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

Model Rule and Supporting Documentation

31 October 2002 Review Draft

The Regulatory Assistance Project

50 STATE STREET, SUITE 3
MONTPELIER, VT 05602
TEL: 802-223-8199
FAX: 802-223-8172

WEBSITE:
HTTP://WWW.RAPONLINE.ORG

177 WATER STREET
GARDINER, ME 04345
TEL: 207-582-1135
FAX: 207-582-1176

## 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. These approximately thirty people came together in an effort to develop model emissions standards for smaller-scale electric generation technologies. The effort began late in 2000 and was conducted mostly through e-mail, list-serve, and telephone conference calls. In addition there were two in-person meetings of the group during 2001.

This document is the second draft product in that nearly two-year effort. Although consensus was not a prerequisite for development of a model rule, it has, with respect to the rule's central features, been for the most part achieved. The members of the Working Group can – and should – applaud themselves for that accomplishment. Their hard work, attention to detail, and continuing belief in the value of the project made this document not only possible, but, we hope, helpful to state and local air quality agencies.

There are a number of people whose contributions should be individually recognized. Nathanael Greene of the Natural Resources Defense Council and Joel Bluestein of Energy and Environmental Analysis, Inc., challenged each other and the Group to construct a solid intellectual framework on which the rule could be hung; out of their dialectic creative resolutions often emerged. They and their organizations, and Tim French of the Engine Manufacturers Association, Professor Jim Lents of the University of California, Riverside, Leslie Witherspoon of Solar Turbines, Inc., John Kelly of the Gas Technology Institute, and Joseph Bryson of the US Environmental Protection Agency provided much of the data, analysis, and insight that the Group needed to make informed policy choices. In addition, we are grateful to the many people and organizations outside the Working Group who took an interest in the rule, and whose comments and suggestions on earlier drafts were invaluable. Lastly, we thank Thomas Basso and Gary Nakarado, both of NREL, and Joseph Galdo of the US Department of Energy for their enthusiastic support of the work. They and their agencies recognize the value of distributed resources, and recognize also that strong environmental regulation is a critical component of an integrated energy policy that will foster the sustainable development and use of these resources. Their vision was an elemental part of our work.

Nancy L. Seidman
Division Director,
Transportation and Consumer Programs
Bureau of Waste Prevention
Massachusetts Department of Environmental Protection

Christopher James
Division Director, Air Planning and Standards
Bureau of Air Management
Connecticut Department of Environmental Protection

Frederick Weston, Director, The Regulatory Assistance Project

# TABLE OF CONTENTS

# I. INTRODUCTION AND PROCESS

The electric industry has substantial and well-documented impacts upon our local, regional, and global environments. As our country's demand for electricity has grown, so has the number of ways in which that demand can be met. Innovations in technology, changes in the economics of the industry, and a variety of regulatory reforms (PURPA, the Electricity Policy Act of 1992, and restructuring in a number of states) have combined to create new opportunities for small-scale, distributed, generation. The effect could be, in a sense, self-perpetuating: the growing availability of cost-effective distributed generation (DG) – micro-turbines, diesel "gen-sets," fuel cells, solar panels, reciprocating engines, etc. – has the potential to further change the nature of the electric network, thereby creating more opportunities for new applications.[1]

But with those opportunities come new challenges. 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. In order to help states prepare for the potential proliferation of new sources of air emissions, the Distributed Resources Emissions Working Group was formed to develop a model rule that states can adopt in whole or adapt, that will foster the deployment of distributed generation and other resources, in ways that are both environmentally sustainable and economically efficient.

RAP enlisted Nancy L. Seidman of the 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 out. 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.

That 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 do we hope to accomplish? What is the purpose of the rule? What is its scope? What constraints do 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 herein as Appendix A).

The Working Group organized itself into several sub-groups that addressed 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

[1] Smaller-scale generation technologies have benefited, and will continue to benefit, from research and development activities by manufacturers, industry associations, and the federal and state agencies. For more information on distributed power and current research efforts, visit the US Department of Energy's website at http://www.eren.doe.gov/distributedpower/.

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, generation duty-cycle (*i.e.*, emergency, peaking, baseload), or location (*e.g.*, 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 2001, the work had advanced sufficiently to convene a second in-person meeting that focused upon the central, interrelated substantive issues – applicability and emissions standards. Proposals that had been developed by various Working Group members 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.

Rulemakings in Texas and California also informed the Working Group's efforts. In June 2001, the Texas Natural Resource Conservation Commission adopted an "Air Quality Permit for Electric Generating Units" that established output-based standards for nitrogen oxides ($NO_X$) from generating facilities of less than ten megawatts. The standards differ between east Texas and west Texas, are phased in over four years, and give emissions credits for combined heat and power (CHP) systems. Around the same time, the staff of the California Air Resources Board (CARB) issued a proposed rule that too set output-based standards for $NO_X$, but also for carbon monoxide (CO), volatile organic compounds, and particulate matter (PM). Like the Texas rule, the CARB rule has a two-step phase-in (the second phase begins in 2007) and gives credit for CHP savings. It also calls for a technology review, to be completed a year and a half before the 2007 standards go into effect. The CARB adopted the rule in November 2001 (with minor amendments early in 2002).[2]

After the May 2001 meeting, discussions continued and an *ad hoc* drafting committee was 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 Group as a whole, for its consideration. In October, after further review and revision, the Working Group agreed to release the draft for public comment. Early the next month, under the title *Public Review Draft*, it was distributed widely.

[2] The Texas standard permit is authorized under Title 30, Texas Administrative Code, Part 1, Chapter 116.601-116.603; see http://www.tceq.state.tx.us/permitting/airperm/nsr_permits/athrize.htm#stdpmt. The California requirements are found in Title 17, California Code of Regulations, Division 3, Chapter 1, Subchapter 8, Article 3, Secs. 94200-94214.

In February 2002, after many responses to the draft were received, the Working Group began the process of molding the draft into its present form. Although reflective of the general inclinations of the Working Group as expressed in the Statement of Principles, the Public Review Draft did not represent a full consensus of the Group. Indeed, there were a number key issues that required further consideration, and working through them took much of the winter and spring. By summer, most of the pieces had to fallen into place, and the work turned to the detailed drafting and editing of the rule and accompanying text.

Most members of the Working Group who were active in the process during 2002 support the rule presented here. There are, naturally, certain provisions of the rule that do not fully satisfy some members; this is in the nature of compromise and consensus building. The members are of course free to express their specific concerns in state proceedings or other fora, as appropriate. However, the majority feel that the rule, taken as a whole, will, when implemented, lead to improvements in the regulation of air emissions from these sources in the country. There were, however, significant disagreements over $CO_2$. [3]

Additional copies of this document can be found at the RAP website: http://www.rapmaine.org.

[3] The reasons for a lack of broad consensus on carbon dioxide are described in Chapter IV, Commentary on the Rule.

## II. GENERAL DESCRIPTION OF THE RULE

This model rule applies to the wide variety of smaller-scale electric generating resources that are becoming increasingly available and that are consequently falling within the ambit of policymakers' interest. They are often referred to collectively as "distributed generation," a term that we will use for simplicity's sake in this document, but we note that it does not fully describe the set of resources that this rule covers. The US Department of Energy defines DG as follows:

> Distributed power is modular electric generation or storage located near the point of use. Distributed systems include biomass-based generators, combustion turbines, concentrating solar power and photovoltaic systems, fuel cells, wind turbines, microturbines, engines/generator sets, and storage and control technologies. Distributed resources can either be grid connected or operate independently of the grid. Those connected to the grid are typically interfaced at the distribution system. In contrast to large, central-station power plants, distributed power systems typically range from less than a kilowatt (kW) to tens of megawatts (MW) in size.[4]

This definition is for the most part suitable for our purposes here, though with one clarification. The Working Group saw no reason to limit its applicability simply to those resources "located near the point of use." Those deployed in remote locations will likely also produce air emissions and, though their air quality and public health impacts may differ from those sited in more populated areas, the Group concluded that those potential impacts, the desire to cover facilities that state laws do not now cover, and the general goal of administrative simplicity warranted a broader applicability requirement.

The model rule regulates five air pollutants: nitrogen oxides, particulate matter, carbon monoxide, sulfur dioxide, and carbon dioxide. It takes an output-based (pounds per megawatt-hour) and fuel- and technology-neutral approach to controlling the emissions (except in the case of sulfur dioxide, which is readily addressed through a fuel sulfur-content requirement). The Group opted for this approach on the grounds that it recognizes and rewards efficiency and will promote innovation. It is also relatively straightforward, allows for compliance through manufacturer certification, and is compatible with competitive markets and other regulatory schemes such as generation performance standards and tradable emissions allowances. The Working Group recognized, however, that not all distributed generation is the same. Given the range of technologies, uses, and environmental profiles, single-point emissions standards applicable to all would not be practical. Depending on how such standards might be set, they would be either ineffective (not stringent enough) or a barrier to DR deployment and its benefits (too stringent). Consequently, the Group developed a rule that differentiates not by technology but by the needs served, which in turn were defined by the circumstances of operation (duty-cycles). In addition, the rule calls for the standards for each pollutant to be phased in three steps over a ten-year period. Originally, the Group identified three duty-cycles – emergency, peaking,

---

[4] DOE definition found at http://www.eren.doe.gov/distributedpower/whatis_main.html.

and baseload – and proposed standards for them, but further analysis led the Group to conclude that only two categories are needed: emergency and non-emergency. Emergency generation is limited in its total annual hours of operation to 300 hours, of which a maximum of 50 hours may be for maintenance operations. Non-emergency covers all other applications.

The general premise of the rule is that the more a generator operates, the less its emissions per megawatt-hour (MWh) 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 (such as peaking facilities) will be more likely 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. Emergency generators can also be seen in this light, although it is complicated by public health and safety imperatives at times of blackout. 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, given the extremely high reliability record of the US power system.

The emissions limits in each category are based on the levels of emissions that current technologies can achieve or are expected to achieve over the next decade. There are three phase-in periods, during which the limits are "ratcheted down." In this sense, the approach resembles the BACT (best available control technology) approach historically used in US air regulation (*i.e.*, the standards tighten as cost-effective improvements in technology are achieved), but it differs in important ways. BACT has traditionally been interpreted to mean that a new project has to be as "clean" as the cleanest current model of the particular technology in question, *i.e.*, diesel, gas combined cycle, oil, atmospheric fluidized bed coal, etc. The approach taken in the rule is not to categorize the emissions standards by technology type, but rather by use or need, recognizing that certain technologies are better suited to particular needs, *e.g.*, diesels for emergency operations, and microturbines and gas reciprocating engines for extended use. In addition, to give added flexibility to suppliers to meet the standards, credits for emissions savings or offsets are given: for combined heat and power (CHP) applications, renewables, and end-use efficiency. The emissions limits push for the cleanest applicable technologies. For reasons explained in detail in Chapter IV, Commentary on the Rule, the rule applies only to new installations, not existing. The model rule also differs from BACT in that it set standards for technology that have not yet been achieved; BACT, in contrast, requires compliance with performance standards that have already been demonstrated and is determined on a case-by-case basis.

