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Distributed Energy Resources Emissions Survey and Technology Characterization

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Technical Report

Distributed Energy Resources Emissions Survey and Technology Characterization

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PRODUCT DESCRIPTION

This report characterizes emissions of gaseous and particulate pollutants from distributed energy resources (DER) technologies. Emissions profiles are provided for currently available equipment as well as for equipment expected to be commercially available by the year 2030. These profiles can be used to compare and evaluate DER technologies and can be used to develop emissions inventories for air quality modeling.

Results & Findings

This study compiled data on emissions of criteria pollutants and greenhouse gases from current, developing, and emerging DER technologies, including reciprocating engines, fuel cells, conventional turbines, and microturbines. The study also compiled information on hazardous air pollutant emissions from DER and on emissions from DER equipment burning biofuels. The study developed emissions profiles based on manufacturers' emissions guarantees for a wide range of device types and sizes. Future emissions profiles were projected for years up to 2030 based on anticipated improvements in DER technologies.

The study evaluated the completeness of the available data on DER emissions and discussed the adequacy of emissions test methods. Data were not available for all pollutants of interest, and measurement methods often were not comparable across DER technologies. Future assessments of DER environmental impacts would be improved by collecting additional baseline measurements of DER emissions as well as data on the long-term performance of those technologies.

Challenges & Objective(s)

The objectives of this study are to determine emissions characteristics of current and future DER devices for use in modeling DER impacts on air quality. Along with the prediction of what DER is deployed and where, we need to know what the air emissions will be of these DER devices. Since the air quality model will be run for future DER deployment scenarios, we need to know the future emissions of DER technologies.

Challenges encountered in this study include predicting future emissions from DER devices that are not yet commercially available. The study authors used information from DER device manufacturers on future development plans and knowledge of pollutant sources and controls to project emissions from future DER devices.

Applications, Values & Use

Project results will be useful to evaluators of environmental impacts of DER deployment. Emissions profiles may be used with DER deployment scenarios and air quality models to assess the air quality impact of installing DER technologies.

E2I Perspective

This work is part of the Environmental Benefits Platform of the E2I Distributed Energy Resources Public/Private Partnership. E2I initiated the Partnership to assemble key public and private stakeholders to work collaboratively to address barriers facing integration of DER into the market. The goal of the Environmental Benefits Platform is to enable environmentally preferred DER deployment in the future. Environmental performance and tradeoff assessments will support the technical development, planning, and deployment of DER. Accurate data on DER air emissions are needed to perform these tradeoff assessments.

Approach

The study authors obtained air emissions data from a wide range of sources, including DER certification programs, research organizations, federal and state agencies, and equipment manufacturers. Emissions data were critically reviewed to determine their applicability to current and future emissions estimates. The authors developed emissions profiles based on manufacturers' performance guarantees and projected technological improvements to DER devices.

Keywords

Air emissions
Combustion turbines
Microturbines
Fuel cells
Reciprocating engines

CONTENTS

LIST OF FIGURES

LIST OF TABLES

1

INTRODUCTION

Distributed energy resources (DER) are of growing interest to technology developers, power project developers, fuel suppliers and traditional power producers. Defined as electric generation at or near the point of use, DER is made possible by the combination of advancing technology trends in smaller generating units and new, small-scale, but efficient generating technologies, along with the changing market environment brought about by energy industry restructuring. While the DER technologies available today are still under development, they may be competitive in some circumstances. However, they could be rendered uneconomic if required to apply expensive emissions reduction or control technologies. Uncertainty over what regulations will apply to DER technologies and what approaches will be available to meet those regulations risk stifling the development of the DER market.

The environmental attributes of small electric generators have not historically received the same level of scrutiny as large, central station power plants. Since most small on-site generators have been used primarily for back-up or emergency applications, operators have been able to use a variety of permitting tools to avoid these generators being treated as a "major source" subject to the most serious scrutiny. However, at the same time that electric industry restructuring is allowing DER to potentially become a growing part of the generating mix, DER is increasingly receiving more scrutiny in environmental permitting.

The complex environmental regulatory process may impact the commercial viability of DER products. Some developers will encounter problems in the form of significant delays and costs for environmental permitting, or added capital and operating costs for advanced emission control options or emission monitoring equipment.

This study examines the technology behind DER, summarizes the current and future air emissions of DER devices, and characterizes the emission control technologies that are needed to meet future environmental requirements within the economic and performance limitations of DER users and developers.

The objectives of this effort are to:

- Describe relevant DER technologies and the operating factors that affect their air emissions.
- Develop tables of criteria pollutant and greenhouse gas emissions.
- Describe the applicability and effectiveness of control technologies.
- Evaluate the availability of emissions data on other pollutants, for biofuels, and at non-standard operating conditions.
- Identify critical data gaps in our understanding of DER emissions and prioritize those gaps for future research and development.

For the purpose of this report, DER are defined to include on-site power generation systems of 25 MW or less. With the continuing development and commercialization of on-site systems in the 1 to 25 kW range, this definition encompasses systems with a 10,000-fold size variation. The applications of DER include:

- Residential, commercial, institutional, industrial, or electric utility ancillary services.
- Base load, intermediate, peaking, or standby service.
- Straight electric generation, cogeneration, or district heating/cooling applications.
- Technology options ranging from established options (engines and turbines) to newer emerging options (microturbines and fuel cells).

With this wide range of applications, it is difficult to identify “best” approaches for emission controls. Certain applications that dictate high capital costs and sophisticated operations may be perfectly appropriate for industrial applications, but economically and institutionally impossible for residential or commercial applications. The goal of this report is to present relevant DER technologies and the operating factors that affect their air emissions in a form that will be helpful to developers and users of DER.

Chapter 2 presents background on the formation of air emissions from DER technologies. Chapter 3 provides information on the source and availability of emission test data for the technologies. Chapters 4, 5, 6 and 7 provide information on the emissions from combustion turbines, microturbines, reciprocating engines and fuel cells, respectively. Chapter 8 discusses use of biofuels in DER applications. Chapter 9 discusses emission measurement issues. Chapter 10 summarizes the data gaps revealed by this study.

2

EMISSION FORMATION AND CONTROL TECHNOLOGIES

The emissions from DER technologies that are of current or potential future regulatory interest include nitrogen oxides (NO_x), sulfur oxides (SO_x), carbon monoxide (CO), unburned hydrocarbons (UHC), carbon dioxide (CO_2), hazardous air pollutants (HAPs) and particulate matter (PM). Each of these may be regulated under one or more current or future regulatory programs. From an emissions formation perspective, these pollutants fall into three major categories (EEA, 1999):

- Emissions related to fuel composition – SO_x, CO_2, PM and some HAPs
- Emissions related to incomplete combustion – CO, UHC, HAPs, and PM.
- Emissions generated by combustion - NO_x.

2.1 Emissions Related to Fuel Composition

Emissions of certain pollutants such as SO_x, CO_2, and PM are a consequence of impurities or constituents of the fuel used. This means that some emissions, such as SO_x, can be avoided or reduced by choice of fuel. In the case of opportunity fuels such as landfill gas or anaerobic digestor gas, pretreatment may be an option to reduce impurities or pollutant precursors (see Chapter 8). If fuel changes or pretreatment are not an option, however, it likely means that if their levels are high enough to be a regulatory problem, they must be addressed through after-treatment.

The levels of SO_x emitted depend on the sulfur content of the fuel. This can be a regulatory issue, since SO_x is a regulated pollutant. It can also be an operational issue, since SO_x emissions may interfere with the operation of catalytic after-treatment systems. Natural gas has negligible sulfur content, so SO_x is typically not a serious issue for gas-fueled systems. Systems using distillate or diesel fuel typically minimize SO_x emissions by using low-sulfur fuel to meet either regulatory or operational requirements. Landfill or anaerobic digester gas can also contain sulfur and other impurities.

While not considered a pollutant in the ordinary sense of directly affecting health, emissions of CO_2 are of concern due to its contribution to global warming. If CO_2 becomes regulated as part of a future greenhouse gas mitigation program, CO_2 emissions will become a regulatory liability. Currently, there is no practical option to prevent the formation of these emissions. All hydrocarbon fuels produce CO_2 when burned. The amount of CO_2 emitted is a function of both fuel carbon content and system efficiency. The carbon content of natural gas is 34 lbs carbon/MMBtu; of oil is 48 lbs carbon/MMBtu; and of (ash-free) coal is 66 lbs carbon/MMBtu. Fuel switching is one approach to carbon mitigation.

Some fuels contain toxic constituents such as mercury and other heavy metals that can be emitted in the exhaust. This is typically not the case for either natural gas or distillate fuel and is not expected to be a major issue for DER applications.

Finally, a small part of NO_x emissions can result from fuel NO_x (NO_x formed from fuel-bound nitrogen). The degree of fuel NO_x formation is primarily a function of the nitrogen content in the fuel. Natural gas does not contain fuel-bound nitrogen even though it does contain molecular nitrogen. Some petroleum fuels and waste gases contain pyridine-like (C_5H_5N) structures or ammonia (NH_3). When these fuels are burned, the nitrogen bonds break and some of the resulting free nitrogen oxidizes to form NO_x. Light distillate oils used in turbines generally have less than 0.015 percent nitrogen content by weight, except some of those produced in the northeastern U.S..

PM emissions from DER include both coarse and fine particles, and fall into both particle size ranges targeted under Clean Air Act regulations: PM_{10} and $PM_{2.5}$. Emissions of PM_{10} (particles with average diameter smaller than 10 microns) can result from carryover of noncombustible trace constituents in the fuel (e.g., metals) and are thus related to fuel composition. Other mechanisms of PM_{10} formation are related to incomplete combustion and are discussed below. $PM_{2.5}$ (particles with average diameter smaller than 2.5 microns) include fine solid particles and particles formed from condensation of organic and inorganic vapors as the exhaust gas cools. The latter component of $PM_{2.5}$ is known as condensible particulate matter (CPM). Common species contributing to CPM include sulfates and semivolatile organic compounds. Fuel composition affects the extent of CPM formation, as well as the carryover of other fine particulates through the combustion process.

PM_{10}, $PM_{2.5}$, and CPM are operationally defined parameters; the fraction of PM and the species collected depend on the sampling apparatus and procedure. EPA-approved methods exist for stationary source sampling of PM_{10} and CPM; EPA has not promulgated a sampling method for $PM_{2.5}$. Results from different test methods are not comparable, and in some cases the methods are not sensitive enough to detect PM from DER devices. Shortcomings and issues with PM test methods are discussed further in Section 9.

2.2 Emissions Related to Incomplete Combustion

Possible emissions resulting from incomplete fuel combustion include CO, UHC and PM. Carbon monoxide is a regulated pollutant that results from incomplete combustion of the carbon in the fuel. CO emissions result when there is inadequate oxygen or insufficient residence time at high temperature. Cooling at the combustion chamber walls and reaction quenching in the exhaust process also contribute to incomplete combustion and increased CO emissions. Excessively lean conditions can also lead to incomplete and unstable combustion and high CO levels.

The pollutants commonly classified as UHCs encompass a wide spectrum of volatile and semi-volatile organic compounds (VOCs and SVOCs). They are discharged into the atmosphere when some of the fuel remains unburned or is only partially burned during the combustion process. With natural gas, some organics are carried over as unreacted trace constituents of the gas, while others may be pyrolysis products of the heavier hydrocarbon constituents. With liquid fuels, large droplet carryover to the quench zone accounts for much of the unreacted and partially pyrolized emissions.

UHC includes a mix of unburned fuel components that are not fully oxidized during combustion. Some of these hydrocarbons may react with other chemicals in the air to create ground-level ozone (smog). Since methane is less reactive, ozone-based regulations typically focus on the non-methane organic compounds (NMOC) or volatile organic compounds (VOCs). Uncombusted methane is a greenhouse gas, however. The UHCs may also contain HAPs such as formaldehyde (HCO), and may be regulated for that reason.

Since efficient system operation depends on complete combustion of the fuel, there ideally would be little or no CO or UHC emissions from a well-designed engine or turbine. Good air/fuel mixing, high temperatures, long residence times and proper air/fuel control would assure complete combustion. The mixture of air and fuel that provides just enough oxygen to combust all of the fuel is called the stoichiometric air/fuel ratio. The ideal air/fuel ratio (A/F ratio) for complete combustion and high efficiency would be slightly more air than stoichiometric. Unfortunately, these conditions are also a recipe for high NO_x formation, as discussed below. CO and UHC emissions are often the result of combustion control compromises needed to reduce NO_x emissions.

CO and UHC also result from quenching of the combustion process at the cylinder or combustor wall or where combustion begins or ends. Engine and combustor components have temperature limits and cannot all be hot enough to avoid quenching. The use of higher-temperature components, the careful design of component cooling systems, and other cylinder and combustor design options are constantly being pursued to reduce quenching and the resulting emissions.

In gas turbines, failure to achieve CO burnout may result from quenching by the dilution air. With liquid fuels, this can be aggravated by carryover of larger droplets from the atomizer at the fuel injector. In gas turbines, CO emissions are usually higher when the unit is run at low loads. In reciprocating engines, quenching can take place at the cylinder walls and the clearance volume (dead space) between the cylinder, rings, and piston crown.

Incomplete combustion can produce PM emissions. Formation mechanisms include agglomeration of soot particles, particularly from liquid fuel firing. Combustion of engine oil can also produce PM emissions. Particles formed by these mechanisms tend to be in the PM_{10} size range.

2.3 Emissions Generated by Combustion

Although fuel-bound nitrogen contributes to NO_x emissions, the primary NO_x formation mechanism is thermal conversion of molecular nitrogen. Thermal NO_x is formed in the combustion chamber when N_2 and O_2 molecules in the combustion air dissociate into free atoms at the elevated temperatures (>2800° F) and pressures encountered during combustion and then recombine to form NO. The reaction rate toward NO formation increases exponentially with temperature. The NO further oxidizes to NO_2 and other NO_x compounds downstream of the combustion chamber. High temperature, slightly fuel-lean operating conditions that minimize pollution from incomplete combustion and increase efficiency tend to increase NO_x.

Air/fuel ratio (A/F ratio) is often characterized as lambda (λ) =

$$\frac{\text{actual A/F ratio}}{\text{stoichiometric A/F ratio}}$$

Where: $\lambda = 1$ = stoichiometric point
$\lambda > 1$ = fuel lean
$\lambda < 1$ = fuel rich

The inverse of the relationship ($1/\lambda$) is referred to as the equivalence ratio (φ, phi).

Figure 2-1 shows a typical emissions profile for CO, HC, and NO_x from a gas engine as a function of λ. The best combustion efficiency and lowest CO and UHC are achieved slightly lean of the stoichiometric point, or $\lambda>1$.

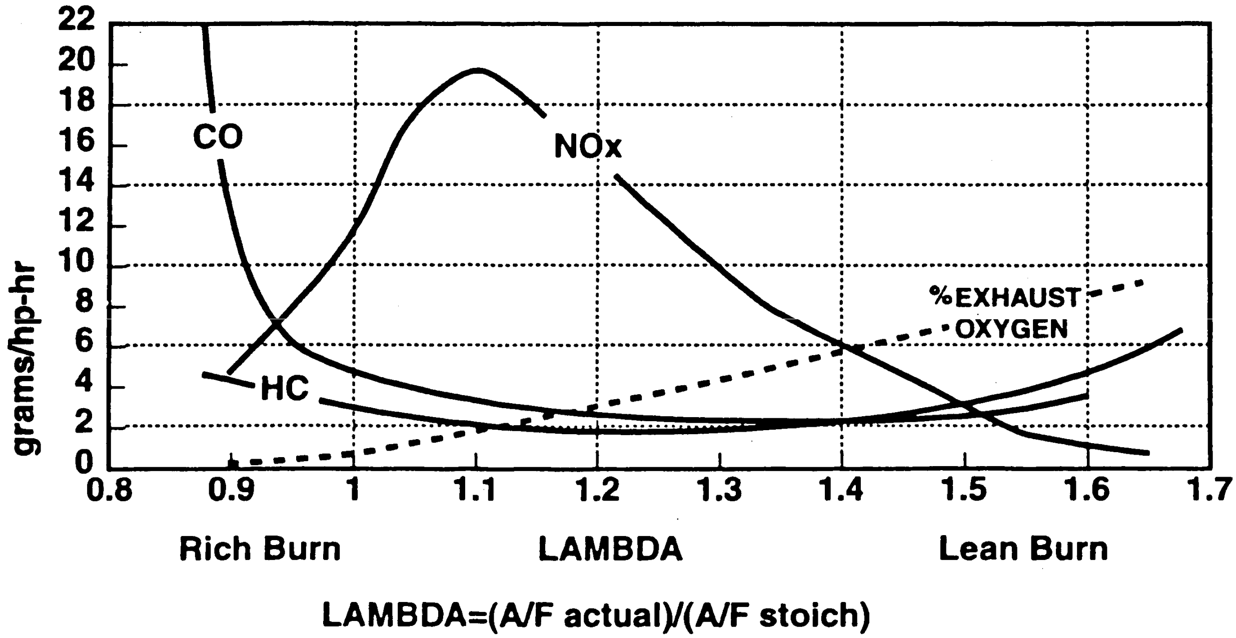

Figure 2-1
Gas Engine Emission Formation

Historically, gas engines were designed to operate near the stoichiometric point for best combustion and efficiency and low CO and UHC emissions. Once NO_x reduction became a priority, a different combustion point had to be found. As lambda decreases from 1 (fuel rich), NO_x formation decreases due to a lack of excess oxygen to mix with nitrogen, but CO and UHC increase due to lack of oxygen, leading to incomplete combustion. Increasing lambda (fuel lean) decreases the temperature and reduces NO_x. There is excess oxygen to burn the CO and UHC until there gets to be too little fuel to support combustion - the lean limit.

Low-NO_x combustors use a variety of techniques to control the A/F ratio to limit combustion temperature and control the available oxygen. This limits NO_x formation while achieving adequate fuel combustion. Many combustors operate in the lean realm where NO_x is reduced but adequate combustion can be sustained. Some use an initial fuel-rich combustion zone to support the combustion in the fuel-lean zone. Although the combustion temperature may be high in the rich zone, there is limited oxygen available to form NO_x. The CO and UHC formed in the rich zone are burned out in the lean zone.

NO_x emissions also vary with the combustion characteristics of the fuel. For gaseous fuels, the constituents in the gas can affect NO_x emissions levels. Gaseous fuel mixtures containing hydrocarbons with molecular weights higher than that of methane (such as ethane, propane and butane) burn at higher flame temperatures. Refinery gases and some unprocessed field gases can contain significant levels of these higher molecular weight hydrocarbons. Conversely, gaseous fuels such as unprocessed field gas or landfill gas may contain significant amounts of inert gases, such as CO_2, which generally produce lower NO_x emissions. These inert gases absorb heat during combustion, thereby lowering flame temperatures and reducing NO_x formation and emissions. Distillate oil burns at a flame temperature that is approximately 150^o F higher than that of natural gas and produces higher NO_x emissions.

2.4 Combustion Control Techniques to Limit Emissions

There are several types of emissions control systems that can be incorporated into DER units to decrease pollutant emissions. Some of these options involve changes to the combustion process itself while others remove pollutant precursors from the fuel or clean up the exhaust gas after combustion has taken place.

Water or Steam Injection- One technique to reduce NO_x emissions is injection of water or steam into the high temperature zones of the flame. While this technique has been used in both engines and turbines, it has primarily been used on turbines. Both water and steam are strong diluents and can quench hot spots in the flame, reducing NO_x. However, positioning of the injection is not precise and some NO_x is still created. Depending on the level of uncontrolled NO_x emissions, water or steam injection can reduce NO_x by 60 percent or more. Both water and steam increase the mass flow through the system and create a small amount of additional power. Use of exhaust heat to raise the steam temperature also increases overall efficiency slightly. The water used for either approach needs to be demineralized thoroughly in order to avoid forming deposits and corrosion in the turbine expansion section. This adds a modest level of cost and complexity to the operation of the turbine. Diluent injection increases CO emissions appreciably as it lowers the temperature in the burnout zone and in the NO_x formation zone.

An important parameter in designing the water or steam injection system is the water to fuel ratio (WFR). CO and UHC emissions increase in a natural gas-fired turbine as the WFR is increased, due to the lowered combustion temperature. Air toxics may be formed when wet controls are used with other fuels at high WFR. Most wet control systems operate at a WFR of 0.6 to 0.7 to provide the maximum degree of NO_x control without creating excessive CO and UHC emissions. Water and steam injection are older techniques that have been replaced by techniques with lower operating costs and less impact on combustion performance.

Dry Low NO_x (DLN) Combustors for Turbines (Lean Premixed Combustors) - DLN combustors mix the fuel and air prior to combustion and operate fuel-lean to reduce the formation of NO_x while avoiding many of the maintenance and operating liabilities associated with wet combustion controls and post-combustion techniques. Conventional turbine combustors use diffusion burners that introduce fuel and air separately into the flame zone. The conventional diffusion burners can produce fuel-rich zones where temperatures are high, resulting in thermal NO_x formation. In a DLN design, the air and fuel are premixed at lean A/F ratios prior to injection into the combustion zone. Because the fuel is combusted with excess air and the fuel is well mixed with the air prior to ignition, peak combustion temperatures are reduced. Because thermal NO_x is the main NO_x formation mechanism in turbines, combustion of the fuel-lean mixture results in greatly reduced NO_x formation rates. DLN works with natural gas, but may require substantial modifications if hydrogen is used as fuel, due to the danger associated with the flame propagation speed of hydrogen.

DLN systems can be designed to reduce CO and UHC emissions by increasing the residence time in the combustion zone. Because the DLN operates at lean premix conditions, NO_x does not increase with residence time as in a conventional combustor. Longer combustion times allow the complete burnout of CO and UHC, lowering emissions of these pollutants.

NO_x control is a continuing trade-off between efficiency, NO_x formation, combustion temperature, and CO and UHC formation. Higher combustion temperature tends to increase system efficiency as well as NO_x emissions. CO and UHC are formed by quenching or incomplete combustion at various points in the combustion process. In turbines, the need to cool the combustor parts creates these conditions. Development of higher temperature combustion parts will help maintain high efficiency with low CO and UHC.

Lean Burn Combustion for Reciprocating Engines – Lean combustion similar to turbine DLN combustors is also used as a NO_x control method in reciprocating engines. In this case, a fuel-rich area is created at the top of the cylinder to allow ignition of the fuel. The rest of the combustion space has a lean fuel mix that quenches the formation of NO_x. Lean burn combustion requires very sophisticated control of fuel mixture and mixing in the cylinder. The staging is sometimes achieved with a small pre-ignition chamber in the engine head (pre-chamber combustion) or through careful design on the fuel mixing process (pre-stratified charge). There is also ongoing research on high energy ignition systems to allow the use of leaner mixtures.

Catalytic Combustion for Turbines - Since thermal NO_x formation is largely dependent on the temperature of the combustion zone, modern combustors are designed to maintain combustion temperatures as low as possible consistent with good combustion and efficiency. The incorporation of a combustion-enhancing catalyst within the combustor is a recent development in turbine technology that allows lower combustor temperatures and less thermal NO_x formation.

Catalytic combustion is a flameless process that oxidizes fuel at lower temperatures than conventional combustion methods. The catalytic system oxidizes the fuel at approximately the required turbine inlet temperature, without higher peak temperatures that would create NO_x. Catalytic combustors have reported sub-3 ppm NO_x (0.130 lb/MWh) levels in long-term testing. One small (1.3 MW) turbine is now commercially available with NO_x emissions guaranteed at this level.

2.5 Post-Combustion Emission Controls

Developers of DER equipment have focused on low-emitting technologies; however post-combustion or add-on emission controls are a potential approach for certain pollutants, particularly for larger systems. Several of the most common emission control systems are described below.

<u>Selective Catalytic Reduction</u> - In selective catalytic reduction (SCR), ammonia or aqueous urea is injected into the flue gas and reacts with NO_x in the presence of a catalyst to produce N_2 and H_2O. The SCR system is located in the exhaust path, where the temperature of the exhaust gas matches the operating temperature of the catalyst. The operating temperature of conventional SCR systems ranges from 400 to 800°F. The cost of conventional SCR has dropped significantly in recent years. Catalyst innovations have been a principal driver, resulting in a 20 percent reduction in catalyst volume and cost with no change in performance.

SCR can be used in both turbine and engine applications and it reduces between 80 to 90 percent of the NO_x in the exhaust, depending on the degree to which the chemical conditions in the exhaust are uniform. When used in series with water/steam injection or DLN combustion, SCR can result in low single digit NO_x levels (2 to 5 ppm). However, SCR systems add a significant cost burden to the installation and maintenance cost of a system, and can severely impact the economic feasibility of smaller projects. SCR requires on-site storage of ammonia, a hazardous chemical. In addition ammonia can “slip” through the process unreacted, contributing to environmental health concerns.

<u>Carbon Monoxide Oxidation Catalysts</u>- Control of CO in exhaust emissions is typically achieved through the use of oxidation catalysts. Some SCR installations incorporate CO oxidation modules along with NO_x reduction catalysts for simultaneous control of CO and NO_x. The CO catalyst promotes the oxidation of CO and hydrocarbon compounds to CO_2 and water as the exhaust stream passes through the catalyst bed. The oxidation process takes place on the catalyst surface so no other reactants are required. The catalyst is usually made of precious metal such as platinum, palladium, or rhodium. Other formulations, such as metal oxides for emission streams containing chlorinated compounds, are also used. CO catalysts are also used to reduce VOCs and organic hazardous air pollutants (HAPs). CO catalysts on gas turbines result in approximately 90 percent reduction of CO and 85 to 90 percent control of formaldehyde (similar reductions can be expected on other HAPs). Oxidation catalysts are now widely used with all types of engines, including diesel engines. They are being used increasingly with lean burn gas engines to reduce their relatively high CO and hydrocarbon emissions. CO catalysts operate at higher temperatures. Therefore, they are typically installed before the heat recovery steam generator (HRSG) while SCRs are installed after the HRSG.

Catalytic Absorption Systems - SCONOx™, patented by Goaline Environmental Technologies (currently EmerChem), is a post-combustion alternative to SCR that reduces NO_x emissions to less than 2.5 ppm (0.108 lb/MWh) and almost 100 percent removal of CO. SCONOx™ uses a single catalyst to oxidize both CO and NO into CO_2 and NO_x. The NO_x is then absorbed onto the catalyst surface while the CO_2 is released up the stack. The NO_x sorbent is periodically regenerated with a hydrogen-rich gas. SCONOx™ can operate in a temperature range of 300 - 700°F and is therefore useful for new systems as well as for retrofitting older systems. The system does not require the use of ammonia, eliminating the potential for ammonia slip associated with SCR. The SCONOx™ system is generally located within the HRSG and under special circumstances may be located downstream of the HRSG. In 1997, the US EPA Region 9 and the South Coast Air Quality Management District recognized SCONOx™ as the lowest achievable emission rate (LAER) for NO_x reduction.

Although the SCONOx system was developed for gas turbines it has also been tested on a diesel engine and is reported to have reduced NO_x emissions by more than 90 percent. It is also reportedly being considered for installation on some gas engines. Although it does not require ammonia, the $SCONO_x$ system is mechanically more complicated than SCR systems and also has a higher capital cost. Its commercial demonstrations are limited to only a few facilities.

Three-Way Catalyst- Catalytic three-way conversion (TWC) is the basic automotive catalytic converter process that reduces concentrations of three major criteria pollutants – NO_x, CO and VOCs. The TWC is also called non-selective catalytic reduction (NSCR). NO_x and CO reductions are generally greater than 90 percent, and VOCs are reduced approximately 80 percent in a properly controlled TWC system. Because the conversions of NO_x to N_2 and CO and hydrocarbons to CO_2 and H_2O will not take place in an atmosphere with excess oxygen (exhaust gas must contain less than 0.5 percent O_2), TWCs are only effective with stoichiometric or rich-burning engines. They cannot be used with lean burn gas engines, diesel engines or combustion turbines, all of which have excess air in their exhaust. Typical "engine out" (i.e., untreated exhaust) NO_x emission rates for a rich burn engine are 10 to 15 g/bhp-hr (29.5 to 44 lb/MWh). NO_x emissions with TWC control are as low as 0.15 g/bhp-hr (0.44 lb/MWh).

The TWC system can increase maintenance costs, and uses noble metal catalysts, which are vulnerable to poisoning and masking, limiting their use to engines operated with clean fuels – e.g., natural gas and unleaded gasoline. Also, the engines must use lubricants that do not generate catalyst-poisoning compounds and have low concentrations of heavy metal and base metal additives. Unburned fuel, unburned lube oil, and particulate matter can also foul the catalyst.

