Output-Based Regulations:
A Handbook for Air Regulators

U.S. Environmental Protection Agency
Combined Heat and Power Partnership

August 2014

FINAL REPORT

This handbook was prepared by ICF International and ERG Inc., under contract to the U.S. Environmental Protection Agency. The Combined Heat and Power Partnership (CHPP) would like to thank Rich Sedano and Rick Weston of the Regulatory Assistance Project and Christian Fellner of EPA's Office of Air Quality Planning and Standards for their thoughtful review of the handbook.

Table of Contents

Table of Contents (Continued)

List of Appendices

List of Appendices (Continued)

List of Tables

List of Tables (Appendices)

List of Figures

EXECUTIVE SUMMARY

The Combined Heat and Power Partnership (CHPP), within the U.S. EPA's Climate Protection Partnerships Division (CPPD), developed this handbook. CPPD's voluntary partnerships work to increase the understanding of the full range of greenhouse gas (GHG) and air quality benefits provided by energy efficiency and clean energy production. Output-based regulations can help air regulators incorporate these benefits into their programs.

The CHPP is a voluntary program that reduces the environmental impact of power generation by fostering the use of CHP. CHP, also known as cogeneration, produces both heat and electricity from a single heat input. CHP is a more efficient, cleaner, and more reliable alternative to conventional generation. The partnership works closely with the CHP industry, state and local governments, and other stakeholders to develop tools and services to support the development of new CHP projects and recognize their energy, environmental, and economic benefits. The use of output-based regulations is a tool that can foster the expansion of CHP.

This handbook was developed to assist air regulators in developing emission regulations that recognize the pollution prevention benefits of efficient energy generation technologies. It is also intended to help CHP project owners better understand and comply with output-based environmental regulations. Clean energy technologies prevent pollution by using less fuel and, thus, reducing associated emissions. Output-based regulations encourage energy efficiency by relating emissions to the productive output of the process, not to the amount of fuel burned.

While output-based regulations have been used for many industries, boilers and power generation sources have traditionally been regulated through *input-based* regulations. This has been changing recently, though, as regulators seek to promote air emission reductions and provide more compliance flexibility to combustion sources.

The CHPP developed this handbook to assist state, local, and tribal regulators in developing output-based regulations. The handbook provides practical information to help regulators decide if they want to use output-based regulations and explains how to develop an output-based emission standard.

What is an output-based regulation?

Output-based *regulations* include output-based emission *standards* as well as output-based *allocations* of emission allowances within a cap and trade program. An output-based emission standard relates emissions to the productive output of the process. Output-based emission standards use units of measure such as lb emission/MWh generated or lb emissions/MMBtu of steam generated, rather than heat input (lb/MMBtu) or pollutant concentration (ppm). In a cap and trade program, emission allowances can be allocated to energy generation sources based on energy output (e.g., electricity or steam generated) rather than fuel burned (i.e., heat input).

Why adopt output-based regulations?

The primary benefit of output-based regulations is that they encourage efficiency and pollution prevention. More efficient combustion technologies benefit from the use of output-based regulations.

The use of these technologies reduces fossil fuel use and leads to multi-media reductions in the environmental impacts of the production, processing, transportation, and combustion of fossil fuels. In addition, reducing fossil fuel combustion is a pollution prevention measure that reduces emissions of all products of combustion, not just the target pollutant of a regulatory program.

Another benefit is that output-based standards allow sources to use energy efficiency as part of their emission control strategy. Allowing energy efficiency as a control measure provides regulated sources, either existing or new, with an additional compliance option that can lead to reduced compliance costs as well as lower emissions. Input- or concentration-based standards do not provide this option.

In a cap and trade program, states can design an output-based allowance allocation system to accomplish a number of environmental objectives. For example, a program that periodically updates output-based allocations encourages increased energy efficiency because sources vie for a larger share of the allocations. A program that allocates output-based allowances to non-emitting electricity generators during these periodic updates provides a financial incentive for the introduction of renewable energy sources, such as wind power. EPA developed guidance for states on how to develop output-based allocations under the NO_x Budget Trading Program in May 2000,[1] and the CHPP has more recently issued whitepapers and other assistance primarily to help state regulators better understand output-based regulations and navigate the process of developing such standards. In addition to this guide, the CHPP issued *Accounting for CHP in Output-Based Regulations*[2] in February 2013 and *Output-Based Environmental Regulations: An Effective Policy to Support Clean Energy Supply*[3] in September 2011.

How do I develop an output-based emission standard?

Several decisions must be made about the format of the rule. Making these decisions involves trade-offs between the degree to which the rule will account for the benefits of energy efficiency, the complexity of the rule, and the ease of measuring compliance.

The steps for developing an output-based emission standard are:

- ***Develop the output-based emission limit.*** The method that is used will depend on whether or not measured energy output data are available.
- ***Specify a gross or net energy output format.*** Net energy output more comprehensively accounts for energy efficiency, but can increase the complexity of compliance monitoring requirements.
- ***Specify compliance measurement methods.*** Output-based standards require designating methods for monitoring electrical, thermal, and mechanical outputs. Instruments to continuously monitor and record energy output are routinely used and are commercially available at a reasonable cost.

[1] EPA. 2000. Developing and Updating Output-Based NO_x Allowance Allocations: Guidance for States Joining the NO_x Budget Trading Program Under the NO_x SIP Call. *http://www.epa.gov/airmarkets/progsregs/nox/docs/finaloutputguidanc.pdf*.
[2] *http://www.epa.gov/chp/resources.html*.
[3] *http://epa.gov/chp/documents/output_based_regs_fs.pdf*.

- ***Specify how to calculate emission rates for CHP units.*** For CHP units, the standard must account for multiple energy outputs. This handbook describes two typical approaches.

How do I comply with an output-based emission standard?

- ***Determine compliance procedures****.* Compliance forms, permit forms, or other necessary documentation must be obtained. The output-based methodology that is used will depend on whether measured energy output data are available.

- ***Determine the data necessary for compliance*****.** Review the compliance calculation and other inputs to determine what data are needed to calculate the emission limit from the CHP system. Electric output data (typically measured in MWh) and thermal output (measured in MMBtu) are often required.

- ***Implement appropriate data collection procedures.*** Install appropriate emission and output measurement devices (electric and thermal) and collect emission and output data.

- ***Calculate compliance*****.** Use the required calculation to determine the output-based emissions or other output-based feature for the CHP system.

- ***Submit completed forms*** to the state utility regulatory agency or other appropriate authority.

Who has developed output-based regulations?

A number of federal, regional, and state programs have adopted output-based emission regulations, including emission standards for large and small generators, cap and trade allowance allocation systems, multi-pollutant regulations, and generation performance standards (Table ES-1).

To provide additional insight into the technical and policy considerations of setting output-based standards, this handbook describes four output-based emission reduction programs. These programs are:

- The output-based approach that EPA used to revise the electric utility boiler New Source Performance Standard (NSPS) (40 CFR Part 60, Subpart Da). This action reflected a major change in approach for the NSPS and provided an efficiency-based rationale for transitioning to output-based regulation. When originally promulgated in 1998, it was the first NSPS for boilers that incorporated output-based emission limits; it allows CHP systems to account for 75 percent of their secondary thermal output. This section also discusses EPA's proposed GHG NSPS for new power plants.

- ***A model rule for output-based standards for small electric generators.*** The model rule is a good example of a straightforward output-based emission limit program that recognizes the thermal output of CHP.

- EPA's guidance on how to allocate emission allowances for the NO_x SIP Call and Clean Air Interstate Rule (CAIR) based on energy output. The NO_x SIP Call approach was developed by a stakeholder group of EPA, states, industry, and environmental groups. The guidance thoroughly discusses how output-based allocation can be applied.[4]

- EPA's output-based approach in its Boiler Maximum Achievable Control Technology (MACT) regulations (40 CFR Part 63, Subpart DDDDD). This rule, finalized in December 2012, applies to industrial, commercial, and institutional boilers and process heaters. The rule contains provisions for boiler/steam turbine CHP to account for their secondary electricity output.

Output-based regulations are continuing to gain attention as EPA, states, and regional planning organizations strive to find innovative ways to attain today's air quality goals. Emissions from energy production processes contribute to a number of air pollution problems, including fine particulates, ozone, acid rain, air toxics, visibility degradation, and climate change. An output-based regulation can be used as part of a regulatory strategy that encourages pollution prevention and the use of innovative and efficient energy-generating technologies. Adopting output-based regulations, therefore, is a valuable tool for protecting air quality while fostering the development of efficient, reliable, and affordable supplies of energy.

Table ES-1. Current Output-Based Treatment of CHP

Type of Program	Regulatory Purview	Output-Based Features
Federal NSPS regulations	NSPS for Stationary Combustion Turbines	Emission limit (lb/MWh) gross output
	NSPS for Industrial-Commercial-Institutional Steam Generating Units	Emission limit (lb/MWh) gross output
	NSPS for Stationary Compression Ignition Internal Combustion Engines	Emission limit (g/KW-hr)
	NSPS for Stationary Spark Ignition Internal Combustion Engines	Emission limit (g/HP-hr)
	NSPS for Aluminum Reduction Plants	Emission limit (kg/Mg) or (lb/ton)
	NSPS for Electric Steam Generating Units	Emission limit (lb/MWh) gross output and (lb/MWh) net output
National Emission Standards for Hazardous Air Pollutants (NESHAP)	NESHAP for Area/Sources: Electric Arc Furnace Steelmaking Facilities	Emission limit (lb/ton)
	NESHAP for Industrial, Commercial, and Institutional Boilers and Process Heaters (Boiler MACT)	Emission limit (lb/MBtu) steam output or (lb/MWh)
	NESHAP for Coal- and Oil-Fired Electric Utility Steam Generating Units (MATS rule)	Emission limit (lb/MWh) or (lb/GWh)
Conventional state emission rate limits	New Jersey mercury emission limits	Emission limit (mg/MWh)

[4] EPA first regulated the transport of NO_x in 1998 with the promulgation of the NO_x SIP Call and its NO_x Budget Trading Program. Several years later, with the goal of further increasing NO_x reductions and helping states attain $PM_{2.5}$ standards, EPA issued the CAIR in 2005. In 2011, EPA finalized the Cross-State Air Pollution Rule to achieve even greater emissions reductions that reflect more stringent air quality standards. For more information about these rules, their cap and trade programs, and their inter-related history, go to: *http://www.epa.gov/airtransport/CSAPR/* and *http://www.epa.gov/cleanairinterstaterule/*.

Table ES-1. Current Output-Based Treatment of CHP

Type of Program	Regulatory Purview	Output-Based Features
State emission standards for distributed generation	New Hampshire	Emission tax (lb/MWh)
	California	Emission limit (lb/MWh)
	Delaware	Emission limit (lb/MWh)
	Rhode Island	Emission limit (lb/MWh)
	Texas	Emission limit (lb/MWh)
	Regulatory Assistance Project	Model rule with output-based emission limit (lb/MWh)
	Connecticut	Emission limit (lb/MWh)
	Maine	Emission limit (lb/MWh)
	Massachusetts	Emission limit (lb/MWh)
	New York	Emission limit (lb/MWh)
State NO_x budget trading programs	Connecticut	Allocation of allowances
	Massachusetts	Allocation of allowances
	Missouri	Allocation of allowances
	New Hampshire	Allocation of allowances
	New Jersey	Allocation of allowances
	Ohio	Allocation of allowances
CAIR state programs	Arkansas	Allocation of allowances
	Connecticut	Allocation of allowances
	Illinois	Allocation of allowances
	Indiana	Allocation of allowances
	Massachusetts	Allocation of allowances
	New Jersey	Allocation of allowances
	Ohio	Allocation of allowances
	Pennsylvania	Allocation of allowances
	Wisconsin	Allocation of allowances
Regional Greenhouse Gas Initiative state programs	Connecticut	Allocation of set-asides
	Massachusetts	Allocation of set-asides
	New York	Allocation of set-asides
State multi-pollutant programs	Massachusetts	Emission limit (lb/MWh)
	New Hampshire	Allocation of allowances
State generation emission performance standards	California	Performance standard (lb/MWh)
	New York	Performance standard (lb/MWh)
	Oregon	Performance standard (lb/MWh)
	Washington	Performance standard (lb/MWh)
New Source Review	Connecticut	Lowest achievable emission rate option

Section 1. Introduction

1.1 Purpose of the Handbook

The U.S. Environmental Protection Agency (EPA) Combined Heat and Power Partnership (CHPP) program developed this handbook to assist air regulators in developing emission regulations that recognize the pollution prevention benefits of efficient energy generation and renewable energy technologies. Output-based *regulations* include output-based emission standards and compliance options as well as output-based *allocations* of allowances within cap and trade programs. Use of output-based regulations can advance the adoption of highly efficient combustion technologies leading to emission reductions.

An output-based standard relates emissions to the energy output of a process (e.g., electricity or thermal output) rather than the material inputs (e.g., fuel burned). An example would be lb/MWh_{output}, rather than $lb/MMBtu_{heat\ input}$.

Output-based regulations do not provide a special benefit to any particular technology and do not increase emissions. They simply level the playing field by allowing energy efficiency to compete on an equal footing economically with any other method of reducing emissions (e.g., combustion controls and add-on controls). For this reason, environmental groups, associations of air regulators, and proponents of clean energy technologies have endorsed the use of output-based regulations (see Appendix C).

While output-based regulations have been used for many sources, boilers and power generation sources have traditionally been regulated through *input-based* regulations. Recently, this has begun to change as regulators have sought to promote pollution prevention and provide compliance flexibility to combustion sources, which face ever-increasing requirements for emission reductions. This handbook is a resource for air regulators who wish to consider applying output-based regulations to boilers or power generation sources. Specifically, the handbook:

- Describes output-based regulations.
- Explains the benefits of output-based regulations.
- Explains how to develop an output-based emission standard or how to comply with an output-based standard.
- Provides a catalogue of the current use of output-based regulations for combustion sources.

Output-based regulations encourage pollution prevention, leading to reduced fuel consumption and associated reductions in emissions.

Now is an important time to examine output-based regulations because of the increasingly competitive energy markets and the improving economics of efficient power-generating technologies. Highly efficient generation systems, such as combined heat and power (CHP), offer the potential to cost-effectively reduce fuel consumption and associated emissions. Output-based regulations recognize the environmental benefits of these technologies.

1.2 Trends Supporting Increased Use of Output-Based Regulation

Increased interest in output-based regulations began in the 1990s. During this period, air regulators faced persistent challenges in achieving progressively more stringent air quality standards while the demand for energy continued to grow. Emissions from fuel combustion were determined to contribute to a variety of air quality problems, including ground-level ozone, fine particulates, acid rain, urban toxics, visibility degradation, and climate change. To achieve air quality goals, state and federal regulators increasingly searched for more cost-effective approaches to achieve greater emission reductions from energy production sources. Against this backdrop, output-based regulations presented a way to provide flexibility to regulators and sources in achieving multi-pollutant emission reductions at the lowest cost.

A number of factors have supported the growing interest in output-based regulations:

- ***Growing difficulty in meeting increasingly stringent air quality standards.*** To meet these standards, regulators and the regulated community constantly look for new, cost-effective tools to reduce emissions. Policymakers realize that more efficient energy conversion technologies can have a substantial effect on reducing emissions. Most importantly, the investment in these technologies creates environmental benefits across all air quality programs.

- ***Pollution prevention as a means of emission control.*** Improving efficiency is one of the best forms of pollution prevention. Avoiding pollution through energy efficiency can have long-term cost benefits through less reliance on emission control equipment and reduced fuel use. Gains in efficiency produce multiple pollutant benefits without creating adverse secondary environmental impacts that are common among end-of-pipe approaches. A number of states have implemented portfolio standards requiring a certain percentage of retail electricity sales or energy savings in the state to come from energy efficiency measures.

- ***Need to assess and compare different generating technologies.*** The widespread deployment of new gas combined cycle generating technology, with emissions measured as flue gas concentration (ppm) rather than the lb/MMBtu common for conventional plants, has made environmental comparisons between technologies difficult. As reducing emissions from electricity generation became a focus, regulators became increasingly interested in clear comparisons between alternative technologies. Output-based regulations place all generators on the same regulatory basis and promote comparisons of environmental performance.