This is a model rule for states, which they will adopt as they see fit. Even so, the rule is intended to promote national consistency across the states, thereby reducing the costs of compliance for suppliers and easing administrative burdens for regulators. For that hope to be realized, several states will need to adopt it (or a rule very similar to it).

This version of the rule differs from the November Public Review Draft in several ways. The timing of the phase-in periods has been extended slightly, to better accommodate manufacturers' research and development cycles. Phase One begins in 2004, Phase Two in 2008, and Phase Three in 2012. Previously, Phase Three began in 2009. For emergency generators, the rule adopts the US EPA standards for off-road engines (converted to lbs/MWh). In the case of $NO_X$ produced by non-emergency generators, the Phase One and Phase Two limits are differentiated for attainment and non-attainment areas. This enables a state with attainment areas to give some added flexibility to suppliers, if it were to conclude, for instance, that the air quality benefits of the stricter emissions standards are not great enough to justify the higher technology costs in the early years. As technology develops, driven in part by increased deployment of distributed resources and stricter standards for on-road engines, the justification for areal differentiation diminishes. With Phase Three, both attainment and non-attainment areas will face the same $NO_X$ limits.

The Working Group recognizes that the model rule's Phase Three standards are "stretch" goals intended to push technology improvements. Though aggressive, the limits are based in large measure on the expected trajectories of technology performance over the next decade. However, given uncertainties about the state of DR technology ten years hence, or of air quality and environmental regulations too, the Working Group concluded that a technology review, to be completed a year before the Phase Three standards go into effect, would be appropriate. The review will require the state to evaluate whether the Phase Three limits are still apt and, if not, how they should be changed. To the extent that states can conduct this review jointly or with federal agencies, its costs can be significantly reduced, and national consistency of standards promoted.

# III. THE RULE

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

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

**I. Purpose.** The purpose of this rule 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.**

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

(B) **Combined Heat and Power**: A generator that sequentially produces both electric power and thermal energy from a single source. Herein referred to as CHP.

(C) **Design System Efficiency**: For CHP, the sum of the full load design thermal output and electric output divided by the heat input.

(D) **Dual-Fuel Generator**: A generator that has the capacity to be fired by either natural gas (including landfill methane, digester gas, or similarly produced gases) or a liquid fuel (*e.g.*, diesel or #2 oil), but not by both fuels simultaneously.

(E) **Emergency**: An electric power outage due to a failure of the electrical grid, on-site disaster, local equipment failure, or public service emergencies such as flood, fire, or natural disaster.

(F) **Emergency Generators**: Generators used only during emergencies or for maintenance purposes, provided that the maximum annual operating hours, including maintenance, shall not exceed 300 hours per calendar year. Emergency generators shall not be operated in conjunction with any voluntary demand-reduction program or any other interruptible power supply arrangement with a utility, other market participant, or system operator.

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

(H) **Installation**: A generator is installed when it begins generating electricity.

(I) **ISO**: International Organization for Standardization.

(J) **Landfill Gas**: Gas generated by the decomposition of organic waste deposited in a landfill (including municipal solid waste landfills) or derived from the evolution of organic compounds in the waste.

(K) **Mobile Diesel Fuel**: Diesel fuel that meets current US Environmental Protection Agency sulfur limits for fuel used by on-highway diesel engines (40 CFR 86).

(L) **Non-Emergency Generator**: Any generator that is not defined herein as an emergency generator.

(M) **Other Gaseous Fuels**: Gaseous fuels other than natural gas, including but not limited to landfill gas, waste gas, and anaerobic digester gas.

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

(O) **Power to Heat Ratio**: For a CHP unit, the design electrical output divided by the design recovered thermal output in consistent units.

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

(Q) **US EPA**: The United States Environmental Protection Agency.

(R) **Waste Gas**: Manufacturing or mining byproduct gases that are not used and are otherwise flared or incinerated. A manufacturing or mining byproduct is a material that is not one of the primary products of a particular manufacturing or mining operation, is a secondary and incidental product of the particular operation, and would not be solely and separately manufactured or mined by the particular manufacturing or mining operation. The term does not include an intermediate manufacturing or mining product which results from one of the steps in a manufacturing or mining process and is typically processed through the next step of the process within a short time.

**III. Effective Date.** This rule is effective on [date].

## IV. Applicability.

(A) This rule applies to all non-mobile generators that are installed on or after the effective date and that are not subject to Prevention of Significant Deterioration (40 CFR 52.21) or Review of New Sources and Modifications (40 CFR 51.160).

(B) **Exemptions.** Generators whose engines are subject to the 40 CFR 89, 90, 91,and 92, (the US EPA's Non-Road Engine Program) will be exempt from compliance with the requirements of this rule.

**V. Emissions.** A generator's emissions of nitrogen oxides ($NO_X$), particulate matter (PM), carbon monoxide (CO), and carbon dioxide ($CO_2$) under full load design conditions or at the load conditions specified by the applicable testing methods shall not exceed the standards set out in the following subparagraphs. Standards are expressed in pounds per megawatt-hour (lbs/MWh) of electricity output. A generator shall meet the applicable standard in effect on the date that the unit is manufactured or on the date one year prior to the installation date of the unit, whichever is later.

(A) **Emergency generators.** A generator may run up to a maximum of 300 hours per year for maintenance, testing, and emergencies. Within that limit of 300 hours per year, a generator may run up to a maximum of 50 hours per year for maintenance and testing. Emergency generators must meet the emissions standards set by the US EPA for non-road engines (40 CFR 89) at the time of installation. Any engine that is certified under the US EPA non-road standards is automatically certified under this rule to operate as an emergency generator. In addition, $CO_2$ emissions standards for emergency generators are as follows:

| | **Carbon Dioxide** |
|---|---|
| Phase One (installed on or after 1/1/04) | 1,900 lbs/MWh |
| Phase Two (installed on or after 1/1/08) | 1,900 lbs/MWh |
| Phase Three (installed on or after 1/1/12) | 1,650 lbs/MWh |

(B) **Non-Emergency Generators.** Emissions standards for non-emergency generators are as follows:

| | **Nitrogen Oxides: Ozone Attainment Areas** | **Nitrogen Oxides: Ozone Non-Attainment Areas** |
|---|---|---|
| Phase One (installed on or after 1/1/04) | 4.0 lbs/MWh | 0.6 lbs/MWh |
| Phase Two (installed on or after 1/1/08) | 1.5 lbs/MWh | 0.3 lbs/MWh |
| Phase Three (installed on or after 1/1/12) | 0.15 lbs/MWh | 0.15 lbs/MWh |

| | **Particulate Matter:** liquid fuel reciprocating engines | **Particulate Matter:** liquid-fuel only non-reciprocating engines | **Carbon Monoxide** | **Carbon Dioxide** |
|---|---|---|---|---|
| Phase One (installed on or after 1/1/04) | 0.7 lbs/MWh | To be determined | 10 lbs/MWh | 1,900 lbs/MWh |
| Phase Two (installed on or after 1/1/08) | 0.07 lbs/MWh | To be determined | 2 lbs/MWh | 1,900 lbs/MWh |
| Phase Three (installed on or after 1/1/12) | 0.03 lbs/MWh | To be determined | 1 lb/MWh | 1,650 lbs/MWh |

(C) **Technology Review.**

(1) By December 31, 2010, 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 Phase Three standards (beginning 1/1/12) should be amended.

(2) Beginning in 2017 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.

(D) **Dual-Fuel Generators.** Dual-fuel generators must meet all applicable requirements of this rule when operated on gaseous fuels. Such generators may operate no more than thirty

(30) days per year on liquid fuel. The liquid fuel must meet current US EPA sulfur limits for fuel used by on-highway diesel engines.

## VI. Emissions Certification, Compliance, and Enforcement.

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

(1) **Certification Process.** Emissions of nitrogen oxides, particulate matter, carbon monoxide, and carbon dioxide from the generator shall be certified in pounds of emissions per megawatt hour (lb/MWh) at full load design (ISO) conditions or at the load conditions specified by the applicable testing methods. If the design of a certified generator is modified, the generator will need to be re-certified. Certification means that a generator meets the required emissions standards and can be installed as supplied. With respect to nitrogen oxides, carbon monoxide, and carbon dioxide, test results from EPA Reference Methods, California Air Resources Board methods, or equivalent testing may be used to verify this certification. When testing the output of particulate matter from liquid-fuel reciprocating engines, ISO Method 8178 shall be used. Test results shall be provided upon request to the agency. Any engine that has been certified to meet the currently applicable US EPA non-road emissions standards and the $CO_2$ standards set out in Section V(A) shall be deemed to be certified for use in emergency generators. A statement attesting to certification must be displayed on the nameplate of the unit or on a label attached to the unit 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 supplier's instructions.

(2) **Responsibility of Supplier.** Certification will apply to a specific make and model of generator. For a make and model of a generator to be certified, the supplier must certify that the generator is capable of meeting the requirements of this rule for the lesser of 15,000 hours of operation or three years. During the initial 15,000-hour operating period, the Agency may enforce compliance with these standards.

(B) An owner of a generator that is not certified under the terms of Section VI.A.will need to demonstrate compliance with this rule through on-site testing using procedures set out in [other applicable state regulations].

(C) **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).

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

## VII. Credit 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:

| Emissions | Waste, Landfill, Digester Gases |
|---|---|
| Nitrogen Oxides | 0.1 lbs/MMBtu |
| Particulate Matter | N/A |
| Carbon Monoxide | 0.7 lb/MMBtu |
| Carbon Dioxide | 117 lb/MMBtu |

(B) **Combined Heat and Power.**

(1) CHP installations must meet the following requirements to be eligible for emissions credits related to thermal output:

(a) At least 20% of the fuel's total recovered energy must be thermal and at least 13% must be electric. This corresponds to an allowed power-to-heat ratio range of between 4.0 and 0.15.

(b) The design system efficiency must be at least 55 percent.

