MODEL REGULATIONS FOR THE OUTPUT OF SPECIFIED AIR EMISSIONS FROM SMALLER-SCALE ELECTRIC GENERATION RESOURCES

Model Rule and Technical Support Documents

Public Review Draft
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PREFACE [AND ACKNOWLEDGEMENTS]

Under a contract with the National Renewable Energy Laboratory (NREL), The Regulatory Assistance Project (RAP) convened a working group of state utility regulators, state air pollution regulators, representatives of the distributed resources industry, environmental advocates, and federal officials. This group of approximately thirty people participated in an effort to develop model emissions standards for smaller-scale, primarily distributed, electric generation technologies. Most of the effort was conducted through e-mail, list-serve, and telephone conference calls, and there were two in-person meetings of the group during 2001.

This document is the public review draft of a model rule. While we hope that the rule "can speak for itself," we recognize that it grapples with some complicated questions and have therefore provided a commentary that describes some of the thinking behind our approach. The Introduction describes our objectives and general process.

The Working Group and RAP welcome your comments and suggestions on the rule. If you wish to do so, you may e-mail them to Rick Weston at rapweston@aol.com, distribute them through the list-serve dremissions@lists.raponline.org, or send them to The Regulatory Assistance Project, 50 State Street, Suite 3, Montpelier, Vermont, 05602. Please submit them before the end of December 2001.

Thank you.

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I. INTRODUCTION

The electric industry has major impacts upon our local, regional, and global environments. Increased competition in the industry can create new environmental problems as well as new opportunities for improvement. There have been significant developments in small-scale generation technologies. The growing availability of cost-effective distributed generation – micro-turbines, diesel "gen-sets," fuel cells, solar panels, natural gas-fired systems, etc. – is changing the nature of the electric network. While the potential electric benefits of such technologies (improved reliability and security, lower costs, and so on) are becoming better understood, their environmental impacts, and benefits, may be less so. The Working Group's task was to develop a set of model rules that states can adopt in whole or adapt, that will foster the deployment of environmentally sustainable and economically efficient distributed generation.

RAP enlisted Nancy Seidman of Massachusetts Department of Environmental Protection and Christopher James of the Connecticut Department of Environmental Protection to act as co-coordinators of the project. After consulting with utility regulators, environmental regulators, industry representatives, and other interested persons, a list of potential members of the working group was put together and, in the fall of 2000, letters of invitation were sent to them. The work began in earnest in January 2001 with a "kick-off" conference call and, at the end of the month in Chicago, our first in-person meeting.

The first meeting was dedicated primarily to developing a set of objectives and principles to guide the work, and a time-line in which to finish it. The group discussed a series of questions: What did we hope to accomplish? What is the purpose of the rule? What is its scope? What constraints did we face? What approach to emissions regulation should we take? A "Statement of Objectives, General Principles, and Scope" emerged over the following couple of months (and is included as Appendix A).

The Working Group organized several sub-groups that would address specific issues: applicability, emissions, manufacturer certification, and offsets (credits for combined heat and power, etc.). The sub-groups developed information and suggested approaches for tackling certain issues. The applicability sub-group considered the scope of the rule. How would the rule's applicability be defined – by generating capacity, output, technology, purpose for generation (*i.e.*, emergency, peaking, baseload), or location (attainment or non-attainment area)? The emissions sub-group put together a comprehensive spreadsheet detailing the emissions performance of current distributed generating technologies, that is to say, the state-of-the-art for technologies that are now, or will very shortly be, available in the market. The certification sub-group studied how other manufacturer certification programs currently work – for example, the US EPA's Energy Star Program for appliances and its off-road mobile engine program. The offsets sub-group considered methods for calculating the net emissions reductions resulting from combined heat and power (CHP) installations and administratively streamlined and reliable ways to credit such installations with those savings.

The sub-groups reported regularly on their progress to the Working Group. By spring, the work had advanced sufficiently to convene a second in-person meeting that focused upon central, interrelated substantive issues – applicability and emissions standards. Proposals that had been developed by various members of the Working Group formed points of departure for the discussion. The meeting revealed areas of consensus and disagreement, and an action plan for resolving outstanding issues was set out.

Discussions continued among various members of the Working Group, and around those discussions an *ad hoc* drafting committee formed. Several drafts of the rule circulated among the *ad hoc* committee during the summer of 2001, so that by September a draft could be forwarded to the Working Group as a whole, for their consideration. In October, after further review and revision, the Working Group agreed to release the draft for public comment.

This draft does not represent a final agreement of the Working Group. Although reflective of the general directions taken by the Working Group, it is intended as a draft for discussion. The issues in developing a national model regulation are complex, and much work can still be done. The Working Group and The Regulatory Assistance Project seek public comment on the draft, which will inform further work and revisions.

All aspects of the rule and its supporting documents are open to comment. The Working Group has already identified a number of outstanding issues. These are enclosed in brackets and, in certain cases, note specific questions or additional requests for information. In several spots, there are brackets within brackets, denoting layers of interrelated issues still to be resolved. If you wish to comment on this document, you may do so by e-mailing them to Rick Weston at rapweston@aol.com, distributing them through the list-serve dremissions@lists.raponline.org, or by sending them to The Regulatory Assistance Project, 50 State Street, Suite 3, Montpelier, Vermont, 05602. Please submit them before the end of December 2001.

II. THE RULE

MODEL REGULATIONS FOR THE OUTPUT OF SPECIFIED AIR EMISSIONS FROM SMALLER-SCALE ELECTRIC GENERATION RESOURCES

[Note: Brackets denote outstanding items or provisions of particular importance.]

Title AA: Output-Based Emissions Standards for Smaller-Scale Electric Generation Facilities

I. Purpose. The purpose of this rule [statute] is to:

(A) Regulate the emissions of certain air pollutants from smaller-scale electric generating units in [this jurisdiction]; and

(B) Reduce the regulatory and administrative requirements for siting units that are affected by this rule.

II. Definitions. [Assumes that the rule is added to a set of existing rules relating to the emissions and siting of electric generating facilities, and makes reference to other relevant definitions.]

(A) **Agency**: The local or state governmental department, division, or agency that has jurisdiction over air pollution emissions of electric generating units.

(B) **Baseload Generator**: A generator that operates more than [700] hours per year.

(C) **Combined Heat and Power**: A generator that sequentially produces both electric power and usable process heat from a single source. Herein referred to as CHP.

(D) **Emergency**: [A limited-duration failure of the electrical grid [or pending probable voltage reductions or imminent grid failure, in accordance with ISO emergency operating procedures].]

(E) **Emergency Generators**: Generators used only during an emergency[, provided that the maximum annual operating hours, including for maintenance, shall not exceed 300]. [Rolling or calendar year, for determining accounting of hours?]

(F) **Fuel Cell**: A type of generator that converts a primary fuel – either hydrogen or a hydrocarbon-based fuel – into electricity or electricity and thermal energy through an electro-chemical reaction.

(G) **Generator**: Any equipment that converts primary fuel (including fossil fuels and renewables fuels) into electricity or electricity and thermal energy.

(H) **Manufacturer**: A person or firm that manufactures, assembles, or otherwise supplies generators subject to the requirements of this rule.

(I) **Mobile Diesel Fuel**: Ultra-low sulfur content fuel, as defined by the United States Environmental Protection Agency (EPA) [citation].

(J) **Owner**: The owner of, or person responsible for, a generator subject to the requirements of this rule.

(K) **Peaking Generator**: A generator that operates fewer than [700] hours per year.

(L) **Power to Heat Ratio**: For a CHP unit, the sum of the actual or forecasted annual average electrical and mechanical energy divided by the total thermal energy of the unit.

(M) **Useful Energy Output**: [still to be defined]

III. Applicability.

(A) This rule applies to all non-mobile generators that are not subject to major source review under the Clean Air Act, 40 CFR 51, and that are installed on or after the effective date of this rule.

(B) **Exemptions.** The following will be exempt from compliance with the emissions requirements of this rule:

(1) Generators that are less than 37 kilowatts in capacity and operate fewer than 100 hours per year, and.

(2) Generators whose engines are subject to the Code of Federal Regulations, Parts 89, 90, and 92, EPA's Non-Road Engine Program.

[IV. Emissions. A generator's emissions of nitrogen oxides (NO_X), particulate matter-10 microns (PM-10), carbon monoxide (CO), and carbon dioxide (CO_2) shall not exceed the standards set out in the following subparagraphs. Standards are expressed in pounds per megawatt-hour of electricity output. A generator shall meet the standards in effect on the date the unit is installed and for the conditions (emergency or total annual hours) under which it operates, according to the following:

(A) **Emergency generators.** Generator may run up to a maximum of 26 hours per year for maintenance and whenever there is an emergency[, up to a maximum of 300 hours per year]. Source must record date and start/stop time for every operation as well as total annual run hours. Maintenance hours must be separately accounted for. Emissions standards for emergency generators are as follows:

	Phase One: January 1, 2003, Through December 31, 2005	Phase Two: January 1, 2006, through December 31, 2008	Phase Three: January 1, 2009, And thereafter
NO_X	21.00 lb/MWh	17.00 lb/MWh	14.00 lb/MWh
PM-10	0.80 lb/MWh	0.80 lb/MWh	0.80 lb/MWh
CO	6.00 lb/MWh	6.00 lb/MWh	6.00 lb/MWh
CO_2	1450.00 lb/MWh	1450.00 lb/MWh	1450.00 lb/MWh

(B) **Peaking Generators.** Emissions standards for peaking generators are as follows:

	Phase One: January 1, 2003, Through December 31, 2005	Phase Two: January 1, 2006, through December 31, 2008	Phase Three: January 1, 2009, And thereafter
NO_X	1.00 lb/MWh	0.60 lb/MWh	[0.40 - 0.30] lb/MWh
PM-10	0.08 lb/MWh	0.05 lb/MWh	0.02 lb/MWh
CO	5.00 lb/MWh	3.00 lb/MWh	0.80 lb/MWh
CO_2	1500.00 lb/MWh	1500.00 lb/MWh	1500.00 lb/MWh

(C) **Baseload Generators.** Emissions standards for baseload generators are as follows:

	Phase One: January 1, 2003, Through December 31, 2005	Phase Two: January 1, 2006, through December 31, 2008	Phase Three: January 1, 2009, And thereafter
NO_X	[0.5 – 0.47] lb/MWh	[0.3 - 0.27] lb/MWh	[0.15 - 0.07] lb/MWh
PM-10	0.08 lb/MWh	0.05 lb/MWh	0.02 lb/MWh
CO	0.60 lb/MWh	0.30 lb/MWh	0.10 lb/MWh
CO_2	1400.00 lb/MWh	1400.00 lb/MWh	1400.00 lb/MWh

(D) **Technology Review.**

(1) By December 31, 2007, the agency shall complete a review of the state of, and expected changes in, technology and emissions rates. This review shall be used by the agency in considering whether the 2009 standards should be amended.