- ***Increased interest in CHP.*** The high efficiency of CHP reduces both energy consumption and emissions, and many regulators were looking for ways to encourage its application. However, CHP replaces two conventional emission sources with one source. Comparing CHP to conventional systems requires an assessment of the energy production capacity that is displaced. Output-based measures facilitate this comparison.

- ***Increased interest in renewable energy technologies.*** Wind turbine technology, along with photovoltaic technology, has become significantly less expensive and more competitive in electricity markets. Growth in wind and solar generation has been dramatic, yet small cost improvements can still make a significant difference. Allocating emission allowances on an output basis can financially reward these facilities for their contribution to meeting allowance allocations.

- ***Increased use of demand response.***[5] Greater participation in demand response programs requires an increased focus on emissions from backup generators, which are often called upon during demand response events. Output-based regulations are an effective way to regulate emissions from these backup generators. Many of the recently developed output-based regulations focus on distributed generation (DG) technologies, including backup generators. As DG proliferates and emissions from DG increase, this new source of pollution becomes important to air regulators and provides a valuable opportunity for the use of output-based regulations.

- ***The development of emission trading programs*.** Market-based emission trading programs are proliferating and can provide a more cost-effective approach to environmental regulation. For example, current "cap and trade" programs such as the Cross State Air Pollution Rule (CSAPR)[6] limit the total tonnage of emissions from one or more fuel combustion sectors. Because of the cap on total emissions, generators strive to maximize the productive output they can generate within their cap. This directly links the cost of allowances to electricity generation and causes generators to think in terms of lb emissions/MWh.

1.3 Using the Handbook

This document provides practical information for an air regulator to consider in developing an output-based regulation.

- ***Section 2*** defines output-based regulations and explains the output-based units of measure typically used for different combustion technologies.

- ***Section 3*** explains how output-based regulations encourage pollution prevention, reduce fuel use and multiple associated pollutants, and can reduce compliance costs.

- ***Section 4*** describes the mechanics of developing output-based standards, and discusses the decisions involved and the compliance implications; this section also discusses complying with output-based regulations.

- ***Section 5*** catalogues recent output-based air regulations at the state, regional, and federal levels and discusses three regulations in detail.

- ***Appendix A*** contains energy conversion factors.

- ***Appendix B*** lists existing output-based regulations.

[5] Demand response is defined as changes in electric usage by end-use customers from their normal consumption patterns in response to changes in the price of electricity over time, or to payments to incentivize lower electricity use when wholesale market prices are high or when system reliability is jeopardized.
[6] *http://www.epa.gov/airtransport/CSAPR/pdfs/CSAPRFactsheet.pdf*.

Section 2. What Is An Output-Based Regulation?

An output-based regulation relates emissions to the productive output of the process. Outputs from combustion sources include electrical, thermal, and mechanical energy. Output-based regulation can be used to develop traditional emission standards or to allocate emission allowances in a cap and trade program. In both cases, they account for the pollution prevention benefits of efficient energy generation and renewable energy technologies.

- ***Output basis for emission standards.*** Output-based *standards* account for the emission benefit of efficiency measures, such as increasing combustion efficiency, increasing turbine efficiency, recovering useful heat, and reducing parasitic losses associated with operating the affected unit (e.g., operation of fans, pumps, motors). Therefore, control strategies for meeting output-based emission standards can include both emission controls *and* efficiency measures.

- ***Output basis for allowance allocations.*** An output basis can also be used in determining *allowance allocation*s in a cap and trade program. An output-based allocation provides more allowances to more efficient plants. Traditionally, allowances (the right to emit one ton per year of a pollutant) have been allocated based on the operating history (usually annual fuel input) of the regulated sources. Allowances also can be updated in the future (referred to as an "updating" allocation system). Adopting an updating allocation system on an output basis and including renewable energy facilities provides an incentive for both energy efficiency and renewable energy.

Output-based regulations are based on electrical, thermal, or mechanical output (MWh, MMBtu, or bhp-hr), rather than the heat input of fuel burned or pollutant concentration in the exhaust.

2.1 Output-Based Units of Measure

The appropriate units of measure for an output-based emission standard depend on the type of energy output and the combustion source. For most applications, the units of measure are pounds of emissions per unit of energy output (Table 2-1). For reciprocating engines, output-based measure is either grams of emissions per brake horsepower-hour (g/bhp-hr) or pounds per megawatt hour (lb/MWh), depending on whether the engine is used to generate mechanical power or electricity.

Table 2-1. Output-Based Units of Measure

For This Type of Energy Production...	Using...	An Output-Based Measure Is...
Electricity generation	• Boilers/steam turbines Reciprocating engines • Combustion turbines	Pounds per megawatt hour (lb/MWh)
Steam or hot water generation	• Industrial boilers • Commercial boilers	Pounds per million British thermal units ($lb/MMBtu_{heat\ output}$)
Mechanical power	• Reciprocating engines	Grams/brake horsepower-hour (g/bhp-hr)

2.2 Output-Based Standards Under the Clean Air Act

Traditionally, most *combustion sources* have been regulated based on heat input ($lb/MMBtu_{heat\ input}$) or the mass concentration of pollutants in the exhaust stream (parts per million or "ppm"). Input-based regulations were used during early Clean Air Act rulemaking efforts in part because data on heat input were more readily available at the time than data on energy output. Subsequently, compliance tests were based on heat input, and energy output data generally were not collected and reported as part of the required monitoring or source test requirements. Similarly, when cap and trade programs were initiated with the 1990 Clean Air Act Amendments (Title IV of which established the Acid Rain Program), emission allowances for individual power plants were allocated based on their historical annual heat input.

Nevertheless, output-based standards are not a new concept within the Clean Air Act. In the form of mass emitted per unit of production, they have been used for many New Source Performance Standards (NSPS), National Emission Standards for Hazardous Air Pollutants (NESHAP), and other state and federal rules. For example:

- The NSPS (40 CFR part 60) uses output-based standards for primary aluminum (subpart S), wool fiberglass (subpart PPP), asphalt roofing (subpart UU), and glass manufacturing (subpart CC). The NSPS for stationary combustion turbines (subpart KKKK) limits emissions from stationary combustion turbines. Affected units have the option of meeting concentration-based or output-based nitrogen oxides (NO_x) and sulfur dioxide (SO_2) emission limits.
- The NESHAP (40 CFR part 63) uses output-based standards for iron and steel (subpart FFFFF), brick and structural clay (subpart JJJJJ), and other industries.
- States have used output-based standards for a variety of regulations. For example, Indiana sets NO_x emission limits for cement kilns in lb/ton of clinker produced (326 IAC 10-1-4); and New Jersey sets NO_x limits for glass melters in lb/ton of glass removed (NJAC 7:27-19.10). More recently, Texas issued a streamlined construction air permitting program in 2012, termed a permit by rule (PBR), under which certain types of natural-gas-fired CHP systems are eligible (i.e., a CHP unit, up to a capacity of 8 MW without additional controls and 15 MW with additional controls, burning only pipeline-quality natural gas). The CHP PBR, codified in 30 TAC 106.513, allows CHP systems that meet the rule's eligibility requirements to comply with output-based NO_x and carbon monoxide (CO) emission limits. Other states have similar requirements.
- The automotive emission standards are expressed in grams/mile.

Section 3. Why Adopt Output-Based Regulations?

Output-based regulations offer a variety of benefits for regulators and the regulated community. For regulators, output-based regulations encourage pollution prevention, leading to reductions in fossil fuel use and associated environmental impacts. For the regulated community, output-based regulations offer greater flexibility and the opportunity for lower compliance costs for individual facilities and society as a whole. Also, because output-based regulations encourage energy efficiency, these regulations can reduce the stress on today's energy systems.

Benefits of output-based regulations:

- *Incentive for pollution prevention*
- *Multi-pollutant emission reductions*
- *Reduced fuel use*
- *Avoidance of upstream environmental impacts of fuel production and delivery*
- *Lower compliance costs*

This chapter demonstrates the benefits of output-based approaches by presenting case study examples of the differences between output- and input-based regulations at the facility level. Section 3.1 explains the emission reduction benefits of output-based regulations. Section 3.2 explains how costs can be reduced by the compliance flexibility that output-based regulations provide. Section 3.3 shows how an output-based format facilitates comparisons of environmental performance. Lastly, Section 3.4 describes CHP technologies and how output-based regulations can be used to account for their unique efficiency benefits.

3.1 Emission Reduction Benefits of Output-Based Regulation

Output-based regulations can reduce air pollution by encouraging energy efficiency and renewable energy technologies. The increased use of these technologies reduces fuel use and leads to multi-media reductions in the environmental impacts of fuel production, processing, transportation, and combustion. Reduced fuel use reduces emissions of all pollutants, not just the target pollutant of the regulatory program. In addition, energy efficiency and renewable energy can create a permanent and consistent emission benefit that is not subject to short-term emission increases that can result from startup, shutdown, or malfunction of add-on control devices (e.g., selective catalytic reduction for NO_x or scrubbers for SO_2). Pollution prevention also reduces the secondary pollutant releases (e.g., sludge and ash disposal) that are often associated with add-on control technologies. The sections that follow illustrate the effect of output-based regulations in a conventional emission standards program and in an emission trading program.

3.1.1 Output-Based Emission Standards

An output-based emission standard provides a clear indicator of emission performance, because it accounts for the emission impact of efficiency in addition to fuel choice and emission controls. A comparison of NO_x emissions at two 300 MW power plants can demonstrate this effect (Figures 3-1a and 3-1b). Assume that each plant operates at an 80 percent capacity factor and generates about 2.1 million MWh per year. Using the traditional input- or concentration-based units of measure, Plant 1 appears to have lower emissions (0.09 lb NO_x/MMBtu or 25 ppm versus 0.12 lb NO_x/MMBtu or 32 ppm for Plant 2). But input- or concentration-based measures do not account for differences in efficiency (34 percent for Plant 1 and 53 percent for Plant 2).

An output-based emission measure accounts for the effect of efficiency (Figure 3-1b). The difference in efficiency means that Plant 2 requires 35 percent less fuel to generate the same electrical output as Plant 1. This means it emits fewer tons, even though it has a higher exhaust concentration. Plant 1 has a lower input-based emission rate, but greater heat input, and emits more than 900 tons per year. Plant 2 has a higher emission rate, but lower heat input, and emits less than 800 tons per year. This example illustrates that emission limits based on heat input or concentration are not good indicators of the actual environmental impact. The output-based emission rate, however, reflects the true difference in emissions. Plant 1 has an output-based emission rate of 0.9 lb/MWh, while the rate for Plant 2 is 0.7 lb/MWh.

Because output-based standards account for the effect of energy efficiency, they allow for the use of efficiency as a control measure. This can result in multi-pollutant emission reductions. In addition to reducing NO_x emissions, the higher efficiency of Plant 2 means lower emissions of all other pollutants, including SO_2, particulate matter (PM), and hazardous air pollutants (HAP), as well as unregulated emissions such as carbon dioxide (CO_2).

Moreover, an output-based standard ensures consistent long-term emission reductions. Under an output-based standard, a decrease in efficiency over time would cause an increase in the emissions per unit of output. This increased emission rate would require the operator to reduce emissions or improve unit efficiency to stay in compliance. On the other hand, under an input-based standard, deterioration of unit efficiency is not reflected in the emission rate, and total annual emissions can increase without affecting compliance.

Thus, an output-based standard offers several advantages:

- It allows sources to benefit from applying energy efficient measures, which lowers fuel use and achieves multi-pollutant emission reductions.
- It ensures consistent, long-term emission reductions.
- It allows regulators to more clearly compare emission performance across different energy-generating technologies and fuels.
- Provides sources with alternative compliance options that can lower costs (see Section 3.2).

Figure 3-1a. Benefits of Output-Based Regulation

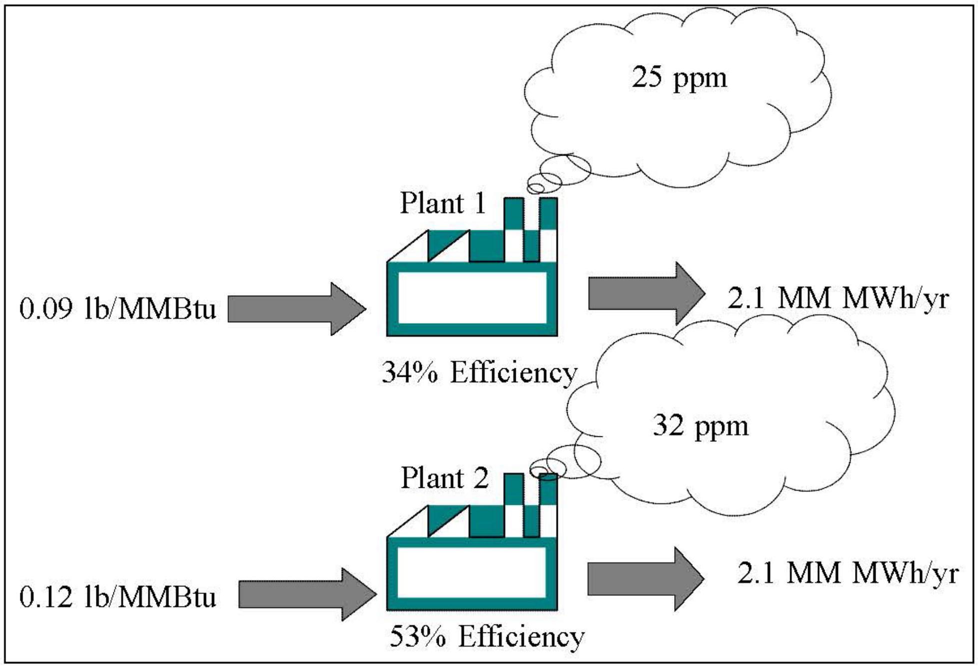
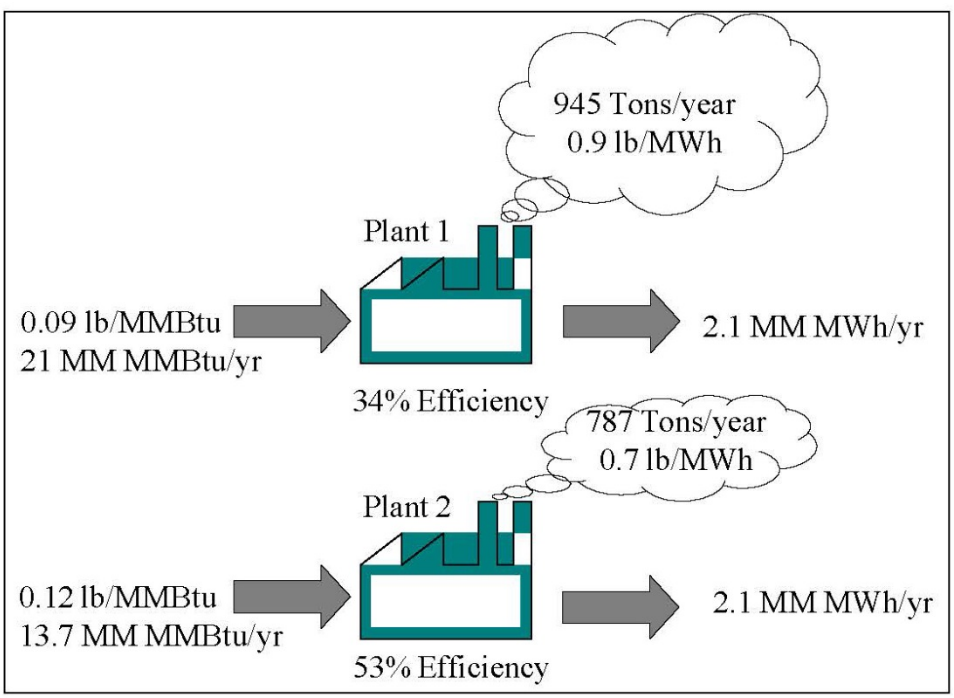


Figure 3-1b. Benefits of Output-Based Regulation



3.1.2 Output-Based Allowance Allocations in Emission Trading Programs

In recent years, recognition of the regional nature of many air quality problems has led to the increasing use of cap and trade programs. In such a program, the total tons of emissions for a given industry sector are capped at the desired level of emission reduction.