Other Exhaust Gas Treatment - While engine manufacturers continue to improve engine-out emissions from gas engines through combustion improvements, work continues on improving the performance and reducing the costs of exhaust gas treatment options. The primary focus for gas engines is the development of lean-NO_x catalysts. It appears that NO_x reduction of 80 percent and both CO and NMHC emissions reductions of 60 percent may be attainable. Long-term testing, however, has raised issues about sustained performance of the catalysts. Both lube oil and fuel sulfur can poison current lean-NOx catalysts. Both precious metal and base metal catalysts are highly intolerant of sulfur.

Another strategy under investigation involves the use of increased exhaust gas recirculation (EGR) and a three-way catalyst for NO_x reduction in a reciprocating engine. Three-way catalysts efficiently reduce $NO_{x,}$ but the exhaust cannot contain excess oxygen. This requirement prevents the use of air as a diluent with a TWC as is used in current lean burn engines. The use of EGR to dilute the fuel-air charge would be similar in principle to lean burn combustion, with recycled exhaust taking the place of excess air to dilute the intake fuel charge and reduce cylinder temperatures and hot spots. The advantage of EGR is that a TWC could then be used to reduce the NO_x because the resulting overall exhaust mixture would be essentially stoichiometric. This approach, however, creates a new set of technical hurdles. While dilution with EGR can reduce NO_x, there is a limit to the amount of dilution. The amount of acceptable EGR dilution is usually less than can be achieved with air, so the NO_x emissions produced by the engine are higher, but the use of the three-way catalyst simplifies any post combustion treatment. Some engines using an aftermarket system of this type are currently available and report NO_x emissions of 0.1 g/bhp-hr (0.3 lb/MWh) or less.

When opportunity fuels such as digester gas, landfill gas, or petroleum processing off-gas are used to generate power, sulfur in these fuels is burned to SO_2. It is generally more cost-effective to remove the sulfur from the fuel gas than remove SO_2 from the exhaust gas. A number of processes are available for this purpose. The most cost-effective at small scale is reaction of hydrogen sulfide (the most common fuel sulfur component) with iron oxide to form solid iron sulfide. This approach can reduce H_2S levels to single digit ppm levels with substantially lower SO_2 levels in the exhaust. Costs for this equipment depend on the size of the unit, but generally range between $35,000 to $58,000. Replacement of the iron oxide is an operating cost.

2.6 Summary

For the fuels and processes of interest in DER, the primary regulated pollutant of interest and concern for control is NO_x. CO, UHC and air toxics may be of secondary concern, but can typically be controlled through good combustion design. SO_x and non-hydrocarbon air toxics are often addressed by fuel choice. Particulates are a major issue for equipment using diesel fuel and may be a concern in the future for more fuels if highly restrictive fine particulate matter regulations are promulgated.

3
EMISSION TEST DATA

This chapter addresses the availability of independent emissions test data for DER technologies, as of December 2003. The first section summarizes available data on criteria pollutants from DER technologies. The second section evaluates the availability of data on HAPs emissions. The third section addresses the availability of emissions data for part-load, start-up/shut-down conditions and long-term emissions performance.

3.1 Criteria Pollutant Emissions for DER Technologies

Assessments of power generation emissions typically rely either on manufacturers' guarantees of performance or regulatory emission standards or permit limits. While both are good indicators of performance, it would be useful to compare them to actual independently measured emissions test data. On one hand, this would help to ensure that the guarantees and regulatory limits are being met. On the other hand, actual equipment typically operates at a safety margin below the guarantee or compliance limit and it would be valuable to know what that margin is.

Manufacturers design their equipment to emit less than their guaranteed or permitted levels in order to ensure that they do not exceed either. They do not like to release data on this margin for fear that customers or regulators will revise their requirements to the actual levels, requiring the manufacturers to reduce further to provide their compliance margin. If the compliance margin is large, it could affect emission inventory or health risk calculations so it is important to assess the actual emissions.

3.1.1 Sources of Emission Test Data

Sources of actual emission test data that were researched for this study include:

- Regulatory compliance - data compiled to show compliance with regulatory programs.
- Rule development procedures - data compiled in the development of new regulatory programs.
- Independent equipment testing - data compiled by independent entities for the purpose of documenting or certifying the performance of generating equipment.
- R&D or equipment development programs - data compiled during the development and testing of new equipment.

3.1.1.1 Regulatory Compliance Data

Some regulatory programs require ongoing reporting of measured emissions. In some cases this includes data from continuous emissions monitors (CEMs). The most readily available such data are the reports from the national acid rain trading program and the Northeast NO_x trading program. Unfortunately, these programs apply to power generators larger than 15 to 25 MW and so do not cover most of the DER technologies. Other compliance reports are generally not available to the public. Regulatory compliance records did not prove to be a useful source of emissions data.

3.1.1.2 Rule Development Procedures

Regulatory agencies often collect emissions data when developing new regulations. The data can be from a number of independent sources and the regulatory agencies sometimes apply quality control screens and normalize the data.

The development process for the California Distributed Generation (DG) emission certification rule (SB 1298) included data collection but focused on permit conditions rather than emission test data. However, the rule requires actual certification testing of NO_x, CO and VOC emissions for small generators. The certification requires emission testing according to standard EPA protocols. Compliance must be achieved on a weighted average of results at 100, 75 and 50 percent load. The results of these tests provide independent data on emissions. Table 3-1 summarizes the results of the certification testing. Two fuel cells and two microturbines have been certified .

Table 3-1
California Small DG Certification Data (lb/MWh)

	NO_x	CO	VOC
Fuel Cells			
UTC PC25C (200 kW)	0.019	0.0024	0.007
Fuel Cell Energy DFC300 (300 kW)	0.05	0.03	0.02
Microturbines			
Capstone C60 (60 kW)	0.24	3.76	0.14
Ingersoll-Rand 70LM (70 kW)	0.13	0.24	0.21

As expected, the fuel cells had very low emissions, though the emissions of the Fuel Cell Energy product were not as low as might be expected. At 0.05 lb/MWh, its NO_x emissions are only slightly lower than those of a conventional large gas combined cycle plant. The NO_x emissions of the microturbines were substantially lower than the typical emission guarantees for such products, which are 0.5 lb/MWh, at best. There was also a quite notable range of CO emissions, over a factor of ten between the two microturbine products.

While these data were helpful for new technologies, the most useful source of emissions data for conventional DER technologies found in this study was the data sources assembled as part of the development of hazardous air pollutant rules for combustion turbines and reciprocating engines (U.S.EPA, 2002a; 2002b). This process was at one time part of a broader HAPs rulemaking called the Industrial Coordinated Combustion Rulemaking (ICCR). As part of this process, equipment owners provided emission test data for turbines and engines. The initial data collection was for HAPs but subsequently was augmented to include criteria pollutant data. The EPA went through several iterations of reviewing and tabulating the data with the most recent version of the database completed in 2002. The final databases include data for a variety of fuels and for emissions of criteria pollutants and HAPs. Approximately 75 gas turbines and 100 reciprocating engines of various sizes are included, representing power generators, cogeneration facilities and gas pipeline compressor drives. Despite the large number of tests included, the data are difficult to apply, as discussed below.

A similar data source is an assessment of NO_x emissions from stationary gas-fired reciprocating engines performed by the U.S. EPA as part of the NO_x State Implementation Plan (SIP) call development (Edgerton, 2000). The report presents data from NO_x emissions tests of about 50 gas engines, mostly compressor drives.

A third source of information in this category is the EPA AP-42 manual of emission factors. AP-42 is a reference document, originally meant to be used in estimating regional emissions inventories for calculating compliance with air quality standards. It is a compilation of emissions test data for a wide variety of processes and fuels. Over time it has become widely used as a referenceable source of emission data for permit calculations and other official and non-official uses. While it is largely based on emission test data, the AP-42 factors are typically average values and therefore difficult to relate to specific kinds of equipment. The data are also usually at least several years old before appearing in the compilation. AP-42 was not used as a primary data source for this study, except when no other sources were available.

3.1.1.3 Independent Equipment Testing

The most useful information would be well-documented independent tests of specific DER technologies. There is little such data for conventional turbines and engines, but it does exist for the developing technologies such as microturbines and fuel cells. Several institutions are in the process of carrying out such studies.

EEA identified some useful public studies done by the California Energy Commission (CEC) (CEC, 1999) and particularly by the EPA Environmental Technology Verification (ETV) Program (SRI, 2001a;b;c;d; SRI, 2002). The ETV Program develops testing protocols and verifies the performance of innovative technologies. The University of California Irvine has such a program that has performed extensive testing of Capstone microturbines (CARB, 2002). These were another useful source of independent test data for the developing technologies. The only caveat is that these technologies are still under development and the commercialized products are likely to have different emission characteristics than the prototypes evaluated in these tests. In addition, some of the manufacturers who provided equipment for these studies have left the DER business since the testing was done.

The Gas Technology Institute (GTI) is in the process of testing a variety of DER technologies. The main focus of the work is performance testing; however, emissions data are being gathered for NO_x, SO_2, CO, CO_2, and excess O_2. The emissions data are being collected at all operating conditions but currently are only being evaluated for full load conditions. The testing program is summarized in Table 3-2. No data are yet available from this work, but they should be available later in 2004.

Table 3-2
GTI Testing Program

Currently Being Tested	Future Tests
Microturbines	**Microturbines**
Capstone C30	Elliott 80
Capstone C60	Bowman 80
Ingersol Rand 70	Ingersol Rand 200
Turbec 100	
Reciprocating Engines	**Reciprocating Engines**
Cummins 1,750 kW	Waukesha – 4 engines <1,000 kW
Caterpillar 1,350 kW	

EPRIsolutions has measured emissions from microturbines (EPRIsolutions 2001a; 2001b) and has compiled tests of units performed by other organizations. However, these latter data have not been published.

3.1.1.4 R&D or Equipment Development Programs

Low emissions are an important aspect of most work on new DER technologies. Most demonstration programs for these new technologies include emission testing to evaluate progress towards these goals. Unfortunately, the detailed results of the tests are not generally available. In most cases, the results simply state whether the goal was met or not but do not provide actual emission testing results. R&D organizations including CEC, DOE, EPRI, GTI and NYSERDA had no specific emission test data available from their DER technology development programs. Some data from GTI, NYSERDA and CEC should be available later in 2004 or in early 2005.

3.1.2 Data Evaluation

The primary sources of emission test data obtained for this study were:

- EPA ICCR database for engines and combustion turbines
- EPA data on gas engines from the SIP call
- Data from ETV, CEC and CARB on microturbines and fuel cells

The ICCR data (EPA, 2002a) include emissions test data for a variety of sizes, fuels and pollutants. Table 3-3 shows the range of data included for engines and turbines.

Although this seems like a highly useful resource, it is difficult to apply for several reasons. The manufacturer and model of the equipment are identified in most cases, but the vintage is not and it is difficult to determine what emission level the equipment should have been achieving. For example, the database may report that a certain turbine was emitting 18 ppm of NO_x but we don't know if that was relative to a manufacturer guarantee/permit limit of 25 ppm or 15 ppm. There has been continuing improvement in emission levels from both engines and turbines in recent years, so it is difficult to judge how well the EPA data represent emissions from current engines and turbines. As it is, we can only summarize the range of emissions represented in the databases. Unfortunately this turns out to be a very wide range, as summarized in Table 3-4, which greatly reduces the usefulness of the data.

The EPA report on gas engines for the SIP call is a much more detailed effort, which discusses the specific characteristics of many of the engines in the context of their emission performance. Most of the engines are from California, and are in pipeline compressor applications. Most use some form of lean-burn combustion for NO_x control, though some are older rich-burn engines with lean-burn retrofits. Some industry representatives have disputed the validity of some of the tests on the grounds that they are not representative of the broader population, are subject to testing error or are out-of-date. The EPA report data are summarized in Table 3-5.

Table 3-3
EPA ICCR Database Parameters

	Reciprocating Engines	Combustion Turbines
Sites	Approximately 100	Approximately 75
Size Range	24 – 7,100 hp	0.8 MW - 87 MW
Pollutants Measured	NO_x, SO_2, PM, CO, NMHC, HAPs	NO_x, SO_2, PM, CO, NMHC, HAPs
Control Technologies	PSC, PCC, SCR, NSCR, Oxy Cat, Combinations	Water/steam injection, lean pre-mix, SCR, SCONOx, CO catalyst
Fuels	Natural gas, diesel, process gas, field gas, digester gas, landfill gas, JP-5, propane	Natural gas, distillate, landfill gas, field gas, digester gas

PSC – pre-stratified charge, PCC – pre-chamber combustion, SCR – selective catalytic reduction, NSCR– non-selective catalytic reduction
(EPA 1993; 2002a)

Table 3-4
Emissions Data Ranges From EPA ICCR Databases

	Reciprocating Engines		**Combustion Turbines**	
	<= 1 MW	> 1 MW	< 15 MW	> 15 MW
NO_x	0.11 - 46 g/bhp-hr 0.3 - 143 lb/MWh	0.5 - 32 g/bhp-hr 1.6 - 100 lb/MWh	14 -160 ppm 0.7 - 8 lb/MWh	2 - 33 ppm 0.1 - 2 lb/MWh
CO	0.5 - 45 g/bhp-hr 1.6 - 140 lb/MWh	1 - 4.6 g/bhp-hr 3.1 - 14 lb/MWh	1.2 - 312 ppm 0.05 - 19 lb/MWh	0.25 - 47 ppm 0.3 - 0.8 lb/MWh
NMHC	0.1 - 65 g/bhp-hr 0.3 - 202 lb/MWh	0.1 - 4 g/bhp-hr 0.3 - 12 lb/MWh	18 - 117 ppm nd	0.04 - 41.5 ppm 0.2 - 0.5 lb/MWh
PM_{10}	0.04 - 0.1 g/bhp-hr 0.12 - 0.3 lb/MWh	0.01 - 0.05 g/bhp-hr 0.03 - 0.16 lb/MWh	nd	0.02 - 0.04 lb/MWh

For natural gas with no add-on emission controls. Some outlier data excluded.
nd=no data
(EPA 1993; 2002b)

The sources of emission data for microturbines and the results are summarized in Table 3-6. As noted above, some of these technologies are still under development and these data may not correspond to ultimate commercial products. In addition, some of the microturbines tested were produced by companies that have since left the microturbine business.

Data on emissions from natural gas-fueled fuel cells were not located for this study. Emissions data for a PC25 PAFC unit are available from an EPA-ETV verification project and from studies conducted on a unit installed at the NYPA Yonkers WWTP. However, these units operated on landfill gas (LFG) or anaerobic digester gas (ADG) rather than natural gas. These studies are discussed in Section 8. A large body of data exists on vehicular applications of PEM fuel cells powered by hydrogen or reformed methane; these are generally not applicable to DER applications. Studies have also been conducted on PEM stationary fuel cells operated on hydrogen and methane (HARC, 2003); these data are not publicly available. These data are in addition to the data from the California Air Resources Board SB1298 certification process presented in Table 3-1.

Table 3-5
Gas Engine Emission Data From EPA Support Document for the NO$_x$ SIP Call

Source	No. of Tests	No. of engines	No. of models	Minimum emissions (g/bhp-hr)	Maximum emissions (g/bhp-hr)	Average emissions (g/bhp-hr)	Tests ≥3 g per bhp-hr		Tests ≥2 g per bhp-hr		Tests ≥1 g per bhp-hr		Tests ≥0.5 g per bhp-hr		Tests ≥4 g per bhp-hr	
							No.	%	No.	%	No.	%	No.	%	No.	%
EPA Memo	269	49	≥22	0.1	6.0	NA	266	99%	258	96%	192	71%	NA	NA	1	<1%
Ventura County	320	23	8	0.1	4.0	0.7	319	>99%	318	99%	275	86%	102	32%	1	<1%
Santa Barbara County	12	3	3	0.1	0.7	0.5	12	100%	12	100%	12	100%	8	67%	0	0%
San Diego County	121	13	5	0.3	4.8	1.1	120	99%	108	89%	52	43%	7	6%	1	1%
S. California Gas Company	7	7	1	0.8	1.5	1.1	7	100%	7	100%	5	71%	0	0%	0	0%
S. California Gas Company	3	3	1	0.5	0.6	0.6	3	100%	3	100%	2	67%	1	33%	0	0%
S. California Gas Company	1	1	1			0.6	1	100%	1	100%	1	100%	0	0%	0	0%
S. California Gas Company	7	5	1	0.4	0.7	0.6	7	100%	7	100%	7	100%	2	29%	0	0%
Pacific Gas and Electric	2	2	1	1.0	1.3	1.2	2	100%	2	100%	1	50%	0	0%	0	0%
GRI Report	3	1	1	1.4	2.4	1.9	3	100%	2	67%	1	33%	0	0%	0	0%
Summary	476	58	15	0.1	4.8	0.8	472	>99%	460	97%	356	75%	120	25%	2	<1%

Sources: S. Edgerton, "Stationary Reciprocating Internal Combustion Engines: Updated Information on NO$_x$ Emissions and Control Techniques," (EC/R Incorporated for U.S. EPA, September 2000)

Table 3-6
Emissions Data for Microturbines (Natural Gas)

Model	Source	Emissions (lb/MWh)			
		NO_x	CO	UHC	SO_2
Bowman 60 kW	CEC	3.7	12.2		
Capstone 28 kW	CEC	0.1	3.9		
Honeywell Parallon 75 kW	ETV	1.0	0.05	0.1	
Mariah 30 kW	ETV	0.2	0.15	0.02	
Power Works 70 kW	ETV	0.05	0.02	0.05	0.05
Capstone 30 kW	ORNL	0.24	1.3	0.05	0.05
Capstone 30 kW	CARB	0.3	0.03	0.02	
Capstone 60 kW	CARB/UCI	0.25	0.07		

CEC – California Energy Commission; ETV – EPA Environmental Technology Verification Program; ORNL – Oak Ridge National Laboratory (DOE); CARB – California Air Resources Board; UCI – University of California, Irvine

3.2 HAPS Emissions for DER Technologies

The only significant source of information on HAPs emissions for DER technologies was the ICCR databases for engines and turbines. These databases include emissions data on a large number of hazardous air pollutants and other pollutants, listed in Tables 3-7 and 3-8. No HAPs data were identified for microturbines and fuel cells.

Table 3-7
HAPs Included in ICCR Reciprocating Engine Database

- 1,1,1-Trichloroethane
- 1,1,2,2-Tetrachloroethane
- 1,1,2-Trichloroethane
- 1,1-Dichloroethane
- 1,2-Dichloroethane
- 1,2-Dichloropropane
- 1,3-Butadiene
- 1,3-Dichloropropene
- 1,4-Dioxane
- 2,2,4-Trimethylpentane
- Acetaldehyde
- Acrolein
- Benzene
- Beryllium
- Cadmium
- Carbon Tetrachloride
- Chlorobenzene
- Chloroethane
- Chloroform
- Chromium
- Dichlorobenzene
- Ethylbenzene
- Ethylene dibromide
- Ethylene dichloride
- Formaldehyde
- Hexane
- Lead
- m/p-Xylene
- Manganese
- Mercury
- Methanol
- Methylene chloride
- n-Hexane
- Naphthalene
- Nickel
- o-Xylene
- PAH
- Selenium
- Styrene
- Tetrachloroethane
- Tetrachloroethylene
- Toluene
- Trichloroethylene
- Vinyl Chloride
- Vinylidene chloride
- Xylene

(EPA, 2002b)

Table 3-8
HAPs Included in ICCR Combustion Turbine Database

1,3 - Butadiene
1,4 - Dichlorobenzene
2,2,4-Trimethylpentane
Acetaldehyde
Acetonitrile
Acrolein
Arsenic
Benzene
Benzyl chloride
Beryllium
Cadmium
Carbon tetrachloride
Chlorobenzene
Chloroform
Chromium
Chromium (VI)
Dioxins
Ethane
Ethylbenzene
Ethylene dichloride
Formaldehyde
Furans
Lead
Manganese
Mercury
Methylene chloride
n-Hexane
Naphthalene
N-nitroso-dimethyl-amine
Nickel
PAHs
Propylene oxide
Selenium
Tetrachloroethylene
Toluene
Trichloroethylene
Vinyl chloride
Vinylidene chloride
Xylenes

(EPA, 2002a)

3.3 Other Emissions Issues

This section summarizes the availability of three special types of emission test data:

- Emissions at part-load
- Emissions during unit start-up/shutdown
- Long-term emissions performance

3.3.1 Emissions at Part-Load

The performance of power technologies at part-load can be very different from their performance at their full-load rated design point. Efficiency is usually lower at part-load, especially for combustion turbines and for smaller prime-movers. The emission rate can also vary, especially emissions of NO_x, CO and UHC, which are affected by combustion characteristics. Ordinarily, NO_x emissions are highest at full load because of high firing/operating temperatures; however, some advanced combustion systems are optimized for lowest emissions at full load and can have higher emissions at part-load. The combination of emission rate differences and the change in efficiency can significantly change the emissions per MWh at different load points. At the same time, the importance of part-load data depends on the likelihood that the equipment will run at part-load. For many DER applications, it seems more likely that the equipment will run at full load most of the time. DER used for emergency generation, power quality, peaking, load response and base load electric generation or CHP would be likely to run primarily at full load. Part-load operation would be most likely in electric or thermal load-following applications.

The ICCR databases include part-load data for many of the engines and turbines. In some cases this appears to be systematic testing of emissions at different load points (100 percent, 75 percent, 50 percent). In other cases, it seems that the emission test happened to be at a time when the unit was running at less than 100 percent load and there is not always a 100 percent load point for comparison. Nevertheless, there is enough information to make some useful comparisons between full and part-load performance.

Part-load data also are available for the following microturbine systems from independent testing studies:

- Honeywell Parallon 75 kW
- Mariah 30 kW
- Capstone 30 kW, 60 kW

3.3.2 Emissions During Unit Start-up/Shutdown

Emissions performance can change significantly during equipment start-up and shutdown as prime mover components and emission control equipment warm up and reach proper operating temperature. This can be a very important factor for large power generators, which can take anywhere from hours to days to start up and reach full load. However, DER technologies typically reach full load in seconds to minutes (except for some fuel cells) and shut down almost instantly. Start-up/shutdown issues are therefore much less significant for DER technologies and do not seem to have been the focus of significant testing. No published test data on DER equipment start-up and shutdown were identified for this study.

3.3.3 Long-Term Emissions Performance

While DER technologies may have good emissions characteristics at installation, it would be useful to know whether emissions levels are maintained over time. One would like to have independent testing of individual DER installations over time to evaluate the long-term performance. No data were located for any of these technologies.

The newer technologies (fuel cells and microturbines) are too new to have been in operation for a significant period of time. Some are not even in commercial use yet. The exception is the UTC phosphoric acid fuel cell, which has been in use for more than 10 years. While no independent long-term test data on PAFC emissions were identified for this study, one would expect little change since the emissions are very low to begin with and originate mostly from the fuel reformer.

4
COMBUSTION TURBINES

4.1 Introduction

Combustion turbines[1] are the technology of choice for new electric generation in the U.S. and much of the world. Low capital investment, low maintenance and low emissions make turbine technology preferable in a business that is restructuring while facing new environmental requirements. Combustion turbine technology developed in the 1930s as a means of propulsion for jet aircraft. Use of combustion turbines for power generation began in the 1940s and 1950s, but it was not until the early 1980s that improved turbine efficiency and reliability resulted in increased utilization for these applications. While many newer turbines are large utility units, current research and development (R&D) programs are producing smaller and more efficient units that are well suited to distributed energy resources applications. Turbines range in size from 30 kW (microturbines) to 250 MW (large industrial frames). Turbines used in large stationary installations are either peaking, simple-cycle, or base load combined-cycle turbines.

Combustion turbines can be used in a variety of configurations:

- Simple-cycle operations - combustion turbines producing power only.
- Combined heat and power (CHP) operations - a turbine with a heat recovery heat exchanger that captures the heat in the turbine exhaust and converts it to useful thermal energy, usually in the form of steam or hot water.
- Combined cycle operations - high pressure steam is generated from recovered exhaust heat and used to create additional power using a steam turbine. Some combined cycles extract steam at an intermediate pressure for use in industrial processes and are combined cycle CHP systems.

Combustion turbines are one of the cleanest means of generating electricity, with emissions of NO_x from some large gas-fired turbines in the single-digit parts per million (ppm) range, either with catalytic exhaust cleanup or lean pre-mixed combustion. However, combustion turbines operating on liquid fuels produce higher emissions than those operating on gas fuels.

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[1] Combustion turbines are sometimes referred to as “gas turbines”. “Gas” in this case refers to the working fluid, not the fuel. Combustion turbines can burn natural gas, distillate oil and a variety of other gaseous and liquid fuels.

4.2 Turbine Mechanics

The combustion turbine is an internal combustion engine operates with rotational rather than reciprocating motion. Turbines are used in a broad scope of applications, including electric power generation, gas pipeline compressor drives, and various industrial applications requiring shaft power. An illustration of the configuration of a turbine is shown below.

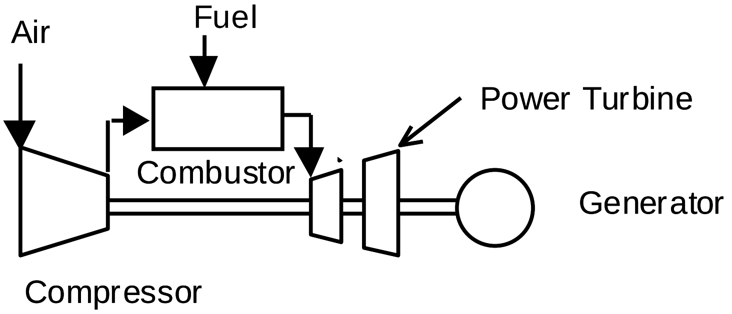

Figure 4-1
Components of a Simple Cycle Gas Turbine

The compressor provides pressurized ambient air to the combustor. Combustors can either be annular, can-annular, or silo. The combustor design is important because it can determine which emission controls can be used on a particular turbine. An annular combustor is a doughnut-shaped, single, continuous chamber that rings the turbine in a plane perpendicular to the airflow. Can-annular combustors are similar to the annular; however, they incorporate can-shaped chambers rather than a single continuous chamber. A silo combustor has one or more chambers mounted external to the turbine body. Each of the combustors performs the same function; fuel is introduced, ignited, and burned. Hot combustion gases leave the combustor and are diluted with additional air from the compressor section and directed to the turbine section at temperatures as high as 2,500° F (1,371°C).

The turbine section comprises one or more sets of turbine blades that use the mechanical energy of the hot combustion products. Some of that energy is used to power the compressor stage. The remaining energy is available to drive an electric generator or other mechanical load. The compressor and all of the turbine blades can be on one shaft or there can be two shafts, one for the compressor and the turbine stages that drive it and a second for the turbine stages that produce useful output. Theoretical turbine efficiency is a function of turbine inlet temperature and pressure ratio across the power turbine, with higher levels of both factors leading to higher efficiency.

4.3 Operating Cycles

The four basic operating cycles for turbines are simple, regenerative or recuperative, combined and CHP cycles.

The *simple-cycle* is the most basic operating cycle, using three main components, an air compressor, combustor, and power turbine. In this cycle after exhaust gases produce power in the power turbine they are vented directly to the atmosphere without recovering their thermal energy. Cycle efficiency, defined as a percentage of useful shaft energy output to fuel energy input, is typically in the 23 to 32 percent range (HHV[2]). This cycle offers the lowest installed capital cost but also provides the least efficient use of fuel and therefore the highest operating cost. Simple-cycle operation is typically used when there is a requirement only for shaft horsepower at low cost and in a compact package.

In a *regenerative or recuperated-cycle* some of the heat of the exhaust gases is used to heat the combustion air prior to injecting the fuel. By recovering some energy that would otherwise be lost and returning it to the cycle, system efficiency can be increased to 40 percent or more. Solar Turbines, Inc. is introducing the Mercury 50 recuperated gas turbine (U.S. DOE, 2003). This 4-MW machine has an electric generation efficiency of 35 percent, which is much higher than comparably sized simple-cycle turbines. Recuperation is often used in microturbines, which increases their electrical efficiency to near 30 percent.

A *combined-cycle turbine* is a turbine system exhausting to a HRSG. The combustion turbine drives an electric generator, and the hot exhaust gas is directed to a HRSG to produce steam. The steam produced in the HRSG is used in a steam turbine, which also drives an electric generator. The HRSG may be fired with additional fuel to increase the steam production and produce additional power from the steam turbine. Because the energy in the turbine exhaust is recovered for power generation, efficiencies can exceed 50 percent.

Combined Heat and Power (CHP) is the simultaneous, sequential production of electricity and thermal energy from a single system. Without cogeneration, steam or hot water is produced in a stand-alone boiler, and the electricity is purchased from offsite generators. A cogeneration application uses a simple-cycle turbine with a HRSG to generate electricity and thermal energy more efficiently than separate production. A generator connected to the combustion turbine produces electricity and the HRSG produces thermal energy. The thermal energy generated in the HRSG from the turbine exhaust can be delivered at a variety of pressure and temperature conditions to meet site thermal process requirements. Where the exhaust heat is not sufficient to meet site requirements, a supplementary burner, or duct burner, can be placed in the exhaust duct upstream of the HRSG to increase the exhaust heat energy. Adding the HRSG equipment increases the capital cost, but recovering the exhaust heat increases the overall fuel efficiency, often to greater than 70 percent and sometimes over 85 percent (HRSG Users Guide, 2002).