(2) A CHP system that meets these requirements can receive a compliance credit against its actual emissions based on the emissions that would have been created by a conventional separate system used to generate the same thermal output. The credit will be subtracted from the actual generator emissions for purposes of calculating compliance with the limits in section V.B. The credit will be calculated according to the following assumptions and procedures:

(a) The emission rates for the displaced thermal system (*e.g.*, boiler) will be:

i. For CHP installed in new facilities, the emissions limits applicable to new natural gas-fired boilers in [state code reference for boiler standards or Standards of Performance for New Sources (40 CFR

60, Subparts Da, Db, Dc), whichever is more stringent] in lb/MMBtu.

ii. For CHP facilities that replace existing thermal systems for which historic emission rates can be documented, the historic emission rates in lbs/MMBtu but not more than:

| Emissions | Maximum Rate |
|---|---|
| Nitrogen Oxides | 0.3 lbs/MMBtu |
| Particulate Matter | N/A |
| Carbon Monoxide | 0.08 lbs/MMBtu |
| Carbon Dioxide | 117 lbs/MMBtu |

(b) The emissions rate of the thermal system in lbs/MMBtu will be converted to an output-based rate by dividing by the thermal system efficiency. For new systems the efficiency of the avoided thermal system will be assumed to be 80% for boilers or the design efficiency of other process heat systems. If the design efficiency of the other process heat system cannot be documented, an efficiency of 80% will be assumed. For retrofit systems, the historic efficiency of the displaced thermal system can be used if that efficiency can be documented and if the displaced thermal system is either enforceably shut down and replaced by the CHP system, or if its operation is measurably and enforceably reduced by the operation of the CHP system.

(c) The emissions per MMBtu of thermal energy output will be converted to emissions per MWh of thermal energy by multiplying by 3.412 $MMBtu/MWh_{thermal}$.

(d) The emissions credits in $lbs/MWh_{thermal}$, as calculated in (c), will be converted to emissions in $lbs/MWh_{emissions}$ by dividing by the CHP system power-to-heat ratio.

(e) The credit, as calculated in (d), will be subtracted from the actual emission rate of the CHP unit to produce the emission rate used for compliance purposes.

(f) The mathematical calculations set out in subsections (a) through (d) above are expressed in the following formula:

Credit $lbs/MWh_{emissions}$ = [(boiler limit lbs/MMBtu)/(boiler efficiency)] * [3.412/(power to heat ratio)]

(C) **End-Use Efficiency and Non-Emitting Resources**. When end-use energy efficiency and conservation measures or electricity generation that does not produce any of the emissions regulated herein 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 non-emitting electricity source 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 and in accordance with guidelines established by the Agency for determining such savings.

**VIII. Fuel Requirements.**

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

(B) **Natural Gas and Other Gaseous Fuels.** Gaseous fuels combusted in these generators shall contain no more than ten grains total sulfur per 100 dry standard cubic feet.

(C) **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. Generators whose total capacity is 200 kW or less will be exempt from this requirement.

**IX. Record Keeping and Reporting.**

(A) **Record-Keeping Requirements.** At the premises where the generator is installed, or at such other place as the Agency approves in writing, the owner shall maintain the records as described in subsections (1) through (4) following. Non-emergency generators with electric generating capacity of less than 200 kW shall be exempt from these requirements. Emergency generators shall be exempt from subsections (1) and (2):

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

during emergencies. Maintenance hours must be separately accounted for. Owner shall record operations when they occur.

(D) **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.

(E) **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.

# IV. COMMENTARY ON THE RULE[5]

The rule attempts to translate into statutory language the objectives and principles that the Working Group developed (see Appendix A). It is divided into eight sections. The first section states its purpose. The second defines specialized terms used in the rule, and the third establishes its effective date.

## A. Definitions (Section II)

The definitions were culled from a variety of sources (*e.g.*, state and federal rules and regulations) or, where necessary, were developed anew for the rule (*i.e.*, "non-emergency generator," "owner," and "supplier"). They are consistent with the current and plain uses of these terms. A state considering adoption of this rule may discover that many of these terms are already defined in its rules and regulations, and should require little if any modification for the purposes here.

Some of the issues surrounding the definition of "emergency" bear elucidation here. As the Working Group ultimately settled on it, an emergency is "[a]n electric power outage due to a failure of the electrical grid, on-site disaster, local equipment failure, or public service emergencies such as flood, fire, or natural disaster." The Group considered a more expansive definition that would allow for the operation of emergency generators in the face of an imminent failure of the electrical grid, in order to stave off the failure. An argument in favor of such an approach posited that strategic operation of emergency generators prior to a failure could result in *lower* net emissions on the assumption that, by avoiding the failure, fewer such generators would be called upon to operate. Whether this would in fact be the case depends on several factors, among them the operational characteristics of the generators used and the amount of electricity produced. There were some concerns with this approach, however, having to do with determining what constitutes an "imminent failure" and what entity makes the determination. Given the competing considerations, the Group decided to stick to the simpler and more restrictive definition, while acknowledging that individual states may want to consider alternative approaches. In any event, however, the Working Group feels that the definition should not allow for the operation of emergency generators simply to overcome what might be termed "economic" emergencies, *i.e.*, high wholesale prices not associated with grid failure, imminent or otherwise.

---

[5] The members of the Working Group have had an opportunity to review this commentary and to provide feedback on it. The Regulatory Assistance Project carefully considered their responses and suggestions, and made changes to the document. It remains, however, RAP's account of the process and does not necessarily reflect all the views of the Working Group members.

**B. Applicability (Section IV)**

The fourth 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, or not covered consistently, 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 installed on or after the effective date and that are not subject to Prevention of Significant Deterioration (40 CFR 52.21) or Review of New Sources and Modifications (40 CFR 51.160)." Major new source review is triggered by specifications relating to 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 derived from federal regulations (40 CFR 51.160) or for 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 in the administrative streamlining that the optional certification process offers. Some states may find that it will be necessary to tailor the applicability provision more specifically to their existing rules and regulations.

Because they are already covered under federal regulations, certain resources are exempted from meeting the rule's emissions standards. These are those whose engines are subject to Parts 89, 90, and 92 of the EPA's Non-Road Engine Program (*e.g*, construction equipment, temporary facilities, marine engines, and locomotives).[6] Included in this category of engines are mobile off-road generators, sited temporarily and used typically for construction or some emergency purposes. This class of generation makes up a small portion of the overall market. Exempting it also reduces administrative burdens on both owners of such facilities and state environmental regulators.

Lastly, the rule applies only to new installations. Information available to the Working Group suggested that existing installations are, by and large, intended for emergency purposes and are, in most states, already covered under the terms of previously approved permits. However, a state

---

[6] Interestingly, there is a potential for railroad locomotives to be used as generators supplying electricity to the grid. California's Sierra Railroad Company recently announced plans to use 48 surplus locomotives as power sources over the next five years, for the purpose of providing extra power to the state during peak periods of electrical use. According to the company, the trains will produce enough electricity to light 100,000 homes. The company calls the proposal "PowerTrainUSA," and expects to operate the trains for about 1,000 hours per year for the next five years. The company will fuel the locomotives with about 7.5 million gallons of biodiesel fuel annually. World Energy press release at: http://www.worldenergy.net/WORLD_ENERGY_NEWS.html. State environmental regulators may want to consider whether the potential consequences of these kinds of innovation warrant modifications to the applicability requirements of the rule.

may choose to require that existing units be subject to emissions limits of some sort (possibly those in this rule, subject perhaps to a different timing of the phase-ins, or other standards altogether). One concern voiced in the Group was that the standards for new installations would invariably require the retrofitting of add-on controls or the entire replacement of some generation, which could be too cumbersome or expensive for these applications. In addition, it was felt by some that, insofar as the rule was being developed in response to a concern about the proliferation of new DG assets, it would be inappropriate to make the requirements retroactive.[7] However, to the extent that an owner of an existing facility 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.

## C. Emissions (Section V)

The fifth 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."[8] 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 electrical output-based (pounds of emissions per megawatt-hour) standards.

### 1. Emissions Regulated, Duty Cycles, and the Phasing-In of Standards

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 five pollutants, although only four would be subject to output-based limits (we note that inclusion of the fifth, carbon dioxide, at the levels recommended, has broad, but not full, support of the Working

[7] Application of this rule to existing facilities raised a number of issues with which the Working Group grappled. While confident in its assumption that the vast majority of existing DG is permitted for emergency use only, the Working Group lacked sufficient information about the national (or regional) inventories of such units: their numbers, technologies, or vintages. These uncertainties, together with the Group's schedule and limited resources, would have made it difficult for the it to assess the potential and costs for emissions control retrofits on existing units, as a prelude to setting standards that would be both achievable and beneficial. In addition, there were concerns about the administration of a retrofit rule: it was not immediately apparent that a significant investment in the time and effort of state environmental regulators would offer significant air quality benefits. However, given the incomplete information available on this topic, the Working Group believes that efforts to more fully understand the scope and nature of the existing fleet of small-scale generation in an area or the nation, and an examination of the potential for cost-effective emissions controls, would be worthwhile.

[8] See Appendix A, "Statement of Objectives, Principles, and Scope," April 30, 2001.

Group). There was no debate about nitrogen oxides, since they contribute to ground-level ozone, acid rain, and other environmental impacts. Sulfur dioxide was not made subject to an emissions limit, despite its elemental connection to acid rain, because many DG technologies run on natural gas, which generally has very little sulfur in it. The exceptions to that are diesel engines or those using diesel (or similar) 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.[9] Low-sulfur fuel also allows the use of catalyst-based control technologies for other pollutants, technologies that may otherwise be poisoned by sulfur in the exhaust stream. Particulate matter is the third pollutant. There was a desire to specify that the limits applied to particulate matter no larger than 2.5 microns in size, but this proved impractical for reasons of testing (refer to the discussion on Emissions Certification, Compliance, and Enforcement below). Moreover, the Group realized that a PM-2.5 standard would target primarily $NO_X$ and $SO_2$, which the rule already addresses separately.[10] Carbon monoxide (CO), because of its direct health impacts, its role in the formation of ground-level ozone, as a surrogate for air toxics, and as an indicator of combustion efficiency, is the fourth pollutant to be regulated. And fifth is carbon dioxide ($CO_2$), considered by many to be a 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 factors affecting their production 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 time to accommodate manufacturers' research and development cycles. Three phases are envisioned. The first begins on January 1, 2004. The second begins four years later, on January 1, 2008. The third begins on January 1, 2012, and continues indefinitely thereafter. Which standards apply depends upon the date a unit is installed (*i.e.*, begins generating electricity). In addition, the rule provides for a technology review to be completed a year before the final (Phase Three) standards take effect. On the basis of that review, the rule-making agency can evaluate whether the final standards remain appropriate or need to be amended in any way. The rule also calls for periodic (quinquennial) technology reviews thereafter.

[9] There is also a low-sulfur content requirement for gaseous fuels (Section VIII (B)).

[10] The Group also recognized that US EPA has not yet classified areas for PM-2.5 air quality designations. Once such designations are made, air regulators will be required to establish state implementation plans to achieve the PM-2.5 public health standards and will therefore need to revisit the PM standards in this rule (if adopted in their states).