Emission allowances, which represent the right to emit one ton per specified time period (e.g., annually or during the ozone season), are allocated directly to industry participants or auctioned. At the end of each time period, every affected source is required to hold allowances equal to its emissions. Sources comply through a combination of reducing emissions and buying additional allowances.

On March 10, 2005, EPA issued the Clean Air Interstate Rule (CAIR). CAIR covers 27 eastern states and the District of Columbia. CAIR requires emissions reductions that each state must achieve using one of two compliance options: (1) meet its emission budget by requiring power plants to participate in an EPA-administered interstate cap and trade system that caps emissions in two stages or (2) meet an individual state emission budget through measures of its choosing. A number of states adopted an output-based approach for both existing and new sources.

Emission allowances are allocated at the beginning of a trading program on either a permanent basis or with a provision for updating allocations for future trading periods. For the national sulfur dioxide trading program, which was established under the Title IV acid rain program, SO_2 allowances were permanently allocated based on historic annual heat input. The regional NO_x Budget left allocation decisions up to state governments and provided guidance to help states that might want to allocate on an output basis (see Section 5.0 for further discussion). The Clean Air Interstate Rule (CAIR) also gave state governments flexibility in determining whether to allocate allowances on an output basis. In June 2014, the U.S. government filed a motion with the U.S. Court of Appeals for the D.C. Circuit to lift the stay of CSAPR, which was intended to replace CAIR. While the Court considers the motion, CAIR remains in place and no immediate action from states or affected sources is expected. An output-based allocation provides more allowances to efficient units than to inefficient ones. The example on the next page illustrates this effect.

The environmental benefit of an output-based allocation system occurs only in programs where allowances are reallocated periodically for future periods (known as an updating allocation system). For the initial allocation, there is no difference in incentives between an input-based system of allocation and an output-based one, because the initial allocation in both cases is based on historical data. However, the opportunity to influence behavior comes when facility operators know that emission allowances will be reallocated in the future. An updating output-based allocation system would provide an incentive for increased energy efficiency because more efficient units would receive relatively more allowances in future allocations.

Alternatively, an input-based reallocation system would provide a relative disincentive for efficiency improvements because an efficient unit would burn less fuel and, therefore, receive fewer allowances.

How Do Input-Based and Output-Based Allowance Allocations Differ?

Consider a state with emissions of 1,700 tons per year and an emissions cap of 1,500 tons per year. This cap represents a 12 percent reduction in emissions. Assume that the only emission sources are the two plants described in Figure 3-1. The table below shows the allocation of allowances under input- and output-based approaches.

Basis of Allocation	Plant 1	Plant 2
Heat Input		
Heat input (million MMBtu/yr)	21.0	13.7
Percent of total heat input	61%	39%
Initial emissions (tons)	945	822
Allowances allocated (tons)	909	591
Implied emission reduction	4%	28%
Energy Output		
Output (million MWh/yr)	2.10	2.10
Percent of total generation	50%	50%
Initial emissions (tons)	945	822
Allowances allocated	750	750
Implied emission reduction	21%	9%

In this example, Plant 1 uses 21 million MMBtu/yr, or 61 percent of the heat input, and Plant 2 uses 39 percent. Allocating the 1,500 allowances by these shares gives 909 allowances to Plant 1 and 591 allowances to Plant 2. If there were no trading, this allocation would impose a 4 percent emission reduction for Plant 1 (the higher-emitting plant) and a 28 percent reduction for Plant 2 (the lower-emitting plant). This allocation approach seems to reward the higher-emitting plant by awarding it more allowances while penalizing the lower-emitting plant.

Alternatively, under an output-based allocation, both plants would receive 750 tons of allowances because they produce the same output. Without trading, this implies a 21 percent emission reduction for Plant 1 and a 9 percent reduction for Plant 2. In this case, the trading program rewards the lower-emitting, more efficient plant. Several states participating in the NO_x SIP Call trading program use output-based allocation, as do some existing and proposed multi-pollutant legislation (see descriptions of these programs in Appendix B).

The primary *environmental* benefits of increased efficiency are the ancillary impacts. For example, if the cap and trade program controls NO_x emissions, total emissions of NO_x would be the same under either allocation method. However, the increased efficiency would reduce emissions of SO_2, CO, CO_2, HAP, and PM, and would reduce fossil fuel demand and the environmental impacts associated with the fuel production and transportation systems.

The section 126 NO_x cap and trade program to reduce interstate ozone transport based the initial allowance allocations on heat input (because good- quality energy output data were not available), but announced that allowances would be updated every five years based on energy output (65 FR 2698, January 18, 2002).

States can design their output-based allocation systems to pursue their own energy and environmental policy agenda. For example, output-based allocation under a cap and trade program provides the opportunity to allocate emission allowances to renewable energy sources. Output-based allowance allocation treats renewable generators and efficiency programs the same as conventional generators. When done on an updating basis, the allocation promotes the increased use and construction of these non-emitting sources by giving them a market-based economic benefit. Output-based allocations also provide the opportunity to promote CHP systems by including their thermal output in the allocation calculation.

Another way to view the allowance allocation process is that it distributes the right to use a public resource—clean air. An output-based approach allocates that limited public resource on the basis of productive output rather than raw materials used.

Thus, output-based allocation of allowances within a cap and trade program:

- Provides economic benefit to more efficient and non-emitting sources, thereby recognizing their contribution to meeting regional emission caps.
- Encourages increased construction and use of efficient energy sources (if done on an updating allocation basis).
- Allocates public resources (the right to emit) in proportion to the public benefit (energy output).

3.2 Cost Reductions from Output-Based Regulations

An output-based emission regulation can reduce compliance costs because it gives process designers greater flexibility in reducing emissions. A facility operator can comply by installing emission control equipment, using a more energy-efficient process, or combining the two steps. Regulating the emissions produced per unit of output has value for equipment designers and operators because it gives them additional opportunities to reduce emissions through more efficient fuel combustion, more efficient cooling towers, more efficient generators, and other process improvements that can increase plant efficiency.

This flexibility is particularly important for NO_x because NO_x formation is a function of combustion temperature and conditions. NO_x concentration and energy efficiency are often a trade-off in combustion design. In some cases, however, equipment designers can reduce emissions by increasing efficiency and allowing a slightly higher flue gas NO_x concentration.

This control approach is not possible with input-based emission limits, but could be used under an output-based limit.

Example of cost flexibility allowed by an output-based emission standard. Consider a planned new or repowered coal-fired utility plant with an estimated uncontrolled NO_x emission rate of 0.35 $lb/MMBtu_{heat\ input}$. To comply with an input-based emission standard of 0.13 $lb/MMBtu_{heat\ input}$, the plant would have to install emission control technology to reduce NO_x emissions by more than 60 percent. On the other hand, if the plant were subject to an equivalent output-based emission standard of 1.3 lb/MWh, it would have the option of considering alternative control strategies by varying both its operating efficiency and the efficiency of the emission control system (Table 3-1). This output-based format allows the plant operator to determine the most cost-effective way to reduce NO_x emissions and provides an incentive to reduce fuel combustion. The total annual emissions are the same in either case.

Table 3-1. Design Flexibility Offered by Output-Based Standard

Plant Efficiency (Percent)	Emission Standard lb/MWh	Required Control Device Efficiency (Percent)
34	1.3	60
40	1.3	55
44	1.3	48

From a broader economic perspective, achieving emission reductions through efficiency can be significantly more attractive than through add-on controls. Add-on controls require an investment of capital but do not increase productive output. In many cases, they reduce efficiency and/or output. The same capital, if used to increase efficiency, will reduce emissions *and increase* productive output. This contradicts the common assumption that a facility operator must choose between cost and emission reductions. Efficiency improvement reduces operating cost, increases production, *and* reduces emissions.

3.3 Output-Based Format as a Measure of Environmental Performance

An output-based format gives a clear measure of the emission impact of producing an energy product, such as electricity or steam. As an example, the most common output-based measure for electricity generation is lb/MWh generated. When emissions are expressed in these units, all sources can be directly compared, and determining the actual tons of emissions for a given level of energy generation is straightforward. Table 3-2 shows conventional input-based units of measure for electric utility emission limits and the comparable output-based units. The ranges shown in the table represent typical ranges of emission rates for each combustion technology.

Output-based standards make comparing emissions between technologies easier. By contrast, comparing 0.1 g NO_x/bhp-hr from an engine to 25 ppm NO_x from a gas turbine to 0.1 lb/MMBtu from a boiler is cumbersome. Using an output-based format, therefore, can simplify emission comparisons and program design for an air quality planner.

Table 3-2. Conventional and Output-Based Measurements for Electricity Generation

Steam Boiler*		Combustion Turbine**		Reciprocating Engine	
lb/MMBtu$_{heat\ input}$	lb/MWh	ppm	lb/MWh	g/bhp-hr	lb/MWh
0.1	1.0	3	0.13	0.1	0.31
0.2	2.0	9	0.4	0.15	0.47
0.3	3.0	15	0.6	0.5	1.56
0.4	4.0	25	1.1	0.7	2.18
0.6	6.0	42	1.8	1.0	3.11

* At 10,000 Btu/kWh heat rate.
** At 12,000 Btu/kWh heat rate.

3.4 Output-Based Regulation and Combined Heat and Power Applications

CHP is one of the best examples of an energy efficiency technology that can reduce fuel consumption and emissions. Although CHP is not a new concept, it is unfamiliar to many regulators, investors, and potential users. This lack of familiarity can create obstacles to its widespread application. One way to promote the use of this environmentally beneficial technology is through output-based regulations.

3.4.1 What Is Combined Heat and Power?

Typical CHP technologies:

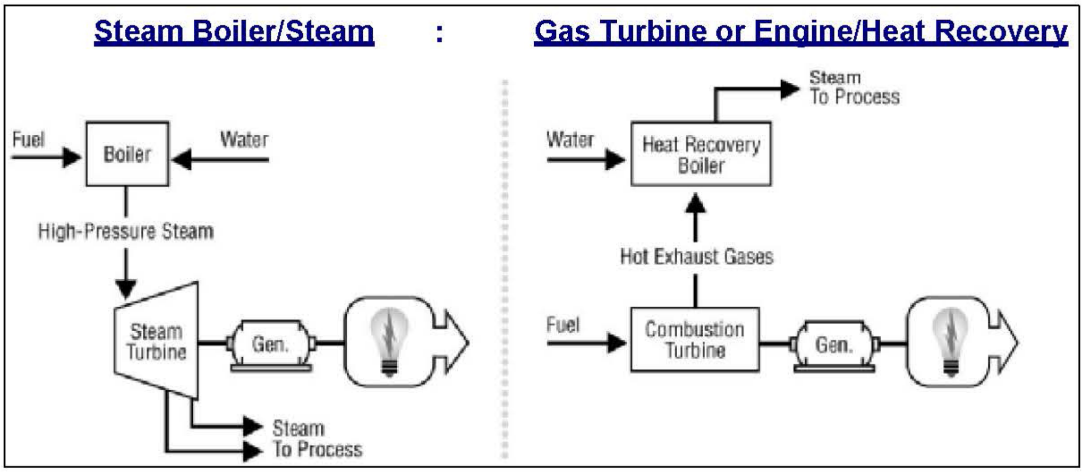
- *Combustion turbines*
- *Reciprocating engines*
- *Boiler/steam turbines*
- *Combined cycle gas turbines*
- *Microturbines*
- *Fuel cells*

CHP is the sequential generation of power (electricity or shaft power) and thermal energy from a common fuel combustion source. CHP captures waste heat that ordinarily is discarded from conventional power generation, which typically discards two-thirds of the input energy as waste heat (typically up exhaust stacks and through cooling towers). CHP systems recover much of this otherwise wasted energy. This captured energy is used to provide process heat, space cooling or heating for commercial buildings or industrial facilities, and cooling or heating for district energy systems. By recovering waste heat, CHP systems achieve much higher efficiency than separate electric and thermal generators. Figure 3-2 shows two common configurations for CHP systems.

The steam boiler/turbine approach was the first application of CHP and the only CHP technology for many years. In this approach, a boiler makes high-pressure steam that is fed to a turbine to produce electricity. However, the turbine is designed so that enough steam is left over to feed an industrial process. This type of system typically generates about five times as much thermal energy as electric energy. Steam boiler/turbine CHP systems are widely used in the paper, chemical, and refining industries, especially when waste or byproduct fuel is available that can be used to fuel the boiler.

In the other common CHP system, a combustion turbine or reciprocating engine is used to generate electricity, and thermal energy is recovered from the exhaust stream to make steam or supply other thermal uses. These systems have been applied more in recent years, as the combustion technologies have developed. These types of CHP systems can use very large (hundreds of MW) gas turbines or very small (tens of kW) microturbine, engine, or fuel cell systems. The electric energy they produce is typically one to two times the thermal energy produced.

Figure 3-2. Two Typical CHP Configurations



The ratio of electrical to thermal energy generated by a CHP system is an important criterion in determining its applicability. This ratio is usually characterized as the power-to-heat ratio (P/H)—the ratio of electric output to thermal output in consistent units. The P/H ratio depends largely on the technology and configuration and can vary from 0.05 to more than 5. Table 3-3 shows typical P/H ratios for common CHP technologies.

Table 3-3. Typical P/H Ratios for Common CHP Technologies

Technology	P/H
Combustion turbine	0.6–1.1
Reciprocating engine	0.5–1.2
Combined cycle	1.0–3.0
Boiler/steam turbine	0.05–0.2

For example, a combustion turbine with a heat recovery system might typically have a P/H ratio of approximately 0.6 units of electricity per unit of thermal energy out (or 1.67 units of thermal energy out for every unit of electricity).

CHP is especially attractive because it can be applied with almost any combustion technology and fuel. This means that it can have many end uses and can use any fuels that are economically available. It is a well-known and well-demonstrated technology. The United States has approximately 83.3 gigawatts (GW) of CHP capacity in place as of the end of 2012, yet the potential for substantial expansion is great. President Obama issued Executive Order 13624 in August 2012, which sets a goal for deploying 40 GW of new, cost-effective industrial CHP capacity by the end of 2020.[7]

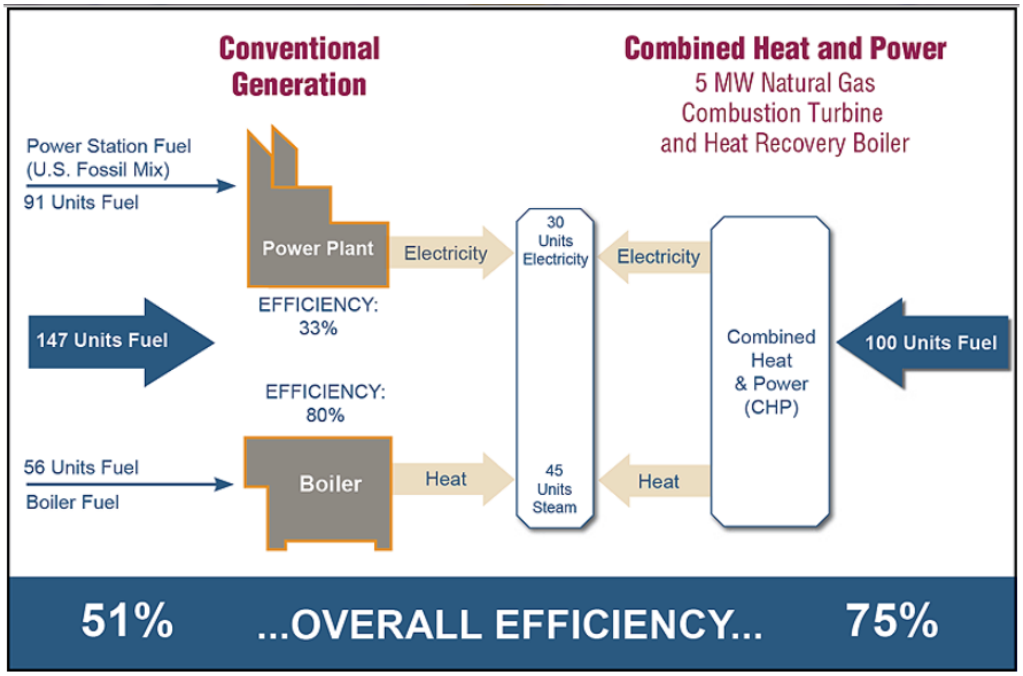
3.4.2 What Are the Benefits of Combined Heat and Power?

