information and documents that the Consultant deems necessary to complete the analysis within a reasonable period of time. The Consultant also retains the right to request and require additional information that it deems appropriate. SED agrees such information shall not be unreasonably withheld.

9. Budget. The consultant's fees will be based on hours spent by staff at their standard hourly rates, subject to a mutually agreed upon not-to-exceed budget, plus out-of-pocket expenses for travel, lodging, subsistence and an allocation of office charges in support of services including computer usage, telephone, facsimile transmission, postage, photo-reproduction and similar expenses.

LIST OF PERTINENT INFORMATION FOR TRANSMITTAL W004896

Name of Facility:	Fore River Station Project
Location:	1 Bridge Street, Weymouth, Massachusetts 02188
Submitted By:	Epsilon Associates, Inc.
Attested To By:	Dale T. Raczynski, P.E. Number 36207
Design Data Sheets:	Air Plan Approval Application Date Received: July 23, 1999 Response to Request for Additional Information Dates Received: July 30, 1999 to February 1999
Plans:	Raytheon Engineers and Constructors Site Plan Drawing No: 42715.081B-SK2000 Elevation Looking North Drawing No: 42715.081B-SK2002 Elevation Looking East Drawing No: 42715.081B-SK2003 SCR Flow and Instrumentation Control Drawing No.: AIG-1 P&ID HRSG Systems Exhaust Gas Drawing No.: MD73041

ATTACHMENT LIST

List of hardcopy cc's:

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Weymouth, MA 02189

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John Winkler, DEP/SERO
Craig Goff, DEP/WERO
Thomas Cusson, DEP/CERO
John Kronopolus, DEP/CERO
Bill DiLibero, DEP/CERO (for DEP website)

Exhibit 27

Section II: Non-AQMD LAER/BACT Determinations

Application No.: MBR-99-COM-012

Equipment Category – Gas Turbine

1. GENERAL INFORMATION		DATE: 4/12/2000
A. MANUFACTURER: Mitsubishi Heavy Industries (MHI)		
B. TYPE: combustion turbine generators	C. MODEL: 501G	
D. STYLE:		
E. APPLICABLE AQMD REGULATION XI RULES:		
F. COST: $ ( )	SOURCE OF COST DATA:	
G. OPERATING SCHEDULE: 24 HRS/DAY	7 DAYS/WK	52 WKS/YR

2. EQUIPMENT INFORMATION	APP. NO.: MBR-99-COM-012
A. FUNCTION: The new combined cycle electric generating facility will consist of two main power blocks each generating 775 MW of electric power. Each power block consists of two combustion turbine generators (CTG), two heat recovery steam generators (HRSG), and one steam turbine generator (STG). Each CTG will have a nominal generating capacity of 250 MW. Each STG will have a nominal generating capacity of 275 MW	
B. MAXIMUM HEAT INPUT: MHI 501G gas turbine = 2,676 MMbtu/hour at -12 degrees F ambient (each) Supplementary fired HRSG = 279 MMbtu/hour at -12 degrees F ambient (each)	C. MAXIMUM THROUGHPUT:
D. BURNER INFORMATION: NO.:	TYPE: dry low-NOx combustors
E. PRIMARY FUEL: natural gas	F. OTHER FUEL: NONE
G. OPERATING CONDITIONS:	

3. COMPANY INFORMATION		APP. NO.: MBR-99-COM-012
A. NAME: Sithe Mystic Development LLC		
B. ADDRESS: 39 Rover Street CITY: Everett	STATE: MA	ZIP: 02129
C. CONTACT PERSON: James McGowan		D. PHONE NO.:

4. PERMIT INFORMATION	APP. NO.: MBR-99-COM-012
A. AGENCY: `Massachusetts Department of Environmental Protection'	B. APPLICATION TYPE: new construction
C. AGENCY CONTACT PERSON: Cosmo Buttaro	D. PHONE NO.: (978) 661-7668

4. PERMIT INFORMATION

APP. NO.: MBR-99-COM-012

E. PERMIT TO CONSTRUCT INFORMATION: 1/25/2000	P/C NO.: MBR-99-COM-012 ☐ CHECK IF NO P/C	ISSUANCE DATE:
F. START-UP DATE: early 2002		
G. PERMIT TO OPERATE INFORMATION:	P/O NO.:	ISSUANCE DATE:

5. EMISSION INFORMATION

APP. NO.: MBR-99-COM-012

A. PERMIT

A1. PERMIT LIMIT:

Short term emission limits for the gas turbines:
NOx =< 21.7 lbs/hr, 0.0074 lbs/MMbtu, 2.0 ppmvd @ 15% O2

CO =< 13.2 lbs/hr, 0.0045 lbs/MMbtu, 2.0 ppmvd @ 15% O2

VOC (unfired) =< 3.8 lbs/hr, 0.0013 lbs/MMbtu, 1.0 ppmvd as methane@ 15% O2

VOC (duct fired) =< 6.4 lbs/hr, 0.0022 lbs/MMbtu, 1.7 ppmvd as methane@ 15% O2

SO2 =< 8.6 lbs/hr, 0.0029 lbs/MMbtu

PM/PM10 =< 32.5 lbs/hr, 0.011 lbs/MMbtu

NH3 =< 8.0 lbs/hr, 0.0027 lbs/MMbtu, 2.0 ppmvd @ 15% O2

Notes:

1. Emission limits are one-hour block averages and do not apply during start-up/shutdown and equipment cleaning. Start-ups shall not last longer than 3 hours.

2. The Massachusetts Department of Environmental Protection and the applicant have entered into a memorandom of understanding (MOU) concerning the use of zero ammonia technology (ZAT) for the control of nitrogen oxides. For the first five years of operation of the facility, there shall be an interim emission rate for ammonia of 2.0 ppmvd @ 15% O2 one-hour block average. Pursuant to the MOU, the emission rate for ammonia after the first five years of operation shall be zero unless the interim 2.0 ppmvd ammonia limit is extended by the Department. During the five year period it will be determined whether a ZAT must be installed at the facility. The determination will be based on the availability, reliability, and comparable costs of the zero ammonia technologies. The MOU provides the methodology for making the determination.

A2. BACT/LAER DETERMINATION: LAER is required for the VOC emissions and BACT is required for the NOx emissions. For this application (for NOx emissions), LAER and BACT requirements are the same. The above permit limits for VOC and NOx comply with LAER and BACT requirements, respectively. The other criteria air pollutants are subject to PSD review.

B. CONTROL TECHNOLOGY

B1. MANUFACTURER/SUPPLIER: To be determined

B2. TYPE: Selective Catalytic Reduction and Oxidation Catalyst

B3. DESCRIPTION:

5. EMISSION INFORMATION

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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, PM10, SOx	
B8.	SECONDARY POLLUTANTS: ammonia (particulate precursor)	
B9.	SPACE REQUIREMENT:	
B10.	LIMITATIONS:	
B11.	LOCATION OF PRIOR DEMONSTRATION & AGENCY: FACILITY: Sunlaw Cogeneration Partners I Federal Cold Storage Cogeneration Facility CONTACT PERSON: Ted Guth PHONE NO.: (619) 670-3157 AGENCY: SCAQMD ADDRESS: 21865 E. Copley Drive CONTACT PERSON: Chris Perri PHONE NO.: (909) 396-2696	
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: The applicant will conduct initial compliance tests (for NOx, CO, VOC, NH3, and PM10/opacity) within 180 days after initial start up of the proposed facility. Testing will be conducted at four representative steady state loads (but not less than 75% of rated base load), except for PM10 which will be tested at 100% of rated base load only.	

C. COST

C1.	CONTROL EQUIPMENT COST: ☐ CHECK IF INSTALLATION COST IS INCLUDED IN CAPITAL COST CAPITAL: $ INSTALLATION: $ (1999) SOURCE OF COST DATA:	
C2.	ANNUAL OPERATIONAL/MAINTENANCE COST: $ (1999) 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

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The applicant will install, calibrate, test and operate a data acquisition and handling system, a CEMS, and a COMS to measure and record the opacity and the NOx, CO, NH3, and O2 emissions from the facility. The applicant will ensure continuous monitoring and compliance with PM/PM10 limits using the parametric monitoring methodology developed during the initial compliance test. Detailed record keeping and reporting requirements are included in the permit.