(2) Beginning in 2014 and every five years thereafter, the agency shall review the state of technology and emissions rates and determine whether the emissions set out herein should be amended.]

V. Emissions Certification, Compliance, and Enforcement.

(A) **Emissions Certification.** A manufacturer may seek to certify that its generators meet the provisions of this rule.

(1) **Certification Process**. [This section needs to address process issues and the question of running at partial load operations.] Emissions of nitrogen oxides, PM-10, carbon monoxide, and carbon dioxide from the generator shall be certified by the manufacturer in pounds of emissions per megawatt hour (lb/MWh). This certification must be displayed on the nameplate of the unit or on a label attached to the unit. Test results from EPA Reference Methods, California Air Resources Board (CARB) methods, or equivalent testing may be used to verify this certification and shall be provided upon request to the agency.

(2) **Responsibility of manufacturer.** Certification will apply to a specific make and model of generator. For a make and model of a generator to be certified, the

manufacturer must demonstrate that the generator is capable of meeting the requirements of this rule for at least 15,000 hours of operation. During the initial 15,000 hour operating period, the Agency may enforce compliance with these standards. If the design of a certified generator is modified, the generator will need to be re-certified. Certification means that a generator may carry a label with the following text:

> This engine has met the standards defined by [state/ US EPA] regulation and is certified as meeting applicable emission levels when it is maintained and operated in accordance with the manufacturer's instructions.

(C) An owner of generation that is not certified under the terms of Section V.A. will need to demonstrate compliance with this rule through on-site testing using procedures set out in [other applicable state regulations]. [Is more detail needed here, or are on-site testing procedures generally covered by existing state regulations?]

(D) **Duty to Comply.** An owner shall comply with the requirements of this rule or with the terms and conditions of any permit issued pursuant to this rule. Neither certification nor compliance with this rule relieves owners from compliance with all other applicable state and federal regulations (*e.g.*, a general permit or a new source review permit).

(E) **Enforceability.** This rule and any permit issued pursuant to it are enforceable by the Agency as provided by law.

VI. Performance Incentives for Concurrent Emissions Reductions.

(A) **Flared Fuels**: If a generator uses fuel that would otherwise be flared (i.e., not used for generation or other energy related purpose), the emissions that were or would have been produced through the flaring can be deducted from the actual emissions of the generator, for the purposes of calculating compliance with the requirements of this rule. If the actual emissions from flaring can be documented, they may be used as the basis for calculating the credit, subject to the approval of the Agency. If the actual emissions from flaring cannot be documented, then the following default values shall be used:

(1) SOx: xxx lbs/MWh
(2) NOx yyy lbs/MWh (engine vs turbine)
(3) CO_2 www lbs/MWh
(4) CH_4 vvv lbs/MWh

[(B) **Combined Heat and Power:** CHP installations must meet the following two requirements to be eligible for emissions credits related to thermal output:

(1) At least 20% of the useful energy output must be thermal and at least 20% [13%] must be electric. This corresponds to a power-to-heat ratio of between 0.25 [0.15] and 4.0.

(2) The average system efficiency when operated in this range of power-to-heat ratios must be at least 55% beginning in 2003, 60% in 2008 and 65% in 2011. Units meeting these requirements must still meet the emissions standards set out above, but may reduce their reported emissions by the amount that a new boiler would emit if it were producing the same amount of thermal energy. This calculation will be performed according to the following assumptions and procedures:

(a) The assumed emissions rates for new boilers shall be based on [insert state code reference for boiler standards].
(b) The input-based emissions rates for new boilers will be converted to output based rates based on an assumed 80% efficiency.
(c) Emission per MMBtu of thermal energy will be converted to MWh of thermal energy by multiplying by 3.412 MMBtu/MWh.
(d) The assumed new boiler output based emissions rate will be converted based on the CHP unit's power-to-heat ratio by dividing the emissions rate by the power-to-heat ratio.
(e) The CHP unit's adjusted emissions rate will be calculated by subtracting the prorated output based new boiler emissions rate from the unadjusted emissions rate of the CHP unit (in lbs/MWh of electricity).]

[(C) **End-Use Efficiency and Non-Emitting Resources**: When end-use energy efficiency and conservation measures or non-emitting electricity generation are installed and operated contemporaneously at the facility where the generator is installed and operated, then the electricity savings credited to the efficiency and conservation measures or supplied by the source of non-emitting electricity shall be added to the electricity supplied by the generator for the purposes of calculating compliance with the requirements of this rule, subject to the approval of the Agency. [How are efficiency savings verified and who verifies them?]]

VII. Fuel Requirements.

(A) **Diesel Engine Fuel**: Generators powered by diesel internal combustion engines shall use only on-road mobile diesel fuel.

(B) **Monitoring.** If the generator is powered by an engine supplied with fuel from more than one tank or if multiple sources (engines and other devices that use the fuel) are supplied fuel by one fuel tank, a non-resettable fuel metering device shall be used to continuously monitor the fuel consumption by the generator's engine. [This is used for cross-checking.

Is this too burdensome for small systems? What does this mean for fuel cells? Should there be a low-end cut-off? Say, 10 kW?]

VIII. Record Keeping and Reporting. [Should units whose daily or annual emissions (lbs/MWh) are below a specified level be exempt from these reporting requirements? If so, what should be the thresholds?]

(A) **Record-Keeping Requirements.** At the premise where the authorized activity takes place, or at such other place as the Agency approves in writing, the owner shall maintain the following records pertaining to such activity:

(1) *Monthly and annual amounts of fuel(s) consumed*. For the purposes of this subparagraph, annual fuel consumption shall be calculated each calendar month by adding (for each fuel) the current calendar month's fuel consumption to those of the previous eleven months;

(2) *Monthly and annual operating hours.* For the purpose of this subparagraph, annual operating hours shall be calculated each calendar month by adding the current calendar month's operating hours to those of the previous eleven months;

(3) *With respect to each shipment of liquid fuel (other than liquefied petroleum gas, to be used in each engine authorized hereunder, a shipping receipt and certification from the fuel supplier of the type of fuel delivered, the percentage of sulfur in such fuel (by weight dry basis), and the method used by the fuel supplier to determine the sulfur content of such fuel*; and

(4) *Date and type of emergency during which an emergency generator is operated*. Owner must certify that non-maintenance run hours occurred only during emergencies.

(C) **Availability of Records.** Unless the Agency provides otherwise in writing, the owner shall maintain each record required by this subsection for a minimum of five years after the date such record is made. An owner shall promptly provide any such record, or copy thereof, to the Agency upon request.

(D) **Duty to Report.**

(1) **Additional Information.** If the Agency requests any information pertinent to the authorized activity or to compliance with a general permit issued pursuant to this rule, the owner shall provide such information within thirty days of such request.

III. COMMENTARY ON THE RULE

The rule attempts to translate into statutory language the objectives and principles that the Working Group developed. It is divided into eight sections. The first section states its purpose. The second defines specialized terms used in the rule.

A. Applicability

The third section addresses the first of the rule's two central issues, applicability. The rule is intended to regulate the emissions of a class of electric generation – smaller-scale, distributed resources – that are not covered under existing state or federal regulations. Historically, distributed resources have accounted for a very small percentage of the nation's installed capacity and even less of its energy but, as technological change and regulatory reform advance, the potential for these new applications to proliferate also increases. With it comes a need to assure that such resources contribute to an improved environmental profile of the electric sector, or at least to one that is no worse that it would have otherwise been.

The applicability provision is therefore intended to close the "gap" in a state's existing air regulations. The rule "applies to all non-mobile generators that are not subject to major source review under the Clean Air Act, 40 CFR 51" installed on or after the rule's effective date. Major new source review is triggered by specifications relating to the size of a resource and its potential to emit; consequently, the rule defines applicability in similar terms. To the extent that a state has minor source review requirements for new sources covered by this regulation (40 CFR 51.160) or some portion of the generation that the rule covers, then the rule's value to a state lies in its codification of emissions standards, and the administrative streamlining that the optional certification process offers.

By virtue of their very small potential for significant impacts, certain resources are exempted from meeting the rules emissions standards. These are those that are less than 37 kilowatts in capacity and operate fewer than 100 hours per year and those whose engines are subject to Parts 89, 90, and 92 of the EPA's Non-Road Engine Program. The first exemption applies primarily to the small portable gasoline-fired generators that are marketed to homes and small businesses and are typically used during blackouts and at remote locations. The second exemption applies to mobile off-road generators that are already covered under EPA regulations. Together, both classes of generation make up a small portion of the overall market and do not constitute a significant threat to air quality. Exempting them also reduces the administrative burden of state air regulators.

Lastly, the rule as written applies only to new installations. Existing installations are, in large measure, intended for emergency purposes and are, in most states, already covered under the terms of previously approved permits. However, agencies may choose to require that existing units meet the requirements of this regulation through a phase-in of its application or with other timing. To the extent that an owner would like to alter a generator's conditions of operation, he or she would, presumably, have to obtain an amended permit from the appropriate state agency. Such an amended permit could require compliance with the provisions of this rule.

B. Emissions

The fourth section of the rule sets out the emissions standards themselves. When viewed together with the applicability provisions, the overall approach to the rule emerges. One objective is to regulate "the emissions output of distributed generation in a technology-neutral and fuel-neutral approach." Another is to "facilitat[e] the development, siting, and efficient use of distributed generation in ways that improve or, at least, do not degrade air quality." A third is to "encourage technological improvements that reduce emissions output." In addition, there was a desire to express the standards in a consistent set of units. This, and the explicit intention to credit efficiency gains, led the Working Group to adopt an electrical output-based (pounds of emissions per megawatt-hour).

The first question to be answered by the Working Group was "What emissions should be regulated?" Nitrogen oxides (NO_X) and sulfur dioxide (SO_2) were the obvious firsts to be identified, followed by particulate matter, carbon monoxide, and carbon dioxide. Unburned hydrocarbons were also considered. In the end, the Working Group settled on four pollutants. There was no debate about nitrogen oxides, since they contribute to ground-level ozone, acid rain, and other environmental impacts. Sulfur dioxide was not included, despite its elemental connection to acid rain, because current distributed generation technologies produce very little, if any, SO_2 . The exceptions to that are diesel engines or those using diesel fuel, but the Working Group concluded that it was administratively easier, and equally as effective, to address this issue through a low-sulfur content fuel requirement rather than an emission standard, and the rule specifies that low-sulfur mobile diesel fuel must be used. Both produce the same result, since it is less costly to use ultra-low sulfur fuel than to install "tailpipe" controls on the engines. Low-sulfur fuel also enables catalyst-based technologies that may be poisoned with sulfur in the fuel to be used. Particulate matter is the second pollutant. There was a desire to regulate particulate matter down to 2.5 microns, [but the Group settled on 10 microns (PM-10) in the knowledge that a PM-2.5 standard would target primarily NO_X and $SO_{2,}$ which are being addressed separately.] The methodology for accurately measuring PM2.5 is also uncertain at this time. Carbon monoxide (CO), because of its direct health impacts, its role in the formation of ground-level ozone, and as a surrogate for other air toxics, is the third pollutant to be regulated. Fourth is carbon dioxide (CO_2), the primary contributor to global climate change.