By providing electrical and thermal energy from a common fuel input, CHP significantly reduces the associated fuel use and emissions. Figure 3-3 compares the efficiency and fuel use of a CHP facility to

[7] *http://www.whitehouse.gov/the-press-office/2012/08/30/executive-order-accelerating-investment-industrial-energy-efficiency*.

the efficiency and fuel use of conventional systems providing the same service. In this case, both systems provide 30 units of electric energy and 45 units of thermal energy to the facility.

Figure 3-3. Efficiency Benefits of CHP



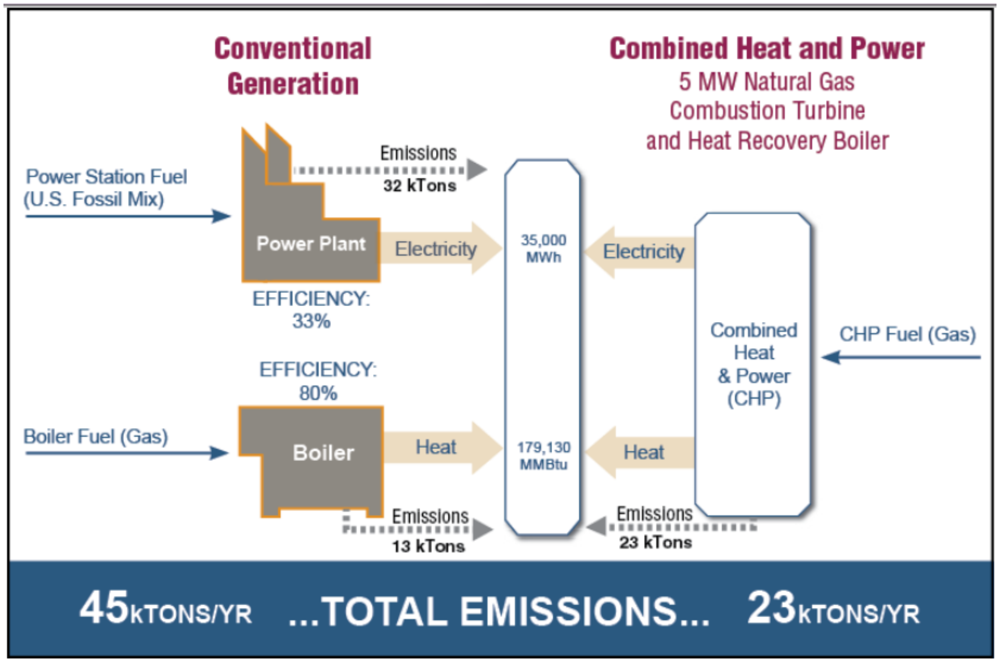
In the conventional system, the electricity required by the facility is purchased from the central grid. Power plants on average are about 33 percent efficient, considering both generating plant losses and transmission and distribution losses.[8] Thermal energy required by the facility is provided by an onsite boiler that might be 80 percent efficient. Combined, the two systems use 147 units of fuel to meet the combined electricity and steam demand. The combined efficiency to provide the thermal and electric service is 51 percent.

With CHP, an onsite system provides the same combined thermal and electric service. Electricity is generated in a combustion turbine and the waste heat is captured for process use. The CHP system satisfies the same energy demand using only 100 units of fuel. This system is 75 percent efficient.

Figure 3-4 shows the emission benefits of the CHP system, in this case for NO_X emissions. The CHP system has much lower emissions because it uses 35 percent less fuel, even if the combustion process has the same input-based emission rates as the conventional equipment. In this example, as is often the case, the new CHP system displaces higher-emitting generators on the electric grid, and the emission rate for the new system is lower than the conventional alternative, thus further reducing emissions. In the case shown, the CHP system emits less than half as much NO_X as the conventional system due to a combination of greater efficiency and lower emission rate.

[8] *http://www.epa.gov/chp/basic/efficiency.html*.

Figure 3-4. Emission Benefits of CHP



This example illustrates the significant energy and environmental benefits that are achievable through the application of CHP. In this case, a large portion of the avoided emissions come from the offsite power plant. The *onsite* emissions from the CHP system are *slightly higher* than in the conventional case because more fuel is burned on site.[9] But the *total regional emissions* are *lower* (23 tons/yr vs. 45 tons/yr). Output-based regulations can be designed to recognize this benefit. Under conventional generation, the two combustion units have a combined output-based emission factor of 1.13 lb/MWh_{t+e}. The CHP system has output-based emissions of 0.58 lb/MWh_{t+e} . Output-based regulations that account for this net regional emission benefit will encourage the application of CHP.

Thus, an output-based regulation:

- Provides a compliance methodology to account for the emission reduction benefits of CHP. Some approaches for designing an output-based regulation to recognize the efficiency of CHP are discussed in Chapter 4.
- Reduces fuel use and net regional emissions by encouraging the adoption of CHP and other highly efficient energy technologies.

[9] Depending on the characteristics of the boiler and CHP combustion device, the on-site emissions could be higher or lower with CHP than with a conventional system.

Section 4. How Do I Develop An Output-Based Emission Standard?

This chapter explains how to develop an output-based emission standard. To begin, several decisions must be made about the format of the rule. Making these decisions will involve trade-offs between the degree to which the rule will account for the benefits of energy efficiency, the complexity of the rule, and the ease of measuring compliance. This chapter explains the technical approach, available options, and the implications of each option. The steps for developing an output-based emission standard are:

1. ***Develop the output-based emission limit***. The method that you use will depend on whether you have measured energy output data available.
2. ***Specify a gross or net energy output format***. Net energy output will more comprehensively account for energy efficiency, but can increase the complexity of compliance monitoring requirements.
3. ***Specify compliance measurement methods***. Output-based rules require designating methods for monitoring electrical, thermal, and mechanical outputs. These outputs are already monitored for commercial purposes at most facilities.
4. ***Specify how to calculate emission rates for CHP units.*** For CHP units, the rule must account for multiple energy outputs. Two commonly used approaches are explained.

4.1 Develop the Output-Based Emission Limit

Ideally, to develop an output-based emission limit, you must obtain emission data and simultaneously measured energy output. Unfortunately, energy output data are not always available. Most emission test data available today are based on energy input, consistent with current compliance measurement requirements. But output-based emission limits can still be developed by converting input-based emission data or existing emission limits to an output-based equivalent using unit conversions and a benchmark energy efficiency. The following sections demonstrate the unit-of-measure conversions from:

- Input-based emission limit in pounds per million Btu ($lb/MMBtu_{heat\ input}$).
- Flue gas concentration limit in parts per million by volume (ppmv).
- Emission limit based on mechanical power in grams per brake horsepower-hour (g/bhp-hr).

for the two primary types of energy outputs:

- Electrical power generation (to lb/MWh).
- Steam or hot water generation (to $lb/MMBtu_{heat\ output}$).

4.1.1 Conversion from Input-Based Emission Limit ($lb/MMBtu/_{heat\ input}$)

Many emission standards for boilers are expressed in lb $emissions/MMBtu_{heat\ input}$. You convert to output-based standards using a benchmark efficiency factor and a unit-of-measure conversion. The conversion is straightforward for electric generators and industrial boilers.

Electric generators. For utility boilers, the output-based unit of measure is lb/MWh of electricity generated.

$$\text{output standard} = (I \times H) \div 1{,}000$$

Where:

output standard	=	Output-based emission limit, lb/MWh
I	=	Input-based emission limit, $lb/MMBtu_{heat\ input}$
H	=	Benchmark heat rate of steam generator set, Btu/kWh
1,000	=	Unit-of-measure conversion, $\frac{1{,}000\ kWh}{MWh} \times \frac{MMBtu}{1{,}000{,}000\ Btu}$

If the power plant efficiency is used as the benchmark rather than the heat rate, calculate the heat rate as shown below.

$$\text{heat rate} = 3{,}413 \div \text{efficiency}$$

For example

$$3{,}413 \div 34\%\ \text{efficiency} = 10{,}000\ \text{Btu} \div kWh_{electric\ output}$$

Then, the output-based emission limit can be calculated using Equation 1.

Example Calculation

Consider a state with an emission limit of 0.15 $lb/MMBtu_{heat\ input}$. Assume that you select a benchmark heat rate of 10,000 Btu/kWh of electric output. Using this heat rate and Equation 1, the equivalent output-based limit would be:

$$\begin{aligned} \text{output standard} &= I \times H \div 1{,}000 \\ &= 0.15\ lb/MMBtu \times 10{,}000\ Btu/kWh \div 1{,}000 \\ &= 1.5\ lb/MWh_{electric\ output} \end{aligned}$$

While this calculation is straightforward, you must determine a benchmark efficiency to use in the calculation. The choice of benchmark efficiency will affect the stringency of the output-based limit. Heat rates for conventional steam turbine power plants can vary from 9,000 to 11,000 Btu/kWh, depending on type of unit and load factor. Heat rates for older units can be higher (i.e., less efficient). Selecting a low heat rate will result in an aggressive limit for the less efficient units in the existing source population. Selecting an average or typical value from the population of affected sources will result in less control of newer, more efficient units. When selecting efficiency, you should consider the goals of the regulatory program (e.g., new source or existing source regulation) and the degree of emission reduction needed.

Heat rates can be calculated from heat input and generation data collected by the Energy Information Administration on Form 767. Heat rate data for individual power plants also are available in EPA's eGRID Database (*http://www.epa.gov/cleanenergy/egrid/*).

Both the heat rate and efficiency should be based on the fuel's higher heating value (HHV), not its lower heating value (LHV). Heating values describe the amount of energy released when fuel is burned. HHVs and LHVs are determined differently, however. HHV is the heating value including the latent heat of the combustion products. HHV is usually used for systems using boilers. LHV is the heating value net of the latent heat in the combustion products. LHV is often used in calculating efficiencies for combustion turbines and reciprocating engines.

EPA's practice is to base all regulatory limits on the HHV of the fuel. Fuel is typically sold based on HHV.

If you know only the LHV, then convert to HHV as follows:

$$HHV = LHV + 10.3\ (H_2 \times 8.94)$$

Where:

H_2	=	mass percent hydrogen in fuel, %
LHV	=	lower heating value, Btu/lb

Factors for specific fuels are listed in Appendix A. For natural gas, the HHV is 1,030 Btu/cf and the LHV is 937 Btu/cf, or LHV ÷ HHV = 0.91.

Commercial/industrial steam boilers. For steam or hot water generators, the output-based unit of measure is lb emission/$MMBtu_{\text{heat output}}$. You can convert an input-based emission rate to an output-based format using the boiler efficiency, as follows:

$$\text{output standard} = I \div E$$

Where:

output standard	=	Output-based emission limit, lb/MWh
I	=	Input-based emission limit, lb/$MMBtu_{\text{heat input}}$
E	=	Benchmark steam generator efficiency, %

Typical steam generator efficiencies are in the range of 75 to 80 percent.

Example Calculation

Consider a state with an emission limit of 0.15 lb/MMBtu for natural-gas-fired industrial boilers. Assume that you select a benchmark efficiency of 80 percent. The output-based limit would be:

$$\begin{aligned}\text{output standard} &= I \div E \\ &= 0.15\ \text{lb/MMBtu} \div 0.80 \\ &= 0.19\ \text{lb/MMBtu}_{\text{heat output}}\end{aligned}$$

4.1.2 Conversion from Flue Gas Concentration Limit (ppmv)

Emission limits for combustion turbines and sometimes for boilers and engines are expressed as concentration standards in ppm by volume on a dry basis. The conversion of concentration measurement (ppmv) to output-based measures is a two-step process.

Step 1. The first step is to convert ppm concentration to an input-based limit and correct for different levels of dilution air in the exhaust gas stream. The conversion is a function of the composition of the exhaust stream and thus varies for different fuels because their combustion products are different. The calculation procedure is:

$$\mathrm{lb/MMBtu_{heat\ input}} = \mathrm{ppm\ x\ k\ x\ F\ x} \left(\frac{20.9}{20.9 - \%O_2}\right)$$

The factor k accounts for unit conversions (i.e., from ppm to lb/dry standard cubic foot); F relates the dry flue gas concentration to the caloric value of the fuel combusted. The k and F factors have been tabulated for a variety of fuels and pollutants (see EPA Method 19 and Appendix A). The last term in the equation adjusts the measured ppm value to a standard O_2 level to correct for any bias due to stack gas dilution. If CO_2 is measured rather than O_2, the method of correction is explained in EPA Method 19. For example, convert an emission limit of 25 ppmv (15 percent O_2) to an input-based limit as follows:

$$\begin{aligned}\mathrm{lb/MMBtu_{heat\ input}} &= 25\ \mathrm{ppm\ NO_x\ @\ 15\%\ O_2\ x\ k\ x\ F} \left(\frac{20.9}{20.9 - 15}\right) \\ &= 0.09\ \mathrm{lb/MMBtu_{heat\ input}}\end{aligned}$$

For natural gas, the conversion is:

$$\mathrm{lb/MMBtu_{heat\ input}} = \mathrm{ppm\ @\ 15\%\ O_2} \div 272$$

Step 2. The second step is to convert the input-based limit to an output-based limit. Use either Equation 1 for electricity generators or Equation 2 for steam or hot water generators.

4.1.3 Conversion from Emission Limit Based on Mechanical Power (g/bhp-hr)

Emissions from reciprocating engines are typically measured in grams per brake horsepower-hour (g/bhp-hr). This is an output-based measure of mechanical power that does not account for the efficiency of the electric generator. You can determine the output-based emission limit using generator efficiency and a unit-of-measure conversion. The conversion is as follows:

output standard = (P × 2.953) ÷ E

Where:

output standard	=	Output-based emission limit, lb/MWh
P	=	Input-based emission limit, $\mathrm{lb/MMBtu_{heat\ input}}$
E	=	Benchmark steam generator efficiency, %
2.953	=	Unit-of-measure conversion, $\frac{1\ \mathrm{lb}}{454.\mathrm{g}}\ \mathrm{x}\ \frac{1\ \mathrm{hp}}{0.746\ \mathrm{kW}}\ \mathrm{x}\ \frac{1{,}000\ \mathrm{kW}}{\mathrm{MW}}$

Using a benchmark efficiency of 95 percent, which is a typical generator efficiency, the conversion can be simplified to:

$$\text{lb/MWh} = \text{g/bhp-hr} \times 3.11$$

4.2 Specify a Gross or Net Energy Output Format

Output-based regulations relate emissions to energy output. You must decide whether the emission limit you are preparing will be expressed as mass per *gross* energy output or mass per *net* energy output. These two approaches have different implications for compliance monitoring and the extent to which the rule accounts for energy efficiency.

Gross output is the total output of a process. Gross output from an electric generating unit would be the gross electric generation (MWh) that comes directly from the electric generator terminals before any electricity is used internally at the plant. Gross output from an industrial boiler would be the gross thermal output ($\text{MMBtu}_{\text{heat output}}$) that comes directly from the boiler header.

Net output is the gross output minus any of the energy output consumed to generate the output. Examples of output that would be subtracted from the gross output when calculating net output include:

- Auxiliary loads related to thermal or electric generation, such as fuel handling and preparation equipment, pumps, motors, and fans.
- Output diverted to operate pollution control devices.
- Thermal output used in heat recovery equipment such as preheaters or economizers.
- House loads (loads used inside the plant for lighting, heating, etc.).

Using a *net* energy output basis provides the greatest incentive for energy efficiency because it accounts for all internal energy consumption at the plant. This method provides an incentive to use energy-efficient devices to lower internal power consumption and realize a net gain in efficiency. But measuring *net* output can be more difficult than measuring *gross* output, because net energy cannot always be directly measured at a single location. Rather, determining *net* output can involve accounting individually for each piece of equipment that uses steam or electricity. At complex industrial sites, it may be difficult to determine the energy associated with power generation or to isolate parasitic losses from energy used by production processes. At utilities, it can be difficult to determine net generation if individual units are subject to different emission limits, because metering net energy from the site would not allocate net energy for each boiler generator set. Thus, while a *net* output format will more completely account for efficiency measures within a process, the associated measurement and recordkeeping requirements can be burdensome.