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[2] Unless otherwise noted, efficiencies quoted in this report are based on higher heating value (HHV), which includes the heat of condensation of the water vapor in the combustion products. In engineering and scientific literature, the lower heating value (LHV – which does not include the heat of condensation of the water vapor in the products) is often used. The HHV is greater than the LHV by approximately 10% with natural gas as the fuel (i.e., 50% LHV versus 45% HHV).

4.4 Emissions Characteristics

The primary pollutants from combustion turbines are NO_x, CO, and VOCs. Other pollutants such as SO_x and particulate matter depend primarily on the fuel used. Combustion turbines operating on natural gas or distillate oil that has been desulfurized in the refinery emit relatively insignificant levels of SO_x. In general, SO_x emissions are greater when heavy oils are used as fuel. SO_x emission control is thus primarily a fuel purchasing issue rather than a gas turbine technology issue. Particulate matter is a marginally significant pollutant for gas turbines using liquid fuels. Ash and metallic additives in the fuel may contribute to PM in the exhaust (Rivera, 2000). Sulfur and particulate emissions can also degrade the performance of catalytic emission control systems for other pollutants and may need to be managed to ensure good catalyst performance.

The gas turbine operating load has a significant effect on the emissions levels of the primary pollutants of NO_x, CO, and VOCs. Gas turbines are typically operated at high loads. Consequently, gas turbines are designed to achieve maximum efficiency and optimum combustion conditions at these high loads. Controlling all these pollutants simultaneously at all load conditions is difficult. Turbines are usually optimized to achieve the lowest emissions at full load. At lower loads, lower thermal efficiencies and more incomplete combustion occur resulting in higher emissions of CO and VOCs, and sometimes in higher NO_x emissions.

Table 4-1 shows typical emissions for four turbine systems for the base year (2003). The emissions are based on no exhaust treatment and reflect manufacturers' guarantees using state-of-the-art commercial technology (EEA, 2003a). The ICCR data on measured emissions, shown in Table 4-2, are difficult to integrate with these guarantees due to lack of vintage information (U.S. EPA, 1993). However, they suggest that NO_x levels will be slightly below the guaranteed levels while CO and VOC levels may be significantly below the guaranteed levels at full load.

Due to the uniqueness of the combustion system of each gas turbine model, clear distinctions need to be made when discussing emissions control technology and the corresponding emissions levels. Those distinctions are technology that is commercially available, technology that is technically proven but not yet commercial, and technology that is technically feasible but neither technically proven nor commercially available. This is particularly true for pollution prevention and combustion technologies. The emissions characteristics in Table 4-1 are based on commercially available equipment. The table does not include one new 1 MW Kawasaki gas turbine that uses catalytic combustion to achieve NO_x levels of 3 ppm. While this turbine is commercially available, the technology is currently available from only one manufacturer for one turbine model and has limited commercial demonstration.

Add-on control options for NO_x and CO can further reduce emissions of each by 80 to 90 percent. For many distributed generation gas turbine installations, exhaust treatment options have for the most part been avoided or not implemented due to the unfavorable capital and operating cost impacts.

Table 4-1
Gas Turbine Emissions Characteristics Without Exhaust Control Options*

Emissions Characteristics	System 1	System 2	System 3	System 4
Electricity Capacity (kW)	1,000	5,000	10,000	25,000
Electrical Efficiency (HHV)	22%	27%	29.0%	34.3%
NO_x, ppmv	42	25	25	25
NO_x, lb/MWh	2.4	1.1	1.0	0.9
CO, ppmv	20	20	20	20
CO, lb/MWh	0.7	0.6	0.5	0.4
SO_x, ppmv	0.23	0.24	0.24	0.24
SO_x, lb/MWh	0.009	0.008	0.007	0.006
THC, ppmv	25	25	25	25
THC, lb/MWh	0.54	0.38	0.36	0.31
NMOC, ppmv	2.5	2.5	2.5	2.5
NMOC, lb/MWh	0.054	0.038	0.036	0.049
PM_{10}, ppmv	nm	nm	nm	nm
PM_{10}, lb/MWh	0.661	0.527	0.493	0.417
CO_2, lb/MWh	1,825	1,475	1,375	1,165
Carbon, lb/MWh	515	412	385	326

* For typical systems commercially available in 2003, including: Solar Turbines Saturn 20 – 1 MW, Solar Taurus 60 - 5 MW, Solar Mars 100 - 10 MW, GE LM2500 – 25 MW. Emissions estimates for untreated turbine exhaust conditions (15 percent O_2, no SCR or other exhaust clean up).
Estimates based on typical manufacturers' guarantees using commercially available dry low NO_x combustion technology.

nm = not measured

Non-methane organic compounds (NMOC) are assumed to be 10 percent of THC (Total Hydrocarbons)

(EEA, 1999; EEA, 2003a; Energy Nexus Group, 2002)

Table 4-2
ICCR Data on Combustion Turbine Emissions

	< 15 MW	> 15 MW
NO_x	14 -160 ppm 0.7 - 8 lb/MWh	2 - 33 ppm 0.1 - 2 lb/MWh
CO	1.2 - 312 ppm 0.05 – 19 lb/MWh	0.25 - 47 ppm 0.3 - 0.8 lb/MWh
NMOC	18 - 117 ppm nd	0.04 - 41.5 ppm 0.2 - 0.5 lb/MWh
PM_{10}	nd	0.02 - 0.04 lb/MWh

nd = no data

(U.S. EPA, 1993)

4.5 Key Technology Advances

Future combustion turbine technology development trends will reflect a continuing drive toward simultaneously achieving low cost, high efficiency and the lowest possible emissions. Efforts to realize higher thermal efficiencies and single-digit emission levels without post combustion treatment focus on advances in blade design and blade design methodology, cooling techniques and materials, and combustion modifications including “ultra-lean” premix (dry low NO_x) and catalytic combustion (U.S. DOE, 2003).

System heat rates are declining (efficiencies are increasing) due to advances in turbine blade and vane design, improved tip sealing of rotating blades, and the use of advanced, high temperature materials such as monolithic ceramics and ceramic thermal barrier coatings. Improvements have occurred over time, due in part to the diffusion of technology from aircraft gas turbines to those for stationary power, and may accelerate with the use of ceramic materials. With increasing turbine inlet temperatures, manufacturers will also increase pressure ratios and obtain corresponding increases in power and decreases in cost per kW. Emissions control can be improved through the use of catalytic combustion or other combustion enhancements that would allow more economic operation of gas turbine systems than is possible with exhaust gas treatment approaches. The efficiency of industrial turbines will improve through the use of:

- Improved internal cooling and the use of ceramic materials for turbine vanes and blades;
- Improved aerodynamic efficiency of vanes and blades (with component profiles resulting from more comprehensive three-dimensional compressible fluid dynamic analyses);
- Improved thermal barrier coatings
- Increased use of recuperated cycles, especially for smaller turbines; and
- Improved tip sealing.

Improvements will be the result of a diffusion of knowledge developed for larger, higher technology applications to smaller industrial machines, rather than breakthroughs on the engineering of these machines.

Table 4-3 provides projections for turbine-out emission characteristics of the advanced gas turbine systems (EEA, 2003a; Energy Nexus Group, 2002). These projections reflect a continued commitment on the part of gas turbine manufacturers to lean premixed (LPM) combustion to the year 2010. The commercially guaranteed levels that are likely to correspond to the ultra-lean burn limit of LPM are 9 ppm NO_x (0.53 lb/MWh) and CO emissions in the 15-20 ppm range (0.46 – 0.70 lb/MWh). It is unlikely that manufacturers will have sufficient confidence in their ability to guarantee these levels, however, until there is substantial operating experience and long-term field data. Consequently, the projections do not reach these levels until 2010. The exceptions to this are the smaller systems, which are projected to have guarantees of 25 ppm (1.36 lb/MWh) for the 1 MW unit and 15 ppm (0.73 lb/MWh) for the 5 MW unit in 2010. It is expected that catalytic combustion will be available for all representative systems by the year 2020 (U.S. DOE, 2003). This corresponds to a guaranteed NO_x level of 3 ppm (0.13 lb/MWh) for all systems but the 1 MW system (9 ppm NO_x, 0.53 lb/MWh), with CO below 9 ppm (0.24 lb/MWh).

Table 4-3
Current and Advanced Combustion Turbine System Characteristics

Emissions & Performance Projections 1,000 kW Gas Turbine CHP System					
Year	Current	2005	2010	2020	2030
System Size, kW	1,000	1,000	1,000	1,000	1,000
Electrical Heat Rate (Btu/kWh), HHV	15,580	14,835	14,215	13,125	12,635
Electric Efficiency (%)	21.9%	23.0%	24.0%	26.0%	27.0%
Fuel Input (MMBtu/hr)	15.6	14.8	14.2	13.1	12.6
Emissions Characteristics					
NO_x emissions, ppmv	42	25	25	15	3
NO_x emissions, lb/MWh	2.43	1.37	1.31	0.73	0.14
CO, ppmv	20	20	15	9	9
CO, lb/MWh	0.71	0.66	0.47	0.26	0.25
SO_x, ppmv	0.23	0.23	0.24	0.24	0.25
SO_x, lb/MWh	0.009	0.009	0.009	0.008	0.008
NMOC, ppmv	2.5	2.5	2.5	2.5	2.5
NMOC, lb/MWh	0.048	0.046	0.045	0.041	0.039
PM_{10}, ppmv	nm	nm	nm	nm	nm
PM_{10} lb/MWh	0.66	0.63	0.59	0.53	0.50
CO_2, lb/MWh	1,887	1,780	1,706	1,575	1,516
Carbon, lb/MWh	515	486	465	430	414

nm = not measured. NMOCs are assumed to be 10 percent of THC (Total Hydrocarbons)

Note: Estimates are for turbine-out emissions without add-on controls. ppm are corrected to 15% O_2. The base case 1 MW size is based on the Solar Turbines Saturn 20 gas turbine. The 5 MW system is based on the Solar Taurus 60. The 10 MW system is based on the Solar Mars 100. The base case 25 MW system is based on the GE LM2500. The advanced cases are based on simultaneous improvements in firing temperature and pressure ratio that result in increases in efficiency and specific power. The improvements are gained from a combination of: 1) improved internal cooling and the use of ceramic materials for turbine vanes and blades; 2) improved aerodynamic efficiency with advanced component profiles resulting from more comprehensive three-dimensional compressible fluid dynamic analyses of vane and blade shape; 3) improved thermal barrier coatings; and 4) improved tip sealing.
(EEA, 2003a; Energy Nexus Group, 2002)

Table 4-3 (continued)
Current and Advanced Combustion Turbine System Characteristics

Emissions & Performance Projections 5,000 kW Gas Turbine CHP System					
Year	Current	2005	2010	2020	2030
System Size, kW	5,000	5,000	5,000	5,000	5,000
Electrical Heat Rate (Btu/kWh), HHV	12,590	12,015	11,375	10,500	9,750
Electric Efficiency (%)	27%	28%	30%	33%	35%
Fuel Input (MMBtu/hr)	62.9	60.1	56.9	52.5	48.7
Emissions Characteristics					
NO_x emissions, ppmv	25	15	5	3	3
NO_x emissions, lb/MWh	1.12	0.64	0.20	0.11	0.10
CO, ppmv	20	20	15	9	9
CO, lb/MWh	0.56	0.54	0.39	0.22	0.21
SO_x, ppmv	0.24	0.23	0.24	0.22	0.23
SO_x, lb/MWh	0.007	0.007	0.007	0.006	0.006
NMOC, ppmv	2.5	2.5	2.5	2.5	2.5
NMOC, lb/MWh	0.039	0.037	0.036	0.033	0.032
PM_{10}, ppmv	nm	nm	nm	nm	nm
PM_{10} lb/MWh	0.53	0.49	0.45	0.38	0.36
CO_2, lb/MWh	1,475	1,405	1,330	1,230	1,140
Carbon, lb/MWh	412	395	377	349	334

Note: One manufacturer currently offers a gas turbine with catalytic combustion that is guaranteed at 3 ppm NO_x.
nm = not measured
NMOCs are assumed to be 10 percent of THC (Total Hydrocarbons)
(EEA, 2003a; Energy Nexus Group, 2002)

Table 4-3 (continued)
Current and Advanced Combustion Turbine System Characteristics

Emissions & Performance Projections 10,000 kW Gas Turbine CHP System					
Year	Current	2005	2010	2020	2030
System Size, kW	10,000	10,000	10,000	10,000	10,000
Electrical Heat Rate (Btu/kWh), HHV	11,765	11,300	10,800	9,950	9,350
Electric Efficiency (%)	29%	30%	32%	34%	37%
Fuel Input (MMBtu/hr)	117.7	113.0	108.0	99.5	93.5
Emissions Characteristics					
NO_x emissions, ppmv	25	15	5	3	3
NO_x emissions, lb/MWh	1.04	0.60	0.19	0.11	0.10
CO, ppmv	20	20	15	9	9
CO, lb/MWh	0.53	0.50	0.40	0.203	0.175
SO_x, ppmv	0.236	0.245	0.219	0.236	0.247
SO_x, lb/MWh	0.007	0.007	0.006	0.006	0.006
NMOC, ppmv	2.5	2.5	2.5	2.5	2.5
NMOC, lb/MWh	0.036	0.035	0.033	0.031	0.030
PM_{10}, ppmv	nm	nm	nm	nm	nm
PM_{10} lb/MWh	0.49	0.45	0.41	0.34	0.29
CO_2, lb/MWh	1,375	1,320	1,265	1,165	1,095
Carbon, lb/MWh	385	370	355	329	283

Note: A recuperated 4MW gas turbine with 35 percent efficiency and 5 ppm NO_x is expected to reach the market in 2004.

nm = not measured

NMOCs are assumed to be 10 percent of THC (Total Hydrocarbons)

(EEA, 2003a; Energy Nexus Group, 2002)

Table 4-3 (continued)
Current and Advanced Combustion Turbine System Characteristics

Emissions & Performance Projections 25,000 kW Gas Turbine CHP System					
Year	Current	2005	2010	2020	2020
System Size, kW	25,000	25,000	25,000	25,000	25,000
Electrical Heat Rate (Btu/kWh), HHV	9,945	9,665	9,225	8,865	8,530
Electric Efficiency (%)	34%	35%	37%	39%	40%
Fuel Input (MMBtu/hr)	248.7	241.6	230.5	221.6	213.3
Emissions Characteristics					
NO_x emissions, ppmv	25	9	5	3	3
NO_x emissions, lb/MWh	0.71	0.53	0.16	0.09	0.09
CO, ppmv	20	20	15	9	9
CO, lb/MWh	0.45	0.43	0.31	0.19	0.18
SO_x, ppmv	0.24	0.25	0.25	0.22	0.22
SO_x, lb/MWh	0.006	0.006	0.006	0.005	0.005
NMOC, ppmv	2.5	2.5	2.5	2.5	2.5
NMOC, lb/MWh	0.031	0.030	0.029	0.028	0.028
PM_{10}, ppmv	nm	nm	nm	nm	nm
PM_{10} lb/MWh	0.41	0.39	0.35	0.31	0.30
CO_2, lb/MWh	1,165	1,130	1,080	1,035	1,000
Carbon, lb/MWh	326	316	306	300	297

nm = not measured

NMOCs are assumed to be 10 percent of THC (Total Hydrocarbons)

(EEA, 2003a; Energy Nexus Group, 2002)

5

MICROTURBINES

5.1 Introduction

Microturbines are small combustion turbines that burn clean gaseous and liquid fuels to create mechanical energy that turns an electrical generator or other load. Today's microturbine technology is the result of development work in small stationary and automotive gas turbines, auxiliary power equipment and turbochargers, much of which was pursued by the automotive industry beginning in the 1950s. Microturbines entered field-testing around 1997 and began initial commercial service in 1999 - 2000.

The size range for microturbines, either commercially available or in development, is from 30 to 400 kilowatts (kW), while conventional gas turbine sizes range from 500 kW to over 400,000 kW. Microturbines, like larger gas turbines, can be used in power-only generation, combined heat and power (CHP) and mechanical drive systems. They are able to operate on a wide variety of fuels, including natural gas, sour gases (high sulfur content), low-Btu gases such as landfill gas and digester gas, biofuels, and liquid fuels such as gasoline, kerosene, and diesel fuel/distillate heating oil.

Microturbines generally have lower electrical efficiencies than similarly sized reciprocating engine generators as well as larger turbines. However, because of their design simplicity and relatively few moving parts, microturbines offer the potential for lower capital costs and reduced maintenance compared to reciprocating engines. Microturbines also have a significantly lower emissions signature (i.e., lower NO_x and CO emissions) than reciprocating engines. Microturbine emissions can be up to twenty times lower than diesel generators and currently available microturbine products produce less than 50 percent of the NO_x emissions of a state-of-the-art natural gas lean burn engine.

5.2 Basic Processes and Components

Microturbines usually have an internal heat recovery heat exchanger called a recuperator. In typical microturbines, the inlet air is compressed in a radial compressor, and then preheated in the recuperator using heat from the turbine exhaust. Heated air from the recuperator is mixed with fuel in the combustor and ignited. The hot combustion gas is then expanded in one or more turbine sections, producing rotating mechanical power to drive the compressor and the electric generator. In single-shaft models, a single expansion turbine turns both the compressor and the generator. Two-shaft models use one turbine to drive the compressor and a second turbine to drive the generator, with exhaust from the compressor turbine powering the generator turbine. The power turbine's exhaust then is used in the recuperator to preheat the air from the compressor.

The basic components of a microturbine are shown in Figure 5-1. The heart of the microturbine is the compressor-turbine package, which is most commonly mounted on a single shaft along with the electric generator. Because the turbine shaft rotates at a very high speed, the electric output of the generator must be processed to provide 60 Hz AC power.

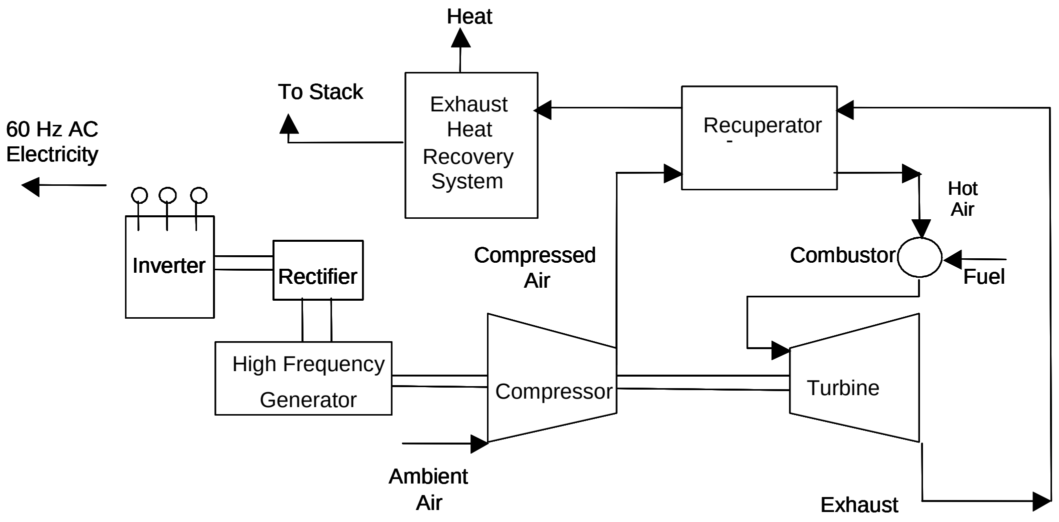

Figure 5-1
Microturbine-Based CHP System (Single-Shaft Design)

The single shaft is supported by two (or more) high-speed bearings. Because single shaft turbines have only one moving part, they have the potential for low maintenance and high reliability. There are also two-shaft versions of the microturbine, in which the turbine on the first shaft only drives the compressor while a power turbine on a second shaft drives a gearbox and conventional electrical generator producing 60 Hz power. The two-shaft design has more moving parts but does not require sophisticated power electronics to convert high frequency AC power output to usable 60 Hz power.

Most current microturbines are based on single-stage radial flow compressors and turbines. Radial flow turbomachinery is better adapted to handle the very small volumetric flows of air and combustion products with reasonably high component efficiency and to obtain a simpler format for construction. In the size range of microturbines—0.5 to 5 lbs/second of air/gas flow—radial flow components offer low surface and end wall losses and provide higher efficiency. They also cost less to manufacture.

Due to their small size and resulting turbine inefficiencies, simple cycle microturbines have very low efficiencies, typically less than 20 percent. Most microturbines use recuperators to help improve this low efficiency. Recuperators are heat exchangers that use the hot turbine exhaust gas (typically around 1,200º F or 650º C) to preheat the compressed air (typically around 300 – 400 ºF/ 150 – 200º C) before going into the combustor, thereby reducing the fuel needed to heat the compressed air to the design turbine inlet temperature (EEA, 2003b).

Microturbines require a recuperator to achieve the efficiency levels needed to be competitive in continuous duty service. Depending on microturbine operating parameters, recuperators can increase machine efficiency by as much as a factor of two. Adding a recuperator to a simple cycle microturbine could mean the difference between a 17 percent efficient system and a 30 percent efficient system. However, since there is an increased pressure drop in both the compressed air and turbine exhaust sides of the recuperator, power output typically declines 10 to 15 percent. Recuperators also lower the temperature of the microturbine exhaust, an important consideration in CHP applications.

Microturbines require gaseous fuel to be supplied in the 64 to 100 psig range, or above. Most local gas distribution systems operate well below this range. Rotary vane, scroll and screw compressors have been used to boost gas pressure at the site to the pressure needed by the microturbine. However, this process reduces the efficiency of the system.

5.2.1 CHP Operation

In CHP operation, a second heat recovery heat exchanger, the exhaust gas heat exchanger, can be used to transfer remaining energy from the microturbine exhaust to a hot water system. Recuperated microturbines have lower-temperature exhaust than simple cycle turbines. However, exhaust heat at low temperatures can be used for a number of different applications, including process or space heating, heating potable water, driving absorption chillers, or regenerating desiccant dehumidification equipment. Some microturbine-based CHP applications do not use recuperators or have the ability to bypass their recuperator to adjust their thermal to electric ratio. The temperature of the exhaust from these microturbines is much higher (up to 1200 ºF or 650°C) and thus more and higher temperature heat is available for recovery (Energetics, 1998).

5.3 Microturbine Emissions

Microturbines have the potential for extremely low emissions. Most microturbines operating on gaseous fuels feature lean premixed (dry low NO_x, or DLN) combustor technology, which was developed relatively recently in gas turbines and is not universally featured on larger gas turbines. The use of a recuperator also helps to better manage the low NO_x combustion process. Because microturbines are able to meet key emissions requirements with this built-in technology, post-combustion emission control (aftertreatment) techniques are currently not needed.

The primary pollutants from microturbines are NO_x, CO, and unburned hydrocarbons. Microturbines emit a negligible amount of SO_2 when fueled by natural gas. They are designed to achieve the objective of low emissions at full load; emissions are often higher relatively when operating at part-load (EEA, 2003b). The causes of formation of these emissions have been previously described in the emission formation section.

5.3.1 Microturbine Emissions Characteristics

Table 5-1 presents typical emissions for new microturbine systems. The data shown reflect manufacturers' guaranteed levels. The limited test data available shown in Table 5-2 indicate that at least some microturbines have actual NO_x emissions below 9 ppm (0.5 lb/MWh) at full load. The measured CO and HC show a great deal of variation but are generally below the guaranteed levels with a few exceptions.

5.4 Key Technology Advances

Manufacturers, researchers, and government agencies are pursuing significant technology improvements that are expected to result in enhanced microturbine performance.

Gas turbine technology advancement efforts have focused primarily on changes in turbine inlet temperature. Increased turbine inlet temperature rapidly increases the power output of the turbine, and, to a lesser extent, also increases efficiency. With an increase in firing temperature, a corresponding increase in pressure ratio yields heightened benefits. Modern large gas turbines employ sophisticated methods of internal turbine cooling to permit higher temperatures without exceeding the turbine material's metallurgical creep limits.[3] Microturbines, however, cannot take advantage of internal turbine cooling, as the complex shape of the flow passage of the small radial inflow turbine does not lend itself to cost-effectively manufactured internal cooling flow passage configurations.

Internal cooling of single stage radial inflow turbines in microturbines is also problematic because it results in the cooling air being entirely for power generation; cooling air cannot enter later turbine stages and provide additional power as is the case with multistage, axial turbines. Materials advancement has therefore become the preferred route to higher temperatures that would increase microturbine efficiencies, based on the partial success with ceramic materials in the automotive gas turbine technology development program.

Significant efficiency increases are expected following cost reduction efforts and size increases. Near-term efforts will include more precise manufacturing tolerances and more effective recuperators. Longer-term efforts will focus on higher firing temperatures and employing ceramics in hot sections. Increased market penetration would provide adequately large manufacturing volumes to support incorporation of high temperature ceramic turbines, combustors and transition pieces into commercial microturbines.

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[3] Metals under stress at high temperatures slowly elongate and eventually break. This phenomenon is known as creep.

Alternatively, the design of metallic radial flow turbines with internal cooling may prove practical. Either technology path would result in efficiency improvements, first to the 32 to 34 percent range (HHV), and later to 36 percent and greater. Such increases in efficiency should be accompanied by cost reductions, as most of the components will not increase in price as rapidly as the increased output power achievable with improved technology (EEA, 2003b; Energetics, 1998).

Table 5-1
Microturbine Emissions Characteristics

Emissions Characteristics	System 1	System 2	System 3	System 4
Nominal Electrical Capacity (kW)	30 kW	70 kW	80 kW	100 kW
Net Electrical Efficiency, HHV	23%	25%	24%	26%
NO_x, ppmv	9	9	25	15
NO_x, lb/MWh	0.5	0.5	1.3	0.7
CO, ppmv	40	9	50	15
CO, lb/MWh	1.3	0.3	1.6	0.4
SO_x, ppmv	0.21	0.23	0.22	0.23
SO_x, lb/MWh	0.008	0.008	0.008	0.007
THC, ppmv	< 9	<9	<9	<9
THC, lb/MWh	<0.2	<0.2	<0.2	<0.2
VOC, ppmv	0.9	0.9	0.9	1
VOC, lb/MWh	0.02	0.018	0.019	0.02
PM_{10}, ppmv	nm	nm	nm	nm
PM_{10}, lb/MWh	0.62	0.57	0.59	0.55
CO_2, lb/MWh	1,765	1,585	1,650	1,535
Carbon, lb/MWh	495	435	435	418

Estimates are based on manufacturers' guarantees for typical systems commercially available in 2003 without add-on emission controls, including Capstone Model 330 30 kW, Ingersoll Rand PowerWorks 70 kW, Turbec T100 100 kW systems

nm = not measured

VOCs (Non-methane Hydrocarbons) are assumed to be 10 percent of THC (Total Hydrocarbons)

(EEA, 1999; EEA, 2003b; Energy Nexus Group, 2002)

Development work continues on both catalytic combustion and advanced pre-mixed combustion to reach NO_x levels below 5 to 9 ppm (0.19 to 0.37 lb/MWh). Catalytic combustors are just now becoming mature enough for commercial service on larger gas turbines and further improvements in conventional combustion are expected with improved pre-mixing and enhanced wall cooling techniques to reduce CO emissions as well. It is likely that one of these paths will be capable of meeting sub-5 to -9 ppm (0.19 to 0.37 lb/MWh) levels on a consistent basis in the future if regulations require compliance at these levels (EEA, 2003b; Energetics, 1998).

Table 5-2
Microturbine Emission Measurements (Natural Gas)

		Emissions (lb/MWh)			
Model	**Source**	**NO_x**	**CO**	**UHC**	**SO_2**
Bowman 60 kW	CEC	3.7	12.2		
Capstone 28 kW	CEC	0.1	3.9		
Honeywell Parallon 75 kW	ETV	1.0	0.05	0.1	
Mariah 30 kW	ETV	0.2	0.15	0.02	
Power Works 70 kW	ETV	0.05	0.02	0.05	0.05
Capstone 30 kW	ORNL	0.24	1.3	0.05	0.05
Capstone 30 kW	CARB	0.3	0.03	0.02	
Capstone 60 kW	CARB/UCI	0.25	0.07		
Capstone 60 kW	CARB CERT	0.24	3.76	0.14	
IR 70LM	CARB CERT	0.13	0.24	0.21	

CEC - California Energy Commission; ETV - EPA Environmental Technology Verification Program; ORNL - Oak Ridge National Laboratory (DOE); CARB - California Air Resources Board; UCI – University of California, Irvine; CARB CERT – Small Generator Certification

5.5 Future Performance

Manufacturers' data, together with a review of ongoing research and development activities, have been used to create performance projections of microturbine systems through 2030. Table 5-3 summarizes the nature and timing of the performance advances assumed to take place from the present through 2030 that underpin the development of the emissions projections (EEA, 2003b).