The Working Group educated itself on how the various pollutants are formed, what their impacts on public health and the environment are, and how they can be controlled. The relationships among various pollutants and the technologies that produce them were of particular significance. A change in combustion temperature or combustion characteristics may, for example, increase or decrease the amount of NO_X that an engine or turbine produces, but may have the opposite effect with respect to CO. And, since carbon dioxide production is a function of how much fuel is used to produce a given amount of power, any action that affects an engine's efficiency directly affects its output of CO_2. The Group's multi-pollutant approach takes these relationships into account.

The Working Group also concluded that phasing the standards in is necessary, in order to provide a reasonable amount of time to accommodate manufacturers' research and development cycles. Three phases are envisioned. The first runs from the present to the end of 2005. The second covers the three years beginning January 1, 2006, and ending December 31, 2008. The third begins on January 1, 2009, and continues indefinitely thereafter. Which standards apply depends upon the date a unit is installed. In addition, there is a provision for a technology review to be completed a year before the final standards take effect. On the basis of that review, the rule-making agency can evaluate whether the final standards can or need to be amended in any way. The rule also calls for periodic technology reviews thereafter.

The Group decided that the rule would apply only to new installations, not existing. There were several reasons for this. First is the understanding that most existing generation to which the rule might apply is used for emergency purposes and, in most states, has been permitted to operate as such under current law. Related to this were administrability concerns. A significant investment in the time and effort of state environmental regulators did not appear to offer significant benefits. Even so, several Working Group members remain interested in exploring ways of encouraging emissions reductions in existing facilities.

Distributed generation technologies vary widely, and consequently so do their applications. The fast-start capabilities and relatively low cost of diesel generators, for example, make them ideal for emergency back-up service. Micro-turbines can provide energy for longer durations, as can reciprocating engines (both diesel and gas) and other technologies, and their overall efficiencies are much improved when their waste heat can be put to use in some other mechanical or thermal process (combined heat and power, or CHP). Moreover, the emissions characteristics of the technologies also vary greatly. Depending on the pollutant and the technologies being compared, the differences can be very significant. Appendix B contains an emissions spreadsheet of the information developed by the Working Group.

These facts persuaded the Working Group that one set of emissions standards to cover all potential applications would not be feasible. First, if the standards are set very strictly, they could greatly restrict the ability of distributed generation to provide real benefits to the electric system, because certain technologies would be prohibited from operating altogether (or at least until improvements could be developed). And second, if the standards are set too loosely, the rule might fail to serve the other environmental purposes for which it is intended.

Therefore, three categories of generation were identified, differentiated not by technology but by the needs served, which in turn were defined by the circumstances and annual hours of operation. The categories are Emergency, Peaking, and Baseload. Emergency generation is not limited in its total annual hours of operation [although 300 hours is being considered], but it is constrained to 26 hours of maintenance operations per year. Peaking generation is limited to [700] hours per year. Baseload operation is anything that operates for more than [700] hours annually.

A comparison of the emissions rates for the three categories reveals the general premise underpinning them. The more a generator operates, the less emitting it must be. This is consistent with the historic approach to the permitting of larger sources, which relates compliance requirements to the cost per ton of reduction. The compliance costs for sources that run very few hours will tend to exceed the thresholds. When the compliance cost is spread out over a greater number of hours of operation, the requirement can be more stringent. Times of blackout, where the trade-off between emergency power needs and air quality may be great, are the obvious example. Emergency generators will run to provide electricity, particularly for essential services such as hospitals, until grid power is restored. These events are unpredictable and usually of limited duration. The Working Group does not consider the potential pollution from emergency generation to be a significant problem.

The first phase standards for emergency generators reflect the current state of uncontrolled diesel reciprocating engine technology. The second phase and third phase standards differ only with respect to NO_X and reflect expected technological changes in diesels over the coming decade, although no significant improvements in efficiency are predicted. Diesels, for reasons already mentioned, will likely remain the primary form of emergency generation for a number of years to come. The Working Group concluded that tailpipe controls such as selective catalytic reduction (SCR) would raise the overall costs of emergency generation prohibitively, while doing very little to improve air quality.

The group discussed whether the emissions standards for DG should be, in some way, related to the emissions output of the facilities that would be displaced. However, the group did not achieve consensus on this point, in part because of disagreements over the question of what mix of new and existing generation might be displaced by DG and how that mix might change over time. The inability to resolve the issue did not, however, prevent the Group from reaching agreement on most aspects of the emissions standards.

DG technologies are well suited to providing service at times of greater demand or of peak (system, transmission, or distribution peak). The generally higher cost per kilowatt-hour of distributed generation (when compared to most grid-supplied energy) will tend to limit cost-effective DG operations to these times, when the marginal cost or market price (*i.e.*, the value) of energy is also high.[1] The economics of grid operation are such that peaking needs have generally been met by resources whose capital (and thus carrying) costs are low, but whose running costs are relatively high. Simple-cycle combustion turbines have typically fit this bill.

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[1] It is not only capacity and energy that DG can provide, but also higher value ancillary system reliability services (reactive power, voltage support, frequency responsive reserves, ten-minute reserves, etc.). See RAP's paper *Accommodating Distributed Resources in Wholesale Markets*, July 2001, for more detail.

Consequently, it is with an eye to such facilities that the standards for peaking generators under this rule were developed.

The Phase One standards for generators providing peaking power approximate the emissions output of today's gas-fired reciprocating engines and small gas turbines. The Phase Two standards anticipate improvements to those technologies. The Phase Three standards correspond to the output of simple-cycle turbines, also with expectations of significant improvements over today's technology.

The Phase One baseload standards roughly match the emissions output of today's cleanest natural gas engines and microturbines. The Phase Two and Three are intended to capture emissions reductions that will flow from technological improvements, are achievable in the coming years, and are consistent with clean air goals.

The Phase Three standards do not precisely correspond to the emissions profiles of high-efficiency, low-emissions gas-fired technologies. They have been adjusted by a practical understanding of the capabilities of the various DG technologies, for example, with respect to carbon dioxide output. Efficiency gains, critical to reducing CO_2 as a product of combustion, are not expected to be great over the next decade. Also, the DG technologies that are likely to compete for peaking services inevitably produce more CO_2 than do those used in emergency applications, and the rule recognizes this reality.

All of the proposed emissions standards and related requirements are still under consideration by the Working Group. Several issues in particular still need to be addressed either in the rule or in the supporting documentation. For example, should any (and, if so, what) adjustments be made for dual-fuel fired systems? Are there any ways to simplify the requirements (for instance, should the Phase 2 peaking standards be the same as the Phase 1 baseload standards)? Should the peaking standards be somehow modified to account for the fact that peak demand for electricity often occurs at times when air quality is already degraded? Should the definition of emergency be expanded to include service provided to avoid an imminent blackout? If so, what criteria need to be met to allow such operation and should a generator be paid by the system operator for the output? What kinds of efficiency gains can be expected over the next decade and do they justify reductions in the carbon dioxide limits over that time? Given our current ability to measure emissions of particulate matter, will it be possible to demonstrate compliance with the proposed standards?

Lastly, the rule does not aim to pick "winners and losers," but it would be disingenuous to assert that the standards will not affect resource choices over time. In light of our growing understanding of atmospheric chemistry, environmental impacts, and public health, it seems only reasonable to expect that the regulation of air pollutants will become increasingly strict. The rule attempts to balance the competing concerns about air quality, technology development and deployment, and cost-effectiveness.

The Working Group recognizes that the Phase Two and Phase Three standards are rigorous, but it is confident that they can be achieved. In certain cases, improvements in efficiency and combustion processes may be enough to enable a technology to meet a standard. In other cases, tailpipe controls or CHP applications, or both, will be necessary.

C. Emissions Certification

The rule, as currently drafted, does not include testing and other procedures for developers to follow in order to establish that their DG installations meet the emissions standards. The rule does, however, give DG manufacturers and suppliers the option to certify the emissions output of their products. The approach taken is fairly straightforward, and relies on testing procedures already developed, or under development, by the US EPA, the California Air Resources Board, or other expert body named by the state. Such certification would have the effect of greatly reducing the administrative burdens of entire product lines, for both developers and state regulators.

One important aspect of the certification process that the draft does not address, but is still being considered by the Working Group, is the load conditions under which the emissions testing is conducted. Generation does not always operate under full load, but also under a range of partial loads, and emissions output varies with those loads. Consequently, the testing requirements should, to the extent possible, replicate those conditions, to establish what in effect will be weighted averages of emissions rates for typical operations.

These varying load conditions, of course, have ramifications for the emissions standards themselves. It is the intent of the rule that the standards be achievable under typical operating conditions.

D. Performance Incentives for Concurrent Emissions Reductions

This section of the rule sets out the circumstances under which a DG application can be credited for displacing emissions that would have otherwise occurred. Specifically, generation that is fired by gases that otherwise would have been burned off or emitted directly into the atmosphere will be able, upon demonstration, to claim an offset to its own emissions of the emissions avoided. Similar credit will also be given to CHP applications, where the waste heat from generation is put to productive mechanical or thermal use, thereby avoiding the incremental emissions that a separately fired process would have produced. The Working Group is generally satisfied with this approach, but is considering ways to simplify it.

In the case of flared gases, a developer will have the option of demonstrating the actual emissions offsets or using the rules default values (which are still to be determined by the Working Group). In the case of CHP, the rule sets out the formula used to calculate the offsets, but leaves it to the state to determine the appropriate boiler and other standards that will provide the inputs for the calculations.

The Working Group is also considering a provision that gives emissions credit for grid-electricity savings achieved at a site by non-emitting resources (*e.g.*, certain renewables) and end-use efficiency measures installed simultaneously with the generation. The intention of such a provision would be to promote other, cost-effective emissions-reducing strategies.

E. Miscellaneous Provisions

Lastly, the rule sets out monitoring and record-keeping requirements. These are typical of those required of other emissions sources. Some members felt that it made sense to exempt generators below a specified size from these requirements; the Working Group is still considering whether this is appropriate and, if so, what would be a reasonable cut-off.