The decision on which format to use in a particular application should balance the likely burden of greater complexity with the potential benefits of encouraging a greater range of efficiency improvement measures within a process. For small, distributed generation technologies (e.g., microturbines or engine generators) the difference between a net output and a gross output is not significant, because the technology is packaged as an integral unit. All losses are internal to the package, and net and gross output are essentially the same.

4.3 Specify Compliance Measurement Methods

Methods for measuring compliance with output-based standards are readily available. You must specify what to measure and the appropriate monitoring locations that correspond to the emission standard. Mass emissions are measured using the same emission monitors and reference methods used for input-based standards. The only variable that changes is the quantity to which the mass emissions will be related. Instruments to continuously monitor and record energy output are routinely used and commercially available at a reasonable cost. Most facilities already monitor their output for a variety of business purposes.

For *electric generation applications,* MWh must be measured. Measurement of MWh is straightforward and highly accurate. In most cases, the electric output of the generator is already being measured to record electricity sales. If it is not already being measured, the generation can easily be recorded by standard kWh meters. Mass emissions would be divided by MWh produced to calculate lb/MWh.

- At large power plants, multiple boilers might serve multiple generators such that a one-to-one relationship does not exist between the emitting units and the generating units. In this case, two different approaches could be used for relating the measured emissions to the measured electric output:
- The simpler approach is to set the output-based emission limit for the overall plant (i.e., all boilers combined). Compliance can be then measured as the total emissions divided by the total generation. In this case, the output-based approach simplifies the compliance issue by focusing on the overall impact—that is, the total emissions per MWh independent of where in the plant the emissions come from. This approach creates an incentive for the plant operator to use the lowest-emitting, most efficient units available.
- If the regulation applies to each boiler, the output from the various generators can be allocated to the boilers according to their steam output. In this case, the emissions for each boiler (lb/hr) are measured at each stack. The total electrical output (MW) is allocated to each boiler based on the percentage of steam output (MMBtu/hour) generated by each boiler. Allocating based on heat input to the boilers would not be as effective, however, because that procedure would ignore the efficiency of the boilers.

For *steam generators*, thermal output ($MMBtu_{heat\ output}$) must be measured. Most large boiler facilities measure boiler thermal output as part of system operation. In many CHP facilities, the thermal output is sold to a separate customer and is therefore measured for commercial billing purposes. Meters can be installed to record the thermal output of the steam or hot water produced. Alternatively, the thermal output can be calculated using measurements of the steam or water flow and temperature rise of the thermal fluid. Mass emissions then would be divided by the thermal output to calculate $lb/MMBtu_{heat\ output}$.

4.4 Specify How to Calculate Emission Rates for Combined Heat and Power Units

CHP has been shown to be beneficial from both an energy and environmental perspective and many regulators would like to provide recognition for these benefits in their regulations by recognizing the increased output of a CHP facility. CHP units produce both electrical and thermal output (e.g., process steam). Therefore, the rule must specify the method to account for the two different types of energy in the compliance computation. Several approaches have been used in current regulations and guidance documents. The different methods can result in different calculated levels of efficiency (i.e., more or less energy output in the denominator of the emission rate) and different compliance measurement requirements.

Two ways to account for the efficiency benefits of the thermal output of a CHP system are:

1. ***Equivalence approach.*** Add the thermal output of the steam to the electric output (in consistent units) when calculating compliance. This method maximizes the total output recorded and reduces the lb/output emission rate. Its actual impact on the output-based emission rate can vary substantially based on the power-to-heat ratio.
2. ***Avoided emissions approach****.* Determine the amount of avoided emissions that a conventional boiler system would otherwise emit had it provided the same thermal output (i.e., purchasing electricity from the grid and generating steam on site). This approach relates the value of the thermal output of the CHP system more directly to the emissions actually avoided by the CHP system.

The two approaches are illustrated in the examples below. Consider a simple 1 MW gas turbine that has emissions of 0.7 lb/hr. Its emission rate is 0.7 lb/MWh electric. In a CHP configuration, the turbine also could produce a thermal output of about 5.7 MMBtu/hr (or about 5700 lb steam/hr of thermal output) in addition to its electric output. Ensure that the output-based emission limit is 0.5 lb/MWh.

Approach 1: equivalence approach (convert thermal output to an equivalent MWh and add to the electric output)

This approach focuses on including the full output in the calculation. It converts all of the energy output to units of MWh and compares the total emission rate to the emission limit. First, convert the thermal output of steam to units of MWh by a unit conversion factor (1 MWh = 3.413 MMBtu). This results in a thermal output of 1.67 MW output. Then, add the thermal and electric output to yield a total output of 1 MW + 1.67 MW = 2.67 MW. Dividing the measured stack emissions by this total output results in a combined emission rate of 0.7 lb/hr ÷ 2.67 MW = 0.26 lb/MWh_{th+e}.

The equivalence approach can recognize 100 percent of the thermal output of steam in the compliance calculation, and the greater overall efficiency of a CHP facility results in a lower emission rate. The rule language would state that the output will be calculated as the electric output plus the thermal output in MW based on the conversion of 1 MWh = 3.413 MMBtu of heat output.

Several states have used this approach. The Texas PBR and Standard Permit and California conventional emission limits and emission performance standard use this method. The U.S. EPA’s 1998 NSPS for utility boilers used the same approach but included only half of the thermal output in the calculation when it was first released; the rule was subsequently revised and now provides credit for 75 percent of the thermal output in the calculation. Many of the states that recognize CHP’s thermal output (including Texas, California, Massachusetts, and Connecticut) have included the full thermal value in order to benefit CHP.

The amount of energy output calculated by this method varies greatly depending on the power-to-heat ratio of the CHP unit. For low P/H ratios (i.e., proportionally high steam generation compared to power), the equivalence approach will result in a relatively high total energy output. This is because at low P/H ratios the unit operates more like a steam boiler than a utility boiler. Output-based emission limits for steam boilers are very different (lower) than those for utility boilers because of the significant energy losses caused by the turbine generators.

Approach 2: avoided emissions approach

This approach recognizes the thermal output by calculating the displaced emissions associated with the thermal output and subtracting them from the measured emission rate. The displaced emissions are the emissions that would otherwise have been generated to provide the same thermal output from a conventional system (applying a new source emission rate).

The avoided emissions approach is a three-step process. First, compute the emission rate (lb/MWh) of the CHP unit based on the total measured emissions and the amount of electricity generated (ignoring process steam use for now). Second, for the steam output, compute the emissions avoided (in lb/MWh) from a conventional boiler system that otherwise would have provided the same steam output. Third, subtract the avoided emission rate from the initial lb/MWh rate that was computed based only on electrical output.

The regulation would specify a five-step process to determine the emission rate for compliance purposes:

1. ***Determine a gross emission rate based on electrical output only.*** To do this, divide the measured stack emissions by the metered electricity generated:

   $$\text{Gross emission rate (lb/MWh}_{\text{electric}}\text{)} = \text{emissions (lb)} \div \text{electrical output (MWh)}$$

2. ***Determine the new source emission rate of the thermal generator that the CHP unit displaces****.* Where a CHP system directly replaces an existing thermal generator, the calculation recognizes the actual displaced emissions up to a maximum rate. The maximum rate would be established to prevent the CHP system from receiving “excessive” recognition for displacing very old, very high-emitting boilers that might be scheduled for replacement anyway. For new CHP systems or where the emissions from the existing steam generation cannot be documented, the calculation for steam generation would be based on the emission limits for a new gas boiler in the particular state. The avoided emissions approach would provide a conservatively low estimate of displaced emissions.
3. Convert the emission rate of the displaced steam boiler from an input to a heat output-based rate ($\text{lb/MMBtu}_{\text{out}}$). The avoided emission rate is:

   $$\text{lb/MMBtu}_{\text{heat output}} = \text{lb/MMBtu}_{\text{heat input}} \div \text{boiler efficiency}$$

4. *Convert the displaced emissions to lb/MWh.* To do so, relate the emission rate of the displaced unit to the electricity produced by the CHP unit. First, convert the Btus of heat output to MWh of heat output. (1 MWh is equivalent to 3.413 MMBtu.) The P/H ratio expresses how much thermal output is produced per unit of electric output, so divide the thermal emission factor by the P/H ratio to get the electric equivalent:

   $$\text{displaced emissions lb/MWh}_{\text{electric}} = \text{lb/MMBtu}_{\text{heat output}} \text{ x } 3.413 \frac{\text{MMBtu}}{\text{MWh}} \div \text{(P/H)}$$

5. Subtract the displaced emission rate from the initial output-based emission rate, which was based only on electrical energy, to obtain the net emission rate. The resulting CHP emission rate is then compared to the emission limit:

CHP emission rate (lb/$MWh_{electric}$) = Gross emissions (lb/$MWh_{electric}$) – Displaced emissions (lb/$MWh_{electric}$)

Example Calculations for the Avoided Emissions Approach

Consider the same CHP project as in the previous example—a new 1 MW_e combustion turbine CHP system with a P/H ratio of 0.6 that must meet an emission standard of 0.5 lb/MWh or less.

1. The measured gross emission rate based only on electrical output is 0.7 lb/$MWh_{electric.}$
2. For this calculation, assume that the CHP unit displaces a typical small industrial boiler with an efficiency of 80 percent. Because the avoided emissions are not known, assume the avoided emissions for a new gas-fired boiler. The state regulation for new gas boilers is 0.05 lb/$MMBtu_{heat\ input}$.
3. Compute the output-based new source emission rate for the thermal output as follows (Equation 2). This is the avoided emission rate for an equivalent industrial boiler:

$$1.5\ \text{lb/MMBtu}_{\text{heat input}} \div 80\%\ \text{efficiency} = 0.06\ \text{lb/MMBtu}_{\text{heat output}}$$

4. Convert the displaced emissions by relating the thermal output emission rate to the electricity produced by this CHP system. This calculation estimates the avoided emissions as a ratio of the lb/MW_e produced by the CHP. Based on the P/H ratio of 0.6, the emission displacement on an electric basis would be:

$$1.5\ \text{lb/MMBtu} \times 3.413\ \text{MMBtu/MWh} \div 0.6 = 0.36\ \text{lb/MWh}$$

5. Adjust the gross emission factor. The gross emission rate is 0.7 lb/MWh. Subtract the displaced emissions of 0.36 lb/MWh from the initial emission limit. The emission rate for compliance purposes, therefore, is:

$$0.70\ \text{lb/MWh} - 0.36\ \text{lb/MWh} = 0.34\ \text{lb/MWh}$$

The unit, therefore, is in compliance with the emission limit of 0.5 lb/MWh. The avoided emissions approach yields an emission rate that is higher than Approach 1, which resulted in an emission rate of 0.26 lb/MWh. This is a function of the P/H.

Table 4-1 computes the displaced boiler emission rate (Steps 3 and 4) for a range of avoided emission rates (Step 2).

Table 4-1. Displaced Boiler Emission Rate (lb/$MWh_{electric}$) for CHP Units

P/H	Displaced Thermal Emission* Rate (lb/$MMBtu_{heat\ input}$)						
	0.01	0.04	0.05	0.1	0.2	0.3	0.4
0.5	0.09	0.30	0.40	0.85	1.71	2.56	3.41
0.7	0.07	0.22	0.29	0.61	1.22	1.83	2.44
1.0	0.05	0.15	0.20	0.43	0.85	1.28	1.71

*Assuming 80 percent boiler efficiency.

Many states set a typical emission limit for new gas boilers at 40 ppm (equal to approximately 0.05 lb/MMBtu). So, for example, a combustion turbine-based CHP system with a P/H ratio of 0.7 would have a displaced emission rate of 0.29 $lb/MWh_{electric}$ to apply against the applicable limit. A reciprocating engine with a P/H ratio of 1.0 would have a displaced emission rate of 0.20 $lb/MWh_{electric}$.

If the avoided emissions per MWh are higher than the emissions from the CHP unit, the result will be a negative emission rate. This could happen if the avoided boiler has a very high emission rate (e.g., for replacement of an old, high-emitting boiler) and/or a very low P/H ratio. While this may seem counter-intuitive, it can be an accurate representation of the emission benefit of the CHP system. That said, some regulators may choose to adjust the emission factor for an older, high-emitting boiler to a lower factor comparable to a new boiler in order to avoid giving credit based on an out-of-date emission limit. This would reduce the likelihood of a negative result.

4.5 Summary of Steps to Develop an Output-Based Standard

Table 4-2 briefly summarizes the information that is provided in this section.

Table 4-2. Summary of Rule Development Steps

1. Develop the output-based emission limit.	Two methods are provided: a. An emission limit can be based on measured emissions and energy output data. b. An input-based emission limit can be converted to an output-based format using the procedures in this section: – Conversion from $lb/MMBtu_{heat\ input}$ for electric generators or steam boilers. – Conversion from flue gas concentration for combustion turbines. – Conversion from g/bhp-hr for engine generators.
2. Specify a gross or net energy output format.	Net energy output will more comprehensively account for energy efficiency, but can increase the complexity of compliance monitoring requirements.
3. Specify compliance measurement methods.	The energy forms that must be measured are electricity generated (MWh), thermal output (MWh or Btu), and shaft power (bhp-hr). These outputs are monitored at most facilities for commercial purposes.
4. Specify how to calculate emission rates for CHP units.	Two methods are described: a. Equivalent MWh output approach b. Avoided boiler emissions approach These two methods provide different results and, thus, different levels of recognition of the efficiency benefits of a given CHP application. Neither is more "correct" than the other, but the equivalent MWh output approach may be simpler to calculate and can result in significantly lower calculated emission rates for low P/H technologies.

4.6 Summary of Steps to Comply with an Output-Based Standard

1. Determine compliance procedures.	Compliance forms, permit forms, or other necessary documentation must be obtained. The method that is used will depend on whether or not measured energy output data are available.
2. Determine the data necessary for compliance.	Review the compliance calculation and other inputs to determine what data are needed to calculate the emission limit from the CHP system. Electric output data typically measured in MWh and thermal output measured in MMBtu are often required.
3. Implement appropriate data collection procedures	Install appropriate emission and output measurement devices (electric and thermal) and collect emission and output data.
4. Calculate compliance.	Use the required calculation to determine the output-based emission limit for the CHP system.
5. Submit completed compliance or other necessary forms.	To the state utility regulatory agency or other appropriate authority.

Section 5. Examples of Output-Based Regulations

A number of federal, regional, and state programs have recently adopted output-based regulations. These regulations include emission standards for large and small generators, cap and trade allowance allocation systems, multi-pollutant regulations, and generation performance standards. Table 5-1 lists existing output-based regulatory programs that apply to electric and thermal generation. Each of these programs is described more fully in Appendix B. Appendix B briefly describes the rule, jurisdiction, applicability (type and size of units covered), specific emission limits or provisions, timing, treatment of CHP units, references to rule language, and other relevant information.