Estimates of the future performance of microturbine CHP systems through 2003 are shown in Table 5-4. These systems feature metallic turbines and hot section parts through 2005. By 2010, all but the smallest (30 kW) unit incorporates a ceramic turbine and hot section parts. Price decreases and minor net efficiency increases are anticipated through 2005, reflecting improved package designs, increases in manufacturing volumes and reductions in certain parasitic losses. Cost reduction is a critical requirement for the advancement of the technology. A 200 to 250 kW microturbine is expected to be introduced in 2005 based on a metallic turbine and components Such units (by Ingersoll) are actually entering early commercialization in 2002/2003. This system is assumed to be upgraded to a 250 kW ceramic turbine in 2010. A 500 kW ceramic turbine is also expected to be introduced to the market in 2010.

The ceramic machines appearing in 2010 (2020 for the 30 kW unit) offer dramatic efficiency improvements over present-day products, resulting from the higher firing temperatures achieved through the use of ceramic components. The levels of performance anticipated in 2010 are for initial product offerings and reflect a degree of conservatism in design, operation and business exposure. The performance expected by 2020 reflects the technical potential of ceramic hot section components, and reaches the DOE advanced microturbine system program goal of 36 percent HHV efficiency (40 percent LHV). The power output also increases significantly with the introduction of ceramics, resulting in larger capacity from the ceramic units. All of these advances assume success in a variety of R&D and new product commercialization programs supported by robust success in microturbine commercialization.

Table 5-3
Projected Microturbine Evolution Through 2030

Current Unit	Current Characteristics	2005	2010	2020	2030
30 kW	Metallic turbine and hot section parts	Modest price decrease due to improved system design and component integration.	Price decrease due to larger manufacturing volumes; performance increases due to component improvements and tighter manufacturing tolerances	Ceramic turbine and hot section parts. Output increases to 50 kW reflecting significant increase in firing temperature	Incremental increases in firing temperature
70 - 80 kW	Metallic turbine and hot section parts	Modest price decrease due to improved system design and component integration; performance increases due to component improvements and improved manufacturing tolerances	Ceramic turbine and hot section parts; Output increases to 110 kW due to significant increase in firing temperature	Incremental increases in firing temperature	Incremental increases in firing temperature
100 kW	Metallic turbine and hot section parts	Modest price decrease due to improved system design and component integration; performance increases due to component improvements and improved manufacturing tolerances	Ceramic turbine and hot section parts; Output increases to 160 kW due to significant increase in firing temperature.	Incremental increases in firing temperature	Incremental increases in firing temperature
250 kW	Under development	200 kW Metallic turbine and hot section parts introduced	Ceramic turbine and hot section parts; Output increase to 250 kW reflecting increased firing temperature	Incremental increases in firing temperature	Incremental increases in firing temperature
500 kW	Under development	Under development	Ceramic turbine and hot section parts	Incremental increases in firing temperature	Incremental increases in firing temperature

Table 5-4
Current and Advanced Microturbine System Characteristics

Emissions and Performance Projections **30 kW Microturbine System**					
Year	Current	2005	2010	2020	2030
Nominal Capacity (kW)	30	30	30	50	50
Turbine	Metallic	Metallic	Metallic	Ceramic	Ceramic
Electrical Heat Rate (Btu/kWh), HHV	15,075	13,650	13,125	10,660	10,035
Electric Efficiency (%), HHV	23%	25%	26%	32%	34%
Fuel Input (MMBtu/hr)	0.42	0.41	0.39	0.53	0.50
Emissions Characteristics					
NO_x emissions, ppmv	9	9	5	3	3
NO_x emissions, lb/MWh	0.51	0.46	0.25	0.11	0.10
CO, ppmv	40	40	30	20	20
CO, lb/MWh	1.38	1.26	0.90	0.44	0.43
SO_x, ppmv	0.21	0.22	0.23	0.23	0.24
SO_x, lb/MWh	0.008	0.008	0.008	0.006	0.006
NMOC, ppmv	0.9	0.9	0.9	0.9	0.9
NMOC, lb/MWh	0.02	0.02	0.02	0.01	0.01
PM_{10}, ppmv	nm	nm	nm	nm	nm
PM_{10} lb/MWh	0.62	0.56	0.53	0.26	0.23
CO_2, lb/MWh	1,765	1,590	1,525	1,250	1,174
Carbon, lb/MWh	495	474	455	334	325

nm = not measured

NMOCs are assumed to be 10 percent of THC (Total Hydrocarbons)

Note: Table data for the 30 kW system for the current year are based on Capstone Model 330. Estimates are for emissions without add-on emissions controls.

(EEA, 2003b)

Table 5-4 (continued)
Current and Advanced Microturbine System Characteristics

Emissions and Performance Projections 70 kW Microturbine System					
Year	Current	2005	2010	2020	2030
Nominal Capacity (kW)	70	70	110	110	110
Turbine	Metallic	Metallic	Ceramic	Ceramic	Ceramic
Electrical Heat Rate (Btu/kWh), HHV	13,545	13,025	10,665	9,750	9,225
Electric Efficiency (%), HHV	25%	26%	32%	35%	37%
Fuel Input (MMBtu/hr)	0.91	0.90	1.17	1.07	1.01
Emissions Characteristics					
NO_x emissions, ppmv	9	9	5	3	3
NO_x emissions, lb/MWh	0.45	0.42	0.20	0.11	0.10
CO, ppmv	9	9	9	9	9
CO, lb/MWh	0.27	0.26	0.21	0.19	0.18
SO_x, ppmv	0.23	0.24	0.22	0.24	0.22
SO_x, lb/MWh	0.008	0.008	0.006	0.006	0.005
NMOC, ppmv	0.9	0.9	0.9	0.9	0.9
NMOC, lb/MWh	0.02	0.01	0.01	0.01	0.01
PM_{10}, ppmv	nm	nm	nm	nm	nm
PM_{10} lb/MWh	0.57	0.55	0.37	0.28	0.22
CO_2, lb/MWh	1,585	1,525	1,250	1,140	1,080
Carbon, lb/MWh	435	434	356	325	307

nm = not measured

NMOCs are assumed to be 10 percent of THC (Total Hydrocarbons)

Note: table data for the 70 kW system for the current year are based on IR Energy Systems 70LM, which is a two-shaft model. Estimates are for emissions without add-on emissions controls.

(EEA, 2003b)

Table 5-4 (continued)
Current and Advanced Microturbine System Characteristics

Emissions and Performance Projections 100 kW Microturbine System					
Year	Current	2005	2010	2020	2030
Nominal Capacity (kW)	100	100	160	160	160
Turbine	Metallic	Metallic	Ceramic	Ceramic	Ceramic
Electrical Heat Rate (Btu/kWh), HHV	13,125	11,770	9,480	8,980	8,750
Electric Efficiency (%), HHV	25%	29%	36%	38%	39%
Fuel Input (MMBtu/hr)	1.31	1.18	1.52	1.44	1.40
Emissions Characteristics					
NO_x emissions, ppmv	15	9	5	3	3
NO_x emissions, lb/MWh	0.72	0.40	0.20	0.10	0.09
CO, ppmv	15	15	15	15	15
CO, lb/MWh	0.45	0.40	0.33	0.31	0.30
SO_x, ppmv	0.21	0.23	0.23	0.25	0.22
SO_x, lb/MWh	0.007	0.007	0.006	0.006	0.005
VOC, ppmv	1	1	1	1	1
VOC, lb/MWh	0.02	0.02	0.01	0.01	0.01
PM_{10}, ppmv	nm	nm	nm	nm	nm
PM_{10} lb/MWh	0.55	0.49	0.31	0.25	0.19
CO_2, lb/MWh	1,535	1,375	1,110	1,050	1,025
Carbon, lb/MWh	437	406	334	316	300

nm = not measured

VOCs (Non-methane Hydrocarbons) are assumed to be 10 percent of THC (Total Hydrocarbons)

Note: Table data for the 100 kW system for the current year are based on the Turbec T100 unit. Estimates are for emissions without add-on emissions controls.

(EEA, 2003b)

Table 5-4 (continued)
Current and Advanced Microturbine System Characteristics

Emissions and Performance Projections 200 kW Microturbine System					
Year	Current	2005	2010	2020	2030
Nominal Capacity (kW)	--	200	250	250	250
Turbine	--	Metallic	Ceramic	Ceramic	Ceramic
Electrical Heat Rate (Btu/kWh), HHV	--	11,375	9,480	8,980	8,750
Electric Efficiency (%), HHV	--	30%	36%	38%	39%
Fuel Input (MMBtu/hr)	--	2.27	2.84	2.24	2.19
Emissions Characteristics					
NO_x emissions, ppmv	--	9	5	3	3
NO_x emissions, lb/MWh	--	0.37	0.17	0.09	0.09
CO, ppmv	--	20	20	20	20
CO, lb/MWh	--	0.50	0.42	0.40	0.38
SO_x, ppmv	--	0.244	0.251	0.218	0.226
SO_x, lb/MWh	--	0.007	0.006	0.005	0.005
NMOC, ppmv	--	1	1	1	1
NMOC, lb/MWh	--	0.01	0.01	0.01	0.01
PM_{10}, ppmv	--	nm	nm	nm	nm
PM_{10} lb/MWh	--	0.45	0.27	0.23	0.19
CO_2, lb/MWh	--	1,330	1,110	1,050	1,025
Carbon, lb/MWh	--	379	316	303	292

nm = not measured

NMOCs are assumed to be 10 percent of THC (Total Hydrocarbons)

Note: Table data for the 250 kW system for 2010 are based on DOE Advanced Microturbine System (AMTS) program goals. Estimates are for emissions without add-on emissions controls.

(EEA, 2003b)

Table 5-4 (continued)
Current and Advanced Microturbine System Characteristics

Emissions and Performance Projections 500 kW Microturbine System					
Year	Current	2005	2010	2020	2030
Nominal Capacity (kW)	--	--	500	500	500
Turbine	--	--	Ceramic	Ceramic	Ceramic
Electrical Heat Rate (Btu/kWh), HHV	--	--	9,480	8,750	8,530
Electric Efficiency (%), HHV	--	--	36%	39%	40%
Fuel Input (MMBtu/hr)	--	--	4.74	4.37	4.27
Emissions Characteristics					
NO_x emissions, ppmv	--	--	5	3	3
NO_x emissions, lb/MWh	--	--	0.17	0.09	0.09
CO, ppmv	--	--	20	20	20
CO, lb/MWh	--	--	0.41	0.38	0.38
SO_x, ppmv	--	--	0.25	0.23	0.23
SO_x, lb/MWh	--	--	0.006	0.005	0.005
NMOC, ppmv	--	--	1	1	1
NMOC, lb/MWh	--	--	0.01	0.01	0.01
PM_{10}, ppmv	--	--	nm	nm	nm
PM_{10} lb/MWh	--	--	0.27	0.18	0.15
CO_2, lb/MWh	--	--	1,110	1,025	1,000
Carbon, lb/MWh	--	--	316	292	284

nm = not measured

NMOCs are assumed to be 10 percent of THC (Total Hydrocarbons)

Note: Based on an extrapolation of DOE Advanced Microturbine System goals and discussions with individual manufacturers. Estimates are for emissions without add-on emissions controls.

(EEA, 2003b)

6

RECIPROCATING ENGINES

Reciprocating internal combustion engines (RICE) are a widespread and well-known technology. North American production exceeds 35 million units per year for automobiles, trucks, construction and mining equipment, marine propulsion, lawn care, and a diverse set of power generation applications. A variety of stationary RICE products are available for a range of power generation market applications and duty cycles, including standby and emergency power, peaking service, intermediate and baseload power, and CHP. Reciprocating engines are available for electrical power generation applications in sizes ranging from a few kilowatts to over 10 MW.

There are two basic types of reciprocating engines – spark ignition (SI) and compression ignition (CI). Spark ignition engines for power generation use natural gas as the preferred fuel, although they can be set up to run on propane, gasoline, or digester/landfill gas. Compression ignition engines (often called diesel engines) operate on diesel fuel or heavy oil, or they can be set up to run in a dual-fuel configuration that burns primarily natural gas with a small amount of diesel pilot fuel.

Diesel engines have historically been the most popular type of reciprocating engine for both small and large power generation applications due to their low cost and rapid start-up capability for emergency back-up applications. However, in the United States and other industrialized nations, diesel engines are increasingly restricted to emergency standby or limited duty-cycle service because of air emission concerns. As a result, the natural gas-fueled SI engine is now the engine of choice for the higher-duty-cycle stationary power market (over 500 hr/yr).

Reciprocating engine technology has improved dramatically over the past three decades, driven by economic and regulatory pressures for power density improvements (more output per unit of engine displacement), increased fuel efficiency and reduced emissions. The emissions signature of natural gas SI engines in particular has improved significantly in the last decade through better design and control of the combustion process and through the use of catalytic treatment of exhaust. Advanced lean burn natural gas engines are available that produce NO_x as low as 0.5 g/bhp-hr (1.5 lb/MWh). Rich burn gas engines with 3-way catalysts have NO_x emissions as low as 0.15 g/bhp-hr (0.47 lb/MWh).

6.1 Basic Engine Processes and Components

All reciprocating internal combustion engines use the same basic process. A combustible fuel-air mixture is compressed between a movable piston and its surrounding cylinder and head and is then ignited. The energy generated by the combustion process drives the piston downward. The piston's linear motion is converted via a crankshaft to rotary power. The piston returns (reciprocates), forcing out the spent combustion (exhaust) gases, and the cycle is repeated.

6.2 Types of Reciprocating Engines

There are two primary reciprocating engine designs relevant to stationary power generation applications – the spark ignition Otto-cycle engine and the compression ignition Diesel-cycle engine. The primary difference between the Otto and Diesel cycles is the method of igniting the fuel. Spark ignition engines (Otto-cycle) use a spark plug to ignite a pre-mixed air fuel mixture introduced into the cylinder. Compression ignition engines (Diesel-cycle) compress the air introduced into the cylinder to a high pressure, raising its temperature to the self-ignition temperature of the fuel, which is injected at high pressure and ignites.

Natural Gas Spark Ignition Engines – Spark ignition engines use spark plugs, with a high-intensity spark of timed duration, to ignite a compressed fuel-air mixture within the cylinder. Natural gas is the predominant spark ignition engine fuel used in electric generation and CHP applications. Other gaseous and volatile liquid fuels, ranging from landfill gas to propane to gasoline, can be used with the proper fuel system, engine compression ratio and tuning. American manufacturers began to develop large natural gas engines for the burgeoning gas pipeline industry after World War II. Smaller engines were developed (or converted from diesel blocks) for gas gathering and other stationary applications as the natural gas infrastructure developed. Natural gas engines for power generation applications are primarily 4-stroke engines available in sizes up to about 5 MW.

Spark ignition engines were initially designed to operate near the stoichiometric point (also known as "rich burn"), where there is just enough air to complete combustion of the fuel. This design is the most direct approach to obtain complete combustion, high operating temperature and good burnout of CO and UHC. It also generates high NO_x emissions, typically 13 g/bhp-hr (39.6 lb/MWh) (Wilhelm, 1999). As low NO_x emissions became important, engine manufacturers developed "lean burn" engines in which the air/fuel ratio is increased by over two times from stoichiometric to reduce peak combustion temperature and NO_x formation.

Using high-energy ignition technology, very lean fuel-air mixtures can be burned in natural gas engines, lowering peak temperatures within the cylinders and resulting in reduced NO_x emissions. The lean burn approach in reciprocating engines is analogous to dry low-NO_x combustors in gas turbines. All major natural gas engine manufacturers offer lean burn, low emission models and are engaged in R&D to further improve their performance. NO_x emissions range from 0.5 g/bhp-hr (1.5 lb/MWh) in multi-MW lean burn engines to 2.0 g/bhp-hr (6 lb/MWh) in smaller engines.

Natural gas spark ignition engine efficiencies are typically lower than diesel engines because of their lower compression ratios (due to knock limitations). However, large, high performance lean burn engine efficiencies approach those of diesel engines of the same size. Natural gas engine efficiencies range from about 25 percent (HHV) for small engines (<50 kW) to 37 percent (HHV) for the largest high performance, lean burn engines. Lean burn engines tuned for maximum efficiency may produce twice the NO_x emissions as the same engine tuned for minimum NO_x. Tuning for low NO_x typically results in a sacrifice of 1 to 1.5 percentage points in electric generating efficiency from the highest level achievable (Wilhelm, 1999; EEA, 2003c).

Although rich burn engines have much higher engine-out emissions than lean burn engines, the rich burn engines can be controlled to lower levels through a relatively low-cost technology, the three-way catalyst (TWC). The TWC is the same emission control technology used on automobiles. It uses a two-stage catalyst system to reduce NO_x, CO and UHC. NO_x is removed in a reducing atmosphere (no oxygen present) in the first stage. Air is then injected and CO and UHC are oxidized in the second stage. Rich burn engines with TWC can achieve NO_x levels of 0.15 g/bhp-hr. Due to the need to maintain a reducing atmosphere in the first stage, this technology cannot be used with lean burn engines.

Diesel Engines - Compression ignition diesel engines are among the most efficient simple-cycle power generation options on the market. Efficiency levels increase with engine size and range from about 30 percent (HHV) for small high-speed diesels up to 42 to 47 percent (HHV) for the large bore, slow speed engines. High-speed diesel engines (1200 rpm) are available up to about 4 MW in size. Low speed diesels (60 to 275 rpm) are available as large as 65 MW but are not typically used in the US.

Depending on the engine and fuel quality, diesel engines produce several times more NO_x (on a ppmv basis) than lean burn natural gas engines. Diesel engines also produce assorted heavy hydrocarbons and particulate emissions; however, they produce significantly less CO than lean burn gas engines. The NO_x emissions from diesels burning heavy oil are typically 25 to 30 percent higher than diesels using distillate oil. Common NO_x control techniques include delayed fuel injection, exhaust gas recirculation, fuel-water emulsification, inlet air cooling, intake air humidification, and compression ratio and/or turbocharger modifications – all designed to eliminate hot spots and reduce the flame temperature within the cylinder.

High-speed diesel engines generally require high quality fuel oil with good combustion properties. No. 1 and No. 2 distillate oil comprise the standard diesel fuels. Low sulfur distillate is used to minimize SO_2 emissions. High-speed diesels are not suited to burning oil heavier than distillate. Heavy fuel oil requires more time for combustion and the combination of high speed and contaminants in lower quality heavy oils cause excessive wear in high-speed diesel engines. Many medium and low speed diesels used mostly for marine applications are designed to burn heavier oils including low grade residual oils or Bunker C oils but are not typically used for DER applications.

Dual Fuel Engines – Dual fuel engines are diesel compression ignition engines predominantly fueled by natural gas with a small percentage of diesel oil as the pilot or ignition fuel. The pilot fuel auto-ignites and initiates combustion in the main air-fuel mixture. Pilot fuel percentages can range from 1 to 15 percent of total fuel input. Some dual fuel engines can be switched back and forth quickly between dual fuel and 100 percent diesel operation. In general, because of lower diesel oil usage, NO_x, smoke and particulate emissions are lower for dual fuel engines than for straight diesel operation—particularly at full load. Particulate emissions are reduced in line with the percentage reduction in diesel oil consumption while the level of NO_x reduction depends on combustion characteristics. However, CO and unburned hydrocarbon emissions are often higher, partly because of incomplete combustion.

Several independent developers and engine manufacturers are testing and commercializing dual fuel retrofit kits for converting existing diesel engines to dual fuel operation. The level of sophistication of these kits varies widely and some require major engine modifications. Derating, efficiencies, and emissions also vary widely and have yet to be fully tested or certified. However, dual fuel conversions are not expected to be as low in emissions as dedicated natural gas engines. In addition, manufacturers may not honor warrantees on an engine that has been retrofitted by an independent third party.

6.3 Emissions Characteristics

Exhaust emissions are the primary environmental concern with reciprocating engines. The primary pollutants are NO_x, CO, and VOCs or unburned, non-methane hydrocarbons. Other pollutants such as SO_x and PM are primarily dependent on the fuel used. Engines operating on natural gas, emit insignificant levels of $SO_{x.}$ Particulate matter (PM) can be an important pollutant for engines using liquid fuels. Ash and metallic additives in the fuel contribute to PM in the exhaust. NO_x emissions are usually the primary concern for engines. Table 6-1 compares NO_x emissions from reciprocating engines. Although the rich burn gas engine has very high NO_x emissions, it can be used with a three way catalyst to reduce emissions of NO_x, CO and UHC. Although it requires careful control of air/fuel ration, the TWC itself is a relatively low capital cost item and does not require any reagents. With the TWC, the rich burn engine's NO_x emissions are as low as 0.15 g/bhp-hr (0.46 lb/MWh), the lowest option for RICE without more expensive, more complicated add-on controls (EEA, 2003c).

Table 6-1
Representative NO_x Emissions From Reciprocating Engines (Without Add on Controls)

Engines	Efficiency Range (%, HHV)	Fuel	NO_x (lb/MWh)	NO_x (g/hp-hr)
Diesel Engines (high speed & medium speed)	35 to 41	Distillate	14.7 – 39.6	5 - 13.4
Diesel Engines (high speed & medium speed)	39 to 45	Heavy Oil	26.6 – 44.3	9 - 15
Lean Burn, Spark Ignition Engine	32 to 38	Natural Gas	1.5 – 5.3	0.5 - 1.8
Rich Burn, Spark Ignition Engine	26 to 33	Natural Gas	12 – 15	3.8 – 4.8

(Wilhelm, 1999)

The control of peak flame temperature through lean burn conditions has been the primary combustion approach to limiting NO_x formation in gas engines. Diesel engines produce higher combustion temperatures and more NO_x than lean burn gas engines, even though the overall diesel engine air/fuel ratio may be very lean. There are three reasons for this:

- heterogeneous near-stoichiometric combustion;
- the higher adiabatic flame temperature of distillate fuel; and
- higher amounts of fuel-bound nitrogen.

The diesel fuel is atomized as it is injected and dispersed in the combustion chamber. Combustion largely occurs at near-stoichiometric conditions at the air-droplet and air-fuel vapor interfaces, resulting in maximum temperatures and higher NO_x. In contrast, lean-premixed homogeneous combustion used in lean burn gas engines results in lower combustion temperatures and lower NO_x production.

NO_x control has been the primary focus of emission control research and development in natural gas engines. Lean burn engine technology was developed during the 1980s as a direct response to the need for cleaner burning gas engines. The focus of lean burn developments was to lower combustion temperature in the cylinder using lean fuel/air mixtures. Lean combustion decreases the fuel/air ratio in the zones where NO_x is produced so that peak flame temperature is less than the stoichiometric adiabatic flame temperature, therefore decreasing thermal NO_x formation. Most lean burn engines use turbocharging to supply excess air to the engine and produce the homogeneous lean fuel-air mixtures. Lean burn engines generally use 50 to 100 percent excess air (above stoichiometric). The typical emissions rate for lean burn natural gas engines is between 0.5 to 2.0 g/bhp-hr (1.5 to 6 lb/MWh).

An added performance advantage of lean burn operation is higher output and higher efficiency. Optimized lean burn operation requires sophisticated engine controls to ensure that combustion remains stable and NO_x reduction is maximized while minimizing emissions of CO and VOCs. Table 6-2 illustrates the tradeoffs between NO_x emissions control and efficiency for a large natural gas engine (EEA, 2003c). At the lowest achievable NO_x levels (45 to 50 ppmv or 1.7 to 1.9 lb/MWh), almost 1.5 percentage points are lost on full-rated efficiency.

Table 6-3 shows gas engine emission characteristics for a range of sizes and current combustion designs based on manufacturer guarantees. The ICCR emission data measurements, shown in Table 6-4, are difficult to correlate to these estimates due to a wide range of results and a lack of specific equipment data. The EPA study of NO_x emissions suggests that lean-burn engines can do better than the levels shown in this table – in the 0.1 to 0.5 g/bhp-hr range if well maintained, though some of that data is disputed by industry.

6.4 Advanced Technology Projections

One of the primary research and development goals of natural gas engine manufacturers is to reduce the environmental impact of the engines. This is being researched through the application of advanced combustion technology and improved sensors and controls to attain emissions levels comparable to gas turbines (i.e., 10 ppmv NO_x or 0.37 lb/MWh). Researchers are attempting to accomplish this goal without sacrificing fuel efficiency and without exhaust gas treatment, or alternatively, with low cost exhaust gas treatment for final control of NO_x, CO and VOCs. Another research goal is to create engines with higher efficiencies, through the application of high temperature materials, engine sensors and controls, and improved combustion practices (Callahan, 2003).

The Advanced Reciprocating Engine Systems (ARES) Program was initiated by the U.S. Department of Energy in 1998. ARES is a consortium of three major engine manufacturers: Caterpillar Inc., Cummins Inc., and Waukesha Engine, and several component suppliers. The goal of the program is to develop an advanced low-cost natural gas engine with high efficiency and ultra-low emissions for DER applications. The ARES performance goals for 2010 are:

- Size range of 500 to 6,500 kW
- 45 percent (2005) to 50 percent (2010) electrical efficiency (LHV), which is a 30 percent increase from today's average efficiency of 38 percent
- 0.1 g/bhp-hr NO_x or 0.3 lb NO_x/MWh, a 95 percent decrease from today's NO_x emissions rate of 2 g/bhp-hr, with no deterioration of other criteria or hazardous air pollutants
- Ten percent reduction in cost of power per kW
- Maintain levels of reliability, availability and maintainability to current state-of-the-art systems.

The California Energy Commission (CEC) Public Interest Energy Research (PIER) program is pursuing a similar program called the Advanced Reciprocating Internal Combustion Engines (ARICE) program. The NO_x emission goal for ARICE is 0.01 g/bhp-hr (0.03 lb/MWH) in 2010. Active research is proceeding on both programs and some early results are starting to be incorporated in current engine offerings.

There are several classes of improvements in gas engines that will increase their attractiveness for on-site and distributed power generation. Efficiencies will improve through increasing operating pressure and engine speed, and the use of thermal barrier coatings. Improved controls will allow very lean combustion that optimizes both efficiency and emissions. Increased operating pressure and engine speed will result in corresponding increases in power and decreases in cost per kW. Emissions profiles will be improved through a combination of combustion improvements and advanced exhaust gas treatment. While there will be much effort to improve high efficiency, lean burn engines, nearer term initiatives will result in more efficient, more durable stoichiometric engines in the smaller size ranges. Table 6-5 forecasts the improvements that will be made in the future to several types of engines (Energy Nexus Group, 2002).

Table 6-2
NO_x Emissions Versus Efficiency Tradeoffs

Engine Characteristics	Low NO_x	High Efficiency
Capacity (MW)	5.2	5.2
Speed (rpm)	720	720
Efficiency, HHV (%)	37.0	38.2
Emissions:		
NO_x, g/hp-hr ppmv @ 15% O_2	0.5 46	1.0 92
CO, g/hp-hr ppmv @ 15% O_2	2.4 361	1.5 227
NMHC, g/hp-hr ppmv @ 15% O_2	0.7 61	0.4 39

Note: based on engine manufacturer's data –
Wartsila 18V34SG Prechamber Lean Burn Gas Engine.