APPENDIX A. STATEMENT OF OBJECTIVES, PRINCIPLES, AND SCOPE

STATEMENT OF OBJECTIVES, GENERAL PRINCIPLES, AND SCOPE REGARDING PROPOSED RULES AND STANDARDS FOR THE REGULATION OF AIR EMISSIONS FROM DISTRIBUTED RESOURCES

April 30, 2001

A. Objectives

The Distributed Resources Emissions Collaborative will identify the issues and will develop the background, criteria, and requirements for a set of recommended rules and performance standards for regulating the air pollutant emissions of smaller-scale electric system generating resources, commonly referred to as distributed generation, or DG (see section on Applicability). The rules and standards are expected ultimately to take the form of a model rule that states can adopt in order to address the potential air quality impacts of new and existing sources of electric generation that are not, for the most part, covered by current state air regulations, policies, or permits. The purpose is to help reduce institutional and infrastructure barriers to cost-effective deployment of distributed power systems, and to do so by facilitating the development, siting, and efficient use of distributed generation in ways that improve or, at least, do not degrade air quality. More specifically, the objectives are:

(1) To research and develop information, tools, and options for regulatory policies that will encourage the deployment of distributed resources where cost-effective and environmentally beneficial; and

(2) To establish and foster adoption of a national model for output-based emissions performance standards for distributed resources that state utility and environmental regulators and other key stakeholders have developed through a collaborative approach.

B. Principles To Guide the Collaborative's Effort

1. Environmental Impacts

The recommended rules and standards should regulate the emissions output of distributed generation in a technology-neutral and fuel-neutral approach, as appropriate.

2. Other Distributed Resources

The recommended rules and standards are intended to encourage, or at least not discourage, the deployment of non-emitting distributed resources.

3. Usefulness

The recommended rules and standards should be of immediate use to states and the electric power industries. They should be acceptable to environmental and utility regulators, energy service providers, and manufacturers of distributed generation; and they should, among other things, simplify the administrative processes of siting and permitting.

4. Impacts on the DR and Electric Industries

The recommended rules and standards should have positive impacts on the DR and electric industries. By promoting consistent or uniform standards in multiple jurisdictions, they can enable manufacturers to standardize designs and capture the benefits of economies of scale. The recommended rules should also encourage pre-installation certification of a unit's emissions output, and compliance with the standards should facilitate siting and permitting.

In addition, the rules and standards should be set so as to encourage technological improvements that reduce emissions output. This characteristic is commonly referred to as *technology-forcing*. In this way, the rules should promote, or at least not hinder, the deployment of environmentally sustainable DR.

5. Timing

The recommended rules and standards can be phased in, or staged, over a specified period. A phase-in schedule should be set so as to be technology-forcing, while giving manufacturers a reasonable opportunity to meet the targets.

C. Scope of Draft Rules

1. Applicability

The proposed regulations should be applicable to DG of specified types and sizes. Approaches for specifying the DG to be covered include:

1. *First Alternative:* The recommended rules and standards should apply to generating facilities not already covered under Title V (Clean Air Act) regulations.

2. *Second Alternative:* These recommended rules and standards should apply to generating facilities whose nameplate capacity is XX megawatts or less, interconnected or serving load at the primary or secondary voltage levels.

<u>2. Standards Expressed</u>

The collaborative will consider whether emissions requirements for distributed generation should be output-based performance standards (expressed in terms of pounds per megawatt-hour or kilowatt-hour), to promote innovation, efficiency, and improvements in generation technology.

<u>3. Emissions Covered</u>

The air pollutants to be considered will include nitrogen oxides, sulfur dioxide, particulates, volatile organic compounds, carbon monoxide, and toxics.

<u>4. Methods for Recognizing the Benefits of CHP and Non-Emitting DR</u>

The collaborative will explore whether the recommended rules should include methods for accounting for the potential air quality benefits of distributed resources whose waste heat is recovered and used in other processes (*e.g.*, space and water heating, industrial processes, etc.), thus displacing combustion of fuels and production of emissions. In addition, the collaborative should explore methods for accounting for the emissions reductions of using gas that would otherwise be flared (*e.g.*, landfill gas) to fuel distributed generation and of on-site end-use efficiency improvements.

<u>5. Certification of Emissions Output</u>

The collaborative will consider means for establishing the emissions output of distributed generation facilities. More specifically, the collaborative should explore approaches by which the emissions output of a unit can be certified in advance, through either a self-certification program or through some other appropriate means.

<u>6. Existing and New Units</u>

The collaborative should explore approaches for addressing the emissions output of existing and new facilities. In this context, it may be appropriate, for example, to differentiate between units used solely for emergency purposes and units available for a wider range of electric system needs, that is to differentiate on the basis of "duty cycles."

APPENDIX [TO THE STATEMENT OF OBJECTIVES]

COMMENTARY ON THE STATEMENT OF OBJECTIVES, PRINCIPLES, AND SCOPE OF THE DISTRIBUTED RESOURCES EMISSIONS COLLABORATIVE

What follows here is a description of some of the issues that the collaborative is exploring. It describes questions that have been raised, but not necessarily settled, by members of the working group. The outline of this commentary generally follows that of the principles.

A. Objectives

Should the deployment of DG result in better (or at least not worse) environmental outcomes than what would have occurred in the absence of the DG? If so, then the question of what generation resources will be displaced (and their emissions, if any) by the use of both existing and new DG becomes relevant to the design of proposed DG emissions standards. Most currently available distributed generation technologies produce air pollutants at a greater rate (on an output basis) than a state-of-the-art natural gas-fired, combined-cycle central generating station (GCC) with best available control technologies (BACT) installed. In contrast, some DG technologies produce emissions at a lower rate than certain other fossil-fuel burning technologies (both existing and new).

An alternative view holds that, for most applications, DG does not compete with or replace central generating facilities, and therefore a comparison to such units is not relevant. In addition, it was noted that air pollution regulation in the United States is not typically based on the concept of emissions displaced by the new technology, but rather on the basis of achievable limits. This approach may or may not be tempered by a consideration of the technology's contribution to the overall emissions of an airshed.

Development of proposed air emissions standards requires the careful balancing of a rules benefits and consequences. Factors to be considered may include the environment, consumer choice, integrated energy and land-use planning, economic efficiency of electricity markets, availability of electricity supplies, and competitiveness of the business sector.

B. Principles To Guide the Collaborative's Effort

1. Environmental Impacts

The role of a technology-neutral and fuel-neutral standard is being considered. Such a standard could, depending on how it is set, preclude the deployment of certain technologies. Also, should the standards differ depending on whether the DG will be deployed in attainment or non-attainment areas? Lastly, the question arose whether other potential environmental harms (*e.g.*, land use and water pollution) should be addressed in addition to air emissions.

2. Other Distributed Resources

The working group concluded that, given the limited time frame and primary focus of the collaborative, the development of explicit rules to encourage the deployment of non-polluting distributed resources (*e.g.,* end-use efficiency, photovoltaics, wind power, etc.) is beyond the scope of work. Future work on this topic could include identifying unintended disincentives in existing permitting processes, developing proposals to undo such disincentives, and creating rules and other policy instruments that recognize the zero emissions of certain distributed resources.

3. Impacts on the DR and Electric Industries

It was noted, however, that current technology-forcing regulations (BACT/LAER) require case-by-case, technology-specific determinations, and that a technology-neutral approach to setting emissions limits that "force" improvements would be new.

C. Scope of Draft Rules

1. Applicability

The collaborative makes a distinction between distributed resources (DR) and distributed generation (DG). Generally speaking, *distributed resources* refers to the broad range of technologies that are not intended to be connected to the bulk electric power transmission system and are typically deployed in close proximity to load. DR includes smaller-scale generation technologies (smaller than traditional central station generator units), energy storage devices, load management activities, and end-use efficiency and conservation measures. *Distributed generation* refers only to the generation subset of DR. Examples of DG include micro-turbines, fuel cells, reciprocating engines, photovoltaics, and wind turbines. The work of the collaborative will focus on regulating the emissions of DG and identifying other, non-emitting DR technologies.

The first alternative expresses the notion that the rule's applicability should be broad, including even the smallest of units (to be covered under some sort of certification program). The second alternative may be narrower in scope, but the practical differences between the two will depend upon the applicability of existing state regulations and the definitions of "primary and secondary voltage levels." There seemed to be a general feeling among the participants that favored the first alternative, but then there was the question of whether rule captures more than regulators want or need to be concerned with (*i.e.*, very small generators used by residences and businesses during blackouts or at remote locations for limited periods of time, *e.g*, at construction sites before line extensions are installed). By the same token, however, the point was made that the rule should be written to include non-grid-connected units, since they too can contribute emissions to an airshed.

Other approaches to the applicability question were raised for consideration. Should the permitting process differ on the basis of a facility's size (generating capacity) or its potential to emit (PTE) or another attribute? Given other aims of the proposed rules (simplicity and DG development), it seemed that too complex an applicability requirement would create more problems than it would solve.

2. Standards Expressed

Output-based standards encourage efficient operation of facilities. Input-based standards (standards calculated on the basis of the amount of pollutant per unit of fuel input) do not reward increases in efficiency and, moreover, are typically differentiated by fuel-type, often discouraging substitution of less polluting fuels. The general preference is for the standards to be expressed in terms of pound of emissions per unit (kWh or MWh) of output, although the idea of using kilowatt-years in the denominator was raised. Because this latter approach may pose certain operational difficulties, it did not find much enthusiasm in the group.

The collaborative may also want to consider other, non-numerical approaches to regulating air emissions. There may, for instance, be ways of permitting facilities that have the effect of limiting emissions without actually specifying their levels, such as through certification standards, definitions, hours of operation, etc.

3. Emissions Covered

The working group is considering whether carbon dioxide should be included among the emissions to be regulated.

4. Methods for Recognizing the Benefits of CHP and Non-Emitting DR

This, like other aspects of the effort, requires gathering information and developing options, which are two purposes of the Collaborative.

5 Certification of Emissions Output

Certification could be mandatory for the smaller units, so that additional permitting is not required, whereas alternative approaches to certification (*e.g.*, case by case permitting) may be appropriate for large units. The cut-off between “smaller” and “larger” would need to be addressed. The program could also call for periodic testing of units that are in use, to measure on-going compliance. This approach to certification provides for a kind of “product labeling” that will be helpful to purchasers of distributed resources, particularly as the size of the units decreases.

6. New and Existing

A question raised by this is what constitutes emergency service? Many states already have rules on this topic (*e.g.*, with respect to actions taken immediately before an ISO calls for voltage reductions), but there is concern among some of the participants that “emergency service” may constitute a significant loophole for DR operations. In addition, it would be helpful to have information on the inventories of existing and expected new facilities to determine whether emergency units could be pressed into service for other purposes.