Table 5-1. List of Current Output-Based Programs

Type of Program	Regulatory Purview	Output-Based Features
Federal NSPS Regulations	NSPS for Stationary Combustion Turbines	Emission limit (lb/MWh) gross output
	NSPS for Industrial-Commercial-Institutional Steam Generating Units	Emission limit (lb/MWh) gross output
	NSPS for Stationary Compression Ignition Internal Combustion Engines	Emission limit (g/KW-hr or g/HP-hr)
	NSPS for Stationary Spark Ignition Internal Combustion Engines	Emission limit (g/HP-hr)
	NSPS for Aluminum Reduction Plants	Emission limit (kg/Mg) or (lb/ton)
	NSPS for Electric Steam Generating Units	Emission limit (lb/MWh) gross output and (lb/MWh) net output
Federal NESHAP	NESHAP for Area/Sources: Electric Arc Furnace Steelmaking Facilities	Emission limit (lb/ton)
	NESHAP for Industrial, Commercial, and Institutional Boilers and Process Heaters (Boiler MACT)	Emission limit (lb/MMBtu) steam output or (lb/MWh)
	NESHAP for Coal- and Oil-Fired Electric Utility Steam Generating Units (MATS rule)	Emission limit (lb/MWh) or (lb/GWh)
Conventional state emission rate limits	New Jersey mercury emission limits	Emission limit (mg/MWh)
State emission standards for distributed generation	New Hampshire	Emission tax (lb/MWh)
	California	Emission limit (lb/MWh)
	Delaware	Emission limit (lb/MWh)
	Rhode Island	Emission limit (lb/MWh)
	Texas	Emission limit (lb/MWh)
	Regulatory Assistance Project	Model rule with output-based emission limit (lb/MWh)
	Connecticut	Emission limit (lb/MWh)
	Maine	Emission limit (lb/MWh)
	Massachusetts	Emission limit (lb/MWh)
	New York	Emission limit (lb/MWh)

Table 5-1. List of Current Output-Based Programs

Type of Program	Regulatory Purview	Output-Based Features
State NO_x Budget Trading Programs	Connecticut	Allocation of allowances
	Massachusetts	Allocation of allowances
	Missouri	Allocation of allowances
	New Hampshire	Allocation of allowances
	New Jersey	Allocation of allowances
	Ohio	Allocation of allowances
CAIR state programs	Arkansas	Allocation of allowances
	Connecticut	Allocation of allowances
	Illinois	Allocation of allowances
	Indiana	Allocation of allowances
	Massachusetts	Allocation of allowances
	New Jersey	Allocation of allowances
	Ohio	Allocation of allowances
	Pennsylvania	Allocation of allowances
	Wisconsin	Allocation of allowances
RGGI state programs	Connecticut	Allocation of set-asides
	Massachusetts	Allocation of set-asides
	New York	Allocation of set-asides
State multi-pollutant Programs	Massachusetts	Emission limit (lb/MWh)
	New Hampshire	Allocation of allowances
State generation emission performance standards	California	Performance standard (lb/MWh)
	New York	Performance standard (lb/MWh)
	Oregon	Performance standard (lb/MWh)
	Washington	Performance standard (lb/MWh)
New Source Review	Connecticut	Lowest achievable emission rate option

To provide additional insight into the technical and policy considerations of setting output-based standards, four of these programs are described in more detail below:

- Section 5.1 describes the output-based approach that EPA used in revisions of the electric utility boiler NSPS (subpart Da). This action reflected a major change in approach for the NSPS and provided an efficiency-based rationale for transitioning to output-based regulation. This section also discusses EPA's proposed greenhouse gas (GHG) NSPS for new power plants, which either would include GHG standards for electric utility boilers in subpart Da and applicable GHG standards for stationary combustion turbines in subpart KKKK or could include GHG NSPS standards for these types of systems under a new subpart TTTT.

- Section 5.2 describes a model rule for output-based standards for small electric generators. The model rule is a good example of a straightforward output-based emission limit program that recognizes the thermal output of CHP.

- Section 5.3 describes the EPA guidance on how to allocate emission allowances for the NO_x SIP Call and the later CAIR based on output. The NO_x SIP Call approach was developed by a stakeholder group of EPA, states, industry, and environmental groups. The guidance thoroughly discusses how output-based allocation can be applied.

- Section 5.4 describes EPA guidance on how output-based emission limits were determined under EPA's Utility Boiler New Source Performance Standard (40 CFR 60 Subpart Da).

In 1998, EPA promulgated revisions to the NSPS for NO_x from Electric Utility Steam Generating Units. The revised NSPS reflected advances in NO_x control technology and a change to a uniform output-based NO_x regulation (lb/MWh). This action was the first NSPS for boilers that incorporated output-based emission limits. In the rationale for revisions, EPA stated that it had "established pollution prevention as one of its highest priorities" and that "one of the opportunities for pollution prevention lies in simply using energy efficient technologies to minimize the generation of emissions" (62 FR 36954). Up to this point, the basis for boiler emission standards had been boiler input energy (i.e., pounds of pollutant per million Btu of heat input). The rule also was the first NSPS to recognize the thermal output of CHP facilities, in this case using the equivalence approach. It allows for CHP systems to account for 75 percent of their thermal output in calculating their output-based emissions.[10] EPA has revised its boiler NSPS (subpart Da) several times since 1998.

EPA considered several different output-based formats. The final structure of the rule was based on the following goals:

1. Provide flexibility in promoting energy efficiency.
2. Permit measurement of parameters related to stack NO_x emissions and plant efficiency on a continuing basis.
3. Be suitable for equitable application to a variety of power plant configurations.

The basis of EPA's decisions on the format of the rule is explained below.

5.1.1 Units of Measure

The revised NO_x emission limit is measured in lb/MWh. EPA considered basing the emission limit on lb per gross boiler steam output ($lb/MMBtu_{heat\ output}$). EPA determined that the latter approach accounted for the boiler efficiency only and ignored turbine cycle efficiency. Since this did not meet one of EPA's goals—providing maximum flexibility in an output-based format—EPA decided that it would not be an acceptable basis. Therefore, EPA selected the lb/MWh format.

5.1.2 Net Versus Gross Energy Output

EPA also decided to define energy output in terms of gross energy output in the 1998 revisions; however, in rule revisions proposed in 2011, EPA decided to also define energy output in terms of net energy output for an affected facility that began construction or reconstruction on or after May 3, 2011. Initially, EPA proposed the emission limit based on net energy output because it wanted to account for both turbine cycle efficiency and internal plant energy efficiency. Concerning the 1998 rule amendments, several commenters on the rule claimed that monitoring net electrical output was not practical because it:

[10] *http://www.epa.gov/ttn/atw/nsps/boilernsps/boilernsps.html*

- Would require significant and costly changes to the existing monitoring systems.
- Could not be measured directly due to the amount of auxiliary electrical equipment at a plant.
- Did not account for the power drain associated with many types of pollution control equipment.
- Would be difficult at plants where both NSPS and non-NSPS units existed.
- Was not well understood because EPA did not provide a specific methodology for determining net output in the proposal.

In the 2011 rule revisions, EPA proposed emission limits based on net energy output since this would provide a greater incentive for improving overall energy efficiency and minimizing parasitic loads. (In general, EPA found that about 5 percent of station power is used internally by parasitic energy demands, though this number varies based on the source.) In its proposed rule changes, EPA noted that a net output approach could result in monitoring difficulties and unreasonable monitoring costs at modified units. However, monitoring net output for new and reconstructed units can be designed into the facility at a low cost.[11]

5.1.3 Selection of the Emission Limit for New Units

The emission limit for new sources that began construction after July 9, 1997, but before March 1, 2005, is 1.6 lb NO_x/MWh gross energy output. EPA initially proposed an emission limit of 1.35 lb/MWh net energy output but decided to change the emission limit in response to comments received after proposal and further analysis of utility units.

The proposed emission limit was based on the use of selective catalytic reduction to reduce NO_x emissions to 0.15 lb/$MMBtu_{\text{heat input}}$. EPA applied an efficiency factor to convert the format to an output-based limit. According to EPA's review of power plant efficiency, most plants fell into the range of 24 to 38 percent efficiency. EPA concluded, however, that newer units (both coal and gas) operate at about 38 percent efficiency, which corresponds to a heat rate of 9,000 Btu per kilowatt hour. This figure was the baseline chosen at proposal, and it resulted in an equivalent output-based emission limit of 1.35 lb/MWh.

$$0.15 \text{ lb/MMBtu} \times 9{,}000 \text{ Btu/kWh} \times 1{,}000 \text{ kWh/MWh} \div 1{,}000{,}000 \text{ Btu/MMBtu} = 1.35 \text{ lb/MWh}$$

After proposal, a majority of commenters opposed the selection of an assumed 9,000 Btu/kWh heat rate for use in converting the input-based emission limit to an output-based emission factor. Several commenters provided examples of state-of-the art units that could not achieve the 9,000 Btu/kWh heat rate that EPA used to set the output-based emission limit. EPA conducted statistical analyses of the data submitted by the commenters and collected additional data to assess the long-term NO_x emission levels that were achievable on an output basis by new units. Considering these new data, EPA promulgated an emission standard based on actual measured output data rather than converted heat input data. This analysis resulted in an output-based emission limit of 1.6 lb/MWh for the 1998 rule. In later revisions, EPA issued lower output-based NO_x emission limits for new affected facilities.

[11] *http://www.epa.gov/ttn/atw/utility/fr03my11.pdf*.

5.1.4 Modified and Reconstructed Units

The revised 1998 NSPS retained an input-based format for existing sources that become subject to the NSPS by reconstruction. In response to the proposed rule, a number of commenters objected to the fact that the proposed output-based limit was not achievable at a reasonable cost by all existing sources. Commenters claimed that EPA's assumed heat rate of 9,000 Btu/kWh (equivalent to 38 percent efficiency) was appropriate for new units and modified units and that existing units should not be required to meet the same output-based standard as new sources. The higher heat rates associated with older, less efficient plants would cause those plants to have a more difficult time complying with the standard. To compensate for the higher heat rates, these existing units might have to use more expensive control devices with higher NO_x removal performance. In justifying the final rule, EPA noted that while most utility plants have efficiencies ranging from 24 to 38 percent, existing plants are likely to operate in the lower end of this efficiency range, which would make meeting an output-based standard more costly. Therefore, to minimize this potential burden, EPA decided to require modified and reconstructed units that become subject to the NSPS to meet a standard of 0.15 lb NO_x/$MMBtu_{heat\ input}$.

In later revisions, EPA issued output-based emission limits and also alternative heat-input-based limits for units that began reconstruction or modification after February 28, 2005, but before May 4, 2011. EPA also issued separate limits for affected facilities that began reconstruction or modification after May 3, 2011.

The revised NO_x emission limits for new, reconstructed, and modified affected facilities are as follows:

Effective Date	NOx Emission Limit
Affected facility that commenced construction after July 9, 1997, but before March 1, 2005	1.6 lb/MWh gross energy output
Affected facility that commenced reconstruction after July 9, 1997, but before March 1, 2005	0.15 lb/$MMBtu_{heat\ input}$
Affected facility that commenced construction after February 28, 2005, but before May 4, 2011	1.0 lb/MWh gross energy output
Affected facility that commenced reconstruction after February 28, 2005, but before May 4, 2011	1.0 lb/MWh of gross energy output or 0.11 lb/$MMBtu_{heat\ input}$
Affected facility that commenced modification after February 28, 2005, but before May 4, 2011	1.4 lb/MWh of gross energy output or 0.15 lb/$MMBtu_{heat\ input}$, regardless of fuel type
Affected facility that began construction or reconstruction after May 3, 2011	0.70 lb/MWh of gross energy output or 0.76 lb/MWh net energy output; applies regardless of boiler or fuel type (except coal)
Affected facility that began construction or reconstruction after May 3, 2011, that burns 75 percent or more coal refuse (by heat input) on a 12-month rolling average basis	0.85 lb/MWh gross energy output or 0.92 lb/MWh net energy output
Affected facility that made modifications after May 3, 2011	1.1 lb/MWh gross energy output

5.1.5 Treatment of Combined Heat and Power Plants

In applying the regulation to a utility boiler that incorporates CHP, one must account for both the electrical energy output and the thermal output (typically steam). For CHP, the revised 1998 NSPS defines "gross energy output" as the gross electrical output plus 50 percent of the gross thermal output of the process steam (converted to units of MWh). The 50 percent steam conversion policy was based on a Federal Energy Regulatory Commission regulation that defines the efficiency of CHP units as "the useful power output plus one half the useful thermal output" (18 CFR 292, section 205). EPA later (2006) revised this definition of "gross energy output" to mean the gross electrical or mechanical output from the affected facility plus 75 percent of the useful thermal output. The rule was again revised for CHP systems that were constructed, reconstructed, or modified after May 3, 2011. The definition of "gross energy output" for these CHP systems is the gross electrical or mechanical output from the affected facility divided by 0.95, minus any electricity used to power the feedwater pumps and any associated gas compressors, plus 75 percent of the useful thermal output.

In establishing its 1998 rule, EPA rejected two other approaches for determining how to account for process steam at CHP plants: (1) consider valuing steam assuming it will be used to generate electricity and (2) consider valuing steam at greater than 50 percent of its heat value, up to 100 percent. Valuing steam as if it were being converted to electricity would cap the energy value at 38 percent of the heat value of the steam (based on the maximum reported efficiency for electrical production with a steam turbine). Because EPA wanted to encourage CHP, it did not choose this option. The Agency did not choose the option of allowing for more than 50 percent of the heat value of steam because it concluded that including all of the thermal output created a potential for calculating an "artificially high" output rate, especially if a large amount of steam is exported. As a sub-option, EPA also considered allowing 100 percent of the heat value, but limiting the amount of thermal energy to a specified percentage of total output. Ultimately, EPA determined that this approach was too complex from a monitoring standpoint. Therefore, EPA adopted the policy of 50 percent thermal energy for steam from CHP plants because the policy will encourage energy efficiency, will not result in artificially high output rates, and will not require complex monitoring.

5.1.6 NSPS CO_2 Limits

EPA is currently working on establishing GHG emission limits for new and existing power plants. EPA released a revised proposed rule to limit GHG emissions from new power plants in January 8, 2014. The proposed NSPS for new power plants is intended to apply generally to those boilers currently regulated under subpart Da and to stationary combustion turbines regulated under 40 CFR subpart KKKK.[12] The proposal is an output-based standard that ranges from 1,000 to 1,100 lb CO_2/MWh based on fuel use and unit size. EPA's GHG NSPS proposal for new power plants uses the equivalence approach to give credit to CHP systems in which the useful electric or mechanical output is at least 20 percent of the total energy output and the useful thermal output is at least 20 percent of the total energy output. CHP systems that meet this eligibility criterion will receive credit similar to that in subpart Da and the proposed amendments to subpart KKKK (77 FR 52554). The measured electric output would be discounted slightly by dividing by 0.95 to account for a 5 percent avoided energy loss in the transmission

[12] EPA has proposed changing applicability language slightly to benefit third-party CHP developers that would otherwise be penalized slightly based on current subpart Da applicability language.

of electricity (EPA's subpart Da language currently uses the same discount).[13] EPA's proposed GHG NSPS for new power plants was open for public comment through May 9, 2014.[14]

EPA released a proposal to regulate GHG emissions from existing power plants on June 2, 2014. Existing units are defined as those that were in operation or had commenced construction as of January 8, 2014. The proposal requires states to meet CO_2 emission targets starting in 2020 on a state-wide basis. The proposed rule is expected to reduce CO_2 emissions by 30 percent below 2005 levels by 2030. State targets proposed by EPA vary widely based on the "unique mix of emissions and power sources" in each state and are output-based. EPA gives states the option to convert the rate-based targets into mass-based goals incorporating renewable and nuclear generation and end use efficiency in setting the goals. The thermal output of affected CHP systems is credited at 75 percent. EPA plans on releasing a final rule by June 2015, and will require states to submit their implementation plans by June 30, 2016. However, extensions for SIP submittal of up to one year may be granted upon request, and an extension of up to two years may be granted to states that are implementing multi-state plans.

5.2 RAP National Model Emission Rule for Distributed Generation

In 2000, the National Renewable Energy Laboratory engaged the Regulatory Assistance Project (RAP) to facilitate the development of a uniform, national model emission rule for small DG equipment. Interest in regulating emissions from DG had been building in recent years due to the increased development of small generators, including microturbines, fuel cells, and small engines. More importantly, there had been increasing concern over the use of high-emitting diesel engines for load response or peaking applications. The development of DG emission regulations in Texas and California had sparked concern that many individual states would develop emission standards for DG and create an overly complex, conflicting set of permitting requirements that would limit the development of DG. The goal of the model rule project was to develop a model rule that could be uniformly applied throughout the United States and provide appropriate environmental protections and technology drivers for DG.

To learn more about Regulation Assistance Project Model Rule for output based emission regulation, see www.raponline.org.

The stakeholder group involved with the process consisted primarily of state energy and environmental regulators with a few participants from the DG industry and representatives from EPA, the U.S. Department of Energy, and environmental groups. The model rule was completed in February 2003. The emission limits for the model rule are presented in Appendix B.

5.2.1 Format of the Rule

The stakeholder group established from the beginning that the rule would be expressed in an output-based format. Several of the participants had been involved in the development of the output-based Texas and California DG rules, and agreed that reflecting efficiency in the regulation was important—especially for very small DG units that do not typically use add-on controls. For these units, pollution prevention and efficiency are the primary emission control alternatives and must be recognized by

[13] *http://www.gpo.gov/fdsys/pkg/FR-2014-01-08/pdf/2013-28668.pdf*.
[14] *http://www2.epa.gov/carbon-pollution-standards/2013-proposed-carbon-pollution-standard-new-power-plants*.

regulation. In addition, the rule sets one standard for all technologies, so the standard must be in units that can be applied to all technologies. An output-based limit in lb/MWh meets this requirement. Finally, the participants wanted the rule to account for the efficiency of CHP and potentially recognize renewable technologies. An output-based approach allowed the flexibility to achieve both of these goals.