Table 6-3
Gas Engine Emissions Characteristics Without Exhaust Control Options

Emissions Characteristics	System 1	System 1a	System 2	System 3	System 4	System 5
Electricity Capacity (kW)	100	100	300	1000	3000	5000
Electrical Efficiency (HHV)	30%	29%	31%	34%	35%	37%
Engine Combustion	Rich	Rich w/TWC	Lean	Lean	Lean	Lean
NO_x, ppmv @ 15% O_2	1,100	11	150	80	44	46
NO_x, g/bhp-hr	15	0.15	2	1	0.7	0.5
NO_x, lb/MWh	46	0.46	6.2	3.1	2.2	1.6
CO, ppmv @ 15% O_2	1,366	67	391	300	290	300
CO, g/bhp-hr	12	0.6	2.0	2.0	2.5	2.4
CO, lb/MWh	37	1.8	6.2	6.2	7.8	7.4
SO_x, ppmv	0.24	0.24	0.24	0.23	0.23	0.23
SO_x, lb/MWh	0.007	0.007	0.006	0.006	0.005	0.005
UHC, ppmv @15% O_2	310	311	830	1400	1130	160
UHC, lb/MWh	4.6	4.6	12.3	20	15.5	2
NMOC, g/bhp-hr	0.7	0.15	1	1	1.3	0.5
NMOC, lb/MWh	2.2	0.46	3.1	3.1	4.0	1.6
CO_2, lb/MWh	1,345	1,330	1,283	1,175	1,135	1,078
Carbon, lb/MWh	377	377	350	328	311	280

For typical systems commercially available in 2003.
Estimates based on typical manufacturers' specifications: MAN 150 kW – 100 kW, Cummins GSK19G – 300 kW, Cummins QSV91G - 1 MW, Caterpillar G3616 LW – 3 MW, Wartsila 18V34SG – 5 MW.

nm = not measured

NMOCs are assumed to be 10 percent of THC (Total Hydrocarbons)

(EEA, 2003c; Energy Nexus Group, 2002)

Table 6-4
ICCR Emission Data for Reciprocating Engines

	<= 1,000 kW	> 1 MW
NO_x	0.11 - 46 g/bhp-hr 0.3 - 143 lb/MWh	0.5 - 32 g/bhp-hr 1.6 - 100 lb/MWh
CO	0.5 - 45 g/bhp-hr 1.6 - 140 lb/MWh	1 - 4.6 g/bhp-hr 3.1 - 14 lb/MWh
NMHC	0.1 - 65 g/bhp-hr 0.3 - 202 lb/MWh	0.1 - 4 g/bhp-hr 0.3 - 12 lb/MWh
PM_{10}	0.04 - 0.1 g/bhp-hr 0.12 - 0.3 lb/MWh	0.01 - 0.05 g/bhp-hr 0.03 - 0.16 lb/MWh

(EPA, 2002)

Table 6-5
Current and Advanced Gas Engine System Characteristics

Emissions & Performance Projections 100 kW Gas Engine System – Rich Burn with Three-Way Catalyst					
Year	Current	2005	2010	2020	2030
System Size, kW	100	100	100	100	100
Electrical Heat Rate (Btu/kWh), HHV	11,500	11,187	10,832	10,500	10,035
Electric Efficiency (%)	30%	31%	32%	33%	34%
Fuel Input (MMBtu/hr)	1.15	1.12	1.08	1.05	1.0
Emissions Characteristics					
NO_x, g/bhp-hr	0.15	0.15	0.10	0.10	0.10
NO_x, ppmv	11	11	8	8	8
NO_x, lb/MWh	0.465	0.465	0.31	0.31	0.31
CO, g/bhp-hr	0.6	0.60	0.50	0.30	0.10
CO, ppmv	69	69	62	40	14
CO, lb/MWh	1.80	1.80	1.50	0.90	0.30
SO_x, ppmv	0.24	0.24	0.25	0.23	0.24
SO_x, lb/MWh	0.007	0.007	0.007	0.006	0.006
NMOC, g/bhp-hr	0.15	0.15	0.10	0.10	0.10
NMOC, lb/MWh	0.46	0.46	0.31	0.31	0.31
CO_2, lb/MWh	1,345	1,308	1,267	1,228	1,174
Carbon, lb/MWh	377	377	351	330	316

NMOCs are assumed to be 10 percent of THC (Total Hydrocarbons)

Estimates based on: MAN 150 kW (stoichiometric with three-way catalyst system)– 100 kW; Cummins GSK19G – 300 kW; Cummins QSV91G – 1,000 kW; Caterpillar G3616 LE – 3 MW; Wartsila 18V34SG - 5 MW

(EEA, 2003c; Energy Nexus Group, 2002)

Table 6-5 (continued)
Current and Advanced Gas Engine System Characteristics

Emissions & Performance Projections **300 kW Gas Engine CHP System, Lean Burn**					
Year	Current	2005	2010	2020	2030
Electrical Heat Rate (Btu/kWh), HHV	10,967	10,832	10,498	10,185	9,749
Electric Efficiency (%)	31%	32%	33%	34%	35%
Fuel Input (MMBtu/hr)	3.3	3.25	3.15	3.06	2.92
Emissions Characteristics					
NO_x, g/bhp-hr	2.00	1.50	1.00	0.50	0.10
NO_x, ppmv	146	113	78	40	8
NO_x, lb/MWh	6.2	4.65	3.1	1.55	0.31
CO, g/bhp-hr	2.00	2.00	1.50	1.50	1.00
CO, ppmv	255	272	215	220	148
CO, lb/MWh	6.2	6.2	4.6	4.6	3.1
SO_x, ppmv	0.22	0.23	0.24	0.21	0.21
SO_x, lb/MWh	0.006	0.006	0.006	0.005	0.005
NMOC, g/bhp-hr	1.00	1.00	1.00	0.75	0.50
NMOC, lb/MWh	3.1	3.1	3.1	2.32	1.55
CO_2, lb/MWh	1,283	1,267	1,228	1,192	1,140
Carbon, lb/MWh	350	334	315	299	299

NMOCs are assumed to be 10 percent of THC (Total Hydrocarbons)
(EEA, 2003c; Energy Nexus Group, 2002)

Table 6-5 (continued)
Current and Advanced Gas Engine System Characteristics

Emissions & Performance Projections 1000 kW Gas Engine System, Lean Burn					
Year	Current	2005	2010	2020	2030
Electrical Heat Rate (Btu/kWh), HHV	10,246	8,979	8,530	8,124	8,124
Electric Efficiency (%)	33%	38%	40%	42%	42%
Fuel Input (MMBtu/hr)	8.20	7.18	6.82	6.50	6.50
Emissions Characteristics					
NO_x, g/bhp-hr	1.0	0.7	0.5	0.25	0.1
NO_x, ppmv	83	66	50	26	11
NO_x, lb/MWh	3.1	2.17	1.55	0.77	0.31
CO, g/bhp-hr	2.6	2.5	2.5	1.5	1.0
CO, ppmv	350	390	412	260	173
CO, lb/MWh	8.06	7.75	7.75	4.65	3.1
SO_x, ppmv	0.23	0.26	0.23	0.24	0.24
SO_x, lb/MWh	0.006	0.006	0.005	0.005	0.005
NMOC, g/bhp-hr	1.0	0.7	0.7	0.6	0.1
NMOC, lb/MWh	2.95	2.17	2.17	1.86	0.31
CO_2, lb/MWh	1,200	1,050	980	950	950
Carbon, lb/MWh	328	287	268	259	259

NMOCs are assumed to be 10 percent of THC (Total Hydrocarbons)
(EEA, 2003c; Energy Nexus Group, 2002)

Table 6-5 (continued)
Current and Advanced Gas Engine System Characteristics

Emissions & Performance Projections 3000 kW Gas Engine System, Lean Burn					
Year	Current	2005	2010	2020	2030
Electrical Heat Rate (Btu/kWh), HHV	10,050	9,611	9,099	8,638	8,222
Electric Efficiency (%)	34%	36%	38%	40%	42%
Fuel Input (MMBtu/hr)	10.1	9.61	9.1	8.64	8.22
Emissions Characteristics					
NO_x, g/bhp-hr	1.00	0.70	0.50	0.25	0.10
NO_x, ppmv	90	68	51	27	11
NO_x, lb/MWh	3.1	2.17	1.55	0.77	0.31
CO, g/bhp-hr	2.00	2.00	1.50	1.50	1.00
CO, ppmv	296	322	253	272	186
CO, lb/MWh	6.2	6.2	4.65	4.65	3.1
SO_x, ppmv	0.21	0.22	0.23	0.21	0.21
SO_x, lb/MWh	0.005	0.005	0.005	0.004	0.004
NMOC, g/bhp-hr	1.00	1.00	0.70	0.60	0.50
NMOC, lb/MWh	3.1	3.1	2.17	1.86	1.55
CO_2, lb/MWh	1,175	1,124	1,065	1,010	962
Carbon, lb/MWh	311	280	265	248	240

NMOCs are assumed to be 10 percent of THC (Total Hydrocarbons)
(EEA, 2003c; Energy Nexus Group, 2002)

Table 6-5 (continued)
Current and Advanced Gas Engine System Characteristics

Emissions & Performance Projections 5000 kW Gas Engine System, Lean Burn					
Year	Current	2005	2010	2020	2030
Electrical Heat Rate (Btu/kWh), HHV	9,213	8,749	8,322	7,935	7,582
Electric Efficiency (%)	37%	39%	41%	43%	45%
Fuel Input (MMBtu/hr)	46.1	43.7	41.6	39.7	37.9
Emissions Characteristics					
NO_x, g/bhp-hr	0.50	0.50	0.40	0.25	0.10
NO_x, ppmv	46	49	41	27	11
NO_x, lb/MWh	1.55	1.55	1.25	0.77	0.31
CO, g/bhp-hr	2.40	2.40	2.00	1.50	1.00
CO, ppmv	384	413	371	309	206
CO, lb/MWh	7.4	7.4	6.2	4.65	3.1
SO_x, ppmv	0.23	0.24	0.26	0.23	0.23
SO_x, lb/MWh	0.005	0.005	0.005	0.004	0.004
NMOC, g/bhp-hr	0.50	0.50	0.50	0.25	0.25
NMOC, lb/MWh	1.55	1.55	1.55	0.77	0.77
CO_2, lb/MWh	1,080	1,025	974	928	887
Carbon, lb/MWh	280	261	240	218	218

NMOCs are assumed to be 10 percent of THC (Total Hydrocarbons)
(EEA, 2003c; Energy Nexus Group, 2002)

7
FUEL CELLS

7.1 Introduction

Fuel cell systems, currently in the early stages of commercialization, are an entirely different approach to the production of electricity from traditional prime mover technologies, in that fuel cells produce direct current (DC) through an electrochemical process without direct combustion of fuel. Fuel cells offer the potential for clean, quiet, and very efficient power generation, benefits that have driven significant investment in their development in the past two decades. As with most technologies that are in the early stages of commercialization, fuel cell systems also face a number of formidable market entry issues resulting from product immaturity, system complexities, and unproven product durability and reliability. These translate into high capital cost, lack of support infrastructure, and technical risk for early adopters. While the future of fuel cells holds many unknowns, the many advantages of fuel cells suggest that they have the potential to significantly change the future structure of the energy industry.

There are five primary types of fuel cell technologies, each having a different electrolyte and a characteristic operating temperature. Two of these fuel cell types, polymer electrolyte membrane (PEMFC) and phosphoric acid fuel cell (PAFC), have acidic electrolytes and rely on the transport of H^+ ions (as shown in Figure 7-1) (EEA, 2003d). They are classified as proton-conducting fuel cells. Two others, the alkaline fuel cell (AFC) and the molten carbonate fuel cell (MCFC), have basic electrolytes that rely on the transport of OH^- and $CO_3^=$ ions, respectively. The fifth type, the solid oxide fuel cell (SOFC), is based on a solid-state ceramic electrolyte, in which oxygen ions ($O^=$) are the conductive transport ion. The latter three types are classified as anion-conducting. Table 7-1 presents fundamental characteristics for each fuel cell type. All of these except for the AFC are under development for DER applications.

Each fuel cell type has been designed to operate at optimum temperatures that strike a balance between ionic conductivity and component stability. These temperatures differ significantly among the five basic types, ranging from near ambient to as high as 1800°F. The proton-conducting fuel cells generate water at the cathode, and the anion-conducting cells generate water at the anode. Electrical generating efficiencies range from 30 percent to over 50 percent The five types of fuel cells can have very different performance characteristics, advantages, and limitations, and therefore will be suited to a wide variety of DER applications.

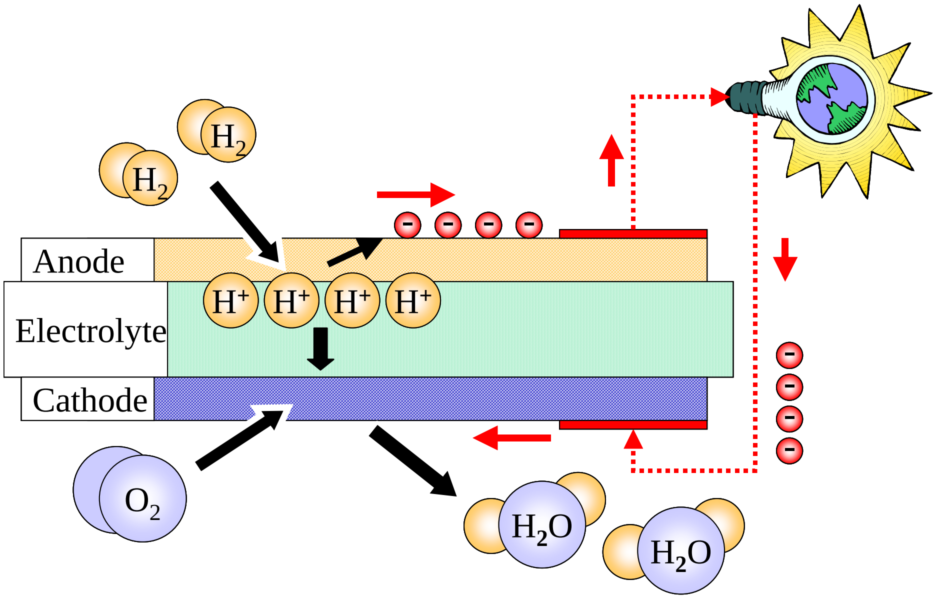

Figure 7-1
Fuel Cell Electrochemical Process

The different fuel cell types share certain important characteristics. First, fuel cells are not thermal energy-based (Carnot-cycle) engines. Because fuel cells are not heat-driven engines, they are not limited to the efficiency constraints of such engines. Instead, they use an electrochemical process to convert the chemical energy of hydrogen into water and electricity. Fuel cells can, in theory, achieve extremely high electrical efficiencies. Second, fuel cells use hydrogen as their fuel, which is typically derived from a hydrocarbon source such as natural gas, either from an external fuel processor or through reforming internal to the fuel cell. Third, all types of fuel cells have very low NO_x emissions because the only combustion processes are the reforming of natural gas or other fuels to produce hydrogen and the burning of a low-energy hydrogen exhaust stream that is used to heat the fuel processor.

A fuel cell contains two electrodes, an anode and a cathode, separated by an electrolyte, or catalyst. To produce a usable quantity of electricity, individual cells (anode, electrolyte and cathode) are assembled in a vertical stack of repeating interconnected components. A number of fuel cell stacks are commercially available for specialized applications. This report focuses on fuel cell systems (i.e., one or more fuel cell stacks, a fuel processor and power electronics) under development for distributed generation applications.

Today, there is only one commercially available fuel cell system with sustained field operational history for distributed generation applications, a 200 kW PAFC unit that has been commercially offered by UTC since 1992. With over 200 units sold, PAFCs have achieved nearly 6 million operating hours in a variety of distributed generation applications (UTC Fuel Cells). Although nearly two dozen companies are currently field testing a variety of fuel cell systems for market entry, the availability of a wide array of off-the-shelf, fully warranted fuel cell systems designed for broad customer classes is still several years away (ACEEE).

Table 7-1
Characteristics of Major Fuel Cell Types

	PAFC	PEMFC	AFC	MCFC	SOFC
Charge Carrier and Type of Electrolyte	H^+ ions (H_3PO_4 - phosphoric acid - solutions)	H^+ ions (with anions bound in polymer membrane)	OH^- ions (typically, aqueous KOH solution)	$CO_3^=$ ions (typically, molten $LiKaCO_3$ eutectics)	$O^=$ ions (Stabilized zirconia ceramic matrix with free oxide ions)
Typical construction	Carbon, porous ceramics	Plastic, metal or carbon	Plastic, metal	High temp metals, porous ceramic	Ceramic, high temperature metals
Internal reforming	No	No	No	Yes, good temperature match	Yes, good temperature match
Oxidant	Air or oxygen-enriched air	Air or oxygen	Purified air or oxygen	Air	Air
Operational Temperature	370-410°F (190-210°C)	150- 180°F (65-85°C)	190-500°F (90-260°C)	1200-1300°F (650-700°C)	1350-1850°F (750-1000°C)
Projected Electrical Efficiency*, % HHV	35 to 45%	30 to 40%	32 to 40%	40 to 50%	45 to 55%
Primary Contaminant Sensitivities	CO>1%, sulfur	CO, sulfur, and ammonia	CO, CO_2, and sulfur	sulfur	Sulfur

Projected electrical efficiencies are for natural gas fired fuel cell systems, including fuel processing (EEA, 2003d; EG&G Services, 2000)

7.2 Basic Processes and Components

Fuel cells produce direct current electricity through an electrochemical process. The reactants, most typically hydrogen and oxygen, are fed into the fuel cell, and power is generated as long as these reactants are supplied. The hydrogen (H_2) is typically generated from a hydrocarbon fuel such as natural gas or LPG. The oxygen is obtained from ambient air.

A fuel cell system consists of three primary subsystems: 1) the fuel cell stack that generates direct current electricity; 2) the fuel processor that converts the natural gas into a hydrogen rich feed stream; and 3) the power conditioner that processes the electric energy into alternating current or regulated direct current.

Figure 7-1 illustrates the electrochemical process in two types of fuel cells, PAFCs and PEMFCs. The fuel cell consists of a cathode (positively charged electrode), an anode (negatively charged electrode), and an electrolyte. The hydrogen and oxygen are fed to the anode and cathode, respectively. The hydrogen and oxygen gases do not directly mix and combustion does not occur. Instead, the hydrogen is oxidized with the help of a catalyst. Because the reaction does not take place at very high temperatures, there is no opportunity for the formation of NO_x. At the anode, the hydrogen gas is electrochemically dissociated (in the presence of a catalyst) into hydrogen ions (H^+) and free electrons (e^-) (EEA, 2003d).

The electrons flow out of the anode through an external electrical circuit. The hydrogen ions flow into the electrolyte layer and eventually to the cathode, driven by their concentration. At the cathode the oxygen gas is electrochemically combined (in the presence of a catalyst) with the hydrogen ions and free electrons to produce water.

The anode provides an interface between the fuel and the electrolyte, catalyzes the fuel reaction, and provides a path through which free electrons are conducted to the load via the external circuit. The cathode provides an interface between the oxygen and the electrolyte, catalyzes the oxygen reaction, and provides a path through which free electrons are conducted from the load via the external circuit. The electrolyte, an ionically conductive (but not electrically conductive) medium, acts as the separator between hydrogen and oxygen to prevent mixing and the resultant direct combustion. It completes the electrical circuit by transporting hydrogen ions from the anode to the cathode.

7.2.1 Fuel Processors

To operate on natural gas or other fuels, fuel cells require a device that converts the fuel into a hydrogen-rich gas stream. This device is known as a fuel processor or reformer. While adding fuel flexibility to the system, the reformer also adds significant cost, complexity and inefficiency. There are three primary types of reformers: steam reformers, autothermal reformers, and partial oxidation reformers. The fundamental differences are the source of oxygen used to combine with the carbon within the fuel to release the hydrogen and the thermal balance of the chemical process. Steam reformers use steam, partial oxidation units use oxygen gas and autothermal reformers use both steam and oxygen

Steam reforming is extremely endothermic and requires a substantial amount of heat input. Partial oxidation units combust a portion of the fuel (i.e. partially oxidize it), releasing heat in the process. Autothermal reformers balance the amount of steam and oxygen used in order to operate at or near the thermal neutral point and do not generate or consume heat.

Whenever hydrogen is obtained from a hydrocarbon fuel, there is usually some carbon monoxide (CO) in the hydrogen. Unfortunately, the low-temperature catalysts used in PEMFCs have low tolerance to CO (commonly called CO-poisoning), which degrades performance. The higher temperature technologies are more tolerant of CO. Alkaline fuel cells are also sensitive to CO poisoning.

Sulfur compounds also poison fuel cell catalysts. Consequently, fuel-processing systems for fuel cells that are designed to operate on infrastructure fuels must include an upstream desulfurizer. The mercaptan odorant used in natural gas is a sulfur compound that typically needs to be removed. Similarly, chlorides must be removed from anaerobic digester gas prior to its use in fuel cells.

7.3 Fuel Cell System Emissions

Since the power generation process in fuel cell systems is electrochemical, no emissions from combustion are produced from the power generation itself. The fuel processing subsystem is the primary source of the limited combustion emissions generated in fuel cell systems. For PAFCs, the anode-off-gas, which typically consists of 8 to 15 percent hydrogen is burned in a catalytic or surface burner element to heat the reformer. The temperature of this very lean combustion can be maintained at less than 1,800° F, which limits the formation of NO_x but is sufficiently high to ensure oxidation of CO and VOCs. SO_x is eliminated because it is typically removed in an adsorption bed before the fuel is processed.

7.3.1 Emissions Characteristics

Table 7-2 shows the emission characteristics of fuel cell systems. Because of their very low emissions, fuel cell systems do not require any emissions control devices to meet current and projected regulations.

Table 7-2
Estimated Fuel Cell Emission Characteristics Without Additional Controls

Emissions Analysis	System 1	System 2	System 3	System 4	System 5	System 6
Fuel Cell Type	PAFC	PEMFC	PEMFC	MCFC	MCFC	SOFC
Electricity Capacity (kW)	200	5-10	150-250	250	2000	100-250
Electrical Efficiency (HHV)	36%	30%	35%	43%	46%	45%
Emissions						
NO_x, ppmv @ 15% O_2	1	1.8	1.8	2	2	2
NO_x, lb/MWh	0.04	0.1	0.1	0.06	0.05	0.05
CO, ppmv @ 15% O_2	2	2.8	2.8	2	2	2
CO, lb/MWh	0.05	0.07	0.07	0.04	0.04	0.04
SO_x, ppmv	0.20	0.24	0.24	0.24	0.24	0.24
SO_x, lb/MWh	0.005	0.0068	0.0058	0.0047	0.0044	0.0045
VOC, ppmv @ 15% O_2	0.7	0.4	0.4	0.5	1	1
VOC, lb/MWh	0.01	0.01	0.01	0.01	0.01	0.01
CO_2, lb/MWh	1,135	1,360	1,170	950	890	910
Carbon, lb/MWh	310	370	315	260	240	245

Basis for characterization: PAFC – UTC, PEMFC 5-10 kW – Composite, PEMFC 150-250 kW – UTC, MCFC – Fuel Cell Energy, SOFC – Siemens Westinghouse.

Electric only, for typical systems under development in 2003.

Estimates are based on fuel cell system developers' goals and prototype characteristics except PAFC for which plenty of test data is available. All estimates are for emissions without after-treatment and are adjusted to 15 percent O_2.

(EEA, 2003d; Energy Nexus Group, 2002)

The certification data from the California DG certification program (Table 3-1) support these data for the commercially available fuel cells and show that some models are cleaner than the manufacturer guarantees. Some additional studies have been completed on PEMC fuel cells operated on hydrogen or methane; these data are not publicly available. Emissions from PAFC operated on ADG and LFG have been measured; these studies are discussed in Section 8.

7.4 Key Technology Advances

Developers and manufacturers of fuel cell systems, with government support, have pursued significant R&D efforts for fuel cells based on their potential for high efficiency and minimal environmental impact. Efforts have focused on technology and product research, leading to system demonstrations and, in the case of PAFC, to sustained commercial use. The critical challenge for all fuel cell systems is cost reduction. Other challenges include increasing system efficiency and power density, reducing maintenance costs, extending maintenance intervals, and validating product durability (Federal Energy Technology Center, 1998). The pace of technology advancements in fuel cell systems has accelerated with the support of the PEMFC technology by the automotive industry and the realization that smaller, modular systems provide viable technology validation platforms and potentially economically feasible products.

Table 7-3 presents projections of the future performance of the six fuel cell CHP systems profiled previously.

Table 7-3
Current and Advanced Fuel Cell System Characteristics

Emissions and Performance Projections 200 kW PAFC System					
Year	**Current**	**2005**	**2010**	**2020**	**2030**
Fuel Cell Technology	PAFC	PAFC	PAFC	PAFC	PAFC
System Size, kW	200	200	-	-	-
Electrical Heat Rate (Btu/kWh), HHV	9,480	9,480	-	-	-
Electrical Efficiency (%)	36%	36%	-	-	-
Fuel Input (MMBtu/hr)	1.90	1.90	-	-	-
Emissions Characteristics					
NO_x, ppmv	1.2	1.2	-	-	-
NO_x, lb/MWh	0.04	0.04	-	-	-
CO, ppmv	2.4	2.4	-	-	-
CO, lb/MWh	0.05	0.05	-	-	-
NMOC, ppmv	0.8	0.8			
NMOC, lb/MWh	0.01	0.01			
CO_2, lb/MWh	1,140	1,140			

NMOCs are assumed to be 10 percent of THC (Total Hydrocarbons)
Emissions projected without add-on controls.
(EEA, 2003d; Energy Nexus Group, 2002)

Table 7-3 (continued)
Current and Advanced Fuel Cell System Characteristics

Emissions and Performance Projections 5-10 kW PEMFC System					
Year	**Current**	**2005**	**2010**	**2020**	**2030**
Fuel Cell Technology		PEMFC	PEMFC	PEMFC	PEMFC
System Size, kW		10	10	10	10
Electrical Heat Rate (Btu/kWh), HHV		11,370	10,660	9,750	9,480
Electrical Efficiency (%)		30%	32%	35%	36%
Fuel Input (MMBtu/hr)		0.11	0.11	0.10	0.09
Emissions Characteristics					
NO_x, ppmv		1.5	1.5	1.4	1.4
NO_x, lb/MWh		0.06	0.06	0.05	0.05
CO, ppmv		2.8	2.5	2.8	2.8
CO, lb/MWh		0.07	0.06	0.06	0.06
NMOC, ppmv		0.7	0.7	0.8	0.8
NMOC, lb/MWh		0.01	0.01	0.01	0.01
CO_2, lb/MWh		1,360	1,280	1,170	1,140

NMOCs are assumed to be 10 percent of THC (Total Hydrocarbons)
Emissions projected without add-on controls.
(EEA, 2003d; Energy Nexus Group, 2002)

Table 7-3 (continued)
Current and Advanced Fuel Cell System Characteristics

Emissions and Performance Projections 200-250 kW PEMFC System				
Year	**2005**	**2010**	**2020**	**2030**
Fuel Cell Technology	PEMFC	PEMFC	PEMFC	PEMFC
System Size, kW	200	200	200	200
Electrical Heat Rate (Btu/kWh), HHV	9,750	9,480	8,980	8,980
Electrical Efficiency (%)	35%	36%	38%	38%
Fuel Input (MMBtu/hr)	1.95	1.90	1.80	1.80
Emissions Characteristics				
NO_x, ppmv	2.8	2.0	1.5	1.5
NO_x, lb/MWh	0.1	0.07	0.05	0.05
CO, ppmv	3.3	1.9	2.0	2.0
CO, lb/MWh	0.07	0.04	0.04	0.04
NMOC, ppmv	0.8	<0.8	<0.8	<0.8
NMOC, lb/MWh	0.01	<0.01	<0.01	<0.01
CO_2, lb/MWh	1,170	1,140	1,080	1,080

NMOCs are assumed to be 10 percent of THC (Total Hydrocarbons)
Emissions projected without add-on controls.
(EEA, 2003d; Energy Nexus Group, 2002)

Table 7-3 (continued)
Current and Advanced Fuel Cell System Characteristics

Emissions and Performance Projections 250 kW MCFC System					
Year	**Current**	**2005**	**2010**	**2020**	**2030**
Fuel Cell Technology	MCFC	MCFC	MCFC	MCFC	MCFC
System Size, kW	250	250	250	250	250
Electrical Heat Rate (Btu/kWh), HHV	7,930	7,930	7,580	6,920	6,960
Electrical Efficiency (%)	43%	43%	45%	49%	49%
Fuel Input (MMBtu/hr)	1.98	1.98	1.90	1.74	1.74
Emissions Characteristics					
NO_x, ppmv	2.0	2.0	1.8	1.6	1.6
NO_x, lb/MWh	0.06	0.06	0.05	0.04	0.04
CO, ppmv	2.3	2.3	2.4	1.9	1.9
CO, lb/MWh	0.04	0.04	0.04	0.03	0.03
NMOC, ppmv	1.0	1.0	<1.0	<1.1	<1.1
NMOC, lb/MWh	0.01	0.01	<0.01	<0.01	<0.01
CO_2, lb/MWh	950	950	908	834	834

NMOCs are assumed to be 10 percent of THC (Total Hydrocarbons)
Emissions projected without add-on controls.
(EEA, 2003d; Energy Nexus Group, 2002)

Table 7-3 (continued)
Current and Advanced Fuel Cell System Characteristics

Emissions and Performance Projections 2,000 kW MCFC System				
Year	**2005**	**2010**	**2020**	**2030**
Fuel Cell Technology	MCFC	MCFC	MCFC	MCFC
System Size, kW	2,000	2,000	2,000	2,000
Electrical Heat Rate (Btu/kWh), HHV	7,420	7,110	6,820	6,560
Electrical Efficiency (%)	46%	48%	50%	52%
Fuel Input (MMBtu/hr)	14.8	14.2	13.6	13.1
Emissions Characteristics				
NO_x, ppmv	1.9	1.9	1.6	1.6
NO_x, lb/MWh	0.05	0.05	0.04	0.04
CO, ppmv	2.4	1.9	1.9	2.0
CO, lb/MWh	0.04	0.03	0.03	0.03
NMOC, ppmv	1.1	<1.1	<1.1	<1.2
NMOC, lb/MWh	0.01	<0.01	<0.01	<0.01
CO_2, lb/MWh	890	850	820	790

NMOCs are assumed to be 10 percent of THC (Total Hydrocarbons)
Emissions projected without add-on controls.
(EEA, 2003d; Energy Nexus Group, 2002)

Table 7-3 (continued)
Current and Advanced Fuel Cell System Characteristics*

Emissions and Performance Projections 100-250 kW SOFC System				
Year	**2005**	**2010**	**2020**	**2030**
Fuel Cell Technology	SOFC	SOFC	SOFC	SOFC
System Size, kW	100	100	100	100
Electrical Heat Rate (Btu/kWh), HHV	7,580	6,960	6,690	6,440
Electrical Efficiency (%)	45%	49%	51%	53%
Fuel Input (MMBtu/hr)	0.76	0.70	0.67	0.64
Emissions Characteristics				
NO_x, ppmv	1.8	1.9	1.6	1.7
NO_x, lb/MWh	0.05	0.05	0.04	0.04
CO, ppmv	2.4	1.9	2.0	2.1
CO, lb/MWh	0.04	0.03	0.03	0.03
NMOC, ppmv	1.0	<1.1	<1.1	<1.2
NMOC, lb/MWh	0.01	<0.01	<0.01	<0.01
CO_2, lb/MWh	908	834	801	772

NMOCs are assumed to be 10 percent of THC (Total Hydrocarbons)

Emissions projected without add-on controls.