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 (*i.e.*, CHP). Moreover, the emissions characteristics of the technologies also vary greatly. Depending on the pollutant and the technologies being compared, the differences can be quite substantial. Appendix B contains a spreadsheet developed by the Working Group in 2001, describing the emissions characteristics of current DG technologies.[11]

These facts persuaded the Working Group that one set of emissions standards to cover all potential applications would not be feasible. On the one hand, if the standards are very strict, they could greatly restrict the ability of distributed generation to provide real benefits to the electric system, because certain technologies might be unnecessarily prohibited from operating under circumstances when their benefits are great and their environmental impacts small. But on the other hand, if the standards are too loose, the rule might fail to serve the environmental purposes for which it is intended.

In the Public Review Draft of November 2001, three categories of generation were set out, differentiated not by technology but by the needs served, which in turn were defined by the circumstances and annual hours of operation (duty cycles). The categories were Emergency, Peaking, and Baseload. In light of the comments on the Draft, of proposed revisions to it, and of further analysis, the Group concluded that there are no significant technological (with respect to emissions and control methods) or operational reasons that separate small-scale generation into clearly differentiable categories of peaking and baseload. Thus, only two duty-cycle categories are identified in this version of the rule: emergency and non-emergency. Emergency generation is limited in its total annual hours of operation to 300 hours, of which a maximum of 30 hours may be for maintenance operations.[12] Non-emergency is all else.

### 2. Factors Considered in Determining the Standards

The general premise underpinning the rule is that the more a generator operates, the lower its emissions per unit of electricity output must be. As explained earlier (Chapter II, General

[11] For one assessment of the current state of technology and projections for improvement, see Energy Nexus Group, "Performance and Cost Trajectories of Clean Distributed Generation Technologies," May 6, 2002, which can be found at www.energynexusgroup.com/reports.asp.

[12] The Group considered whether a cap on emergency generators' total annual operating hours was appropriate. The logic was that, since the purpose is to provide power at the very times it is most needed, a cap could threaten public safety if it caused an emergency generator to be prematurely shut down. The countervailing concern was that US EPA rules under the Clean Air Act currently distinguish among sources on the basis of operating hours and that enforceability problems are raised in the absence of boundaries on those hours. The concept of "practical enforceability" was articulated by the DC Circuit Court in *National Mining Association v. EPA* [No.95-1006, argued April 20, 1995, decided July 21, 1995], but the EPA has yet to develop a rule and currently relies on various policy memos that are inherently inconsistent and difficult to enforce. Consequently, the Group decided to retain the 300-hour limit, which, given the current level of electric system reliability in the US, is unlikely to be exceeded.

Description of the Rule), this is consistent with the historic approach to the permitting of larger sources, which relates compliance requirements to the cost per ton of reduction – that is, which requires the best achievable performance within certain thresholds based on the costs of control. 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. Given the extremely high reliability record of the US power system, the Working Group concluded that the potential pollution from emergency generation is not a significant risk, and certainly one worth bearing at times when public health and safety are threatened by the loss of electric power.

This "performance-vs-cost" basis for emissions regulation was complicated in this case insofar as the Working Group was attempting to set limits for multiple technologies and multiple pollutants. The various technologies have different strengths and weaknesses and, as noted earlier, there are trade-offs both between performance and emissions reductions and among the emissions themselves. Put another way, some emissions reductions come at the cost of efficiency and some at the cost of other emissions. For example, significant reductions in $NO_X$ have been achieved through changes in combustion processes (in both reciprocating engines and turbines), but some thermal efficiency is sacrificed in doing so, and thus there are increases in $CO_2$ output. In addition, carbon monoxide output is often increased, a so far common consequence of a combustion process configured to minimize $NO_X$.

Similar challenges are raised by the variety of post-combustion ("after-treatment exhaust" or "tailpipe") controls. There are two primary methods of removing $NO_X$ from an exhaust stream, selective catalytic reduction (SCR) and the three-way catalyst. SCR is highly effective (although it can be costly for small-scale applications) and it is typically used in large industrial and electric generating facilities. It makes use of toxic chemicals (*e.g.*, urea, ammonia) and produces solid waste, two features which (aside from its handling and removal costs) render it impractical for many DG applications. Three-way catalyst technologies, similar to those used in motor vehicles, convert $NO_X$ to elemental nitrogen and oxygen (and also convert CO and hydrocarbons to carbon dioxide and water). Three-way catalysts will not operate in the presence of, and will be damaged, by high proportions of oxygen in the exhaust stream; thus lean-burn gas-fired reciprocating engines and combustion turbines face a particular challenge in cost-effectively achieving low levels of $NO_X$ emissions. [13] The three-step phase-in of the emissions standards is an implicit recognition of the engineering and cost hurdles that DG manufacturers will confront

---

[13] For a fuller general description of DG technologies, their emissions and operational characteristics, and emissions control technologies, see generally Bluestein, Joel, *Environmental Benefits of Distributed Generation*, Energy and Environmental Analysis (Arlington, VA, December 2000), which is available on the RAP website, www.rapmaine.org.

over the coming decade; the timing is designed to give them an opportunity and an incentive to overcome those hurdles.[14]

a. Emergency Generators

The rule requires that emergency generators meet the emissions standards for $NO_X$ (and non-methane hydrocarbons, NMHC), CO, and particulate matter set by the US EPA for non-road engines. The Tier 1 standards reflect the current state of non-road diesel in-cylinder technology, differentiated by size (in kilowatts). The Tier 2 and 3 standards reflect expected technological changes in diesels over the coming five years. In the November Public Review Draft, the Working Group had proposed standards phased in, like those for the other categories of generation, over three years. Commenters on that draft noted that the proposed limits were, for the most part, *less* stringent than those of the EPA and that the phasings-in did not coincide with those in the EPA's program. For these reasons, they recommended that the rule simply reference the EPA's requirements, thus achieving some measure of administrative efficiency while sparing suppliers from having to comply with duplicative, but not altogether consistent, requirements. The Group agreed.[15]

The Working Group considered carbon dioxide limits for emergency generators. On the grounds that diesels, for reasons already mentioned, will likely remain the primary form of emergency generation for a number of years to come, they are already highly efficient, and no significant improvements in their efficiency over the coming decade are predicted, the Group first settled on 1,450 lbs/MWh for all three phases of the rule. Later, the Group concluded that other technologies can also provide emergency service and, therefore, the standards applicable to non-emergency generators should apply to emergency facilities as well. For reasons given in the following discussion on non-emergency generators, $CO_2$ limits were not unanimously adopted by the Group.

b. Non-Emergency Generation

The Working Group considered whether the emissions standards for non-emergency generation should, in some way, be related to the emissions output of the facilities that might or would be displaced by that new generation. This became a central debate among the Group. Some

[14] Section B.5 of the Statement of Objectives, Principles, and Scope states that "[a] phase-in schedule should be set so as to be technology-forcing, while giving manufacturers a reasonable opportunity to meet the targets." (See Appendix A below.)

[15] Although at least as stringent as the limits originally proposed by the Working Group, the EPA's standards are still not so low as to require that new emergency generators be immediately fitted with exhaust after-treatment emissions controls. It is expected that manufacturers will find ways to comply with the later standards (referred to by EPA as Tier 2 and 3 standards; see Appendix C) that will not require tailpipe controls, *i.e.*, through improved combustion processes. Tier 4 standards are currently being developed, and it is anticipated that they will adopted sometime in the near future. It is likely that the Tier 4 standards will be such as to require exhaust after-treatment control systems. Such controls cannot function if the exhaust stream contains a high level of sulfur; therefore the Tier 4 standards will be accompanied by a low-sulfur fuel requirement, along the lines of that already included in the model rule.

members argued that new distributed generation would often displace higher-emitting central generation, including coal-fired facilities whose emissions output in many instances are greater than that of the new DG. Thus they argued that policymakers should adopt standards that encourage the deployment of DG, because air quality overall would therefore be improved. Others in the Group disagreed with this approach. They argued that emissions regulation under the Clean Air Act is not intended merely to achieve marginal improvements over existing air quality but rather to meet public health-based ambient air standards. They contended moreover that it would be difficult to establish with a high degree of confidence what emissions are actually being displaced by new distributed generation. They asserted that the operations of thousands of dispersed DG units, operating independently, would be impractical to model, and that their effects on the dispatch of the electric system would vary significantly from hour to hour, day to day, and year to year. It is possible, they argued, that DG would displace less-polluting resources at certain times. They also pointed out that, even if the displaced emissions of central generating facilities could be quantified, those emissions (typically exhausted through tall stacks in remote areas) are not directly comparable to DG emissions (near ground level in populated areas), and thus should not form the basis for the rule's limits.

The contending positions were never reconciled. This did not, however, prevent the Group from reaching agreement on the standards (with the exception, as noted, of carbon dioxide). Acknowledging the impasse, the Group turned instead to an examination of the practical implications of emissions limits on distributed generation, and approached the problem with an eye to technological capabilities and reasonable expectations for improvements over time.

i. Nitrogen Oxides

Perhaps the most controversial aspect of the rule is that it sets $NO_X$ standards for non-emergency generators that are differentiated by area: attainment and non-attainment. This distinction is shorthand for describing whether an area of the country meets the EPA's ambient air quality standards for ground-level ozone (of which $NO_X$ is a precursor). If it does not, it is considered to be in "non-attainment," and the state is required, among other things, to develop a state implementation plan (SIP) that delineates the actions it will take to bring the area into attainment.

The Working Group were divided on this issue at first. For those opposed to the distinction, there was a concern that less stringent standards would contribute to a speedier deterioration of air quality in attainment areas. They contended also that, if machines are being built to meet non-attainment standards, it makes sense for several reasons to promote their deployment in all areas: differentiation would not promote the goal of national consistency in standards, it would weaken the technology-forcing impacts of the rule, and, because of diminished economies of scale, it would likely increase the per-unit costs of machines to be deployed in non-attainment areas.

Balanced against these points was the argument that the kinds of facilities covered by the rule produce emissions that are, by definition, below the federal New Source Review (NSR) significance level, which is to say, are small contributors to the overall emissions inventory. As such, it seemed reasonable to suppose that limits could be set for non-attainment areas that might have the effect of excluding certain technologies (*e.g.*, gas reciprocating engines without after-treatment exhaust controls) that might, in the near term at least, be acceptable in attainment areas (that is, would have a minimal impact on ambient air quality, and thus controls would not be cost-justified). Moreover, went the argument, the attainment/non-attainment distinction would remove some of the financial pressure that a ubiquitous non-attainment-based standard would impose on manufacturers in the short term.

The opposing views were reconciled by an understanding that, in the longer run, more stringent emissions limits for the broad range of combustion technologies and uses (of which DG is a small part) will be both necessary and inevitable. This gave currency to a proposal within the Working Group that called for differentiated $NO_X$ standards in the first two phases of the rule and a combined standard in the third phase, after the technology review. It turned out to be more than a solid enough foundation on which to proceed.

EPA determines whether an area is in attainment or not, on a pollutant-by-pollutant basis. In the rule, $NO_X$ is the only pollutant treated differently in attainment and non-attainment areas. The Group considered whether carbon monoxide deserved like treatment, but, given that there are very few CO non-attainment areas in the nation and that CO problems are caused primarily by mobile sources, decided against it. The Group concluded that any additional requirements to address CO concerns in those areas would best be handled by local air regulators.