5.2.2 Treatment of Combined Heat and Power

RAP made providing recognition for CHP an important priority in the rule development process. The group evaluated several possible methods. Several prior rules had recognized CHP by including the thermal output converted to electric equivalent as part of the output calculation (equivalence approach). Although this method does recognize the thermal output, the effect is largely a function of the relative amounts of thermal and electric energy created and is not tied to the actual environmental benefit of the CHP created by displacing conventional emitting units.

The RAP group decided to take an approach based on calculation of the displaced emissions from the thermal output (avoided emissions approach—see section 4.4). The emission standards apply to the electrical output of the system, and the measured emissions are reduced based on the emissions avoided by the displacement of a thermal generator (steam boiler) providing the same thermal output as the CHP system. For a greenfield CHP facility, the avoided emissions are based on the emission limits applicable to a new natural gas boiler. For a retrofit system, the avoided emissions are based on the emission rate of the boiler actually displaced by the system. There is a cap on this avoided emission rate, however, to avoid basing the displacement on old, very high-emitting boilers.

5.3 EPA Guidance on Output-Based NO_x Allowance Allocations

In October 1998, EPA issued the NO_x SIP Call to reduce regional transport of ozone in the 22 northeastern states. To meet the requirements of the SIP Call, states can adopt further emission regulations or participate in a regional cap and trade program. In this cap and trade program, EPA allocated NO_x allowances for an ozone season cap and trade program to the states, but it allowed each state to allocate the allowances to individual emission sources in the state.

To learn more about output-based allowance allocations, read Developing and Updating Output-Based NO_x Allowance Allocations, Guidance for States Joining the NO_x Budget Trading Program Under the NO_x SIP Call, May 8, 2000 (http://www.epa.gov/airmarkets/progsregs/nox/docs/finaloutputguidanc.pdf).

Although the most prominent model for this allocation was the input-based allocation approach of the acid rain SO_2 trading program, there was increasing interest in an output-based allocation system that would account for the benefits of new, more efficient generators. Despite this interest, stakeholders had a lot of questions about the actual mechanics of output-based allocation systems and whether such a system could be efficiently implemented.

EPA convened a stakeholder working group to investigate and analyze these questions and assist in developing guidance for states interested in applying output-based allocation in their NO_x trading programs. The group was composed of EPA staff, industry representatives, state regulators, and environmental groups. It worked for most of 1999 and produced a guidance document that addresses issues including:

- The types of facilities to which the guidance applies.
- The assignment of allowances to units, plants, or generators.
- Technical and policy concerns in selecting the location for measuring or calculating output data to be used in allocations.
- Requirements for sources, such as monitoring, recording, and reporting output data.
- Potential sources of output data.
- Regulatory provisions to include in state rules and actual regulatory language specifying the allocation procedures.

Some of these issues are summarized in the following sections.

5.3.1 Allocation of Allowances

Perhaps the most basic issue considered by the stakeholder group was the actual mechanism for allocating allowances on an output basis, including industrial boilers and CHP facilities. The basic concept is that each unit receives allowances in proportion to its share of the total energy output in the state. In most states, a separate pool of allowances was established for electric generators and for industrial boilers. Under an output-based allocation program, an electric generating unit that generates 5 percent of the total electricity generated in the state would receive 5 percent of the allowances available for electric generators. An industrial boiler that generates 5 percent of the total thermal output generated in the state would receive 5 percent of the allowances available for industrial boilers. A CHP facility would receive a share of each pool based on its generation of electricity and steam. If a CHP facility generated 2 percent of the electricity and 3 percent of the steam in the state inventory of affected units, it would receive 2 percent of the electricity allowances and 3 percent of the boiler allowances. The guidance document presents a variety of examples of these allocation procedures and some variations for states whose emission pools are organized differently. Overall, however, the guidance illustrates that the procedure is straightforward and relatively simple.

One related issue was that a one-to-one relationship does not always exist between emission units and electric generating units. Compliance is based on emission units but an output-based allocation would relate to generating units. Some stakeholders asked whether this situation creates a problem for compliance or enforcement. The stakeholder group determined that enforcement would remain the same, regardless of how the allowances are allocated. It is up to the sources to ensure that they have adequate allowances in their compliance account at the facility level, regardless of how many emission units are on site. The allocation basis does not change the approach for the source either, as long as the plant operators can transfer allowances as needed to cover the actual emissions from their emission units. In fact, some industry representatives suggested that to allocate allowances at the plant level rather than at the unit level—whether based on emissions or output—would be just as easy from a compliance perspective.

5.3.2 Availability, Measurement, and Reporting of Output Data

One of the biggest obstacles to output-based regulations is concern about the collection of data on output. Environmental regulators are familiar with collecting data on heat input and emissions, but not output. The stakeholder group determined that collecting these data is new for many regulators but does not present any fundamental technical barriers.

One of the key insights is that the productive output of a process is a commercial product and is therefore accurately measured for commercial purposes. In other words, utilities must measure their generation in order to get paid. Measurement of the electric output of a generating unit is straightforward and highly accurate and is a normal order of business for most generators. Similarly, many CHP facilities are in the business of selling steam and must measure thermal output for contractual purposes. While this is less true for thermal output of industrial boilers, most operators of large boilers measure their steam output for plant management purposes. The group found that accurate measurement technology is available "off-the-shelf" for electric and thermal output streams, so that in the end these data are likely to be more accurate than the heat input data used in input-based allocation systems.

A more complex question is how to measure the output. This issue is also referred to as the "net versus gross" issue. In a large facility, some of the electricity and/or steam is used internally to operate plant systems, including pollution control devices. The electric output could be measured at the generator terminals (gross) or after the internal loads as it leaves the plant (net). From the policy perspective, the net output is the preferable concept because it indicates the actual energy available from the plant. Some stakeholders suggested that in a net energy approach, energy used for pollution control devices should not be subtracted from the gross output, because it benefits the environment. Others pointed out, however, that there are different ways to reduce emissions, and subtracting energy used for pollution control would be an incentive for more efficient pollution prevention techniques.

Actually determining how to measure net output can be difficult for a complex power generation or industrial facility. The energy flows are complicated and sometimes the plant uses grid electricity (i.e., not generated on site) for some of its parasitic loads. The plant may have co- located facilities (administrative offices not directly related to the plant operation) that use some of the power generated on site that should not be subtracted for allocation purposes. The guidance document produced by the stakeholder group provides a number of diagrams illustrating how and where net and gross output should be measured. In the end, the final guidance allows regulators to choose either net or gross output, whichever method is most expedient. For very small generators, the net versus gross decision might not be relevant because parasitic loads are internal to the prime mover.

Overall, the guidance document provides a highly effective "cookbook" for the implementation of output-based allocation. Since its release, several states have implemented these approaches and have operated emission trading programs with output-based allocation. The NO_x SIP Call output-based guidance document also served as a basis for states to implement output-based allocations under EPA's CAIR rule, which regulates NO_x and SO_2 emissions. CAIR covers 27 eastern states and the District of Columbia. On April 29, 2014, the Supreme Court reversed a lower court ruling vacating CSAPR, which is intended to be a successor to CAIR. At this time, CAIR remains in place until EPA has time to review the opinion and decide upon a course of action.

5.4 Utility Boiler Maximum Achievable Control Technology Standards

In December 2012, EPA finalized "National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters." This rule is commonly referred to as the "Boiler MACT." It impacts large boilers and process heaters at industrial, commercial, and institutional facilities that have the potential to emit 10 tons per year (tpy) or more of any single HAP, or a combination of such pollutants in excess of 25 tpy. The covered pollutants include CO (as a surrogate for organic HAP), hydrogen chloride, mercury, filterable PM, or total selected metals. Existing sources must comply with the standards by January 31, 2016; however, if needed, may request from their permitting authority an additional year to comply.

Under the rule, all boilers must follow work practice standards that include annual boiler tune-ups and a one-time energy assessment. These work practice standards complete the compliance obligation for natural-gas-fired boilers and existing small (<10 million Btu per hour heat input) coal- and oil-fired boilers; however, large coal and oil-fired boilers must meet the emission limits specified in the rule. The rule presents an opportunity for major source sites with coal- and oil-fired boilers to consider switching to natural gas, and subsequently to consider natural-gas-fired CHP,[15] instead of installing costly emission controls to comply with the rule. The compliance date for existing major sources is January 31, 2016; existing sources that install CHP can have until January 31, 2017 (sources may request an additional year to comply if they need the time to install controls or to repower; this includes the installation of CHP, waste heat recovery, or gas pipeline or fuel feeding infrastructure).

5.4.1 Allocation of Allowances

The Boiler MACT has alternative output-based limits for all pollutants, and the thermal and electric output are used to calculate compliance. The output-based limits are an alternative "applicable only to boilers and process heaters that generate steam." The limits are expressed in lb/MMBtu of steam output. "Steam output," in the context of CHP, means "For a boiler that cogenerates process steam and electricity (also known as combined heat and power), the total energy output, which is the sum of the energy content of the steam exiting the turbine and sent to process in MMBtu and the energy of the electricity generated converted to MMBtu at a rate of 10,000 Btu per kilowatt-hour generated (10 MMBtu per megawatt-hour)."

[15] *http://www.epa.gov/chp/documents/boiler_opportunity.pdf*.

Appendix A: Energy Conversion Factors

Appendix A: Energy Conversion Factors

Energy Conversions

Conversion from Btu higher heating value (HHV) to Btu lower heating value (LHV)
multiply by 0.91 for natural gas
multiply by 0.94 for diesel

Conversion from lb/MMBtu HHV to lb/MMBtu LHV
multiply by 1.099 for natural gas
multiply by 1.064 for diesel

	HHV	LHV
Natural gas (Btu/cf)	1,030	937
Natural gas (Btu/lb)	21,980	20,000
Diesel (Btu/gallon)	137,000	128,780
Diesel (Btu/lb)	19,490	18,320

1 horsepower hour (hp-hr) = 2,545 Btu
1 kW = 3,413 Btu per hour (Btu/hr)
1 kWh = 3,413 Btu
0.7457 kW = 1 hp

1,000,000 Btu = 1 MMBtu = 392.9 hp-hr
1 MMBtu/hr = 293 kW
1 MMBtu = 293 kWh
1 kW = 1.341 hp

Turbines

NO_x emissions for turbines are typically presented as parts per million (ppm) reported at 15 percent O_2 in the exhaust stack. Other means of reporting emission use heat input (lb per MMBtu), output (lb per MWh), and time (tons per year).

Conversion from lb/MMBtu to ppm

From lb/MMBtu HHV to ppm @15% O_2 For Natural Diesel Gas		
NO_x	272	258
CO	446	423
SO_2	196	185

From lb/MMBtu LHV to ppm @15% O_2 For Natural Diesel Gas		
NO_x	248	235
CO	406	385
SO_2	178	169

Conversion from ppm to lb/MWh using heat rate

$$\text{lb/MWh} = \frac{(\text{ppm @15\% } O_2) \times (\text{Btu HHV/kWh heat rate})}{(272 \times 1{,}000)}$$

or

$$\text{lb/MWh} = \frac{(\text{ppm @15\% } O_2) \times (\text{Btu LHV/kWh heat rate})}{(248 \times 1{,}000)}$$

Example:

$$\text{lb/MWh} = \frac{(25 \text{ ppm}) \times (10{,}500 \text{ Btu HHV/kWh})}{(272 \times 1{,}000)} = 0.97 \text{ lb/MWh}$$

Conversion from ppm to lb/MWh using efficiency

$$\text{lb/MWh} = \frac{(\text{ppm @15\% } O_2) \text{ x } (3.413)}{(272) \text{ x } (\% \text{ efficiency HHV})} \quad \text{or} = \quad \frac{(\text{ppm @15\% } O_2) \text{ x } (3.413)}{(248) \text{ x } (\% \text{ efficiency HHV})}$$

Example:

$$\text{lb/MWh} = \frac{(25 \text{ ppm}) \text{ x } (3.413)}{(272) \text{ x } (0.325)} = 0.97 \text{ lb/MWh}$$

Conversion from lb/MWh to tons/year

tons/year = (lb/MWh emission rate) × (MW capacity) × (% utilization) × (8,760 ÷ 2,000)

Example:
tons/year = (0.951 lb/MWh) × (5 MW) × (0.30 utilization) × (8,760 ÷ 2,000) = 6.25 tons/year

Engines

NO_x emissions for engines typically are reported as g/hp-hr. Other means of reporting emission use heat input (lb/MMBtu), concentration (ppm) and time (tons per year).

The efficiency of engines is described in terms of percent efficiency or brake-specific fuel consumption (BSFC) in Btu/hp-hr.

Conversion from BSFC to % efficiency

% efficiency = 2,545 / (BSFC Btu/hp-hr)

Example:
% efficiency = 2,545 / (7,276 Btu/hp-hr) = 35% efficiency

Conversion from g/hp-hr to lb/MWh

lb/MWh = (g/hp-hr) × (3.11) (including 95% generator efficiency)

Example:
lb/MWh = (5 g/hp-hr) × (3.11) = 15.55 lb/MWh

Conversion from g/hp-hr to lb/MMBtu

lb/MMBtu HHV = (g/hp-hr) × (efficiency of engine HHV) × (0.866)

Example:
lb/MMBtu HHV = (5 g/hp-hr) × (0.35) × (0.866) = 1.52 lb/MMBtu HHV

Conversion from g/hp-hr to ppm

ppm @15% O_2 = (g/hp-hr) × (efficiency of engine HHV) × (235) for natural-gas-fired engines ppm @15% O_2 = (g/hp-hr) × (efficiency of engine HHV) × (223) for diesel-fired engines

Example:
ppm @15% O_2 = (5 g/hp-hr) × (0.35) × (235) = 411 ppm @15% O_2

Conversion from g/hp-hr to tons/year

$$\text{tons/year} = \frac{(\text{g/hp-hr}) \times (\text{hp capacity}) \times (\%\ \text{utilization})}{(103.6)}$$

Example:

$$\text{tons/year} = \frac{(5\ \text{g/hp-hr}) \times (3{,}000\ \text{hp}) \times (0.30\ \text{utilization})}{(103.6)} = 43.4\ \text{tons/year}$$

Conversion between different O_2 corrections for ppm reporting

$$\text{ppm @actual \% } O_2 = \frac{(\text{ppm @15\% } O_2) \times (20.9 - \text{actual \% } O_2)}{(20.9 - 15)}$$

Example:
ppm @1% O_2 = (346 ppm @15% O_2) × (20.9 – 1) × (1 ÷ (20.9 – 15)) = 1,167 ppm @ 1% O_2

Generalized conversion from ppm to lb/MMBtu

$$\text{lb/MMBtu} = \frac{(\text{ppm } NO_x \text{ @actual \% } O_2) \times (20.9) \times (F_d) \times (K)}{(20.9 - \text{actual \% } O_2)}$$

F_d HHV = 8,710 dscf/MMBtu HHV for natural gas
F_d HHV = 9,190 dscf/MMBtu HHV for diesel

Example: natural gas turbine at 15% O_2
lb/MMBtu = (25 ppm) × (20.9) × (8,710) × (1.194×10^{-7}) ÷ (20.9 – 15) = 0.092 lb/MMBtu HHV

F_d Factors from EPA Method 19

Fuel	**F_d dcf/10^6 Btu**
<u>Coal</u>:	
Anthracite	10,100
Bituminous	9,780
Lignite oil	9,860
Oil*	9,190
<u>Gas</u>:	
Natural	8,710
Propane	8,710
Butane	8,710
Wood	9,240
Wood bark	9,600
MSW	9,570

* Crude, residual, or distillate.

K Factors

Pollutant	**K (lb/scf)/ppm**
NO_x	1.194×10^{-7}
SO_2	1.660×10^{-7}
CO	7.264×10^{-8}

Appendix B: Existing Output-Based Regulations

Appendix B: Existing Output-Based Regulations

This appendix lists and describes output-based regulations currently in effect or under development.