(EEA, 2003d; Energy Nexus Group, 2002)

8

BIOFUELS

This chapter provides information on the emissions of DER technologies using a variety of biomass-derived fuels. These include gaseous fuels derived from biomass as well as diesel-like liquid biofuel, often called “biodiesel”. These fuels are addressed in two categories:

- Conventional biogases – These gases include landfill gas (LFG), anaerobic digester gas (ADG) and agricultural biogas. These fuels have some track record of usage for DER applications and this section provides information on available emission test data for these fuels.
- New biofuels – These include biomass-based gasification and biodiesel. These fuels have had little or no application history and this chapter characterizes the availability of data on DER emissions from these fuels.

8.1 Conventional Biogases

Biogases include LFG, digester gas and agricultural biogases. All are the result of anaerobic decomposition of organic materials. They typically are composed of about half methane, about half CO_2, and smaller amounts of non-methane organic compounds and other contaminants.

ADG is a product of sewage treatment in which sewage sludge is allowed to decompose in a closed vessel in order to reduce its volume and create a more stable residue. In addition to methane and CO_2, it contains contaminants including hydrogen sulfide (H_2S), other sulfur compounds and a variety of other corrosive gases that evolve from chemical products in the waste. The gas is formed in a closed vessel, so digester gas is already “collected”. The gas has typically not been vented to the outside because of odor and the potential for fire or explosion. Historically, ADG has been flared or used to heat hot water for use in the sewage clean-up process. Using the gas in a boiler to heat water is the simplest application and meets a need at sewage treatment plants, though it probably has a lower value than electricity that can be produced with DER technologies. Recent projects have focused on CHP applications that can supply both electricity and hot water.

LFG is created when buried organic waste in a landfill naturally decomposes. In addition to methane and CO_2, it contains contaminants including hydrogen sulfide (H_2S), other sulfur compounds and a variety of other corrosive gases that evolve from chemical products in the waste. LFG also contains chemicals called siloxanes, which are silica-based compounds that derive from various consumer products in the waste stream. The siloxanes create significant problems for power technologies, as discussed below. LFG also contains water and particulates and HAPs. The composition of the LFG depends on the composition of the materials in the landfill. It can vary depending on the location in the landfill and it can change over time as different components decompose.

Historically, LFG was allowed to escape into the air as it percolated through the soil. The main drawback to this was odor, though LFG also contributes to other air quality problems. Methane, a major component of LFG, is a greenhouse gas, with a global heating potential 20 times that of CO_2. In 1996, the U.S. EPA promulgated rules requiring the collection and destruction of LFG under New Source Performance Standards (NSPS) and Emissions Guidelines (EG). If a landfill's non-methane organic compound (NMOC) emissions are greater than or equal to 50 tonnes/year (about 55 tons/year), the landfill rule requires the installation of a gas collection and control system. Sources must collect the LFG and destroy it at 98 percent efficiency. There are also specified operation and maintenance procedures as well as specific recordkeeping and reporting requirements.

The regulatory requirement to collect and destroy LFG is a key factor in its use for power generation. Without the regulatory requirement, landfill operators would probably not commit the capital required to collect the LFG. Once the capital has been committed in response to the regulatory requirement, there is an incentive to put it to some productive, income-generating application. The requirement to collect the gas essentially creates a fuel resource that did not exist before that requirement. Large landfills do not generally have large thermal or electric loads on-site or nearby, however, so the ability to sell power to the grid is important to the economics of most projects. The scale of landfills subject to the NSPS is such that LFG projects are generally in the 1 to 5 MW range.

Agricultural biogas is formed from the decomposition of crop or animal wastes and is often created in large livestock farming operations. Agricultural biogas historically has been allowed to escape into the air and this is still the most common practice. It can be collected from conventional waste storage facilities as simply as by covering the waste with a tarp to collect the gas. More sophisticated digester gas systems can be used to generate biogas that is over 90 percent pure methane. The composition of the gases depends on the type of waste. Agricultural waste typically has fewer precursors of contaminants and corrosive materials; however, it does contain sulfur derived from sulfa drugs and natural compounds in animal waste. Based on the size of most agricultural operations, DER projects at these facilities would typically be smaller than 1 MW.

Because there is no requirement to collect agricultural biogas, it is still generally allowed to escape into the atmosphere and has not developed substantially as a source of fuel for DER. The status of this resource is similar to that of LFG prior to the landfill NSPS. Without a driver to collect the gas and with relatively little on-site electric demand, there is little incentive to invest the capital needed to develop the resource.

The attraction of using these gases is that they are essentially “free fuel”, which can make a big difference in the economics of a DER project. The increased flexibility of electric industry restructuring has also created a major driver. Digester gas is part of a controlled process (sewage processing) in a more urban area so the odor and potential for fire or explosion have generally required flaring if the gas was not used productively. Sewage plants have electric and thermal loads and were already collecting the digester gas, so they are excellent candidates for on-site CHP applications.

Landfill and agricultural biogases are diffuse resources and were historically allowed to escape. Since they are typically generated in rural settings, their main perceived impacts were odor. In the case of landfills, however, the requirement to collect and destroy the gas essentially “created” a new resource. There is a significant cost to gather the gas as required by the regulations. If the gas is flared, the effort is a dead loss. If the gas can be used to generate electricity, then there is a potential to recover some of the cost of compliance. This change has not yet taken place for agricultural biogas. There is not yet the impetus for gathering the gas, and interconnection barriers and other institutional barriers are still slowing the growth of this market.

8.1.1 Biogas Emissions

Turbines and engines are established commercial technologies that have been used with biogas. Microturbines and phosphoric acid fuel cells are in the early stages of commercialization and have limited application either with pipeline natural gas or biogases. Other types of fuel cells are still under development.

Wellhead natural gas contains a variety of contaminants, inert gases, moisture and particulates. All of these are removed in processing so that pipeline natural gas is a very clean fuel with consistent combustion characteristics. Waste and byproduct gases are similar in many ways to raw, wellhead natural gas. This creates a variety of challenges to their direct use. First, the contaminants in the gas cause erosion and corrosion of the DER equipment. They also prevent the use of catalytic combustion or emission reduction devices. Second, the heating value of the gas is approximately half that of pipeline natural gas because of the large CO_2 content. This has different implications for different technologies. Modern power generation technologies use very sophisticated combustion design and control technologies to maximize efficiency and minimize emissions. The proper operation of these technologies relies on consistent fuel characteristics. The range of characteristics inherent in biogases is beyond the allowable range for many of these technologies. Some of the specific components of waste and byproduct fuels and the operational problems that they can cause include:

- Solids – can cause erosion of critical surfaces or plugging of orifices
- Water – retards combustion and can cause erosion, corrosion or catastrophic damage to critical surfaces or components
- Non-methane fuel components (butane, propane, carbon monoxide, hydrogen) - change combustion characteristics; if present in liquid form can cause physical damage
- Sulfur and sulfur compounds – cause corrosion in engines, increase maintenance requirements (more frequent overhauls and oil changes), poison catalyst materials
- CO_2 – reduces heating value, reduces combustibility
- Siloxanes – create a glassy deposition on high temperature surfaces; particles can break off and damage working parts

The siloxanes are one of the most difficult components to deal with. These silica-based compounds derive from a variety of consumer products. At high temperatures they form a glassy deposit on DER components. This can directly affect the operation of the equipment, and pieces of the deposit can break or flake off and damage other parts of the generator. Current practice for engines and turbines seems to be to hope for the best and make repairs as necessary.

In addition to the operation of the engine, fuel contaminants affect catalyst systems used either for emission reduction or catalytic combustion. Sulfur and other compounds can “poison” catalysts and block their operation. Siloxanes and other compounds can “mask” catalysts by forming a physical layer that prevents the catalyst from working.

Some minimal amount of gas cleaning is required for almost any prime mover using biogas. This would include removal of solids and water. The ideal would then be to be able to operate with the remaining contaminants and this has been the practice to date. It has meant living with the corrosive components and siloxanes. Recently, there has been work on additional clean-up technologies for LFG and ADG, including:

- Chemical “filters” to remove sulfur compounds
- Cooling the gas to remove additional moisture
- Filter systems to remove siloxanes
- Chemical systems to remove CO_2 to produce pipeline quality gas
- Cryogenics also can be used, though at a higher cost.

These are the same types of techniques used to process raw natural gas and it is possible to create pipeline-quality gas from LFG. The question is whether it is economic for these small quantities. There is both a capital cost and an energy cost, since some of these processing steps are very energy intensive. Since the primary attraction of waste and byproduct fuel is that it is free, there comes a point at which the cost of gas cleanup becomes prohibitive. Fuel quality issues aside, the potential regulated emissions from these sources are identified below:

- SO_x – SO_x emissions are a direct function of the sulfur content of the fuel. With complete combustion, any sulfur in the fuel will be emitted as SO_x. Since waste and byproduct fuels contain sulfur or H_2S, there will be SO_x emissions. The amount depends on the specific fuel.
- CO_2 - CO_2 is an unavoidable product of combustion of hydrocarbon fuels. In addition, most biogas contains a significant amount of CO_2 in the fuel itself. In the case where the methane fuel would otherwise have been vented, the net effect of combustion is a major reduction in GHG impact because the GHG potential of methane is 23 times greater than that of CO_2.
- Particulates - Emissions of solid particulates from combustion of a clean gas fuel are small to insignificant. The emissions of condensible and ultrafine particulates are still being studied. Impurities and contaminants in the fuel can cause the formation of particulates from either flaring or prime movers, though the results will be fuel-specific and there is little consistent data for comparisons.

- NO_x - NO_x emissions are primarily a result of the reaction between oxygen and nitrogen in the combustion air at high temperatures during the combustion process. The low heating value and high content of CO_2 in biogases can limit the combustion temperature and reduce NO_x formation.
- CO and unburned hydrocarbons/VOCs - These are both products of incomplete combustion. DER prime movers are designed to promote complete combustion in order to maximize the energy converted. However, complete combustion is often a tradeoff against reducing NO_x. Low-NO_x combustion technologies often result in increased CO and hydrocarbon emissions. Stationary sources are not usually the major source of these pollutants and this tradeoff is often deemed reasonable by regulators. The exception is the requirement to destroy 98 percent of landfill gases. If DER technologies cannot meet this requirement, their applicability for LFG applications is reduced.
- HAPs– Most of the air toxics potentially produced by DER technologies are hydrocarbon products of incomplete combustion.

The primary sources of data on emissions from combustion of biogases include:

- Data from DER equipment manufacturers on emissions from waste and byproduct fuels
- Emission testing of DER technologies
- EPA’s AP-42 Emission Factors
- Local permit applications - California jurisdictions such as the South Coast Air Quality Management District (SCAQMD) and Bay Area Air Quality Management District (BAAQMD) - tend to have the most stringent technology-specific emission limits. These limits are a useful indicator of the current state-of-the-art of emissions, especially for smaller sources but do not represent actual emission test results.
- Permit information from the EPA BACT/LAER Clearinghouse. This database lists information from recent air permits meeting Best Available Control Technology (BACT) and Lowest Achievable Emission Rate (LAER) criteria. While useful, it has a few drawbacks:
  - It represents permit limits rather than actual test data.
  - Not all permit data are reported to the clearinghouse.
  - There can be a significant lag before data are reported.
  - There may not be any verification of whether the permit levels are actually achieved.
  - Most of the projects are much larger than the DER technologies that are of interest here.

The following sections summarize the available information on NO_x, CO and unburned hydrocarbon emissions of DER technologies burning biogas fuels.

8.1.2 Reciprocating Engines

As noted above, NO_x emissions are often the most significant permitting issue for DER applications. There are two main approaches to NO_x control in reciprocating gas engines: lean burn combustion and rich burn/TWC. However, the contaminants in waste and byproduct fuel gases will typically poison or "mask" the catalyst in a TWC system and this technology cannot be used with biogas unless the gas is highly cleaned. This means that lean burn combustion is the primary option available for biogas combustion. Although significant and complex changes must be made to the fuel handling and combustion control system to accommodate the lower heat content of waste and byproduct fuels, the high CO_2 content of biogas fuel can actually help reduce NO_x by acting as a diluent and reducing the combustion temperature. Other contaminants in the fuel increase operating and maintenance costs as discussed above.

Table 8-1 lists the available emissions data. AP-42 gives a NO_x emission factor of 0.8 g/bhp-hr (2.6 lb/MWh) for this application. The BACT/LAER Clearinghouse lists permits for 1 to 2 g/bhp-hr (3.1 to 6.2 lb/MWh) for engines using LFG. The SCAQMD guideline is 0.6 g/bhp-hr (1.9 lb/MWh) and regulators and manufacturers confirm that reciprocating engines can achieve this level or slightly lower. The CARB guidance uses the same value.

Table 8-1
Emission Summary for Lean Burn LFG Reciprocating Engines*

Data Source	NO_x		CO		VOC	
	g/bhp-hr	lb/MWh	g/bhp-hr	lb/MWh	g/bhp-hr	lb/MWh
AP-42	0.8	2.6	1.6	5.1	NA	NA
SCAQMD	0.6	1.9	2.5	7.8	0.8	2.5
BACT/LAER	1	3.1	2.9	9.02	0.25	0.78
BACT/LAER	2	6.2	2.3	7.2	0.375	1.17
CARB	0.6	1.9	2.5	7.8	0.6	1.9
Composite		1.9		8.0		1.9

* For engines in the 1 MW or larger range.
NA – not available. SCAQMD – South Coast Air Quality Management District of California. EPA Best Available Control Technology (BACT) and Lowest Achievable Emission Rate (LAER) Clearinghouse. CARB – California Air Resources Board.

Although lean burn engines can achieve these low NO_x emission levels, it is typically at the cost of complete combustion, meaning higher CO and VOC emissions. The CO data are fairly consistent, in the range of 2 to 3 g/bhp-hr (7 to 9 lb/MWh) except for the AP-42 factor, which is somewhat lower. The HC/VOC data are in the range of 1.2 to 2.5 lb/MWh.

There are reports that these engines sometimes cannot achieve the 98 percent LFG destruction required by the landfill NSPS. In order to meet this requirement, they may require the addition of a post-combustion thermal oxidizer. This is a furnace-like device that completes the combustion of the LFG, often with assistance of additional fuel and with the creation of additional NO_x emissions.

Normally, it would be technically feasible to use post-combustion catalytic NO_x reduction technology (selective catalytic reduction or SCR) to reduce NO_x emissions as well as an oxidation catalyst to reduce CO and HC emissions. However, the contaminants in the gases can poison or mask the catalyst, so this is not typically an option.

There is extensive work underway to reduce NO_x emissions from reciprocating engines. A variety of pathways are being considered, some of which include catalytic components. If the future engine technology follows this path, it will not be available for waste and byproduct fuel gases that contain contaminants that would poison or mask the catalyst.

8.1.3 Combustion Turbines

State-of-the-art NO_x control for small combustion turbines also uses very lean combustion to achieve NO_x levels of 15 to 25 ppm (0.65 to 1.1 lb/MWh) on pipeline natural gas. This approach, known as “lean pre-mix combustion”, mixes the fuel with a large volume of air to lower the peak flame temperature and thus limit NO_x formation. In order to achieve the desired low NO_x levels, the combustor is designed and carefully controlled so that there is barely enough fuel to sustain combustion.

The reduced heat content of biogas fuels does not provide enough heat to sustain combustion in lean burn combustion systems designed for pipeline natural gas, so these systems cannot be used. Instead, the turbines must apply a conventional “diffusion burner” which can achieve 25 to 35 ppm NO_x (1.1 to 1.5 lb/MWh). (Some turbine manufacturers will not guarantee NO_x levels below 32 ppm on LFG, but there are LFG turbines operating with permits at 25 ppm.) At this level of NO_x, turbine manufacturers believe that they can achieve 98 percent LFG destruction; however, available test data are not adequate to guarantee that result.

Table 8-2 lists emissions data for combustion turbines firing LFG. AP-42 lists NO_x emissions for turbines burning LFG ranging from 33 to 44 ppm (1.7 to 2.2 lb/MWh). The BACT/LAER clearinghouse lists an even wider range, from 32 to 63 ppm (1.6 to 3.2 lb/MWh). The SCAQMD and BAAQMD guidance is 25 ppm (1.25 lb/MWh) and there are some turbines permitted at that level, though as noted above, some manufacturers will not guarantee that level.

The AP-42 data for CO range from 0.1 to 0.4 lb/MMBtu (1.2 to 4.8 lb/MWh). The SCAQMD guidance is within that range at 3.4 lb/MWh. The BACT/LAER data are higher but may be out of date. The available data for HC are in the range of 0.1 lb/MWh.

Due to the low volume of turbines sold for alternative fuel use, it is unlikely that manufacturers will make the investment required to develop separate versions of the low NO_x combustors that could operate on alternative fuels. In addition, the characteristics of the waste and byproduct fuels vary sufficiently that it may be difficult to match them with one alternative design.

While SCR is sometimes used to limit NO_x from small turbines, it cannot be used with waste and byproduct fuels that include contaminants that would poison or mask the catalyst. Besides lean combustion, catalytic combustion is one of the primary directions of current work on further reducing NO_x emissions from turbines. This path will be unavailable to systems using waste and byproduct fuels with contaminants that would poison or mask the catalyst.

Table 8-2
Emission Summary for Lean Burn LFG Combustion Turbines

Data Source	NO_x		CO		VOC	
	ppm	lb/MWh	lb/MMBtu	lb/MWh	ppm	lb/MWh
AP-42	33-44	1.7-2.2	0.1-0.4	1.2-4.8	0.013	0.16
SCAQMD	25	1.28	130 ppm	3.4	NA	NA
BACT/LAER	32-63	1.6-3.2	0.75	9.0	0.0062	0.07
CARB	25	1.25	NA	NA	NA	NA
Composite		1.25		3.5		0.1

NA – not available. SCAQMD – South Coast Air Quality Management District of California. EPA Best Available Control Technology (BACT) and Lowest Achievable Emission Rate (LAER) Clearinghouse. CARB – California Air Resources Board.

8.1.4 Microturbines

Waste and byproduct fuels create the same kinds of contaminant problems for microturbines as for other small generators. Because microturbines are at an early stage of commercialization, there have been only a few applications on waste and byproduct fuels. Microturbine LFG and ADG projects to date use extensive gas clean-up technology (for particulates, sulfur, moisture and siloxanes) to allow the use of a standard microturbine design. Extensive emission testing data are not yet available, but microturbine manufacturers believe that they can achieve the standard emission levels on this cleaned gas even though it has a much lower heat content than pipeline natural gas. Less gas cleanup may be required for digester gas, associated gas and agricultural biogas applications. If the standard emissions levels can be maintained in these applications, the microturbine could be the lowest-emitting DER technology for those applications, though the extensive cleanup may be cost-prohibitive.

8.1.5 Fuel Cells

There is only one commercial fuel cell technology available today (PAFC), though there are several others under development. All have very low emissions. Fuel cells typically require a very clean, hydrogen-rich fuel stream, free of the kind of contaminants found in waste and byproduct fuel gases. On the other hand, fuel cell systems already incorporate a fuel-processing system to turn commercial fuels into hydrogen-rich fuel. Therefore it could be that adding additional clean-up steps may be less of an issue for fuel cells than for other technologies. A test by ETV (1998) used an extensive clean-up train to remove contaminants from the fuel and protect the fuel cell. Under these conditions, the PAFC achieved its normal very low emissions performance. A demonstration project at the NYPA Yonkers Wastewater Treatment Plant (Spiegel and Preston, 2000) took a similar approach, using ADG as the fuel source. The conclusion of that test was that more work needs to be done on the clean-up technology. NYPA plans to conduct further testing of PC25 fuel cells operating on ADG. These tests will provide additional data on emissions from these units.

8.2 New Biofuels

8.2.1 Biodiesel

Biodiesel is a diesel replacement fuel made from natural, renewable sources such as new and used vegetable oils and animal fats. Like petroleum diesel, biodiesel operates in compression-ignition engines. Biodiesel has physical properties very similar to conventional diesel.

Table 8-3
Physical Characteristics of Biodiesel

Specific gravity	0.87 to 0.89
Kinematic viscosity @ 40°C	3.7 to 5.8
Cetane number	46 to 70
Higher heating value (Btu/lb)	16,928 to 17,996
Sulfur, wt%	0.0 to 0.0024
Cloud point °C	-11 to 16
Pour point °C	-15 to 13
Iodine number	60 to 135
Lower heating value (Btu/lb)	15,700 to 16,735

Blends of up to 20 percent biodiesel (mixed with petroleum diesel fuels) can be used in nearly all diesel equipment and are compatible with most storage and distribution equipment. These low level blends (20 percent and less) don't require engine modifications and can provide the same payload capacity as diesel. Higher blends, even pure biodiesel (100 percent biodiesel, or B100), can be used in many engines built since 1994 with little or no modification. Transportation and storage, however, require special management. Material compatibility and warrantee issues haven't been resolved with higher blends.

There has been relatively little testing and application of biodiesel to date and most of it has focused on transportation engines. However, the emissions data for transportation engines can be extended to stationary applications for DER.

The most complete assessment of emissions from engines using biodiesel is an analysis by the EPA (U.S.EPA, 2002b). This analysis evaluated 80 biodiesel emissions studies, listed in Appendix C. The results of the analysis are illustrated in Figure 8-1. Because biodiesel has low sulfur and high oxygen content, using biodiesel in a conventional diesel engine substantially reduces emissions of unburned hydrocarbons, carbon monoxide, sulfates, polycyclic aromatic hydrocarbons, nitrated polycyclic aromatic hydrocarbons, and particulate matter. These reductions increase as the amount of biodiesel blended into diesel fuel increases. The best emissions reductions are seen with B100.

The use of biodiesel decreases the solid carbon fraction of particulate matter (since the oxygen in biodiesel enables more complete combustion to CO_2) and reduces the sulfate fraction (biodiesel contains less than 24 ppm sulfur), while the soluble, or hydrocarbon, fraction stays the same or increases. Therefore, biodiesel works well with new technologies such as diesel oxidation catalysts (which reduce the soluble fraction of diesel particulate but not the solid carbon fraction).

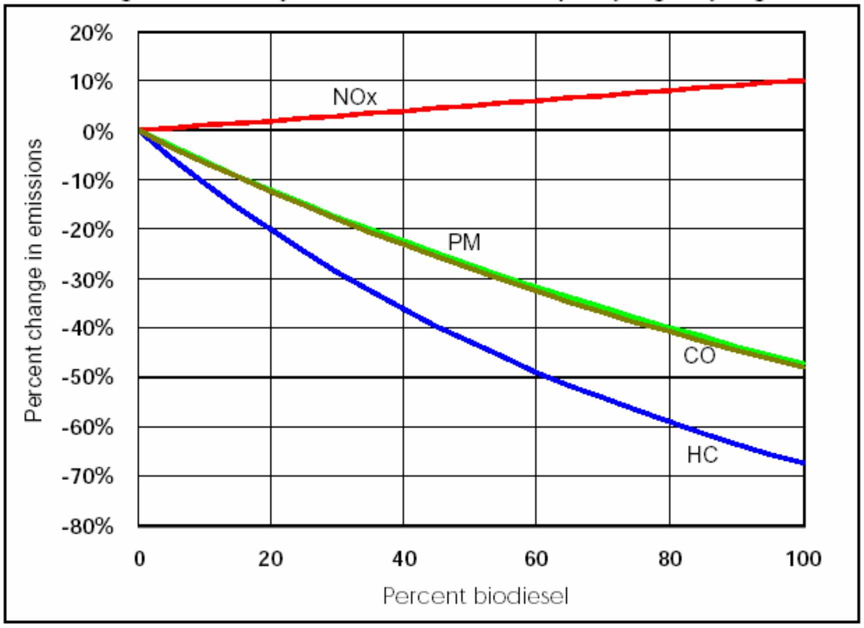

Figure 8-1
Biodiesel Emissions in Reciprocating Engines

Testing to date indicates that emissions of nitrogen oxides increase with the concentration of biodiesel in the fuel. Some biodiesel produces more nitrogen oxides than others, and some additives have shown promise in modifying the increases. More research is needed to resolve this issue. A February 2003 report by the National Renewable Energy Laboratory (NREL) is one example of a project addressing this issue (McCormick, 2003).

8.2.2 Biomass Gasification

Besides natural anaerobic production of biogas, hydrocarbon materials can be gasified in a heated reactor under appropriate conditions. There is a long history of gasification of coal, petroleum coke and other fossil fuels. There is also interest in applying gasification technology to biomass. The advantage is that different forms of biomass can be converted to one consistent fuel form and used in highly efficient fuel cell, combined cycle or other turbine systems. The gasifier product is similar to conventional biogas, a combination of hydrogen, CO and CO_2 and small amounts of other gases. Depending on the source of the biomass, the sulfur content could be very low and the content of other impurities could be lower than in LFG or other sources of biogas. In addition, gasifier systems commonly include gas clean-up systems.

While there is interest in the potential use of biomass gasification as a fuel source for DER, there have been relatively few actual demonstrations of biomass gasification and no data for a DER system using biomass gasification fuel were identified for this study. One would expect the results to be similar to those of conventional biogas without some of the problems and emissions related to impurities in the gas.

9

EMISSION MEASUREMENT ISSUES

Beyond the actual emission levels of the DER technologies, the methods for determining the emissions may become an issue, for several reasons:

- Lower emission levels – as regulations require lower and lower emission levels, more sensitive emission measurement technologies are required. As the equipment becomes more sensitive, there is increased likelihood of incorrect results due to contamination of the equipment or operator error. Are measurement technology and protocols keeping up with regulation?
- Newly regulated pollutants – as new pollutants are regulated, new measurement technologies and protocols must be developed to appropriately measure them.
- Comparability – Different measurement techniques and protocols are used for different technologies and applications. Turbines have typically used power generation measurement protocols while small engines have used protocols designed for mobile applications. In some cases the results of these tests are not directly comparable and can create conflicting results. What is needed to provide consistent, comparable measurements for DER technologies?

The above issues are complicated by the diversity of DER technologies and sizes. Combustion turbines larger than 10 MW may be subject to the same requirements as large power plants, including use of continuous emissions monitors (CEMs). At the small end of the DER scale, the equipment may only undergo an initial start-up test or may be certified at the factory. The emission levels are also very different, ranging from less than 0.1 lb NO_x/MWh for a fuel cell, for example, to more than 20 lb NO_x/MWh for a diesel engine.

The following sections address the primary species of concern for DER in the context of these emission measurement issues.

9.1 NO_x

The primary measurement concern related to NO_x has been the feasibility of measuring lower and lower emission limits. Typically, NO_x emitted from stationary sources is measured using a chemiluminescence-type instrument (EPA Method 7E or equivalent). The sensitivity of this method is approximately 1-2 ppm. Recent studies of CEM equipment (Gluck, 2003) indicate that the equipment is capable of accurate measurement at these levels. Lower detection limits can be obtained by modifying the instrument span and calibration gas mixtures; however, the lower limits come at the expense of method precision. Interference by moisture can also be a concern at the lower concentrations.

New measurement techniques are being developed, including those based on differential absorbance of ultraviolet light, that will continue to improve the accuracy of low-level NO_x measurements. Despite the improving capability of the equipment, some protocols may need to be updated for these very low levels to ensure proper mixing and sampling and avoidance of incorrect “artifact results”.