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30 April 2001

APPENDIX B. EMISSIONS CALCULATIONS

Table 1: Emission Rates for New DG Technologies

		Solid Oxide Fuel Cell	Phosphoric Acid Fuel Cell	Uncontrolled Gas-Fired Lean Burn IC Engine	3-way Catalyst Gas-Fired Rich Burn IC Engine	Uncontrolled Diesel Engine	SCR Controlled Diesel Engine	Micro Turbine	Small Gas Turbine	Medium Gas Turbine	Large Gas Combined Cycle	Large Gas Turbine	ATS Simple Cycle Gas Turbine	1998 Average Coal Boiler	1998 Average Fossil	1998 Average PowerGen
Efficiency	% (HHV)	42%	37%	36%	29%	38%	38%	25%	27%	30%	51%	31%	35%	33%	33%	47%
	Btu/kWh	8,126	9,224	9,481	11,769	8,982	8,982	13,652	12,780	11,353	6,640	10,964	9,870	10,322	10,382	7,197
Typical Capacity (kW)		25	200	1,000	1,000	1,000	1,000	25	4,600	12,900	500,000	70,140	4,200	300,000	300,000	300,000
NOx	gm/hp-hr			0.70	0.15	7	1.5									
	ppm@15%O2	0.2	1.0					9	25	15	2.5	15.0	9.0			
	lb/MMBtu	0.0007	0.0036								0.01	0.05	0.03			
								0.03	0.09	0.05						
	lb/day	0.0035	0.2	52.2	11.2	522.1	111.9	0.3	126.9	189.7	716.5	996	32.2	40,291	36,448	24,684
	Tons/yr	0.001	0.03	9.5	2.0	95.3	20.4	0.05	23.2	34.6	131	182	5.9	7,353	6,652	4,505
SO2	lb/MMBtu	0.0006	0.0006	0.0006	0.0006	0.0505	0.0505	0.0006	0.0006	0.0006	0.0006	0.0006	0.0006			
	lb/day	0.0029	0.0266	0.14	0.17	10.9	10.9	0.005	0.8	2.1	47.8	11.1	0.60	96,490	83,771	56,732
	Tons/yr	0.0005	0.0048	0.02	0.031	2.0	2.0	0.0009	0.15	0.38	8.7	2.0	0.11	17,610	15,288	10,354
PM-10	gm/hp-hr			0.01	0.01	0.25	0.25									
	ppm@15%O2	0	0													
	lb/MMBtu	0	0					0.0066	0.0066	0.0066	0.0066	0.0066	0.0066			
	lb/day	-	-	0.75	0.75	18.6	18.6	0.05	9.3	23.2	525.9	121.8	6.6	2,175.0	1,952.9	1,353.9
	Tons/yr	-	-	0.14	0.14	3.4	3.4	0.01	1.7	4.2	96.0	22.2	1.2	396.9	356.4	247.1
CO2	lb/MMBtu	117	117	117	117	159	159	117	117	117	117	117	117			
	lb/day	570	5,175	26,594	33,014	34,356	34,356	957	164,912	410,826	9,313,126	2,157,211	116,289	15,229,728	14,622,394	10,137,077
	Tons/yr	104	944	4,853	6,025	6,270	6,270	175	30,097	74,976	1,699,645	393,691	21,223	2,779,425	2,668,587	1,850,017
CO	gm/hp-hr			1.6	1.3	2	2									
	ppm@15%O2	?	?					40	25	25	6	25	25			
	lb/MMBtu	?	?	-	-	-	-	0.09	0.05	0.05	0.01	0.05	0.05			
	lb/day	0.0000	0.0	119	96	149	149	1	77	193	1048	1012	55	0	0	0
	Tons/yr	0.000	0.00	22	18	27	27	0	14	35	191	185	10	0	0	0
UHC	gm/hp-hr	?	?	5.3	0.13	0.4	0.4									
	ppm@15%O2	?	?					9	25	25	2	25	25			
	lb/MMBtu	?	?	-	-	-	-	0.03	0.09	0.09	0.01	0.09	0.09			
	lb/day	0.0000	0.0	395	10	30	30	0.3	122	303	550	1591	86	0	0	0
	Tons/yr	0.000	0.00	72	2	5	5	0.0	22	55	100	290	16	0	0	0
NOx	lb/MWh	0.01	0.03	2.2	0.5	21.8	4.7	0.44	1.15	0.61	0.06	0.59	0.32	5.60	5.06	3.43
SO2	lb/MWh	0.005	0.006	0.006	0.007	0.454	0.454	0.008	0.008	0.007	0.004	0.007	0.006	13.4	11.6	7.9
PM-10	lb/MWh	-	-	0.03	0.03	0.78	0.78	0.09	0.08	0.07	0.04	0.07	0.07	0.30	0.27	0.19
CO2	lb/MWh	950	1,078	1,108	1,376	1,432	1,432	1,596	1,494	1,327	776	1,281	1,154	2,115	2,031	1,408
CO	lb/MWh	?	?	5.0	4.0	6.2	6.2	1.2	0.7	0.6	0.1	0.6	0.5			
UHC	lb/MWh	?	?	16.5	0.4	1.2	1.2	0.42	1.10	0.98	0.05	0.95	0.85			

Threshold (TPY)

Number of Units to Equal the Major Source Threshold for NOx

250	390,529	8,601	26	122	3	12	5,166	11	7	2	1	43
100	156,212	3,440	10	49	1	5	2,066	4	3	1	1	17
50	78,106	1,720	5	24	1	2	1,033	2	1	0	0	9
25	39,053	860	3	12	0	1	517	1	1	0	0	4
10	15,621	344	1	5	0	0	207	0	0	0	0	2

This spreadsheet shows air emissions values for a number of distributed generation technologies. The values are given for a variety of emissions – nitrogen oxides, sulfur dioxide, carbon monoxide, carbon dioxide, particulate matter (PM-10), and unburned hydocarbons – and they are characterized in terms of pounds of emissions per unit of electrical output. These are typical values for new units of the specified technologies. They do not apply to older, existing units. The values were calculated on the basis of assumptions about typical operating conditions; however, because actual operating conditions are rarely typical, the actual emissions performance of a unit may differ from these values.

Table 2:

Value *Factor* *Source* *Notes*

Solid Oxide Fuel Cells

Value	Factor	Source	Notes
42%	Efficiency	http://www.fe.doe.gov/techline/tl_ sofcdemo.html	
0.2	ppm NOx	http://www.fe.doe.gov/techline/tl_ sofcdemo.html	
0.0006	lb/MMBtu SO2	AP-42 Chapter 1, Section 4	
0	ppm PM-10	no data, no source	
116.88	lb/MMBtu CO2	EIIP Report, Vol. VIII, Table 1.4-3	

Phosphoric Acid (ONSI) Fuel Cells

Value	Factor	Source	Notes
37%	efficiency	NREL paper	http://www.sercobe.es/espejo/Energia/EnergiasNoNucleares/UsoRacional/IndustEnergia/PilaComb/Tutorial/Fuelcells.htm
1.00	ppm NOx	Phone: Herb Healy, ONSI, 860-727-2200	
0.0006	lb/MMBtu SO2	AP-42 Chapter 1, Section 4	
0	ppm PM-10	no data, no source	
116.88	lb/MMBtu CO2	EIIP Report, Vol. VIII, Table 1.4-3	

Gas IC Engine

Value	Factor	Source	Notes
7,011	Btu/hp-hr for 770 kW Cat Model G3516	Caterpiller Website, gas model G3516, 130 LE	
36%	*efficiency lean burn*	*Onsite Energy/Caterpiller*	36%
29%	*efficiency rich burn*	*Onsite Energy/Caterpiller*	
0.70	gm/hp-hr NOx lean burn engine	NSR/RBLC Identifier NM-0026	Clean Burn engine Cat 3612 TA/SW66
9.00	ppm NOx @15% O2	NSR/RBLC Identifier CA-0645	3-way catalyst
0.150	*gm/hp-hr NOx 3-way catalyst*	*Bluestein assumption*	
0.0006	lb/MMBtu SO2	AP-42 Chapter 1, Section 4	
0.0100	gm/hp-hr PM-10 - filterable+condensable	NSR/RBLC Identifier CO-0032,CO-0033	
1.6	g/hp-hr CO lean burn	Caterpiller G3516 Data Sheet DM5150	
5.3	g/hp-hr UHC lean burn	Caterpiller G3516 Data Sheet DM5150	
12.9	g/hp-hr CO rich burn engine out	Caterpiller G3516 Data Sheet DM5145	
90%	TWC cat CO reduction		
1.3	g/hp-hr HC rich burn	Caterpiller G3516 Data Sheet DM5145	
90%	TWC cat HC reduction		
116.88	lb/MMBtu CO2	EIIP Report, Vol. VIII, Table 1.4-3	

Diesel Engine

Value	Factor	Source	Notes
114	gal/hr for 1,640 kW Cat Model 3516B	Caterpiller Website, diesel model 3516B	
38.0%	*efficiency*	*calculated*	35%
	gm/hr NOx uncontrolled	Caterpiller Website, diesel model 3516B	
7	*gm/hp-hr NOx uncontrolled*	Caterpiller Website, diesel model 3516B	
1.50	gm/hp-hr NOx with SCR	Hedman/SCAQMD	SCR
500.00	ppm sulfur in diesel, on road	current requirement for road diesel	Federal Register: 5/13/99 Vol 64 #92

This spreadsheet shows air emissions values for a number of distributed generation technologies. The values are given for a variety of emissions – nitrogen oxides, sulfur dioxide, carbon monoxide, carbon dioxide, particulate matter (PM-10), and unburned hydocarbons – and they are characterized in terms of pounds of emissions per unit of electrical output. These are typical values for new units of the specified technologies. They do not apply to older, existing units. The values were calculated on the basis of assumptions about typical operating conditions; however, because actual operating conditions are rarely typical, the actual emissions performance of a unit may differ from these values.