The Phase One $NO_X$ attainment standard for non-emergency generators approximates the uncontrolled emissions output of today's smaller (50 kW to 1 MW) lean-burn gas-fired reciprocating engines, which are in the range of 3-4 lbs/MWh. Today, lean-burns less than 1 MW in size are the most common and efficient DG technology (excluding emergency diesels). As the size of the lean-burn engine increases, its $NO_X$ output decreases somewhat. Engines in the 1-5 MW range emit approximately 2.2-3.0 lbs/MWh and the 5-10 MW engines emit around 1.5-2.2 lbs/MWh. The Phase One attainment standard allows the smaller engines to compete in the short term, because tailpipe controls (SCR) are not cost-effective for them. Other technologies – small turbines, controlled rich-burns, and perhaps SCR-controlled diesels – come in well below this limit. The Phase Two standard anticipates technological improvements to the small lean-burns that will bring them into line with their larger siblings, without necessarily requiring controls. Moreover, it is equivalent to the level called for in the regional $NO_X$ "SIP Call" for large power plants.

The Phase One $NO_X$ non-attainment standard requires the installation of exhaust after-treatment controls on the various technologies, but is set so as to enable them, in their current state, to meet the standard. The Phase Two limit demands technological improvements, though ones that are within the range of current expectations.

The Phase Three $NO_X$ standard applies to machines in both attainment and non-attainment areas. It is set at a level that is approximately 70 percent cleaner than today's cleanest combustion-based DG technologies. Meeting it will require significant combustion and tailpipe control improvements and, in some cases, will also require that the generator be deployed in a CHP configuration. The Working Group considers the standard to be a "stretch" goal, but one that is within the range of reasonable expectations for technology improvements.[16] The future, however, is uncertain. The technology review in 2010 affords policymakers an opportunity to evaluate the standards in light of then current information and, if appropriate, modify them.

ii. Particulate Matter

The setting of standards for particulate matter was complicated by uncertainties arising from the manner in which the emissions are measured. The methods for testing PM output differ by technology type – some methods simply cannot be used with certain technologies – and they differ in ways that leave their measurements unable to be meaningfully compared. These differences mean that PM testing in one technology may identify particles that go unrecorded in the testing of other technologies. For instance, turbine testing typically captures both the filterable ("front half") and condensable ("back half") emissions, whereas testing of reciprocating engines only catches the front half.[17] Consequently, reciprocating engines appear, in certain instances, to produce significantly less PM than turbines, which, when both are gas-fired, seems improbable.

The Group considered briefly whether to resolve the PM problem through a fuel-input, rather than emissions output, requirement. The logic behind such an approach lay in the understanding that imminent federal standards for PM-2.5 (particulate matter below 2.5 microns in size) will be focused on reducing the primary PM contributors: $NO_X$ and $SO_2$ derivatives. Since gas technologies do not produce any $SO_2$ to speak of and the model rule already addressed $NO_X$, there was a certain appeal to the idea of a fuel-input requirement. However, there was still strong support among members for an output standard, in keeping with the overall objectives that we had set for ourselves.

The Group ultimately decided on a dual approach that would simplify the testing requirements and, for the most part, make use of output-based limits. It is the closest that the rule comes to technology-differentiated standards. The PM limits and testing requirements apply only to liquid fuel generators. Gas-fired machines are exempt from the PM standards (however, as noted

[16] Refer, for example, to the US DOE's Advanced Reciprocating Engine System (ARES) Program at www.eren.doe.gov/der and the California Energy Commission's Public Interest Energy Research programs into environmentally-preferred advanced generation at www.energy.ca.gov/pier/epag.

[17] The quantity of particulate matter produced by combustion is not an absolute, as the form it takes is a function of temperature and, to a lesser extent, pressure. In general terms, particulates can be broken down into two categories – a "filterable" fraction and a "condensable" one. The "filterable" fraction exists as a solid at the temperature of the sampling filter. This is also referred to as the "front half". The "condensable" fraction is a vapor at the temperature of the sampling filter and it passes through the filter. At lower temperatures, a portion of the vapor may condense and become solid. Typically, particulate sampling equipment consists of a filter and a set of condensers (or impingers). Vapor that is collected in the impingers is considered the "condensable" fraction. It is also referred to as the "back half."

earlier, air regulators will need to reconsider the PM standards when the US EPA determines PM-2.5 air quality designations), and the rule specifies that ISO Method 8178 be used for testing reciprocating engines.[18] Generators fired by gaseous fuels (including waste, landfill, and other gases) are subject to a low-sulfur fuel requirement (Section VII: ten grains per 100 dry standard cubic feet). In this way, the vagaries associated with the PM testing of turbines are avoided, but low PM output is assured. Lastly, dual-fuel generators (by which is meant generators that operate on either gas or liquid fuel, though not simultaneously) are also exempt from the output-based standards; they are, however bound by the low-sulfur fuel requirements that the rule sets for both gas and liquid fuels. Generators of this type operate primarily on natural gas, but they may, for regulatory or other reasons, be subject to interruption at times of high gas demand. During those hours, they will operate on liquid fuel. The Working Group did not want to craft a rule that inhibited this kind of market behavior. However, to assure that liquid-fuel operations are kept at a reasonable minimum, the rule caps such operations at thirty days per year.

US EPA's PM emissions limits for on-road engines are more stringent (as are the $NO_X$ and CO limits) than they are for off-road engines. In 2007, the federal limit will be 0.03 lbs/MWh (that is, 0.01 g/bhp-hr) for on-road engines, whereas by 2009 it is expected to be 0.07 lbs/MWh (0.02 g/bhp-hr) for off-road engines. The different standards flow in part from technological differences between on-road and off-road diesel engines. Off-road engines typically lag behind their on-road counterparts in the application of high-pressure fuel injection and, lacking increased airflow and cooling capabilities, cannot run at the higher temperatures (and thus with the improved combustion characteristics) of on-road engines. The stationary engines used in electric generation are based on off-road engine designs.

It is, however, reasonable to expect that, over the next decade, the emissions output of off-road engines will be brought in line with those of on-road engines. In light of this, the Group settled on the off-road limit for Phase Two and the on-road limit for Phase Three. The Phase One PM limit is based on the current capabilities of liquid-fuel generators (primarily diesels). The Phase Two and Three standards will require improved combustion processes and the use of particulate traps.

The rule's approach to particulate matter addresses most, though not all, potential sources of PM from distributed generation. Noticeably absent from it are standards applicable to non-reciprocating, liquid fuel-only engines (*e.g.*, turbines). A lack of time and reliable information prevented the Group from more fully investigating the questions surrounding this subset of generators. As with the gas-fired technologies, the critical issues are the consistency of testing and the setting of standards that reasonably relate to the measurements that can be taken. Some members of the Group felt that non-reciprocating, liquid fuel-only generators will likely make up

[18] ISO Method 8178 is referred to as a "partial dilution" method; it doesn't measure the "back half." It is used for testing, among other things, on-road engines and the performance after-treatment exhaust controls. The method also works both in the field and under controlled circumstances. Whether ISO Method 8178 or other method is used, the key for regulators is to be sure that the chosen test is reliable under all relevant conditions. For a discussion of these and related issues, refer to the report "Evaluation of PM-2.5 Testing Issues For Electric Generating Reciprocating Engines and Turbines," M.J.Bradley & Associates, June 20, 2002, which can be found at www.rapmaine.org.

a small, possibly very small, share of new DG installations and thus it was not necessary, as a practical matter, to propose PM standards for them. Others were concerned that the Group's inability to propose standards might be understood (wrongly) to mean that the Group had concluded that this potential source of emissions need not be regulated. Although unable to resolve the dilemma, the Group acknowledges it by identifying an additional category of standards and noting that they have yet to be determined. Policymakers in each state will need to take up the question as they consider adoption of this rule.

iii. Carbon Monoxide

Carbon monoxide is a product of incomplete combustion and its emissions are higher with reciprocating engines than they are for other technologies subject to the rule. As previously mentioned, CO output is also affected by changes to the combustion process that are aimed at reducing $NO_X$. With this understanding, the Group set CO standards that, though aggressive, are intended not to handicap manufacturers' ability to decrease $NO_X$ output. The Phase One standard can be met by uncontrolled gas-fired lean-burn engines and by rich-burns with a three-way catalyst. The Phase Two standard will require tailpipe controls on both lean- and rich-burns. Lean-burns will be able to meet the Phase Three standard with an oxidation catalyst; but, for the rich-burns to achieve it, significant technological advancements will likely be necessary. Most turbines are already able to meet the Phase Three limit.

iv. Carbon Dioxide

As noted earlier, carbon dioxide output is a function of an engine's thermal efficiency. There are no currently practical after-treatment controls that remove $CO_2$ from an exhaust stream. In setting carbon dioxide standards, the Group wanted to encourage the deployment of efficient technologies, but it did not want $CO_2$ to prove the disqualifying factor for a technology that otherwise satisfies the requirements of the rule. The Phase One and Two standard of 1,900 lbs/MWh can be met by the turbines and reciprocating engines. The Phase Three standard of 1,650 lbs/MWh assumes an efficiency among the gas-fired technologies of at least 24%, and will require improvements in some small turbine models. Because increases in efficiency reduce a user's fuel costs, it is reasonable to expect that the needed improvements will be largely market-driven.

Although the Working Group's Statement of Principles identified carbon dioxide as one of the emissions to be regulated by the rule, in the end the proposed $CO_2$ standards did not receive the Group's full support. At least one member felt that the limits were not stringent enough, and another opposed their inclusion altogether. Most members, however, feel that $CO_2$ warrants the attention of policymakers, and support its retention in the rule. RAP concurs, and we have included it as proposed.

3. Other Issues

The Working Group recognizes that the Phase Two and Phase Three standards are rigorous "stretch" goals that should have the desired "technology forcing" effect. Technology-forcing regulation has, in a number of instances, proven to be both effective and cost-effective (*e.g.*, automobile mileage and emissions standards); and, in certain instances, the improvements (particularly emissions reductions) have been achieved at lower cost and with less disruption than initially foreseen by the affected industry. For such standards to be effective, they must be related in some way to industry research and development, to the expectations for technological progress, and to the market for the technologies under consideration. The distributed resources market differs significantly from, say, the automobile market – it is much smaller – and this affects whether and at what rate changes in technology can be effected. It was an appreciation for these considerations, among others, that led the Group to settle on the phase-in durations, the technology review, and the duty-cycle characterizations in this version of the rule that differ from those first proposed in the Public Review Draft.