While the existing level of measurement performance is adequate for combustion technologies, it may not be adequate to measure emissions from fuel cell systems, which can be less than 1 ppm. From a regulatory perspective, accurate measurements at this level may not be necessary. Some jurisdictions already classify fuel cells as “renewable” generators because their emissions are so low. The potential emissions of NO_x from a 200 kW PAFC would be only about 50 pounds per year, tiny in the scale of stationary source inventories. However, concerns about localized air quality impacts of DER emissions could require NO_x to be measured accurately at sub-ppm levels. In that case, more sensitive methods would be required.

Although CO measurement has not yet become as important an issue as NO_x measurement, one can expect similar concerns in the future if CO is used as a surrogate for DER HAPs (see Section 9.3, below).

9.2 Particulate Matter

Measurement of PM raises several issues. First, there are several types of PM and several protocols already in use that can give different results. Second, there are concerns over the accuracy of these methods and the move to measure $PM_{2.5}$ adds to these concerns.

Total PM includes both primary particulates (those that are in a solid phase at stack gas temperatures) and condensible particulate matter (CPM). CPM consists of those chemical species which are in vapor form at stack gas temperatures, but which condense into a liquid or solid aerosol at ambient temperatures. Solid PM can be further divided by size fraction; PM_{10} and $PM_{2.5}$ are the most commonly measured size ranges.

PM emissions from reciprocating engines, both gaseous-fueled and compression ignition, are determined using a dilution tunnel method as specified by the US EPA in 40 CFR 86 Subpart N and 40 CFR 89. On-road and non-road engines use these methods for certification, and the methods can also be applied to reciprocating engines used for DER applications.

In the dilution tunnel method, engines are set up and run in a test cell, and exhaust from the engine is diluted in a tunnel. A small portion of the total exhaust flow is diluted with ambient air to create a constant flow rate and passed through filters to measure particulate matter. The temperature of the diluted exhaust must be less than 125° F (52° C). Particles are collected on a fluorocarbon–coated glass filter (sometimes more than one filter is used) and weighed. Emissions levels are determined based on time and exhaust flow and expressed in terms of micrograms per brake-horsepower hour.

Solid particulates from other stationary sources, including turbines, are typically collected according to US EPA or California ARB Method 5, EPA 17, or EPA 201A. In EPA Method 5, PM is withdrawn from the source using a probe and collected on a glass filter (the "front half") at

248° F (120° C). PM material can also be collected and quantified from the sampling probe and equipment. The particles collected on the filter material are weighed and correlated to the exhaust flow and output as required. The condensable fraction of the exhaust stream can be captured in cooled impingers (the "back half"). EPA Method 202 measures CPM using the impinger approach. Some regulators require CPM to be quantified and added to the solid PM to obtain a total PM measurement.

Results from Method 5/202 and dilution tunnel methods are not directly comparable since the techniques used are different. The PM results from stationary sources tested with Method 5 will generally be higher than the results using the dilution tunnel method, especially if the back half results are included. However, since the dilution tunnel method captures particles on the filter at a much lower temperature, some of the condensable fraction will be captured on the filter and will be reported, so that even the filter-only data are not necessarily comparable.

Impinger methods for measuring CPM are subject to a systematic bias that can cause the method to greatly overestimate true emissions. The bias is due primarily to oxidation of SO_2 (a non-CPM species) to sulfuric acid (H_2SO_4) in the Method 202 impingers. This artifact can often be larger than actual particulate emissions and/or emissions limits. Other gaseous species can also undergo oxidation to particulates in the impingers.

Several research teams are currently developing a dilution tunnel sampling method that can be routinely applied to stationary sources. Dilution tunnels have been used to measure stationary source emissions for many years, but their application has been limited by the size and complexity of the equipment. The intent of the ongoing research is to develop a smaller, less expensive sampling apparatus. To date, the prototype dilution tunnels have been tested at gas- and oil-fired combustion turbines, coal-fired boilers, and other industrial combustors. All tests reported to date have been on equipment much larger than the DER size range, although results of CEC tests on emergency diesel generators are expected to be published in 2004. It would be useful to determine the applicability of the new dilution tunnel methods to DER devices. Concurrence on one protocol that provides improved and consistent PM results would be of significant value for DER as well as for larger power generation technologies.

9.3 Hazardous Air Pollutants

Hazardous air pollutants (HAPs) include a list of 183 substances that the EPA has identified as toxic. The primary HAP of concern for DER technologies is formaldehyde. The EPA is in the process of finalizing HAPs control requirements for DER technologies (EPA 2002, EPA 2003). The proposed allowable emission levels are extremely low (as low as 25 ppb). This very low level, in addition to the fact that measurement of formaldehyde has not historically been required, means that measurement of formaldehyde presents a new problem for DER. In part for this reason, the HAPs requirements for DER use CO as a surrogate for formaldehyde. However, accurate, cost-effective formaldehyde measurement will be important to DER users.

Current approaches to formaldehyde measurement include impinger/chemical analysis methods (CARB Method 430, EPA Method 323) and Fourier transform infrared spectroscopy (FTIR) (EPA Method 320). Inconsistent and variable results have been reported for all of these methods. This is reflected in EPA's request in the new MACT standards for additional information on these and other methods for formaldehyde measurement. There is ongoing work in this area, especially for improved FTIR methods.

Emissions of ammonia also can be an issue for some DER applications. The use of SCR for NO_x control results in some ammonia released in the exhaust stream. This "ammonia slip" is often regulated to low levels. Accurate monitoring of ammonia slip is also needed for proper operation of the SCR. Better ammonia sensors are needed to accurately monitor ammonia emissions.

10

DATA GAPS ANALYSIS

This chapter summarizes the data gaps identified by this study and identifies the top priorities for further research on DER emissions.

10.1 Emissions Data

10.1.1 Current Data on Criteria Pollutants

Table 10-1 summarizes the data gaps for criteria pollutant data for DER technologies. Little independent emissions test data exists for current technology reciprocating engines and combustion turbines. The primary available source of information is manufacturer guarantee and test data. There are only scattered emission data from recent technology demonstration projects. While emissions data from CEMs are collected for some state and federal regulatory programs, they do not include equipment in the DER size range.

Table 10-1
Data Gaps – Criteria Pollutant Emissions for DER Technologies

Issue	Status	Comment
Conventional Turbines and Reciprocating Engines		
NO_x, CO, UHC, PM, SO_2, CO_2	Very little current data	Available data tend to be out-of-date, not well documented.
$PM_{2.5}$	No data available	Need to harmonize measurement protocols with other stationary source methods.
Microturbines, Fuel Cells		
NO_x, CO, UHC, PM, SO_2, CO_2	Some current data	Some current data are available and more are being generated. However, most of the technologies are not yet commercial so the validity of the data for predicting future performance is not clear.
$PM_{2.5}$	No data available	Need to establish whether new dilution tunnel methods can measure low level emissions

The best source of data found on conventional equipment was database inventories prepared for EPA's air toxics rulemakings. While this does provide a relatively broad view of engine and turbine emissions test data, it is based on diverse data sources and reflects a broad mix of equipment types, vintages and testing procedures so it is difficult to discern consistent results or identify the most current models in order to interpret the results. The wide range of emission values calls into question the credibility of some of the measurements.

There was surprisingly little independent emissions test data on new, developing DER technologies such as microturbines and fuel cells. Emission test data from R&D organizations (DOE, GTI, EPRI, NYSERDA, CEC) was not publicly available in most cases. There are efforts to systematically test DER emissions such as the program at the University of California at Irvine and GTI; however, the results are not yet publicly available. The primary sources of data that we located were scattered R&D reports from states and the work of the EPA-sponsored Environmental Technology Verification program (ETV). The other caveat is that these technologies are still under development and their emissions characteristics are changing. Emissions test data may not be representative of the commercial products that ultimately reach the market. Some of the products in development will not reach the market at all.

Overall, there is a lack of current, systematic emissions test data for criteria pollutants from currently available, commercial DER technology. There is more data for NO_x emissions, less consistent data for VOC/NMOC/UHC, very little for PM, and none for $PM_{2.5}$.

10.1.2 Data on HAPs Emissions

Table 10-2 summarizes the data gaps for HAPs emissions from DER technologies. The primary source of data on hazardous air pollutant emissions was the emissions databases used by EPA in its HAPs rulemaking. These data reflect a wide range of sources and testing procedures and have been criticized by some in industry as less than rigorous. There is very little data for new developing technologies.

Table 10-2
Data Gaps – HAPS Emissions

Issue	Status	Comment
Conventional Turbines and Reciprocating Engines		
All HAPs	Very little current, verifiable data	Available data tend to be out-of-date, not well documented. Measurement protocols may need to be improved.
Microturbines, Fuel Cells		
All HAPs	No data	May not be significant enough to warrant measurement. Measurement protocols may need to be improved.

Overall, there is a lack of current, systematic emissions test data for HAPs from DER technologies. While the current focus for HAPs from DER is primarily is on formaldehyde, there is may be interest in other HAPS in future regulatory initiatives. That said, the low emission levels and small size of DER technologies may keep them below the threshold of regulatory interest.

10.1.3 Other Emissions Data

Table 10-3 summarizes the data gaps for other categories of data on conventional emissions. The study found some data on part-load emissions performance and no data on start-up/shut-down emissions. Standardized protocols for measuring part-load performance would help in developing such data. That said, these factors may not be as important for DER technologies as they are for larger power technologies. More importantly, there was no systematic evaluation of long-term emissions performance of DER technologies. While some of the technologies are just reaching commercial status and do not have a long-term record, this would be a good time to initiate such a program in order to verify the performance of the new technologies as well as the continuing performance of conventional technology as it exists and as it evolves in the future.

Table 10-3
Data Gaps – Other Emissions Issues

Issue	Status	Comment
Part-Load Emissions		
All technologies	Very little current, verifiable data	Scattered data from different operational environments. Difficult to correlate to commercially available products. Standardized measurement protocols should be developed to represent load-following conditions.
Start-Up/Shut-Down		
All technologies	No data available	May not be important since start-up/shut-down are very small parts of operating profile for DER.
Long-Term Emissions		
All technologies	No data available	Newer technologies do not have sufficient operating experience. Longitudinal performance testing should be pursued.

10.2 Emission Measurement

Table 10-4 summarizes the data gaps relevant to emissions measurement. There are several issues that need to be addressed in the area of emissions measurement. Measurement of PM emissions is already an issue due to the different protocols used for different technologies and concerns with the accuracy and reliability of those protocols. The move to regulation of $PM_{2.5}$ exacerbates these concerns by putting a greater focus on condensible PM, which is a particularly weak point in the accuracy and consistency of these protocols. More reliable and accurate PM measurement techniques are needed that can be applied consistently to all DER technologies, in particular for $PM_{2.5}$.

New HAPs regulations for DER focus on formaldehyde emissions, which have not historically been measured and are regulated at very low emission levels. The regulations allow CO control and measurement to be used as a surrogate for formaldehyde; however, direct measurement of formaldehyde will be more appropriate for some applications. Simple, accurate and cost-effective formaldehyde measurement techniques would be beneficial for DER applications.

Table 10-4
Data Gaps – Emission Measurement

Issue	Status	Comment
Criteria Pollutants		
NO_x, CO	More sensitive methods required to accurately measure emissions from non-combustion technologies (fuel cells)	Accurate measurement may not be a high priority due to the very low emission levels.
PM, $PM_{2.5}$	Need concurrence on one technique for all power gen technologies. Need better speciation of PM and appropriate approach for measurement of $PM_{2.5}$.	Work in progress on dilution tunnel method for $PM_{2.5}$; however, method has been optimized for large gas- and oil-fired boilers and turbines. Applicability to DER-size devices is currently being determined.
HAPs		
Formaldehyde	Need more reliable, more accurate methods for very low level measurements.	Work underway on alternative methods
Other HAPs	May need additional methods for future regulations.	May not be an issue for smaller DER technologies.

Measurement techniques for NO_x and CO appear to be evolving to keep up with increasingly stringent emission limits and cleaner combustion technologies. They may not be adequate to measure the very low emission levels from fuel cells, however, those emissions may be too low to be of concern to regulators. Nevertheless, there is room for improvement in sensitivity, accuracy and cost minimization.

10.3 Biofuels

Table 10-5 summarizes the data gaps for biofuels. Some data are available on emissions of DER technologies using conventional biofuels such as LFG, digester gas and agricultural biogas. While more data would be useful, the fuels themselves are so variable that it is difficult to draw broad conclusions about emissions performance with great specificity. There is a fair amount of information on biodiesel emissions in transportation engines and very little information on DER technologies using biogasification fuels. More emissions test data on biodiesel and biogasification fuels would be valuable if these fuels are to be pursued for DER applications.

Table 10-5
Data Gaps –Biofuels

Issue	Status	Comment
Emissions Data		
LFG, digester gas, agricultural biogas	Very little current, verifiable data	Fuel and technology characteristics vary widely. It will be difficult to develop consistent, reliable data
Biodiesel	Extensive data on transportation engines.	
Biogasifier product	No data	May not be relevant since start-up/shut-down are very small parts of operating profile for DER.

10.4 Prioritization of Data Gaps

Future research needs relating to DER emissions are determined by a number of factors:

- The adequacy of the existing, publicly available data
- Knowledge that there is data from research efforts already completed (but not yet available), in progress, or in the planning stages
- The uses of the data, which could include regulation of DER emissions, modeling of DER implementation scenarios and air quality impacts

Several important data gaps that may require additional research effort were identified in this study. Table 10-6 lists these data gaps in order of decreasing importance. The top priority data gaps are those that are:

- Likely to create large uncertainties in analyzing DER deployment scenarios or impacts
- Not currently being addressed by other research organizations, and
- Related to current or future regulatory efforts.

Table 10-6
Prioritization of Data Gaps

Data Gap	Comment
Baseline criteria pollutant emissions	Confirmation of baseline performance levels for DER technologies is important for pre-certification of DER technologies, emission impacts, and risk analysis. There is some work beginning in this area for very small DER devices but little for the larger technologies, or for more conventional technologies including gas engines, dual-fuel engines, advanced diesel engines and combustion turbines.
Long-term performance	Required to confirm the validity of the baseline testing.
Biofuels emissions	There is a great deal of interest in increased use of biofuels. Agricultural biogas may be the next growth area in this sector. There would be value in determining the variability in the fuel characteristics the environmental impacts of greater use of this resource.
Improved PM, $PM_{2.5}$ measurement	This is an area of great confusion and inconsistency. Implementation of $PM_{2.5}$ standards greatly increases the need for consistent reliable measurements. There is already work addressing this need, but it is not currently targeted at devices in the DER size range.
Improved formaldehyde measurement	Better methods are needed to support new HAPs requirements. HAPs regulations are still developing and will become more important over time. There is already work in progress on new formaldehyde methods.

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EMISSIONS TABLES IN SI UNITS

Table A-1
California Small DG Certification Data (kg/MWh)

	NO_x	CO	VOC
Fuel Cells			
UTC PC25C (200 kW)	0.008	0.001	0.003
Fuel Cell Energy DFC300 (300 kW)	0.02	0.013	0.009
Microturbines			
Capstone C60 (60 kW)	0.10	1.70	0.06
Ingersoll-Rand 70LM (70 kW)	0.06	0.10	0.09

Table A-2
Emissions Data Ranges From EPA ICCR Databases

	Engines		Turbines	
	<= 1 MW	> 1 MW	< 15 MW	> 15 MW
NO_x	0.11 - 46 g/bhp-hr 0.13 - 65 kg/MWh	0.5 - 32 g/bhp-hr 0.72 - 45 kg/MWh	14 -160 ppm 0.31 – 3.6 kg/MWh	2 - 33 ppm 0.4 – 0.9 kg/MWh
CO	0.5 - 45 g/bhp-hr 0.73 - 64 kg/MWh	1 - 4.6 g/bhp-hr 1.4 – 6.4 kg/MWh	1.2 - 312 ppm 0.02 – 8.6 kg/MWh	0.25 - 47 ppm 0.13 - 0.4 kg/MWh
NMOC	0.1 - 65 g/bhp-hr 0.13 - 92 kg/MWh	0.1 - 4 g/bhp-hr 0.13 – 5.4 kg/MWh	18 - 117 ppm nd	0.04 - 41.5 ppm 0.09 - 0.2 kg/MWh
PM_{10}	0.04 - 0.1 g/bhp-hr 0.05 - 0.13 kg/MWh	0.01 - 0.05 g/bhp-hr 0.01 - 0.07 kg/MWh	nd	0.009 - 0.02 kg/MWh

For natural gas with no add-on emission controls. Some outlier data excluded.
nd=no data

Table A-3
Emissions Data for Microturbines (Natural Gas)

Model	Source	Emissions Tested (kg/MWh)			
		NO_x	CO	UHC	SO_2
Bowman 60 kW	CEC	1.6	5.5		
Capstone 28 kW	CEC	0.04	1.7		
Honeywell Parallon 75 kW	ETV	0.45	0.02	0.04	
Mariah 30 kW	ETV	0.09	0.07	.009	
Power Works 70 kW	ETV	0.02	0.009	0.02	0.02
Capstone 30 kW	ORNL	0.1	0.58	0.02	0.02
Capstone 30 kW	CARB	0.13	0.013	0.009	
Capstone 60 kW	CARB/UCI	0.11	0.031		
IR 70LM	CARB CERT	0.05	0.10	0.09	

CEC – California Energy Commission; ETV – EPA Environmental Technology Verification Program; ORNL – Oak Ridge National Laboratory (DOE); CARB – California Air Resources Board; UCI – University of California, Irvine

Table A-4
Gas Turbine Emissions Characteristics Without Exhaust Control Options*

Emissions Characteristics	System 1	System 2	System 3	System 4
Electricity Capacity (kW)	1,000	5,000	10,000	25,000
Electrical Efficiency (HHV)	22%	27%	29%	34%
NO_x, ppmv	42	25	25	25
NO_x, kg/MWh	1.08	0.54	0.49	0.40
CO, ppmv	20	20	20	20
CO, kg/MWh	0.32	0.27	0.22	0.18
SO_X, ppmv	0.23	0.24	0.24	0.24
SO_X, kg/MWh	0.004	0.004	0.003	0.003
THC, ppmv	25	25	25	25
THC, kg/MWh	0.24	0.17	0.16	0.14
NMOC, ppmv	2.5	2.5	2.5	2.5
NMOC, kg/MWh	0.024	0.017	0.016	0.014
PM_{10}, ppmv	nm	nm	nm	nm
PM_{10}, kg/MWh	0.299	0.239	0.223	0.188
CO_2, kg/MWh	828	669	624	528
Carbon, kg/MWh	234	187	175	148

* For typical systems commercially available in 2003, including: Solar Turbines Saturn 20 – 1 MW, Solar Taurus 60 - 5 MW, Solar Mars 100 - 10 MW, GE LM2500 – 25 MW. Emissions estimates for untreated turbine exhaust conditions (15 percent O_2 no SCR or other exhaust clean up).
Estimates based on typical manufacturers' guarantees using commercially available dry low NO_x combustion technology.

nm = not measured

Non-methane organic compounds (NMOC) are assumed to be 10 percent of THC (Total Hydrocarbons)

(EEA, 1999; EEA, 2003a; Energy Nexus Group, 2002)

Table A-5
Current and Advanced Combustion Turbine System Characteristics

Emissions & Performance Projections 1,000 kW Gas Turbine System					
Year	**Current**	**2005**	**2010**	**2020**	**2030**
System Size, kW	1,000	1,000	1,000	1,000	1,000
Electrical Heat Rate (KJ/kWh), HHV	16,437	16,651	14,997	13,847	13,330
Electric Efficiency (%)	21.9%	23.0%	24.0%	26.0%	27.0%
Fuel Input (GJ/hr)	16.4	15.6	14.9	13.8	13.2
Emissions Characteristics					
NO_x, ppmv	42	25	25	15	3
NO_x, kg/MWh	1.10	0.62	0.59	0.33	0.06
CO, ppmv	20	20	15	9	9
CO, kg/MWh	0.32	0.29	0.21	0.12	0.11
SO_x, ppmv	0.23	0.23	0.24	0.24	0.25
SO_x, kg/MWh	0.004	0.004	0.004	0.003	0.003
NMOC, ppmv	2.5	2.5	2.5	2.5	2.5
NMOC, kg/MWh	0.022	0.020	0.020	0.018	0.017
PM_{10}, ppmv	nm	nm	nm	nm	nm
PM_{10}, kg/MWh	0.30	0.28	0.26	0.24	0.23
CO_2, kg/MWh	856	807	774	714	688
Carbon, kg/MWh	234	220	211	195	188

nm = not measured. NMOCs are assumed to be 10 percent of THC (Total Hydrocarbons)

Note: Estimates are for turbine-out emissions without add-on controls. ppm are corrected to 15% O_2. The base case 1 MW size is based on the Solar Turbines Saturn 20 gas turbine. The 5 MW system is based on the Solar Taurus 60. The 10 MW system is based on the Solar Mars 100. The base case 25 MW system is based on the GE LM2500. The advanced cases are based on simultaneous improvements in firing temperature and pressure ratio that result in increases in efficiency and specific power. The improvements are gained from a combination of: 1) improved internal cooling and the use of ceramic materials for turbine vanes and blades; 2) improved aerodynamic efficiency with advanced component profiles resulting from more comprehensive three-dimensional compressible fluid dynamic analyses of vane and blade shape; 3) improved thermal barrier coatings; and 4) improved tip sealing.

Table A-5 (continued)
Current and Advanced Combustion Turbine System Characteristics

Emissions & Performance Projections 5,000 kW Gas Turbine System					
Year	**Current**	**2005**	**2010**	**2020**	**2030**
System Size, kW	5,000	5,000	5,000	5,000	5,000
Electrical Heat Rate (KJ/kWh), HHV	13,282	12,676	12,000	11,077	10,286
Electric Efficiency (%)	27%	28%	30%	33%	35%
Fuel Input (GJ/hr)	66.3	63.4	60.0	55.3	51.3
Emissions Characteristics					
NO_x, ppmv	25	15	5	3	3
NO_x, kg/MWh	0.53	0.30	0.29	0.05	0.05
CO, ppmv	20	20	15	9	9
CO, kg/MWh	0.25	0.24	0.18	0.09	0.09
SO_x, ppmv	0.24	0.23	0.24	0.22	0.23
SO_x, kg/MWh	0.003	0.003	0.003	0.002	0.002
NMOC, ppmv	2.5	2.5	2.5	2.5	2.5
NMOC, kg/MWh	0.017	0.016	0.016	0.014	0.014
PM_{10}, ppmv	nm	nm	nm	nm	nm
PM_{10}, kg/MWh	0.24	0.22	0.20	0.17	0.16
CO_2, kg/MWh	669	637	603	558	517
Carbon, kg/MWh	187	179	171	158	152

Note: One manufacturer currently offers a gas turbine with catalytic combustion that is guaranteed at 3 ppm NO_x.

nm = not measured

NMOCs are assumed to be 10 percent of THC (Total Hydrocarbons)

(EEA, 2003a; Energy Nexus Group, 2002)

Table A-5 (continued)
Current and Advanced Combustion Turbine System Characteristics

Emissions & Performance Projections 10,000 kW Gas Turbine System					
Year	**Current**	**2005**	**2010**	**2020**	**2030**
System Size, kW	10,000	10,000	10,000	10,000	10,000
Electrical Heat Rate (KJ/kWh), HHV	12,412	11,921	11,394	10,497	9,864
Electric Efficiency (%)	29%	30%	32%	34%	37%
Fuel Input (GJ/hr)	124.1	119.2	113.9	104.9	98.6
Emissions Characteristics					
NO_x, ppmv	25	15	5	3	3
NO_x, kg/MWh	0.48	0.28	0.16	0.05	0.04
CO, ppmv	20	20	15	9	9
CO, kg/MWh	0.24	0.22	0.17	0.09	0.08
SO_x, ppmv	0.24	0.25	0.22	0.24	0.25
SO_x, kg/MWh	0.003	0.003	0.002	0.002	0.002
NMOC, ppmv	2.5	2.5	2.5	2.5	2.5
NMOC, kg/MWh	0.016	0.015	0.014	0.014	0.013
PM_{10}, ppmv	nm	nm	nm	nm	nm
PM_{10}, kg/MWh	0.22	0.20	0.18	0.15	0.13
CO_2, kg/MWh	624	599	574	528	497
Carbon, kg/MWh	175	168	161	149	128

nm = not measured.   NMOCs are assumed to be 10 percent of THC (Total Hydrocarbons)

Note: A recuperated 4MW gas turbine with 35 percent efficiency and 5 ppm NO_x is expected to reach the market in 2004.

nm = not measured

NMOCs are assumed to be 10 percent of THC (Total Hydrocarbons)

(EEA, 2003a; Energy Nexus Group, 2002)

Table A-5 (continued)
Current and Advanced Combustion Turbine System Characteristics

Emissions & Performance Projections 25,000 kW Gas Turbine System					
Year	**Current**	**2005**	**2010**	**2020**	**2020**
System Size, kW	25,000	25,000	25,000	25,000	25,000
Electrical Heat Rate (KJ/kWh), HHV	10,491	10,196	9,732	9,352	8,999
Electric Efficiency (%)	34%	35%	37%	39%	40%
Fuel Input (GJ/hr)	262.3	254.8	243.1	233.7	225.0
Emissions Characteristics					
NO_x ppmv	25	9	5	3	3
NO_x, kg/MWh	0.42	0.24	0.14	0.05	0.05
CO, ppmv	20	20	15	9	9
CO, kg/MWh	0.20	0.20	0.14	0.08	0.08
SO_x, ppmv	0.24	0.25	0.25	0.22	0.22
SO_x, kg/MWh	0.003	0.003	0.003	0.002	0.002
NMOC, ppmv	2.5	2.5	2.5	2.5	2.5
NMOC, kg/MWh	0.014	0.014	0.013	0.013	0.013
PM_{10}, ppmv	nm	nm	nm	nm	nm
PM_{10}, kg/MWh	0.186	0.177	0.159	0.141	0.136
CO_2, kg/MWh	528	512	490	469	453
Carbon, kg/MWh	148	143	139	136	135

nm = not measured

NMOCs are assumed to be 10 percent of THC (Total Hydrocarbons)

(EEA, 2003a; Energy Nexus Group, 2002)

Table A-6
Microturbine Emissions Characteristics

	System 1	**System 2**	**System 3**	**System 4**
Nominal Electrical Capacity (kW)	30 kW	70 kW	80 kW	100 kW
Net Electrical Efficiency, HHV	23%	25%	24%	26%
Emissions Characteristics				
NO_x, ppmv	9	9	25	15
NO_x, kg/MWh	0.23	0.23	0.59	0.32
CO, ppmv	40	9	50	15
CO, kg/MWh	0.59	0.14	0.73	0.18
SO_x, ppm	0.21	0.23	0.22	0.23
SO_x, kg/MWh	0.004	0.004	0.004	0.003
THC, ppmv	< 9	<9	<9	<9
THC, kg/MWh	<0.09	<0.09	<0.09	<0.09
NMOC, ppmv	0.9	0.9	0.9	1
NMOC, kg/MWh	0.009	0.008	0.009	0.009
PM_{10}, ppmv	nm	nm	nm	nm
PM_{10}, kg/MWh	0.28	0.26	0.27	0.25
CO_2, kg/MWh	800	719	748	696
Carbon, kg/MWh	225	197	197	190

Estimates are based on manufacturers' guarantees for typical systems commercially available in 2003 without add-on emission controls, including Capstone Model 330 30 kW, Ingersoll Rand PowerWorks 70 kW, Turbec T100 100 kW systems

nm = not measured

VOCs (Non-methane Hydrocarbons) are assumed to be 10 percent of THC (Total Hydrocarbons)

(EEA, 1999; EEA, 2003b; Energy Nexus Group, 2002)

Table A-7
Microturbine Emission Measurements (Natural Gas)

Model	Source	Emissions (kg/MWh)			
		NO_x	CO	UHC	SO_2
Bowman 60 kW	CEC	1.6	5.5		
Capstone 30 kW	CEC	0.04	1.7		
Honeywell Parallon 75 kW	ETV	0.45	0.02	0.04	
Mariah 30 kW	ETV	0.09	0.07	0.09	
Power Works 70 kW	ETV	0.02	0.009	0.02	0.02
Capstone 30 kW	ORNL	0.1	0.58	0.02	0.02
Capstone 30 kW	CARB	0.13	0.013	0.009	
Capstone 60 kW	CARB/UCI	0.11	0.03		
Capstone 60	CARB CERT	0.10	1.7	0.06	
IR 70LM	CARB CERT	0.05	0.10	0.09	

CEC - California Energy Commission; ETV - EPA Environmental Technology Verification Program; ORNL - Oak Ridge National Laboratory (DOE); CARB - California Air Resources Board; UCI – University of California, Irvine; CARB CERT – Small Generator Certification