Value	*Factor*	*Source*	*Notes*
3,300.00	ppm sulfur in diesel, nonroad	typical, offroad diesel	Federal Register: 5/13/99 Vol 64 #92
30.00	ppm sulfur in diesel, possible proposed	potential future requirement	Federal Register: 5/13/99 Vol 64 #92
0.25	gm/hp-hr PM-10	NSR/RBLC Identifier CA-0691	
0.4	g/hp-hr HC	Caterpiller	
2	g/hp-hr CO	Caterpiller	
159.38	lb/MMBtu CO2	EIIP Report, Vol. VIII, Table 1.4-3	

Microturbine

25%	Efficiency	Capstone Model 330, 30 kW	Capstone Turbines webpage
9	ppm NOx	Capstone Model 330, 30 kW	Capstone Turbines webpage
0.0006	lb/MMBtu SO2	AP-42 Chapter 3, Section 1	
0.0066	lb/MMBtu total PM-10 filterable + condensable	AP-42 Chapter 3, Section 1	
40	ppm CO	Capstone	
9	ppm HC	Capstone	
116.88	lb/MMBtu CO2	EIIP Report, Vol. VIII, Table 1.4-	

SmallTurbine

12,780	Btu/kWh heat rate HHV	Solar Centaur 50 - 4.6 MW	Solar Data
25	ppm NOx	Solar	
0.0006	lb/MMBtu SO2	AP-42 Chapter 3, Section 1	
0.0066	lb/MMBtu total PM-10 filterable + condensable	AP-42 Chapter 3, Section 1	
25	ppm CO		
25	ppm UHC		
116.88	lb/MMBtu CO2	EIIP Report, Vol. VIII, Table 1.4-3	

Medium Turbine

11,353	Btu/kWh HHV	Alstom Cyclone - 12.9 MW	Intl. Turbomachinery Handbook 1999, page 121 10,900 kj/kWh LHV
15	ppm NOx	Bluestein assumption	
0.0006	lb/MMBtu SO2	AP-42 Chapter 3, Section 1	
6.60E-03	lb/MMBtu total PM-10 filterable + condensable	AP-42 Chapter 3, Section 1	
25	ppm CO		
25	ppm UHC		
116.88	lb/MMBtu CO2	EIIP Report, Vol. VIII, Table 1.4-3	

Large Gas Combined Cycle

6,640	Btu/kWh heat rate HHV	GE S-207FA (MS7001FA), 529.9 MW	Intl. Turbomachinery Handbook 1999, page 128 6375 kj/kWh LHV
2.5	ppm NOx	NSR/RBLC Identifier ME-0018	
0.0006	lb/MMBtu SO2	AP-42 Chapter 3, Section 1	
6.60E-03	lb/MMBtu total PM-10 filterable + condensable	AP-42 Chapter 3, Section 1	
6	ppm CO		

This spreadsheet shows air emissions values for a number of distributed generation technologies. The values are given for a variety of emissions – nitrogen oxides, sulfur dioxide, carbon monoxide, carbon dioxide, particulate matter (PM-10), and unburned hydocarbons – and they are characterized in terms of pounds of emissions per unit of electrical output. These are typical values for new units of the specified technologies. They do not apply to older, existing units. The values were calculated on the basis of assumptions about typical operating conditions; however, because actual operating conditions are rarely typical, the actual emissions performance of a unit may differ from these values.

Value	Factor	Source	Notes
2	ppm HC		
116.88	lb/MMBtu CO2	EIIP Report, Vol. VIII, Table 1.4-3	

Large Gas Turbine

10,964	Btu/kWh heat rate HHV	GE PG6101(FA), 70.1 MW	Intl. Turbomachinery Handbook 1999, page 116 10,526 kj/kWh LHV
15	ppm NOx	Bluestein estimate	
0.0006	lb/MMBtu SO2	AP-42 Chapter 3, Section 1	
6.60E-03	lb/MMBtu total PM-10 filterable + condensable	AP-42 Chapter 3, Section 1	
25	ppm CO		
25	ppm UHC		
116.88	lb/MMBtu CO2	EIIP Report, Vol. VIII, Table 1.4-3	

ATS Gas Turbine

9,870	Btu/kWh heat rate	Caterpiller/Solar Turbines website	
9	ppm NOx	Stategic Goal of ATS program	http://www.fe.doe.gov/coal_power/ats/ats_so.html
0.0006	lb/MMBtu SO2	AP-42 Chapter 3, Section 1	
6.60E-03	lb/MMBtu total PM-10 filterable+condensable	AP-42 Chapter 3, Section 1	
25	ppm CO		
25	ppm UHC		
116.88	lb/MMBtu CO2	EIIP Report, Vol. VIII, Table 1.4-3	

AEO Data

6,701,000	tons/year NOx from coal boilers	1998 EPA Vol 2, Table 25	
11,671,000	tons/year SO2 from coal boilers	1998 EPA Vol 2, Table 25	
273,000	tons/year PM10 from coal boilers	1998 National Emissions Trends, Table A-5	
138,000	tons/year PM25 from coal boilers	1998 National Emissions Trends, Table A-5	
1,911,627,000	tons/year CO2 from coal boilers	1998 EPA Vol 2, Table 25	
377,000	tons/year NOx from gas boilers	1998 EPA Vol 2, Table 25	
1,000	tons/year SO2 from gas boilers	1998 EPA Vol 2, Table 25	
1,000	tons/year PM10 from gas ombustion	1998 National Emissions Trends, Table A-5	
1,000	tons/year PM25 from gas combustion	1998 National Emissions Trends, Table A-5	
195,868,000	tons/year CO2 from gas boilers	1998 EPA Vol 2, Table 25	
137,000	tons/year NOx from oil boilers	1998 EPA Vol 2, Table 25	
759,000	tons/year SO2 from oil boilers	1998 EPA Vol 2, Table 25	
9,000	tons/year PM10 from oil combustion	1998 National Emissions Trends, Table A-5	
8,000	tons/year PM25 from oil combustion	1998 National Emissions Trends, Table A-5	
100,895,000	tons/year CO2 from oil boilers	1998 EPA Vol 2, Table 25	
19,000	tons/year PM10 from IC engines	1998 National Emissions Trends, Table A-5	
19,000	tons/year PM25 from IC engines	1998 National Emissions Trends, Table A-5	
0.1022	lb/MMBtu NOx rate for turbines	2000 1st Qtr CEM data	include only blrtype=CC or CT, delete 16 records with no NOx rate
0.0102	lb/MMBtu SO2 rate for turbines	2000 1st Qtr CEM data	include only blrtype=CC or CT, delete 16 records with no NOx rate

This spreadsheet shows air emissions values for a number of distributed generation technologies. The values are given for a variety of emissions – nitrogen oxides, sulfur dioxide, carbon monoxide, carbon dioxide, particulate matter (PM-10), and unburned hydocarbons – and they are characterized in terms of pounds of emissions per unit of electrical output. These are typical values for new units of the specified technologies. They do not apply to older, existing units. The values were calculated on the basis of assumptions about typical operating conditions; however, because actual operating conditions are rarely typical, the actual emissions performance of a unit may differ from these values.

Value	*Factor*	*Source*	*Notes*
1,807,480,000	MWh/year coal boiler generation	1998 EPA Vol 1, Table A2	
247,956,000	MWh/year gas boiler generation	1998 EPA Vol 1, Table A4	
102,669,000	MWh/year oil boiler generation	1998 EPA Vol 1, Table A3	
673,702,000	MWh/year nuclear generation	1998 EPA Vol 1, Table A2	
304,403,000	MWh/year hydro generation	1998 EPA Vol 1, Table A2	
7,206,000	MWh/year renewable generation	1998 EPA Vol 1, Table A2	
7,489,000	MWh/year oil turbine/IC generation	1998 EPA Vol 1, Table A3	
61,266,000	MWh/year gas turbine/IC generation	1998 EPA Vol 1, Table A4	
910,867,000	tons/year consumption for coal boilers	1998 EPA Vol 1, Table A5	
161,821,000	bbls/year consumption for oil boilers	1998 EPA Vol 1, Table A6	
16,793,000	bbls/year consumption for oil turbine/IC	1998 EPA Vol 1, Table A6	
2,618,037,000	mcf/year consumption for gas boilers	1998 EPA Vol 1, Table A7	
640,017,000	mcf/year consumption for gas turbine/IC	1998 EPA Vol 1, Table A7	
511,000	tons/year consumption anthracite coal	1998 Cost and Quality of Fuels, Table ES4	
478,252,000	tons/year consumption bituminuous coal	1998 Cost and Quality of Fuels, Table ES4	
373,496,000	tons/year consumption sub-bituminuous coal	1998 Cost and Quality of Fuels, Table ES4	
77,189,000	tons/year consumption lignite coal	1998 Cost and Quality of Fuels, Table ES4	
8,255,000	bbls/year consumption of #2 oil	1998 Cost and Quality of Fuels, Table 9	
156,851,000	bbls/year consumption of #4,#5,#6 oil	1998 Cost and Quality of Fuels, Table 9	
7,479	Btu/lb anthracite coal	1998 Cost and Quality of Fuels, Table ES4	
12,033	Btu/lb bituminous coal	1998 Cost and Quality of Fuels, Table ES4	
8,728	Btu/lb sub-bituminous coal	1998 Cost and Quality of Fuels, Table ES4	
6,471	Btu/lb lignite coal	1998 Cost and Quality of Fuels, Table ES4	
10,241	Btu/lb average U.S. Coal	1998 Cost and Quality of Fuels, Table 4	
151,066	Btu/gallon average U.S. oil	1998 Cost and Quality of Fuels, Table 9	
138,766	Btu/gallon average U.S. fuel oil	1998 Cost and Quality of Fuels, Table 9	
151,723	Btu/gallon average U.S. #4, #5, #6 oil	1998 Cost and Quality of Fuels, Table 9	
1,022	Btu/cf average U.S. gas	1998 Cost and Quality of Fuels, Table 14	
	Btu/gallon #1 distillate (diesel)		
7,248,543	*NOx tons/yr from fossil generation*	*calculated*	
12,434,348	*SO2 tons/yr from fossil generation*	*calculated*	
302,000	*PM-10 tons/yr from fossil generation*	*calculated*	
2,261,251,666	*CO2 tons/yr from fossil generation*	*calculated*	

CEM Data

5,425,799	tons/year NOx from Title IV units	1999 CEM Data	
474,399	tons/year NOx from T4 units, not coal	1999 CEM Data	
4,951,400	*tons/year NOx from T4 coal units*	*calculated*	
12,470,504	tons/year SO2 from Title IV units	1999 CEM Data	
612,716	tons/year SO2 from T4 units, not coal	1999 CEM Data	
11,857,788	*tons/year SO2 from T4 coal units*	*calculated*	
1,769,627,431	MWh/year coal generation	1999 EIA Form 759	
2,143,656,841	MWh/year fossil generation	1999 EIA Form 759	
3,165,331,454	MWh/year generation	1999 EIA Form 759	

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Table 3:

Value	*Factor*	*Source*
278	lb/MMBtu HHV to ppm for NOx, gas	EEA - Dist Gen Appendix B
456	lb/MMBtu HHV to ppm for CO, gas	EEA - Dist Gen Appendix B
200	lb/MMBtu HHV to ppm for SO2, gas	EEA - Dist Gen Appendix B
290	lb/MMBtu HHV to ppm for HC, gas	EEA - Dist Gen Appendix B
3,413	% efficiency to Btu/kWh	EEA - Dist Gen Appendix B
2,545	Btu per hp-hr	EEA - Dist Gen Appendix B
239	factor for gm/hp-hr to ppm for gas engine	EEA - Dist Gen Appendix B
0.91	conversion HHV to LHV for natural gas	EEA - Dist Gen Appendix B
0.7457	kW per hp	EEA - Dist Gen Appendix B
0.95	% generator efficiency	assumed
0.7	lb/hr	
47.6	MMBtu/hr	
0.0170	g/hp-hr	
2.9526	g/hp-hr to lb/MWh	

116.88	CO2 lb/MMBtu for natural gas	EIIP Report, Vol. VIII, Table 1.4-3
161.22	CO2 lb/MMBtu for distillate oil	EIIP Report, Vol. VIII, Table 1.4-3
159.38	CO2 lb/MMBtu for kerosene	EIIP Report, Vol. VIII, Table 1.4-3
173.67	CO2 lb/MMBtu for residual oil	EIIP Report, Vol. VIII, Table 1.4-3
227.53	CO2 lb/MMBtu for anthracite coal	EIIP Report, Vol. VIII, Table 1.4-3
205.18	CO2 lb/MMBtu for bituminous coal	EIIP Report, Vol. VIII, Table 1.4-3
212.15	CO2 lb/MMBtu for sub-bituminous coal	EIIP Report, Vol. VIII, Table 1.4-3
215.08	CO2 lb/MMBtu for lignite coal	EIIP Report, Vol. VIII, Table 1.4-3
173.10	*CO2 lb/MMBtu for oil*	*calculated*
208.10	*CO2 lb/MMBtu for coal*	*calculated*

This spreadsheet shows air emissions values for a number of distributed generation technologies. The values are given for a variety of emissions – nitrogen oxides, sulfur dioxide, carbon monoxide, carbon dioxide, particulate matter (PM-10), and unburned hydocarbons – and they are characterized in terms of pounds of emissions per unit of electrical output. These are typical values for new units of the specified technologies. They do not apply to older, existing units. The values were calculated on the basis of assumptions about typical operating conditions; however, because actual operating conditions are rarely typical, the actual emissions performance of a unit may differ from these values.