In keeping with the goal of technology-neutrality, this rule offers no dispensations for specific kinds of generating facilities.[19] This was of special concern to several members and commenters. In particular, the Working Group was urged to set alternative standards and offsets for biomass (primarily wood-burning) facilities. The argument was that these facilities, which tend to produce significant quantities of particulate matter, provide other benefits (fuel diversity, local employment, long-term carbon-neutrality, and so on) of sufficient value to trade against their emissions profiles. Several members of the Working Group found this reasoning at least partly persuasive, but the potential public health impacts of PM were of greater concern to the Group as a whole. For this reason, the Group decided against special provisions for biomass generation.[20]

The rule does not give explicit credit for reductions in line losses that distributed resources, when sited near load, provide. There are several reasons for this. First, the rule is intended to apply to all smaller-scale facilities, regardless of location. Second, a credit provision that would apply to some facilities but not others would create an undue administrative burden, and would complicate the manufacturer certification component of the rule. And third, the value of such a credit is highly dependent on the physical and operational characteristics of the network and generation market in which the distributed resource is situated. The Group concluded that the

[19] It does, however, give credit for emissions offsets through CHP and the installation of end-use efficiency and non-emitting renewables (Section VII).

[20] In light of other policy initiatives to promote renewables-based generation, a state might conclude that alternative standards for emissions from biomass facilities, or other regulatory approaches, are also warranted. One suggestion, for instance, would give a biomass facility credit against its carbon dioxide output for the carbon in its fuel, so long as that fuel is procured through sustainable harvesting methods. The reasoning is that sustainable harvesting, in effect, keeps the carbon in a "closed loop" between the forest and the generating facility, and thus no incremental carbon emissions are created. Under this approach, if all of the facility's fuel were harvested in a sustainable manner, its carbon dioxide output would net to zero.

calculation and application of such a credit would impose difficulties that outweigh the benefits of the simpler approach.[21]

As stated previously, the rule is intended to apply to facilities that are not covered under existing state and federal air regulations, and the applicability provision is written to achieve that result. The Working Group considered, however, whether other provisions of the rule could, in some way, affect the behavior of owners whose facilities are components of larger energy-using processes that come under the jurisdiction of the federal Clean Air Act (specifically, the Amendments of 1990, or CAA) or other state requirements. The rule is not intended to enable those subject to it to evade other applicable regulatory requirements. In particular, it should not be construed to allow facilities otherwise subject to new source review under the CAA to avoid that review. For instance, the model rule imposes no requirement that a CHP system and the displaced emissions source be owned by the same party. The question arose as to whether this might allow an owner to treat its energy-using systems in a way that would reduce the regulatory requirements with which those systems would otherwise be required to comply under the CAA. The Group concluded that the opportunity for such behavior was slight, if not non-existent. The rule focuses on small sources, those that generally come in below Title V requirements but are not always picked up by state minor new source permitting programs.

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 is an attempt to balance the sometimes competing concerns about air quality, technology development and deployment, and cost-effectiveness.

## D. Emissions Certification, Compliance, and Enforcement (Section VI)

The rule does not include testing and other procedures for owners 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 bodies named by the state. In the case of particulate matter, it identifies the specific protocol to be used. Such certification should reduce the administrative burdens upon entire product lines, for both suppliers and state regulators.

[21] At least one member of the Working Group noted that the rule could be seen to give some (albeit implicit) credit to DG for emissions reductions resulting from reduced line losses. The "credit" comes in the form of Phase III standards that are slightly less stringent than limits set to match the output of the most efficient gas-fired combined cycle units.

The rule specifies that the emissions standards apply to full load design conditions or at the load conditions specified by the applicable testing methods. ISO Method 8178 specifies a range of load conditions for testing, but other test methods do not necessarily do so. The rule allows for full load testing in such circumstances. The Working Group understands that distributed generation does not always operate under full load, but also under a range of partial loads, and that emissions output often varies with those loads. The Group nevertheless opted for this approach for two reasons. One, it should greatly simplify matters for both suppliers and regulators. And two, it avoids the difficult job of developing representative operating cycles for the variety of technologies, the emissions profiles associated with those cycles, and the emissions limits themselves in light of the varied operations. The Group did not have sufficient information at this point to warrant a more sophisticated approach, but expects that, in the light of more information and experience, this decision may need to be revisited. Actual emissions from a unit will not differ merely because the standards reflect a weighted average of partial and full load operations. Except to the extent that the standards prevent a unit or technology from operating at all, they will have no effect on how an owner actually operates its machine. Consequently what matters is to have standards that will serve the objectives sought, while easing the means and costs of compliance and enforcement.

Experience with DG over the coming years will reveal whether this approach is appropriate. New information may cause regulators to give an answer to the question "Should facilities be required to meet the standards under all operating conditions?" that differs from the one implicit in the model rule now. Similarly, new federal regulations with respect to particulate matter (PM-2.5), for example, may require changes in standards and testing. The technology review will provide policymakers an opportunity to examine these issues in greater detail.

The rule states that, "For a make and model of a generator to be certified, the supplier must certify that the generator is capable of meeting the requirements of this rule for the lesser of 15,000 hours of operation or three years." This is, in effect, a manufacturer warranty that the engine will meet the standards for the first 15,000 hours of its life (or three years, whichever comes first). The provision does not require that each machine, or that some number of machines from the model line, be tested for 15,000 hours in order to be certified. The provision merely establishes the performance requirements for a machine that is certified. Environmental regulators will, presumably, conduct random tests of certified units in the field, to determine whether they are performing as expected and whether the model line shall continue to enjoy certification (*i.e.*, whether new units in the line will be entitled to the certification).

## E. Credit for Concurrent Emissions Reductions (Section VII)

This section of the rule sets out the circumstances under which a DG facility can be credited for displacing emissions that would have otherwise occurred in the absence of the DG. 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.

In the case of flared gases, a developer will have the option of demonstrating the actual emissions offsets or of using the rules default values. The default values are based on emissions data provided by the US EPA (AP-42), modified slightly in light of technological capabilities and current practices. The low Btu content of landfill and digester gases proscribes, in certain cases, the use of low-$NO_X$ combustion technologies. In those instances, the simple flaring of the gas will produce less $NO_X$ than internal combustion will. The question for policymakers then is whether the incremental generation of electricity from these gases is worth a slightly higher $NO_X$ output than the standards would otherwise allow. The default values in the rule presume, as do the rules in Texas and California, that it is better to use the fuels to produce electricity than it is to merely flare them off, and that in these limited circumstances, the value of the incremental electricity is greater than cost of the incremental emissions. However, we acknowledge that in some areas local air quality conditions may counsel for a different approach.

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.[22]

There is also 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 intent of such a provision is to promote other, cost-effective emissions-reducing strategies. This provision, when first proposed, was attended by some controversy. A number of commenters and members of the Working Group voiced concern about it. Although there was broad support for the concept, there were worries that it might be unworkable in practice. There is a risk of problems with "free-ridership" (that is, the taking of credit for savings that would have occurred anyway) and a risk that the savings themselves may be incorrectly calculated. Here was an opportunity, some argued, for regulators (particularly in states with little previous experience in evaluating end-use efficiency savings) to be taken advantage of.

[22] One commenter pointed out that the CHP provision gives credit for the displacement of emissions from an on-site combustion source rather than, for example, some form of electric cooling. While the proposed methodology does not directly address the emissions associated with displaced electric cooling, it could address this circumstance by giving credit for the direct-fired absorption chiller or desiccant system that would be displaced by the CHP system. Ultimately, heat recovered from a CHP system will replace heat that could have otherwise been provided by direct combustion and the proposed methodology can give credit for the associated emissions. The Working Group considered whether CHP that displaces emissions from central station electric generation should be credited for those savings. Though recognizing that the concept is theoretically sound, there were several reasons why the Group nevertheless decided against including it in the rule. The first was our conclusion that most CHP systems will replace on-site boiler and other combustion systems, and thus the rule captures the lion's share of applications. Second was the problem of calculating the displaced emissions (*e.g.*, average vs. marginal). And third was the practical difficulty posed by the wide variation in emissions rates from area to area; establishing system emissions rates across the country was beyond the scope and resources of the Group.

These are reasonable concerns and worthy of some attention by policymakers if they choose to retain this provision. The Working Group concluded that the provision has merit and that its implementation challenges can be overcome. Each state is free to determine whether and how to do so.

## F. Miscellaneous Provisions (Sections VIII and IX)

Lastly, the rule sets out monitoring and record-keeping requirements. These are typical of those required of other emissions sources. Generators under 200 kW and emergency generators are exempt from certain of the provisions, reducing administrative burdens that would yield only small benefit.

# 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 Working Group 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 Working Group'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.

**2. Standards Expressed**

The Working Group 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.

**3. Emissions Covered**

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

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

The Working Group 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 Working Group 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.

**5. Certification of Emissions Output**

The Working Group will consider means for establishing the emissions output of distributed generation facilities. More specifically, the Working Group 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.

**6. Existing and New Units**

The Working Group 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 WORKING GROUP

What follows here is a description of some of the issues that the Working Group 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 Working Group'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 its limited time frame and primary focus, 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 Working Group 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 Working Group 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 Working Group 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 Working Group.

### 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.

# 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 | Unc. Micro Turbine | Unc. Small Gas Turbine | Unc. Medium Gas Turbine | Large Gas Combined Cycle (SCR) | Unc. 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 | | | |

## Number of Units to Equal the Major Source Threshold for NOx

| Threshold (TPY) | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 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

| | | | |
|---|---|---|---|
| 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

| | | | |
|---|---|---|---|
| 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

| | | | |
|---|---|---|---|
| 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

| | | | |
|---|---|---|---|
| 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 | |

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 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:**