Table A-8
Current and Advanced Microturbine System Characteristics

Emissions and Performance Projections 30 kW Microturbine System					
Year	**Current**	**2005**	**2010**	**2020**	**2030**
Nominal Capacity (kW)	30	30	30	50	50
Turbine	Metallic	Metallic	Metallic	Ceramic	Ceramic
Electrical Heat Rate (KJ/kWh), HHV	15,904	14,400	13,846	11,246	10,586
Electric Efficiency (%), HHV	23%	25%	26%	32%	34%
Fuel Input (GJ/hr)	0.44	0.43	0.41	0.55	0.52
Emissions Characteristics					
NO_x, ppmv	9	9	5	3	3
NO_x, kg/MWh	0.23	0.21	0.11	0.05	0.05
CO, ppmv	40	40	30	20	20
CO, kg/MWh	0.63	0.57	0.41	0.20	0.20
SO_x, ppmv	0.21	0.22	0.23	0.23	0.24
SO_x, kg/MWh	0.004	0.004	0.004	0.003	0.003
NMOC, ppmv	0.9	0.9	0.9	0.9	0.9
NMOC, kg/MWh	0.009	0.009	0.009	0.005	0.005
PM_{10}, ppmv	nm	nm	nm	nm	nm
PM_{10}, kg/MWh	0.281	0.254	0.240	0.118	0.104
CO_2, kg/MWh	800	721	692	567	533
Carbon, kg/MWh	225	215	206	152	147

nm = not measured

NMOCs are assumed to be 10 percent of THC (Total Hydrocarbons)

Note: Table data for the 30 kW system for the current year are based on Capstone Model 330. Estimates are for emissions without add-on emissions controls.
(EEA, 2003b)

Table A-8 (continued)
Current and Advanced Microturbine System Characteristics

Emissions and Performance Projections 70 kW Microturbine System					
Year	**Current**	**2005**	**2010**	**2020**	**2030**
Nominal Capacity (kW)	70	70	110	110	110
Turbine	Metallic	Metallic	Ceramic	Ceramic	Ceramic
Electrical Heat Rate (KJ/kWh), HHV	14,289	13,741	11,251	10,286	9,732
Electric Efficiency (%), HHV	25%	26%	32%	35%	37%
Fuel Input (GJ/hr)	0.96	0.94	1.23	1.12	1.06
Emissions Characteristics					
NO_x, ppmv	9	9	5	3	3
NO_x, kg/MWh	0.20	0.19	0.09	0.05	0.05
CO, ppmv	9	9	9	9	9
CO, kg/MWh	0.12	0.12	0.10	0.09	0.08
SO_x, ppmv	0.23	0.24	0.22	0.24	0.22
SO_x, kg/MWh	0.004	0.004	0.003	0.003	0.002
NMOC, ppmv	0.9	0.9	0.9	0.9	0.9
NMOC, kg/MWh	0.009	0.005	0.005	0.005	0.005
PM_{10}, ppmv	nm	nm	nm	nm	nm
PM_{10}, kg/MWh	0.259	0.249	0.168	0.127	0.100
CO_2, kg/MWh	718	692	567	517	490
Carbon, kg/MWh	197	197	161	147	139

nm = not measured

NMOCs are assumed to be 10 percent of THC (Total Hydrocarbons)

Note: Table data for the 70 kW system for the current year are based on IR Energy Systems 70LM, which is a two-shaft model. Estimates are for emissions without add-on emissions controls.
(EEA, 2003b)

Table A-8 (continued)
Current and Advanced Microturbine System Characteristics

Emissions and Performance Projections 100 kW Microturbine System					
Year	**Current**	**2005**	**2010**	**2020**	**2030**
Nominal Capacity (kW)	100	100	160	160	160
Turbine	Metallic	Metallic	Ceramic	Ceramic	Ceramic
Electrical Heat Rate (KJ/kWh), HHV	13,846	12,417	10,001	9,473	9,231
Electric Efficiency (%), HHV	25%	29%	36%	38%	39%
Fuel Input (GJ/hr)	1.38	1.24	1.60	1.51	1.47
Emissions Characteristics					
NO_x, ppmv	15	9	5	3	3
NO_x, kg/MWh	0.33	0.18	0.09	0.05	0.04
CO, ppmv	15	15	15	15	15
CO, kg/MWh	0.20	0.18	0.10	0.14	0.14
SO_x, ppmv	0.21	0.23	0.23	0.25	0.22
SO_x, kg/MWh	0.003	0.003	0.003	0.003	0.002
NMOC, ppmv	1	1	1	1	1
NMOC, kg/MWh	0.009	0.009	0.005	0.005	0.005
PM_{10}, ppmv	nm	nm	nm	nm	nm
PM_{10}, kg/MWh	0.25	0.22	0.14	0.11	0.09
CO_2, kg/MWh	696	624	503	476	465
Carbon, kg/MWh	198	184	152	143	136

nm = not measured

VOCs (Non-methane Hydrocarbons) are assumed to be 10 percent of THC (Total Hydrocarbons)

Note: Table data for the 100 kW system for the current year are based on the Turbec T100 unit. Estimates are for emissions without add-on emissions controls.

(EEA, 2003b)

Table A-8 (continued)
Current and Advanced Microturbine System Characteristics

Emissions and Performance Projections 250 kW Microturbine System					
Year	**Current**	**2005**	**2010**	**2020**	**2030**
Nominal Capacity (kW)	--	200	250	250	250
Turbine	--	Metallic	Ceramic	Ceramic	Ceramic
Electrical Heat Rate (KJ/kWh), HHV	--	12,000	10,001	9,473	9,231
Electric Efficiency (%), HHV	--	30%	36%	38%	39%
Fuel Input (GJ/hr)	--	2.39	2.99	2.36	2.31
Emissions Characteristics					
NO_x, ppmv	--	9	5	3	3
NO_x, kg/MWh	--	0.17	0.08	0.04	0.04
CO, ppmv	--	20	20	20	20
CO, kg/MWh	--	0.23	0.19	0.18	0.17
SO_x, ppmv	--	0.24	0.25	0.23	0.23
SO_x, kg/MWh	--	0.003	0.003	0.002	0.002
NMOC, ppmv	--	1	1	1	1
NMOC, kg/MWh	--	0.005	0.005	0.005	0.005
PM_{10}, ppmv	--	nm	nm	nm	nm
PM_{10}, kg/MWh	--	0.20	0.12	0.10	0.09
CO_2, kg/MWh	--	603	503	476	465
Carbon, kg/MWh	--	172	143	137	132

nm = not measured

NMOCs are assumed to be 10 percent of THC (Total Hydrocarbons)

Note: Table data for the 250 kW system for 2010 are based on DOE Advanced Microturbine System (AMTS) program goals. Estimates are for emissions without add-on emissions controls.
(EEA, 2003b)

Table A-8 (continued)
Current and Advanced Microturbine System Characteristics

Emissions and Performance Projections 500 kW Microturbine System					
Year	**Current**	**2005**	**2010**	**2020**	**2030**
Nominal Capacity (kW)	--	--	500	500	500
Turbine	--	--	Ceramic	Ceramic	Ceramic
Electrical Heat Rate (KJ/kWh), HHV	--	--	10,001	9,231	8,999
Electric Efficiency (%), HHV	--	--	36%	39%	40%
Fuel Input (GJ/hr)	--	--	5.00	4.61	4.50
Emissions Characteristics					
NO_x, ppmv	--	--	5	3	3
NO_x, kg/MWh	--	--	0.08	0.04	0.04
CO, ppmv	--	--	20	20	20
CO, kg/MWh	--	--	0.19	0.17	0.17
SO_x, ppmv	--	--	0.25	0.23	0.23
SO_x, kg/MWh	--	--	0.003	0.002	0.002
NMOC, ppmv	--	--	1	1	1
NMOC, kg/MWh	--	--	0.005	0.005	0.005
PM_{10}, ppmv	--	--	nm	nm	nm
PM_{10}, kg/MWh	--	--	0.12	0.08	0.07
CO_2, kg/MWh	--	--	503	465	454
Carbon, kg/MWh	--	--	143	132	129

nm = not measured

NMOCs are assumed to be 10 percent of THC (Total Hydrocarbons)

Note: Based on an extrapolation of DOE Advanced Microturbine System goals and discussions with individual manufacturers. Estimates are for emissions without add-on emissions controls.

(EEA, 2003b)

Table A-9
Representative NO_x Emissions from Reciprocating Engines (Without Add on Controls)

Engine	Efficiency Range (%, HHV)	Fuel	NO_x (kg/MWh)
Diesel Engines (high speed & medium speed)	35 to 41	Distillate	6.7 – 17.9
Diesel Engines (high speed & medium speed)	39 to 45	Heavy Oil	12.0 - 20.0
Lean Burn, Spark Ignition Engine	32 to 38	Natural Gas	0.7 – 2.4
Rich Burn, Spark Ignition Engine	26 to 33	Natural Gas	5.4 – 6.8

(Wilhelm, 1999)

Table A-10
NO_x Emissions Versus Efficiency Tradeoffs

Engine Characteristics	Low NO_x	High Efficiency
Capacity (MW)	5.2	5.2
Speed (rpm)	720	720
Efficiency, HHV (%)	37	38.2
Emissions:		
NO_x, kg/MWh	0.67	1.34
ppmv @ 15% O_2	46	92
CO, kg/MWh	3.2	2.0
ppmv @ 15% O_2	361	227
NMHC, kg/MWh	0.95	0.54
ppmv @ 15% O_2	61	39

Note: based on engine manufacturer's data –
Wartsila 18V34SG Prechamber Lean Burn Gas Engine.

Table A-11
Gas Engine Emissions Characteristics Without Exhaust Control Options

Emissions Characteristics	System 1	System 1a	System 2	System 3	System 4	System 5
Electricity Capacity (kW)	100	100	300	800	1000	5000
Electrical Efficiency (HHV)	30%	29%	31%	34%	35%	37%
Engine Combustion	Rich	Rich w/TWC	Lean	Lean	Lean	Lean
NO_x, ppmv @ 15% O_2	1,100	11	150	80	44	46
NO_x, kg/MWh	20.87	0.21	2.81	1.41	1.00	0.73
CO, ppmv @ 15% O_2	1,366	67	391	300	290	300
CO, kg/MWh	16.8	0.8	2.8	2.8	3.5	3.4
SO_x, ppmv	0.24	0.24	0.24	0.23	0.23	0.23
SO_x, kg/MWh	0.003	0.003	0.003	0.003	0.002	0.002
UHC, ppmv @15% O_2	310	311	830	1400	1130	160
UHC, kg/MWh	2.08	2.08	5.58	9.07	7.03	0.91
NMOC, kg/MWh	1.00	0.21	1.41	1.41	1.81	0.73
CO_2, kg/MWh	610	603	582	533	515	489
Carbon, kg/MWh	171	171	159	149	141	127

For typical systems commercially available in 2003.

Estimates based on typical manufacturers' specifications: MAN 150 kW – 100 kW, Cummins GSK19G – 300 kW, Cummins QSV91G - 1 MW, Caterpillar G3616 LW – 3 MW, Wartsila 18V34SG – 5 MW.

nm = not measured

NMOCs are assumed to be 10 percent of THC (Total Hydrocarbons)

(EEA, 2003c; Energy Nexus Group, 2002)

Table A-12
ICCR Emission Data for Reciprocating Engines

	<= 1,000 kW	> 1 MW
NO_x	0.13–64.8 kg/MWh	0.72-45.3 kg/MWh
CO	0.72-63.5 kg/MWh	1.4-6.3 kg/MWh
NMHC	0.13-91.6 kg/MWh	0.13-5.4 kg/MWh
PM_{10}	0.05-0.13 kg/MWh	0.013-0.07 kg/MWh

Table A-13
Current and Advanced Gas Engine CHP System Characteristics

Emissions & Performance Projections 100 kW Gas Engine System – Rich Burn with Three-Way Catalyst					
Year	**Current**	**2005**	**2010**	**2020**	**2030**
System Size, kW	100	100	100	100	100
Electrical Heat Rate (KJ/kWh), HHV	12,132	11,802	11,427	11,077	10,586
Electric Efficiency (%)	30%	31%	32%	33%	34%
Fuel Input (GJ/hr)	1.21	1.18	1.13	1.10	1.05
Emissions Characteristics					
NO_x, ppmv	11	11	8	8	8
NO_x, kg/MWh	0.21	0.21	0.14	0.14	0.14
CO, ppmv	69	69	62	40	14
CO, kg/MWh	0.81	0.81	0.68	0.40	0.13
SO_x, ppmv	0.24	0.24	0.25	0.23	0.24
SO_x, kg/MWh	0.003	0.003	0.003	0.003	0.003
NMOC, kg/MWh	0.21	0.21	0.14	0.14	0.14
CO_2, kg/MWh	610	593	575	557	533
Carbon, kg/MWh	171	171	159	150	143

NMOCs are assumed to be 10 percent of THC (Total Hydrocarbons)

Estimates based on: MAN 150 kW (stoichiometric with three-way catalyst system)– 100 kW; Cummins GSK19G – 300 kW; Caterpillar G3516 LE – 800 kW; Caterpillar G3616 LE – 3 MW; Wartsila 5238 LN - 5 MW
(EEA, 2003c; Energy Nexus Group, 2002)

Table A-13 (continued)
Current and Advanced Gas Engine CHP System Characteristics

Emissions & Performance Projections 300 kW Gas Engine CHP System, Lean Burn					
Year	**Current**	**2005**	**2010**	**2020**	**2030**
Electrical Heat Rate (KJ/kWh), HHV	11,570	11,427	11,075	10,745	10,285
Electric Efficiency (%)	31%	32%	33%	34%	35%
Fuel Input (GJ/hr)	3.48	3.42	3.32	3.22	3.08
Emissions Characteristics					
NO_x, ppmv	148	115	79	40	8
NO_x, kg/MWh	2.68	2.00	1.39	0.66	0.16
CO, ppmv	255	272	215	220	148
CO, kg/MWh	2.81	2.81	2.09	2.09	1.41
SO_x, ppmv	0.22	0.23	0.24	0.21	0.21
SO_x, kg/MWh	0.003	0.003	0.003	0.002	0.002
NMOC, kg/MWh	1.41	1.41	1.41	1.05	0.70
CO_2, kg/MWh	582	574	557	540	517
Carbon, kg/MWh	159	152	143	136	136

NMOCs are assumed to be 10 percent of THC (Total Hydrocarbons)
(EEA, 2003c; Energy Nexus Group, 2002)

Table A-13 (continued)
Current and Advanced Gas Engine CHP System Characteristics

Emissions & Performance Projections 800 kW Gas Engine System, Lean Burn					
Year	**Current**	**2005**	**2010**	**2020**	**2030**
Electrical Heat Rate (KJ/kWh), HHV	10,809	9,472	8,999	8,570	8,570
Electric Efficiency (%)	33%	38%	40%	42%	42%
Fuel Input (GJ/hr)	8.65	7.57	7.19	6.85	6.85
Emissions Characteristics					
NO_x, ppmv	83	66	50	26	11
NO_x, kg/MWh	1.41	0.98	0.70	0.35	0.14
CO, ppmv	350	390	412	260	173
CO, kg/MWh	3.66	3.52	3.52	2.11	1.41
SO_x, ppmv	0.23	0.26	0.23	0.24	0.24
SO_x, kg/MWh	0.003	0.003	0.002	0.002	0.002
NMOC, kg/MWh	1.34	0.98	0.98	0.84	0.14
CO_2, kg/MWh	544	476	445	431	431
Carbon, kg/MWh	149	130	122	117	117

NMOCs are assumed to be 10 percent of THC (Total Hydrocarbons)
(EEA, 2003c; Energy Nexus Group, 2002)

Table A-13 (continued)
Current and Advanced Gas Engine CHP System Characteristics

Emissions & Performance Projections 1000 kW Gas Engine System, Lean Burn					
Year	**Current**	**2005**	**2010**	**2020**	**2030**
Electrical Heat Rate (KJ/kWh), HHV	10,602	10,139	9,599	9,113	8,674
Electric Efficiency (%)	34%	36%	38%	40%	42%
Fuel Input (GJ/hr)	10.65	10.13	9.60	9.11	8.67
Emissions Characteristics					
NO_x, ppmv	90	68	51	27	11
NO_x, kg/MWh	1.41	0.98	0.70	0.35	0.14
CO, ppmv	296	322	253	272	186
CO, kg/MWh	2.81	2.81	2.11	2.11	1.41
SO_x, ppmv	0.21	0.22	0.23	0.21	0.21
SO_x, kg/MWh	0.002	0.002	0.002	0.002	0.002
NMOC, kg/MWh	1.41	1.41	0.98	0.84	0.70
CO_2, kg/MWh	517	464	441	411	398
Carbon, kg/MWh	141	127	120	112	109

NMOCs are assumed to be 10 percent of THC (Total Hydrocarbons)
(EEA, 2003c; Energy Nexus Group, 2002)

Table A-13 (continued)
Current and Advanced Gas Engine CHP System Characteristics

Emissions & Performance Projections 5000 kW Gas Engine System, Lean Burn					
Year	**Current**	**2005**	**2010**	**2020**	**2030**
Electrical Heat Rate (KJ/kWh), HHV	9,719	9,230	8,779	8,371	7,999
Electric Efficiency (%)	37%	39%	41%	43%	45%
Fuel Input (GJ/hr)	48.6	46.1	43.8	41.8	39.9
Emissions Characteristics					
NO_x, ppmv	46	49	41	27	11
NO_x, kg/MWh	0.70	0.70	0.57	0.35	0.14
CO, ppmv	384	413	371	309	206
CO, kg/MWh	3.36	3.36	2.81	2.11	1.41
SO_x, ppmv	0.23	0.24	0.26	0.23	0.23
SO_x, kg/MWh	0.002	0.002	0.002	0.002	0.002
NMOC, kg/MWh	0.70	0.70	0.70	0.35	0.35
CO_2, kg/MWh	465	433	398	362	362
Carbon, kg/MWh	127	118	109	99	99

NMOCs are assumed to be 10 percent of THC (Total Hydrocarbons)
(EEA, 2003c; Energy Nexus Group, 2002)

Table A-14
Estimated Fuel Cell Emission Characteristics Without Additional Controls*

Emissions Analysis	System 1	System 2	System 3	System 4	System 5	System 6
Fuel Cell Type	PAFC	PEMFC	PEMFC	MCFC	MCFC	SOFC
Electricity Capacity (kW)	200	5-10	150-250	250	2000	100-250
Electrical Efficiency (HHV)	36%	30%	35%	43%	46%	45%
Emissions						
NO_x, ppmv @ 15% O_2	1	1.8	1.8	2	2	2
NO_x, kg/MWh	0.02	0.05	0.05	0.03	0.02	0.02
CO, ppmv @ 15% O_2	2	2.8	2.8	2	2	2
CO, kg/MWh	0.02	0.03	0.03	0.02	0.02	0.02
SO_x, ppmv	0.21	0.24	0.24	0.24	0.24	0.24
SO_x, lb/MWh	0.002	0.003	0.003	0.002	0.002	0.002
NMOC, ppmv @ 15% O_2	0.7	0.4	0.4	0.5	1	1
NMOC, kg/MWh	0.005	0.005	0.005	0.005	0.005	0.005
CO_2, kg/MWh	515	617	531	431	404	413
Carbon, kg/MWh	141	168	143	118	109	111

Basis for characterization: PAFC – UTC, PEMFC 5-10 kW – Composit, PEMFC 150-250 kW – UTC, MCFC – Fuel Cell Energy, SOFC – Siemens Westinghouse.

Electric only, for typical systems under development in 2003.
Estimates are based on fuel cell system developers’ goals and prototype characteristics except PAFC for which plenty of test data is available. All estimates are for emissions without after-treatment and are adjusted to 15 percent O_2.
(EEA, 2003d; Energy Nexus Group, 2002)

Table A-15
Current and Advanced Fuel Cell System Characteristics

Emissions and Performance Projections 200 kW PAFC Fuel Cell System					
Year	**Current**	**2005**	**2010**	**2020**	**2030**
Fuel Cell Technology	PAFC	PAFC	PAFC	PAFC	PAFC
System Size, kW	200	200	-	-	-
Electrical Heat Rate (KJ/kWh), HHV	10,001	10,001	-	-	-
Electrical Efficiency (%)	36%	36%	-	-	-
Fuel Input (GJ/hr)	2.0	2.0	-	-	-
Emissions Characteristics					
NO_x, ppmv	1.2	1.2	-	-	-
NO_x, kg/MWh	0.02	0.02	-	-	-
CO, ppmv	2.4	2.4	-	-	-
CO, kg/MWh	0.02	0.02	-	-	-
VOC, ppmv	0.8	0.8			
NMOC, kg/MWh	0.005	0.005			
CO_2, kg/MWh	517	517			

NMOCs are assumed to be 10 percent of THC (Total Hydrocarbons)
Emissions projected without add-on controls.
(EEA, 2003d; Energy Nexus Group, 2002)

Table A-15 (continued)
Current and Advanced Fuel Cell System Characteristics

Emissions and Performance Projections 5-10 kW PEMFC System					
Year	**Current**	**2005**	**2010**	**2020**	**2030**
Fuel Cell Technology		PEMFC	PEMFC	PEMFC	PEMFC
System Size, kW		10	10	10	10
Electrical Heat Rate (KJ/kWh), HHV		11,995	11,246	10,286	10,001
Electrical Efficiency (%)		30%	32%	35%	36%
Fuel Input (GJ/hr)		0.11	0.11	0.10	0.09
Emissions Characteristics					
NO_x, ppmv		1.5	1.5	1.4	1.4
NO_x, kg/MWh		0.03	0.03	0.02	0.02
CO, ppmv		2.8	2.5	2.8	2.8
CO, kg/MWh		0.03	0.03	0.03	0.03
VOC, ppmv		0.7	0.7	0.8	0.8
NMOC, kg/MWh		0.005	0.005	0.005	0.005
CO_2, kg/MWh		617	581	531	517

NMOCs are assumed to be 10 percent of THC (Total Hydrocarbons)
Emissions projected without add-on controls.

(EEA, 2003d; Energy Nexus Group, 2002)

Table A-15 (continued)
Current and Advanced Fuel Cell System Characteristics

Emissions and Performance Projections 200-250 kW PEMFC System					
Year	**Current**	**2005**	**2010**	**2020**	**2030**
Fuel Cell Technology		PEMFC	PEMFC	PEMFC	PEMFC
System Size, kW		200	200	200	200
Electrical Heat Rate (KJ/kWh), HHV		10,286	10,001	9,473	9,473
Electrical Efficiency (%)		35%	36%	38%	38%
Fuel Input (GJ/hr)		2.05	2.00	1.89	1.89
Emissions Characteristics					
NO_x, ppmv		2.8	2.0	1.5	1.5
NO_x, kg/MWh		0.05	0.03	0.02	0.02
CO, ppmv		3.3	1.9	2.0	2.0
CO, kg/MWh		0.03	0.02	0.02	0.02
VOC, ppmv		0.8	<0.8	<0.8	<0.8
NMOC, kg/MWh		0.005	<0.005	<0.005	<0.005
CO_2, kg/MWh		531	517	490	490

NMOCs are assumed to be 10 percent of THC (Total Hydrocarbons)

Emissions projected without add-on controls.
(EEA, 2003d; Energy Nexus Group, 2002)

Table A-15 (continued)
Current and Advanced Fuel Cell System Characteristics

Emissions and Performance Projections **250 kW MCFC Fuel Cell System**					
Year	**Current**	**2005**	**2010**	**2020**	**2030**
Fuel Cell Technology	MCFC	MCFC	MCFC	MCFC	MCFC
System Size, kW	250	250	250	250	250
Electrical Heat Rate (KJ/kWh), HHV	8,366	8,336	7,999	7,300	7,300
Electrical Efficiency (%)	43%	43%	45%	49%	49%
Fuel Input (GJ/hr)	2.08	2.08	2.00	1.83	1.83
Emissions Characteristics					
NO_x, ppmv	2.0	2.0	1.8	1.6	1.6
NO_x, kg/MWh	0.03	0.03	0.02	0.02	0.02
CO, ppmv	2.3	2.3	2.4	1.9	1.9
CO, kg/MWh	0.02	0.02	0.02	0.01	0.01
VOC, ppmv	1.0	1.0	<1.0	<1.1	<1.1
NMOC, kg/MWh	0.005	0.005	<0.005	<0.005	<0.005
CO_2, kg/MWh	431	431	412	378	378

NMOCs are assumed to be 10 percent of THC (Total Hydrocarbons)
Emissions projected without add-on controls.
(EEA, 2003d; Energy Nexus Group, 2002)

Table A-15 (continued)
Current and Advanced Fuel Cell System Characteristics

Emissions and Performance Projections 2,000 kW MCFC Fuel Cell System					
Year	**Current**	**2005**	**2010**	**2020**	**2030**
Fuel Cell Technology		MCFC	MCFC	MCFC	MCFC
System Size, kW		2,000	2,000	2,000	2,000
Electrical Heat Rate (KJ/kWh), HHV		7,828	7,501	7,195	6,920
Electrical Efficiency (%)		46%	48%	50%	52%
Fuel Input (GJ/hr)		15.6	15.0	14.4	13.84
Emissions Characteristics					
NO_x, ppmv		1.9	1.9	1.6	1.6
NO_x, kg/MWh		0.02	0.02	0.02	0.02
CO, ppmv		2.4	1.9	1.9	2.0
CO, kg/MWh		0.02	0.01	0.01	0.01
VOC, ppmv		1.1	<1.1	<1.1	<1.2
NMOC, kg/MWh		0.005	<0.005	<0.005	<0.005
CO_2, kg/MWh		404	386	372	358

NMOCs are assumed to be 10 percent of THC (Total Hydrocarbons)
Emissions projected without add-on controls.

Table A-15 (continued)
Current and Advanced Fuel Cell System Characteristics

Emissions and Performance Projections 100-250 kW SOFC Fuel Cell System					
Year	**Current**	**2005**	**2010**	**2020**	**2030**
Fuel Cell Technology		SOFC	SOFC	SOFC	SOFC
System Size, kW		100	100	100	100
Electrical Heat Rate (KJ/kWh), HHV		7,996	7,342	7,057	6,794
Electrical Efficiency (%)		45%	49%	51%	53%
Fuel Input (GJ/hr)		0.80	0.73	0.70	0.67
Emissions Characteristics					
NO_x, ppmv		1.8	1.9	1.6	1.7
NO_x, kg/MWh		0.02	0.02	0.02	0.02
CO, ppmv		2.4	1.9	2.0	2.1
CO, kg/MWh		0.02	0.01	0.01	0.01
VOC, ppmv		1.0	<1.1	<1.1	<1.2
NMOC, kg/MWh		0.005	<0.005	<0.005	<0.005
CO_2, kg/MWh		412	378	363	350

NMOCs are assumed to be 10 percent of THC (Total Hydrocarbons)

Emissions projected without add-on controls.
(EEA, 2003d; Energy Nexus Group, 2002)

Table A-16
Emission Summary for Lean Burn LFG Reciprocating Engines*

Data Source	NO_x		CO		VOC	
	g/bhp-hr	kg/MWh	g/bhp-hr	kg/MWh	g/bhp-hr	kg/MWh
AP-42	0.8	1.17	1.6	2.31	NA	NA
SCAQMD	0.6	0.86	2.5	3.53	0.8	1.13
BACT/LAER	1	1.40	2.9	4.09	0.25	0.35
BACT/LAER	2	2.81	2.3	3.26	0.375	0.53
CARB	0.6	0.86	2.5	3.53	0.6	0.86
Composite		0.86		3.62		0.86

* For engines in the 1 MW or larger range.
NA – not available. SCAQMD – South Coast Air Quality Management District of California. EPA Best Available Control Technology (BACT) and Lowest Achievable Emission Rate (LAER) Clearinghouse. CARB – California Air Resources Board.

Table A-17
Emission Summary for Lean Burn LFG Combustion Turbines

Data Source	NO_x		CO		VOC	
	ppm	kg/MWh	kg/MMBtu	kg/MWh	Ppm	kg/MWh
AP-42	33-44	0.77-0.99	0.04-0.18	0.54-2.2	0.013	0.07
SCAQMD	25	0.58	130 ppm	1.54	NA	NA
BACT/LAER	32-63	0.72-1.5	0.34	4.0	0.0062	0.03
CARB	25	0.56	NA	NA	NA	NA
Composite		0.56		1.6		0.04

NA – not available. SCAQMD – South Coast Air Quality Management District of California. EPA Best Available Control Technology (BACT) and Lowest Achievable Emission Rate (LAER) Clearinghouse. CARB – California Air Resources Board.

Table A-18
Physical Characteristics of Biodiesel

Specific gravity	0.87 to 0.89
Kinematic viscosity @ 40°C	3.7 to 5.8
Cetane number	46 to 70
Higher heating value (KJ/kg)	18,841 to 20,032
Sulfur, wt%	0.0 to 0.0024
Cloud point °C	-11 to 16
Pour point °C	-15 to 13
Iodine number	60 to 135
Lower heating value (KJ/kg)	17,476 to 18,627

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