Figure 1:

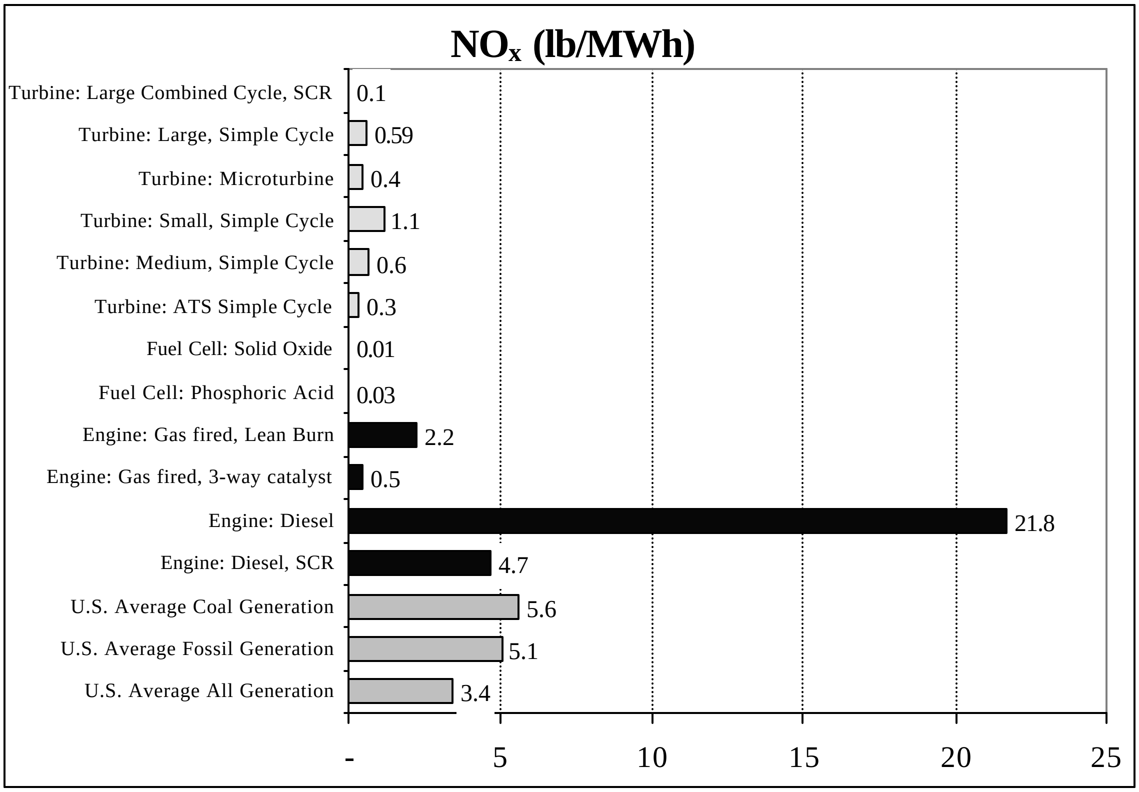
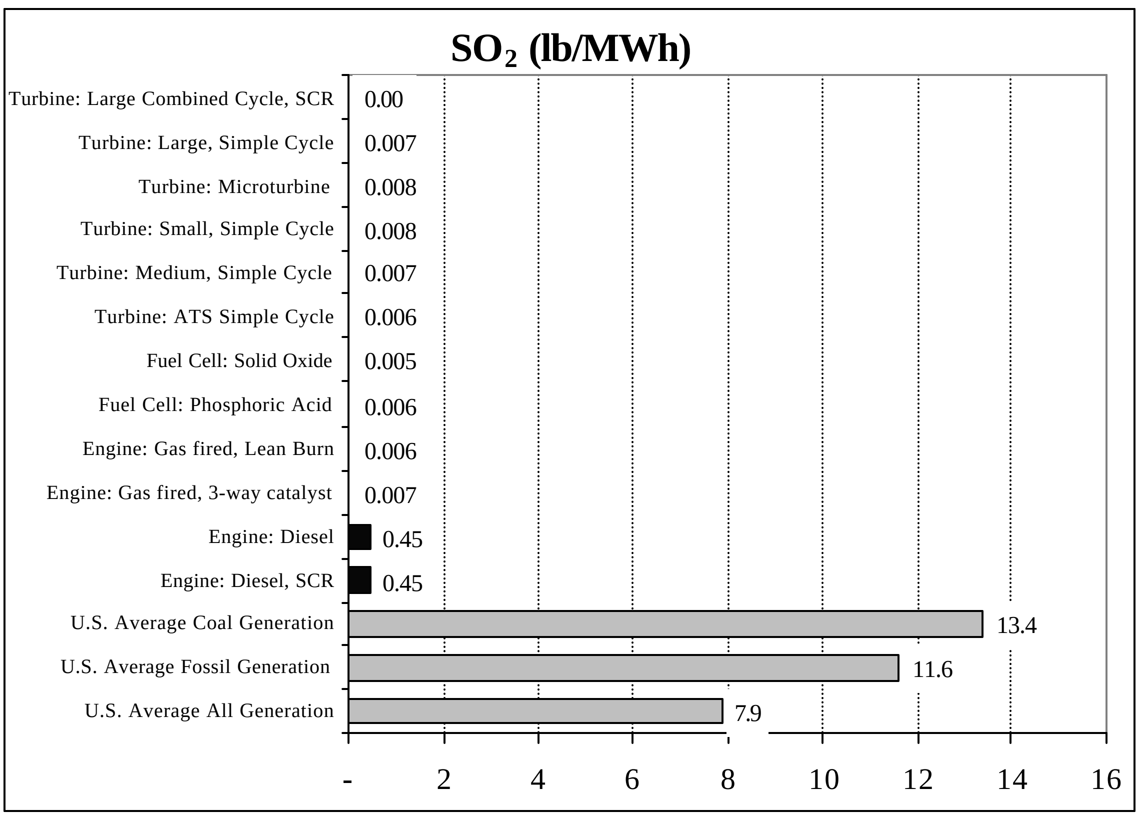


Figure 2:



These figures show air emissions values for a number of distributed generation technologies. The values are given for a variety of emissions – nitrogen oxides, sulfur dioxide, carbon monoxide, carbon dioxide, particulate matter (PM-10), and unburned hydocarbons – and they are characterized in terms of pounds of emissions per unit of electrical output. These are typical values for new units of the specified technologies. They do not apply to older, existing units. The values were calculated on the basis of assumptions about typical operating conditions; however, because actual operating conditions are rarely typical, the actual emissions performance of a unit may differ from these values.

Figure 3:

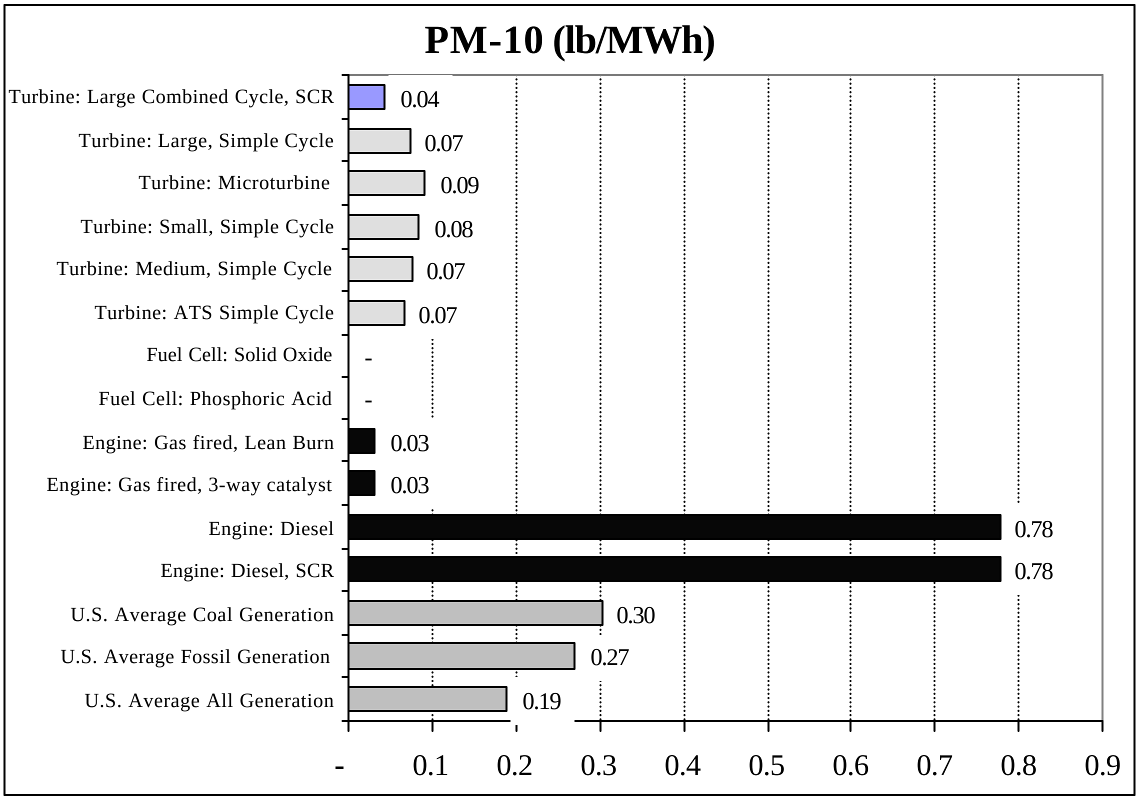
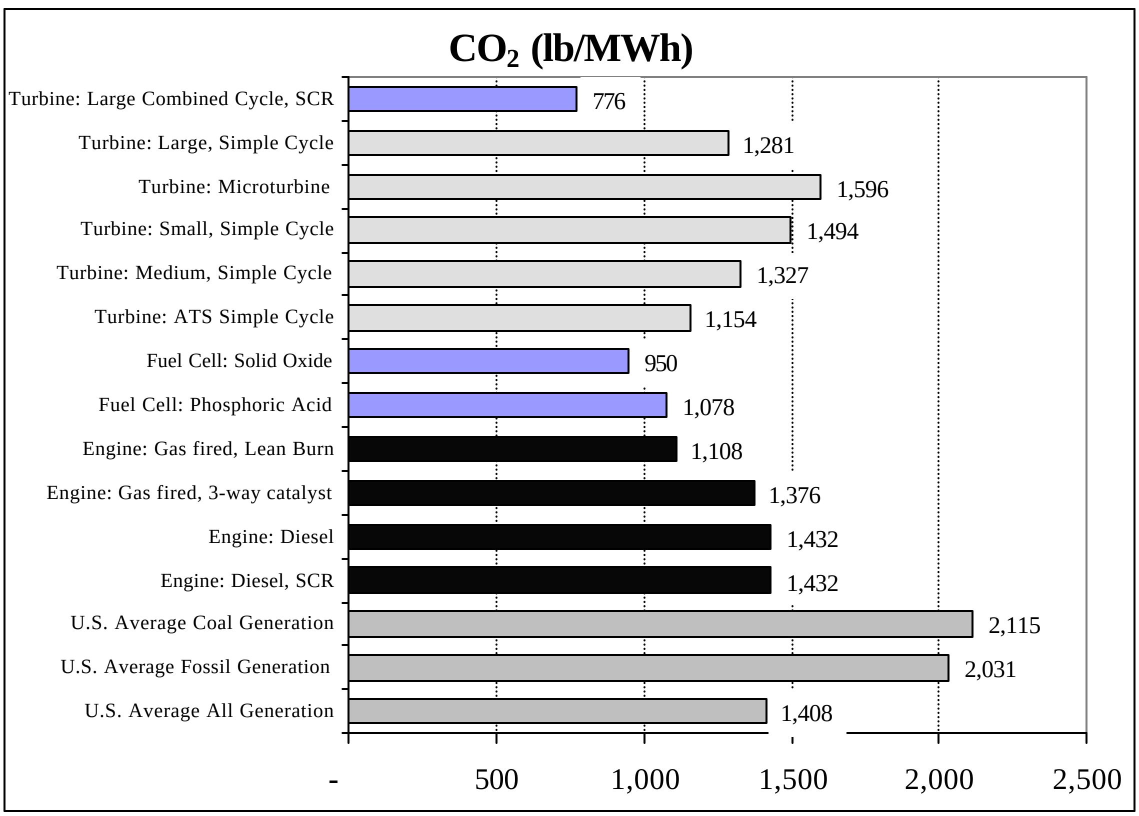
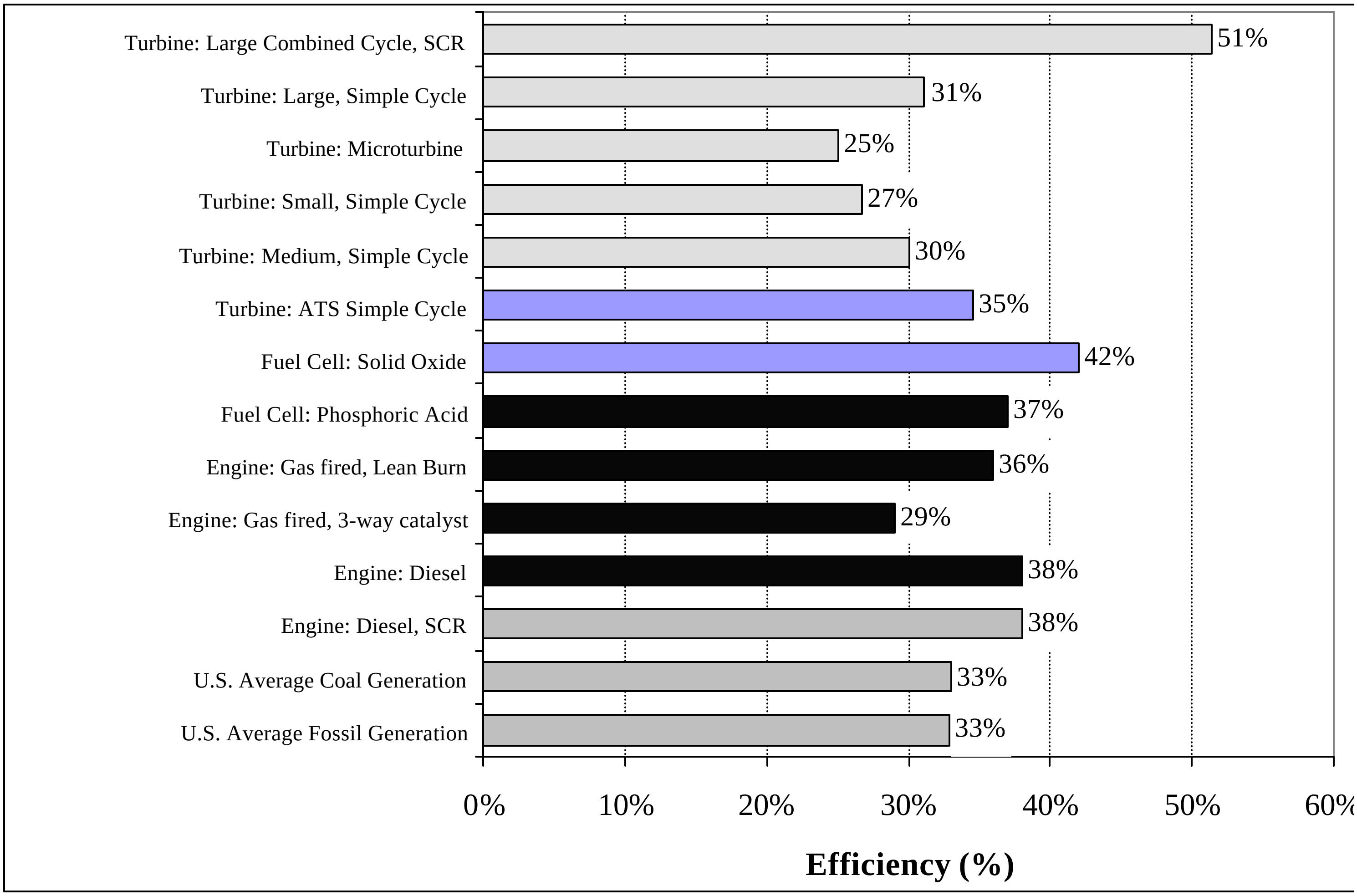


Figure 4:



These figures show air emissions values for a number of distributed generation technologies. The values are given for a variety of emissions – nitrogen oxides, sulfur dioxide, carbon monoxide, carbon dioxide, particulate matter (PM-10), and unburned hydocarbons – and they are characterized in terms of pounds of emissions per unit of electrical output. These are typical values for new units of the specified technologies. They do not apply to older, existing units. The values were calculated on the basis of assumptions about typical operating conditions; however, because actual operating conditions are rarely typical, the actual emissions performance of a unit may differ from these values.

Figure 5:



This figure shows air emissions values for a number of distributed generation technologies. The values are given for a variety of emissions – nitrogen oxides, sulfur dioxide, carbon monoxide, carbon dioxide, particulate matter (PM-10), and unburned hydocarbons – and they are characterized in terms of pounds of emissions per unit of electrical output. These are typical values for new units of the specified technologies. They do not apply to older, existing units. The values were calculated on the basis of assumptions about typical operating conditions; however, because actual operating conditions are rarely typical, the actual emissions performance of a unit may differ from these

APPENDIX C. WORKING GROUP MEMBERS

State Environmental Regulators
Grant Chin, California Air Resources Board
Chris James, Connecticut Department of Environmental Protection
Janet McCabe, Office of Air Management, Indiana Department of Environmental Management
Ron Methier, Chief, Georgia Air Protection Branch, Department of Natural Resources
Brock Nicholson, Division of Air Quality, North Carolina Department of Environment and Natural Resources
Brad Nelson, North Carolina Department of Environment and Natural Resources
Nancy Seidman, Massachusetts Department of Environmental Protection
Nancy Sutley, California Environmental Protection Agency

State Energy Officials
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Fred Hoover, Director, Maryland Energy Administration
William Keese, Chairman, California Energy Commission
Ethan Rogers, Programs Manager, Energy Policy Division, Indiana Department of Commerce
William Steinhurst, Director of Regulated Utility Planning, Vermont Department of Public Service
Scott Tomashevfky, California Energy Commission
Linda Taylor, Minnesota Energy Office

State Utility Regulators
James Burg, Chairman, South Dakota Public Utilities Commission
John Farrow, Commissioner, Wisconsin Public Utilities Commission
Edward Garvey, Commissioner, Minnesota Public Utilities Commission
Roger Hamilton, Commissioner, Oregon Public Utilities Commission
Terry Harvill, Commissioner, Illinois Commerce Commission
Alison Silverstein, Advisor to the Chairman, Public Utilities Commission of Texas

Non-State Governmental Participants
Thomas Basso, National Renewable Energy Laboratory
Joel Bluestein, Energy and Environmental Analysis, Inc.
Joe Bryson, United States Environmental Protection Agency
Kevin Duggan, Capstone Turbines, Inc.
Joseph Galdo, United States Department of Energy
Nathanael Greene, Natural Resources Defense Council
Eric Heitz, Energy Foundation
Jim Lents, Professor, CERT, University of California, Riverside
Katie McCormack, Energy Foundation
Catherine Morris, Center for Clean Air Policy
Gary Nakarado, National Renewable Energy Laboratory
Merrill Smith, United States Department of Energy
Carl Weinburg, The Regulatory Assistance Project
Frederick Weston, The Regulatory Assistance Project
Leslie Witherspoon, Solar Turbines, Inc.
Eric Wong, Caterpillar, Inc.

Working Group Subgroups

Membership in the subgroups was open to all Working Group members. What follows below is a listing of those who participated in conference calls, information gathering, and early drafting efforts.

Emissions Subgroup
Joel Bluestein
Kevin Duggan
Nancy Seidman
Chris James
Nathanael Greene
Catherine Morris
Eric Wong
Rick Weston

Combined Heat and Power
Jim Lents
Joel Bluestein
Nathanael Greene
Katie McCormack
Carl Weinberg
Rick Weston

Applicability
Jim Burg
Paul Burks
Grant Chin
Chris James
Eric Wong
Ron Methier
Katie McCormack
Catherine Morris
Joel Bluestein
Roger Hamilton
Ethan Rogers
Nathanael Greene
Rick Weston

Emissions Certification
Nancy Seidman
Kevin Duggan
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