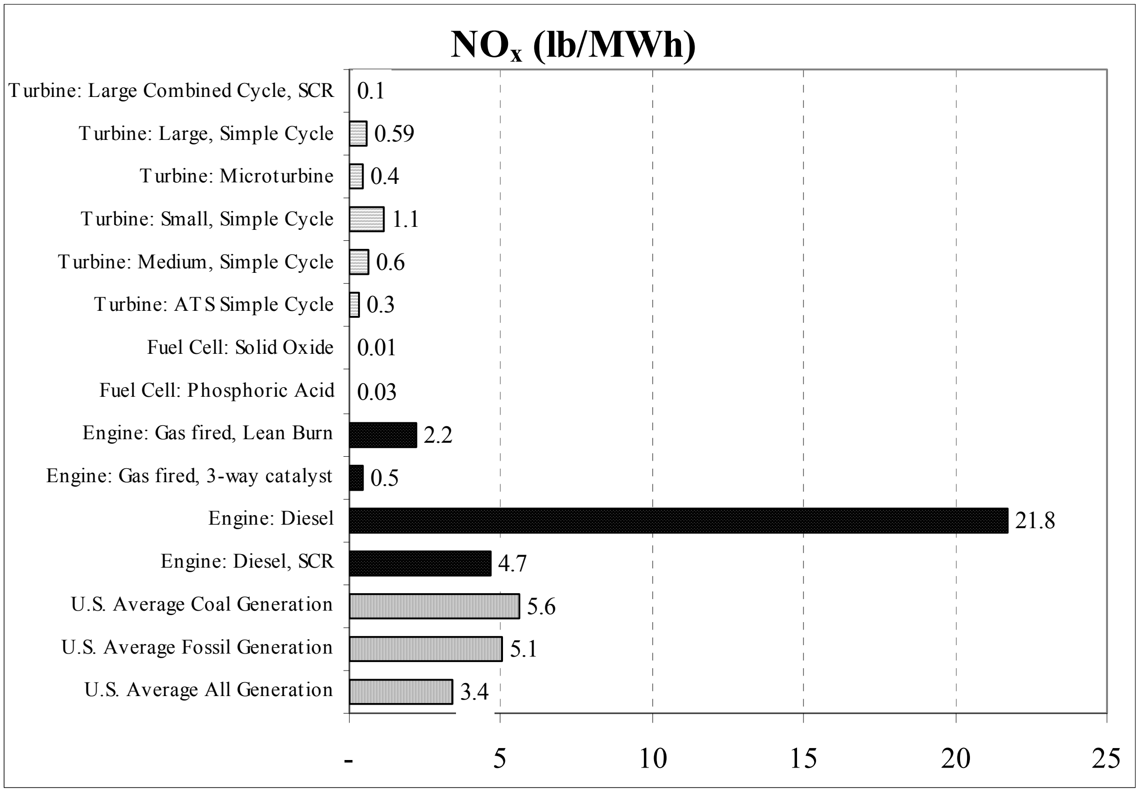
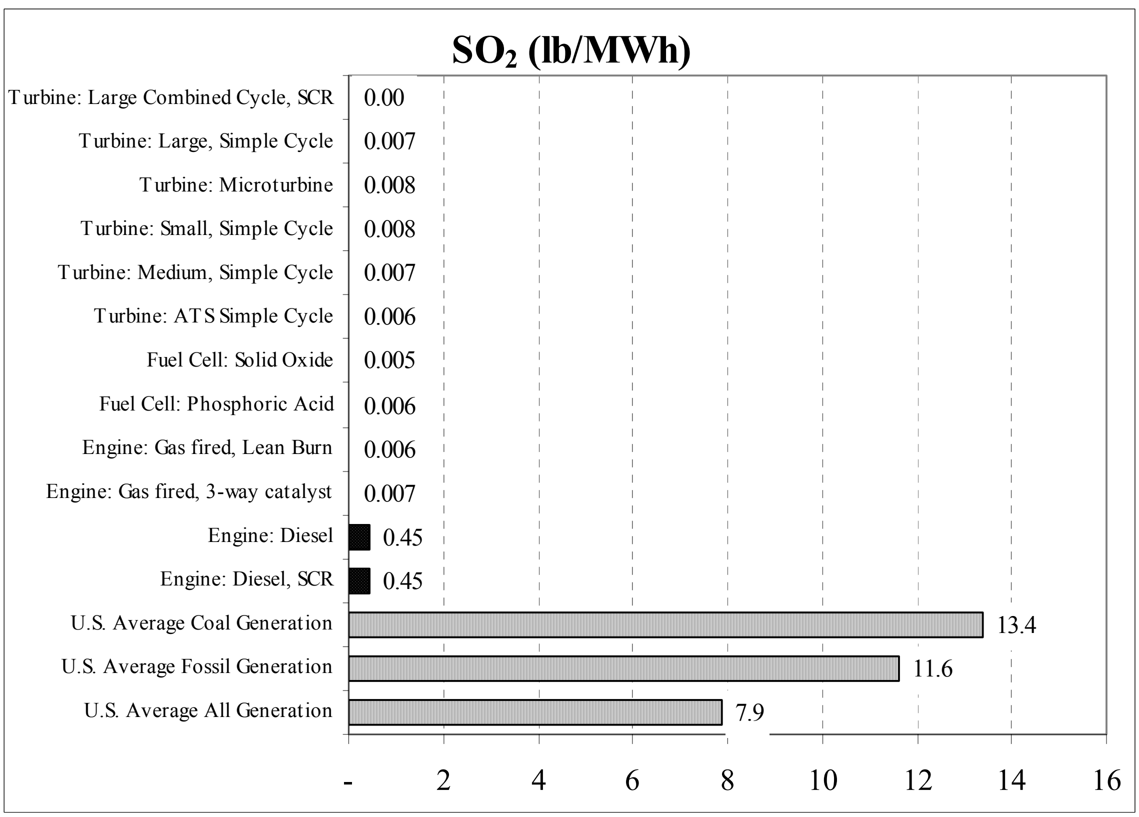



**Figure 2:**




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:**

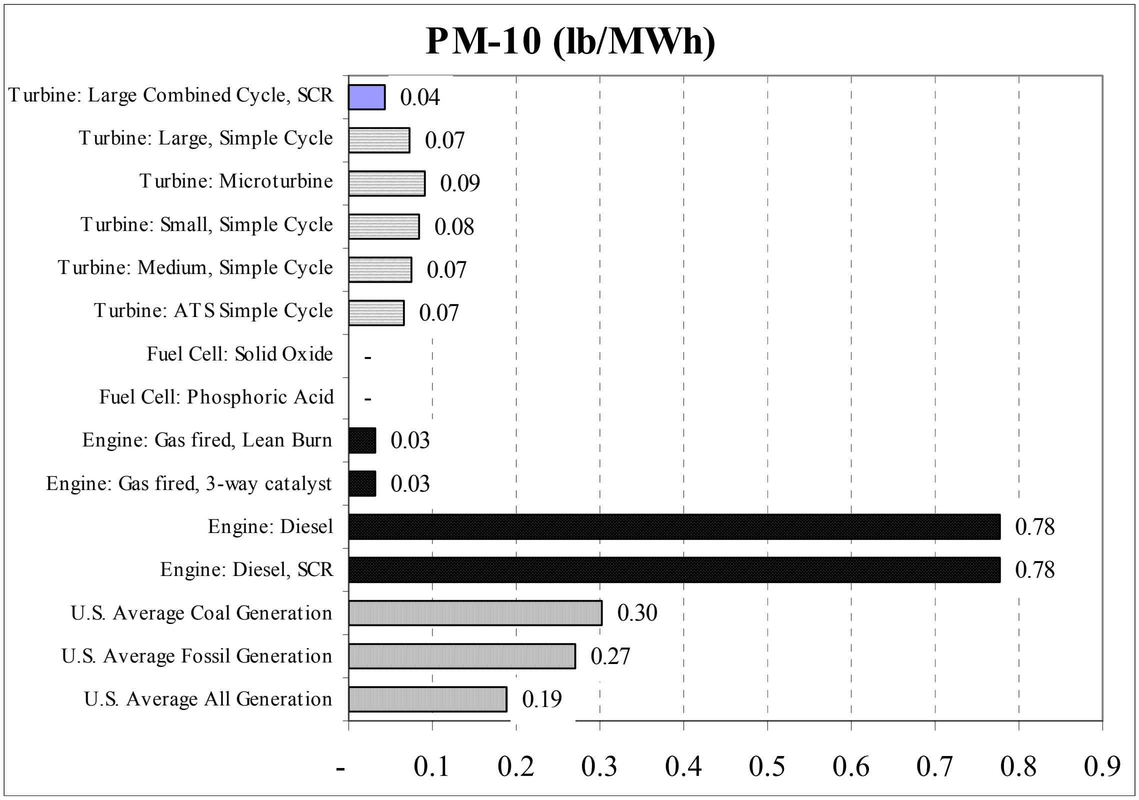
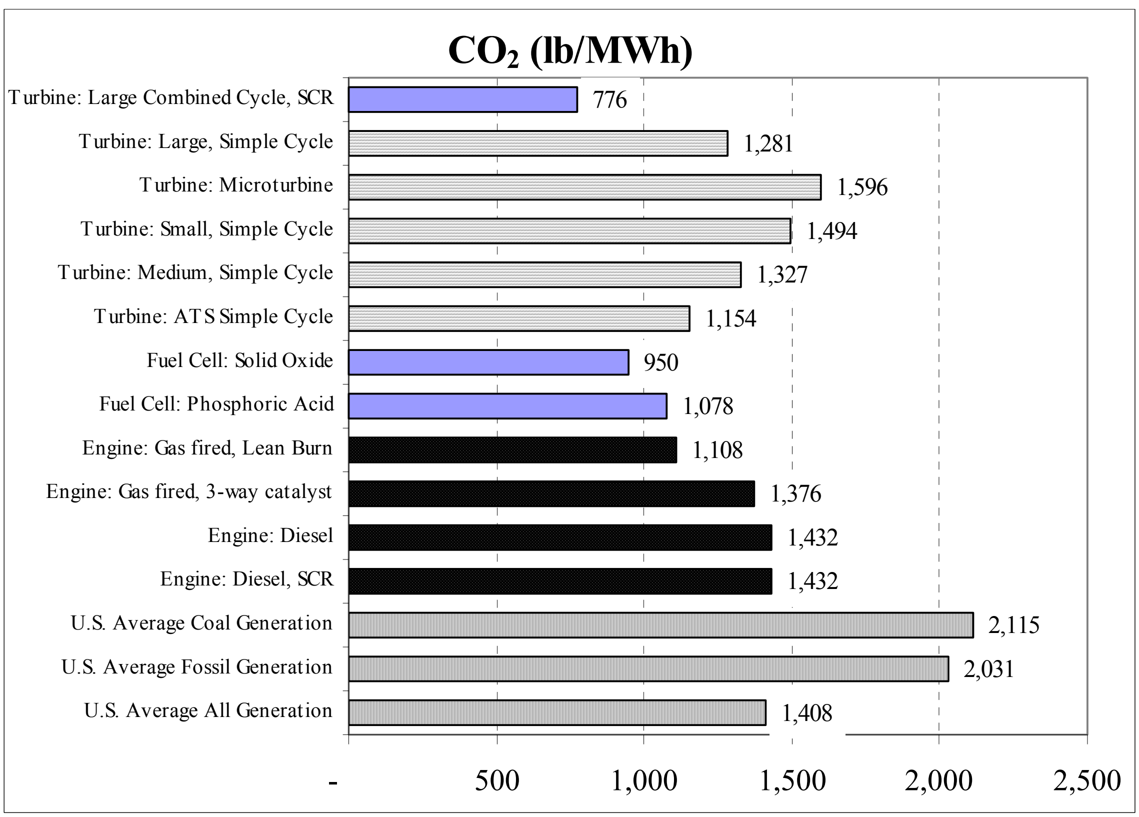
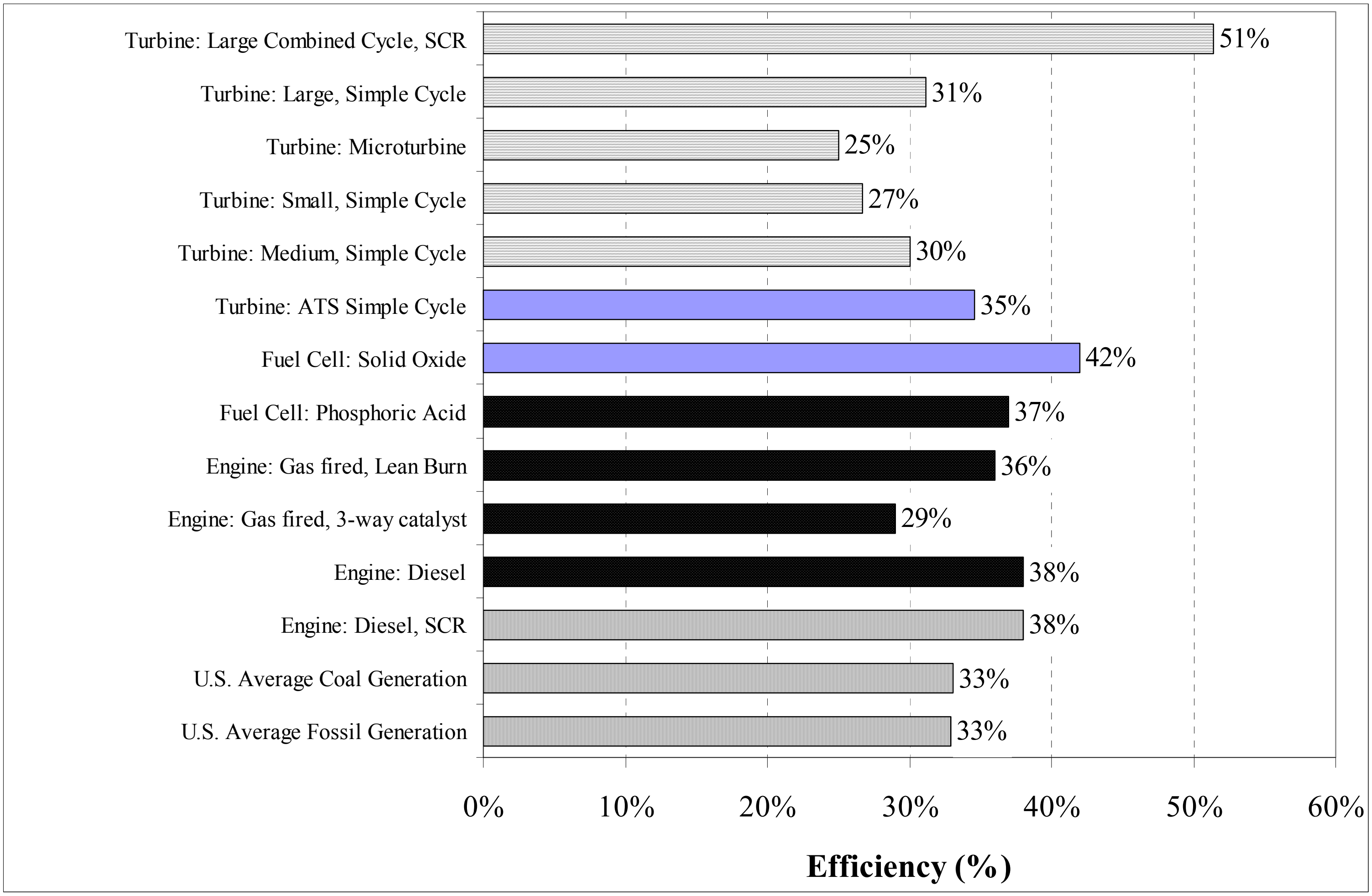



**Figure 4:**




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 hydrocarbons – 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 hydrocarbons – 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.

## APPENDIX C. US EPA NON-ROAD ENGINE STANDARDS

The emissions values for NMHC + $NO_X$, CO, and PM are given in two units of measurement. The first unit of measurement is grams per kilowatt-hour (g/kWh), the second (in parentheses) is pounds per megawatt-hour (lbs/MWh). The emissions rates in lbs/MWh were calculated by multiplying the rates in g/kWh by a conversion factor of 2.2 (assuming 453.59 grams per pound).

| Rated Power (kW) | Tier | Model Year | $NO_X$ | HC | NMHC + $NO_X$ | CO | PM |
|---|---|---|---|---|---|---|---|
| kW < 8 | Tier 1 | 2000 | - | - | 10.5 (23.1) | 8.0 (17.6) | 1.0 (2.2) |
| | Tier 2 | 2005 | - | - | 7.5 (16.5) | 8.0 (17.6) | 0.8 (1.8) |
| 8≤ kW< 19 | Tier 1 | 2000 | - | - | 9.5 (20.9) | 6.6 (14.5) | 0.8 (1.8) |
| | Tier 2 | 2005 | - | - | 7.5 (16.5) | 6.6 (14.5) | 0.8 (1.8) |
| 19 ≤ kW < 37 | Tier 1 | 1999 | - | - | 9.5 (20.9) | 5.5 (12.1) | 0.8 (1.8) |
| | Tier 2 | 2004 | | | 7.5 (16.5) | 5.5 (12.1) | 0.6 (1.3) |
| 37 ≤ kW < 75 | Tier 1 | 1998 | 9.2 | - | - | - | - |
| | Tier 2 | 2004 | - | - | 7.5 (16.5) | 5.5 (12.1) | 0.4 (.9) |
| | Tier 3 | 2008 | - | - | 4.7 (10.3) | 5.0 (11.0) | |
| 75 ≤ kW < 130 | Tier 1 | 1997 | 9.2 | - | - | - | - |
| | Tier 2 | 2003 | - | - | 6.6 (14.52) | 5.0 (11.0) | 0.3 (.7) |
| | Tier 3 | 2007 | - | - | 4.7 (8.8) | 5.0 (11.0) | |
| 130 ≤ kW < 225 | Tier 1 | 1996 | 9.2 | 1.3 | - | 11.4 (25.1) | 0.5 (1.1) |
| | Tier 2 | 2003 | - | - | 6.6 (14.6) | 3.5 (7.7) | 0.2 (.4) |
| | Tier 3 | 2006 | - | - | 4.0 (8.8) | 3.5 (7.7) | |
| 225 ≤ kW < 450 | Tier 1 | 1996 | 9.2 | 1.3 | - | 11.4 (25.1) | 0.5 (1.1) |
| | Tier 2 | 2001 | - | - | 6.4 (14.1) | 3.5 (7.7) | 0.2 (.4) |
| | Tier 3 | 2006 | - | - | 4.0 (8.8) | 3.5 (7.7) | |
| 450 ≤ kW < 560 | Tier 1 | 1996 | 9.2 | 1.3 | - | 11.4 (25.1) | 0.5 (1.1) |
| | Tier 2 | 2002 | - | - | 6.4 (14.1) | 3.5 (7.7) | 0.2 (.4) |
| | Tier 3 | 2006 | - | - | 4.0 (8.8) | 3.5 (7.7) | |
| KW > 560 | Tier 1 | 2000 | 9.2 | 1.3 | - | 11.4 (25.1) | 0.5 (1.1) |
| | Tier 2 | 2006 | - | - | 6.4 (14.1) | 3.5 (7.7) | 0.2 (.4) |

The source of this table is the Federal Register/Vol. 63, No. 205/Friday, October 23, 1998/Rules and Regulations/ Page 57001.

# APPENDIX D. WORKING GROUP MEMBERS

The model rule was nearly two years in the making. During that time, the membership of the Working Group changed somewhat, as some members left and new ones joined. The following is a list of all past and present members.

State Environmental Regulators
Grant Chin, California Air Resources Board
Christopher 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 L. Seidman, Massachusetts Department of Environmental Protection
Nancy Sutley, California Environmental Protection Agency

State Energy Officials
Paul Burks, Executive Director, Division of Energy Resources, Georgia Environmental Facilities Authority
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.
Tim French, Engine Manufacturers Association
Joseph Galdo, United States Department of Energy
Nathanael Greene, Natural Resources Defense Council
Eric Heitz, Energy Foundation
John Kelly, Gas Research Institute

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
Joseph Suchecki, Engine Manufacturers Association
Carl Weinburg, The Regulatory Assistance Project
Frederick Weston, The Regulatory Assistance Project
Leslie Witherspoon, Solar Turbines, Inc.
Eric Wong, Caterpillar, Inc.

# APPENDIX E. COMMENTERS

American Gas Cooling Center, Mark E. Krebs, AGCC Education Committee Chairman, Laclede Gas Company, December 14, 2001, and August 13, 2002
Biomass Energy Resource Center, Tim Maker, Director, December 19, 2001
Burlington Electric Department, John Irving, December 24, 2001
Conservation Law Foundation, Richard B. Kennelly Jr., Director, Energy Project, December 31, 2001
Cummins Power Generation, Michael Brand, September 24, 2002
Elliott Energy Systems, J. Britt Ingram, Combustor Development Group, January 28, 2002
Engine Manufacturer's Association, Joseph Suchecki, Director, Public Affairs, January 11, 2002
Environmental Defense, Mark MacLeod, February 20, 2002
Gas Technology Institute, John Kelly, Director, Distributed Energy Resources, December 26, 2001
H Power, Chris Haun, November 27, 2001
Innovative Technology Group, Larry Reinhart, Sales Manager, November 19, 2001
International District Energy Association, Mark Spurr, June 28, 2002
Massachusetts Department of Environmental Protection, Donald Squires, November 6, 2001
Millennium Cell, Adam Briggs, November 6, 2001
Missouri Department of Natural Resources, Roger T. Randolph, Director, December 19, 2001
New Hampshire Department of Environmental Services, Andrew M. Bodnarik, Regional & National Issues Manager, Air Resources Division, November 20, 2001.
NiSource, Bruce M. Diamond, Director, Environmental & Agency Relations, November 2001
North East Environmental Products, Bruce Lamarre, December 2001 (received January 3, 2002)
Natural Resources Defense Council, Nathanael Greene, Senior Policy Analyst, January 15, 2002
National Rural Electric Cooperative Association, Rae Cronmiller, Environmental Counsel, and John Holt, Manager, Generation and Fuels, February 19, 2002
Pace Energy Project, Fred Zalcman, Executive Director, January 25, 2002
Rolls-Royce Energy Business, Al Wei, Business Development Director, December 31, 2001
Solar Turbines, Leslie Witherspoon, Manager Environmental Programs, February 4, 2002
Vermont Agency of Natural Resources, Conrad W. Smith, Counsel, Air Pollution Control Division, September 25-26, 2002
Vermont Department of Public Service, Michael R. Kundrath, Policy and Program Analyst, November 2, 2001
Waukesha Engine, Robert Stachowicz, September 13 and 17, 2002