B.1 Conventional Emission Rate Limit Programs

Conventional emission rate regulations, such as New Source Performance Standards (NSPS), reasonably available control technology (RACT), or maximum achievable control technology (MACT), can be made output-based simply by changing the format of the standards. These types of regulations can allow energy efficiency to act as a pollution control measure and enable more direct comparisons among regulated entities. They can also include provisions that account for the energy efficiency and pollution reduction benefits of combined heat and power (CHP) projects.

B.1.1 New Source Performance Standards for Utility Boilers

NSPS are technology-based emission standards that are set for specific processes and pollutants under the 1970 Clean Air Act. The NSPS limits apply to new, modified, or reconstructed facilities that meet the applicability criteria in the rule. The U.S. Environmental Protection Agency (EPA) periodically reviews the limits set in the NSPS.

In 1998, EPA revised the nitrogen oxides (NO_x) limits for electric utility steam generating units and industrial-commercial-institutional steam generating units (40 CFR Part 60 Subparts Da and Db). These revisions changed the format of the NO_x emission limit for new electric utility boilers from an input basis (lb/MMBtu) to an output basis (lb/MWh) and thereby provided a means for improved efficiency to contribute to meeting the new standards. The regulation was changed from a fuel-specific limit (i.e., different limits for different fuels) to a single limit of 1.6 lb NO_x/MWh gross energy output, regardless of fuel type. The rule has been modified several times since 1998, with current emission limits for new units set at 0.70 lb/MWh gross energy output or 0.76 lb/MWh net energy output. Compliance with the NO_x emission limit is determined on a 30-day rolling average basis. EPA added compliance and monitoring provisions explaining how sources must demonstrate compliance with the output-based standards. The regulation allows CHP facilities to take a credit for the process steam generated that is equal to 75 percent of the thermal output of process steam converted to MWh (equivalence method). The change in format for a major emission standard was an important precedent in the diffusion and acceptance of output-based standards. The NSPS is discussed in more detail in section 5.2 of this report.

Additional information:
William Maxwell
Energy Strategies Group, Sector Policies and Programs Division (C439-01)
U.S. EPA
Research Triangle Park, NC 27711
(919) 541-5430
http://www.epa.gov/ttn/atw/nsps/boilernsps/boilernsps.html

B.1.2 New Source Performance Standards for Stationary Combustion Turbines

EPA's NSPS for Stationary Combustion Turbines (40 CFR Part 60, subpart KKKK) limits emissions from stationary combustion turbines. Affected units have the option of meeting concentration-based or output-based NO_x and sulfur dioxide (SO_2) emission limits.

The rule has been modified several times since 2003, with current NO_x emission limits for new units set starting at 0.43 lb/MWh gross energy output up to 8.7 lb/MW gross energy output (limits are based on the size, fuel use, and location). Compliance with the proposed NO_x emission limit is determined on a 30-day rolling average basis. EPA added compliance and monitoring provisions explaining how sources must demonstrate compliance with the output-based standards. The regulation allows CHP facilities to take a credit for the process steam generated that is equal to 100 percent of the thermal output of process steam converted to MWh.

Additional information:
Christian Fellner
Combustion Group, Emission Standards Division
U.S. EPA
Research Triangle Park, NC 27711
(919) 541-4003
http://www.epa.gov/ttn/atw/nsps/turbine/turbnsps.html

B.1.3 New Jersey Mercury Emission Limitations

The state of New Jersey finalized output-based emission limits for mercury from coal-fired boilers in 2006 (N.J.A.C. 7:27-27.7). The rule specifies that as of December 15, 2007, the mercury emissions from any coal-fired boiler shall not exceed 3 milligrams per megawatt hour (mg/MWh), based on the annual weighted average of all tests performed during four consecutive quarters; alternatively, the owner or operator of a coal-fired boiler must achieve a 90 percent reduction in mercury emissions as measured at the exit of the air pollution control apparatus. Compliance is to be determined by averaging three stack emission test runs per quarter for four consecutive quarters, measuring the net MWh for each quarter, and then calculating annual weighted averages using the quarterly averages and the net MWh generated. The Department of Environmental Protection (DEP) will allow averaging among units at the same site.

The DEP finalized an extension of the December 15, 2007, compliance deadline to December 15, 2012, for any facility that, by December 15, 2007, installed and operates air pollution control systems to control: (1) NO_x emissions to less than 0.100 lb/MMBtu for dry bottom boilers and 0.130 lb/MMBtu for wet bottom boilers; (2) SO_2 emissions to less than 0.150 lb/MMBtu; and (3) particulate matter (PM) emissions to less than 0.030 lb/MMBtu. This extension of the compliance deadline is only available for half of the New Jersey coal-fired capacity of a company. The other half of the coal-fired capacity must achieve the mercury emission limits by December 15, 2007.

If a unit plans to shut down by December 15, 2012, the DEP will allow it to be exempt from the proposed regulations.

Additional information:
Office of Legal Affairs
New Jersey DEP
401 East State Street
P.O. Box 402
Trenton, New Jersey 08625-0402
http://www.nj.gov/dep/rules/adoptions/2006_0906mercury.pdf

B.1.4 Mercury MATS

EPA issued final Mercury and Air Toxics Standards (MATS) in February 2012. The rule sets standards to limit mercury, acid gases, and other toxic pollution from power plants. MATS applies to new and existing coal- and oil-fired EGUs larger than 25 MW. The rule also affects CHP systems: "A unit that cogenerates steam and electricity and supplies more than one third of its potential electric output capacity and more than 25 megawatts electrical output to any utility power distribution system for sale shall be considered an electric utility steam generating unit."[16] Existing sources generally have up to four years to comply with MATS. The rule sets emission limits based on heat input in lb/MMBtu or lb/TBtu, but also provides alternative output-based emission limits (either in lb/MWh or lb/GWh gross output) as an option.

Additional information:
William Maxwell
Combustion Group, Emission Standards Division
Office of Air Quality Planning and Standards
U.S. EPA
Research Triangle Park, NC 27711
(919) 541-5430
http://www.gpo.gov/fdsys/pkg/FR-2012-02-16/pdf/2012-806.pdf

B.2 Regulations for Distributed Generation

Distributed generation (DG) refers to the use of technologies such as microturbines, diesel generator sets, fuel cells, solar panels, and reciprocating engines to satisfy small-scale electrical power needs closer to the point of use. There is increasing interest in DG because of a desire for improved reliability, energy efficiency, and lower costs. With innovations in DG technology, there has been increased interest in how one consistently and appropriately regulates small distributed electric generators. This activity has coincided with the interest in output-based regulation, and several new regulatory programs have incorporated output-based measures as a means of recognizing efficiency as a pollution control measure. Several of these regulations also include provisions to account for the efficiency advantages of CHP. Most of these programs are conventional emission rate limit programs in many respects, but they include some innovative features.

B.2.1 New Hampshire Emission Fee

New Hampshire has an output-based emission fee program for DG. The program requires affected generators to report NO_x emissions and power production and either (1) offset their emissions through the purchase of NO_x emission allowances within the Ozone Transport Region or (2) pay an emission fee. The new regulation affects any internal combustion engine or combustion turbine that generates electricity for use or sale and emits more than 5 tons of NO_x per year. However, backup, startup, and emergency generators are exempted, as are generators used in areas where electrical power is not reasonably and reliably available. The amount of the fee per ton of NO_x emitted is $100 from October 1 to April 30 and $200 from May 1 to September 30. The fee increases over time but is capped at $500 per ton from October 1 to April 30 and $1,000 from May 1 to September 30. A NO_x

[16] *http://www.gpo.gov/fdsys/pkg/FR-2012-02-16/pdf/2012-806.pdf*.

emission reduction fund will be established with these fees and used to reduce NO_x emissions from generation sources. No fee or allowance is required for the first 7 lb/MWh of NO_x. The original intent of the 7 lb/MWh threshold was to focus the fee on higher-emitting engines, including diesels. However, this limit provides the additional benefit of encouraging efficiency by rewarding units that emit at a lower output-based rate.

Additional information:
Joe Fontaine
New Hampshire Department of Environmental Services
29 Hazen Drive
P.O. Box 95
Concord, NH 03302-0095
(603) 271-6794
http://www.gencourt.state.nh.us/rsa/html/nhtoc/NHTOC-X-125-O.htm

B.2.2 California Senate Bill 1298 Regulations for Distributed Generation

In 2000, California passed Senate Bill 1298 (SB 1298), which required the California Air Resources Board (CARB) to set new emission standards and provide guidance for permitting new DG projects. In California, generators larger than 50 MW require air permits from the California Energy Commission, while the 35 local air quality districts issue permits for units smaller than 50 MW. Very small projects have been exempted from permitting by the individual districts. The size threshold for the permitting exemption varies from district to district. The threshold is typically up to 250 kW for microturbines, engines less than 50 hp, and fuel cells.[17] This variation makes it difficult to implement the regulation. SB 1298 calls for CARB to:

- Establish an emission certification program for the small projects that are exempt from permitting.
- Develop a best available control technology (BACT) guidance document for DG projects less than 50 MW but large enough to require local district permits. (BACT in California is equivalent to lowest achievable emission rate [LAER] in other states.)

Certification Program

The final certification regulations became effective in October 2002. The certification program sets emission standards that must be achieved by all affected DG units that are manufactured for sale, lease, use, or operation in California. Amendments to the regulation were adopted by the Board on October 9, 2006 and became effective September 7, 2007. The program is implemented in two phases.

Phase I took effect on January 1, 2003, and sets the standards summarized in **Table B-1**.

[17] *http://www.arb.ca.gov/energy/dg/background/background.htm*.

Table B-1. 2003 California Distributed Generation Certification Standards (lb/MWh)

Pollutant	Not Integrated with CHP	Integrated with CHP
Oxides of nitrogen	0.5	0.7
Carbon monoxide	6.0	6.0
Volatile organic compounds	1.0	1.0
Particulate matter	Corresponding to natural gas with sulfur content not more than 1 grain/100 scf	

The standards include a separate limit for DG units that include CHP as part of a standardized package. DG units that use CHP may be certified to the above emission standards if they are sold with CHP technology integrated into a standardized package by the applicant and they achieve a minimum energy efficiency of 60 percent based on 100 percent load. In addition, DG units that are sold with a zero emission technology integrated into a standardized package can have the electric power output of the zero emission technology added to the electrical power output of the DG unit to meet the emission standards.

Phase II took effect January 1, 2007, and is based on the emission level that CARB determines to be BACT for permitted central station power plants. Table B-2 summarizes the 2007 certification standards.

Table B-2. 2007 California Distributed Generation Fossil Fuel Emission Standards (lb/MWh)

Pollutant	lb/MWh
Oxides of nitrogen	0.07
Carbon monoxide	0.10
Volatile organic compounds	0.02
Particulate matter	Corresponding to natural gas with sulfur content not more than 1 grain/100 scf

In its 2006 amendments, CARB also established separate emission limits for waste gas systems. These limits apply to any DG unit that is fueled by digester gas, landfill gas, or oil-field waste gas.

Table B-3. 2007 California Distributed Generation Waste Gas Emission Standards (lb/MWh)

Pollutant	Emission Standard lb/MWh	
	On or after 1/1/2008	On or after 1/1/2013
Oxides of nitrogen	0.5	0.07
Carbon monoxide	6.0	0.10
Volatile organic compounds	1.0	0.02

In Phase II, DG units that use CHP can increase the output calculation by 1 MWh for every 3.4 MMBtu of heat recovered in the CHP system if the system is an integrated package with the DG system and if the overall system has an efficiency of at least 60 percent. This recognizes 100 percent the thermal output generated.

Certified Technologies

The regulation also specifies appropriate testing, testing parameters, labeling, and recordkeeping requirements, along with information about the equipment to be submitted by the manufacturer for certification. The executive officer or an authorized representative will periodically inspect manufacturer, distributors, and retailers selling or leasing DG in California to ensure compliance with the regulations. Failure of the inspection can lead to denial, suspension, or revocation of certification. The equipment must be guaranteed to meet the certification for 15,000 hours of operation. As of April 2013, 27 technologies have been certified.[18]

BACT Guidelines

CARB released its *Guidance for Permitting of Electrical Generating Technologies* in July 2002. The document provides guidance to assist air control districts in making air permitting decisions for new electrical generators that are smaller than 50 MW but larger than the local exemption level. It expresses currently achievable emissions on an output basis.

Most BACT definitions in California are consistent with the federal LAER definition and are often referred to as "California BACT." "California BACT" should not be confused with the less restrictive federal BACT.

The CARB BACT guidance document summarizes CARB's evaluation of the status of California BACT for electrical generators smaller than 50 MW. SB 1298 calls for the guidance to approach the emission levels of the cleanest central station power plants. The CARB guidance suggests that the central station levels will only be achievable by DG technologies through the application of a CHP credit.

Table B-4 summarizes the 2002 guidance for combustion turbines. Table B-5 summarizes the 2002 guidance for reciprocating engines. All of the standards are expressed in lb/MWh. There is no recognition for thermal energy produced by CHP.

[18] *http://www.arb.ca.gov/energy/dg/eo/eo-current.htm*.

Table B-4. CARB BACT Guidance for Small Combustion Turbines*

Equipment Category	NO_x** lb/MWh	VOC** lb/MWh	CO** lb/MWh	PM lb/MWh
< 3MW	0.5 (9 ppmvd)	0.1 (5 ppmvd)	0.4 (10 ppmvd)	An emission limit corresponding to natural gas with fuel sulfur content of no more than 1 grain/100 standard cubic feet
3–12 MW Combined cycle	0.12 (2.5 ppmvd)	0.04 (2 ppmvd)	0.2 (6 ppmvd)	
Simple cycle	0.25 (5 ppmvd)	0.04 (2 ppmvd)	0.2 (6 ppmvd)	
>12 and <50 MW Combined cycle	0.1 (2.5 ppmvd)	0.03 (2 ppmvd)	0.15 (6 ppmvd)	An emission limit corresponding to natural gas with fuel sulfur content of no more than 1 grain/100 standard cubic feet
Simple cycle	0.2 (5 ppmvd)	0.03 (2 ppmvd)	0.15 (6 ppmvd)	
Waste Gas Fired	1.25 (25 ppmvd)	---	---	---

* *http://www.arb.ca.gov/energy/powerpl/powerpl.htm*, *http://www.arb.ca.gov/energy/dg/guidance/guidelines.pdf*. All standards based upon three-hour rolling average and in lb/MWh.
** Equivalent limit is presented in ppmvd, expressed at 15 percent O_2.

Table B-5. CARB BACT Guidance for Reciprocating Engine Generators*

Equipment Category	NO_x lb/MWh	VOC lb/MWh	CO lb/MWh	PM lb/MWh
Fossil-fuel-fired	0.5 (0.15 g/bhp-hr or 9 ppmvd**)	0.5 (0.15 g/bhp-hr or 25 ppmvd**)	1.9 (0.6 g/bhp-hr or 56 ppmvd**)	0.06 (0.02 g/bhp-hr)
Waste-gas-fired	1.9 (0.6 g/bhp-hr or 50 ppmvd**)	1.9 (0.6 g/bhp-hr or 130 ppmvd**)	7.8 (2.5 g/bhp-hr or 300 ppmvd**)	NA

* All standards based upon three-hour rolling average and in lb/MWh.
** Equivalent limit is presented in ppmvd, expressed at 15 percent O_2.

Additional information:
Jonathan Foster
California Air Resources Board
1001 "I" Street
P.O. Box 2815 Sacramento, CA 95812
(916) 327-1512
http://www.arb.ca.gov/energy/dg/dg.htm

B.2.3 Delaware Small Distributed Generation Rule

Division of Air and Waste Management Regulation No. 1144 specifies limits on DG and emergency generation units. Delaware's output-based regulation, entitled "Control of Stationary Generator Emissions," limits emissions of NO_x, nonmethane hydrocarbons, PM, SO_2, carbon monoxide (CO), and carbon dioxide (CO_2). This regulation applies to new and existing stationary DG units. DG units must comply with the limits beginning on January 11, 2006. CHP systems can receive a compliance credit against their actual emissions based on the emissions that would have been created by a conventional separate system used to generate the same thermal output. The credit will then be subtracted from the actual generator emissions for determining compliance. The credit (measured in $lb/MWh_{emissions}$) is equal to the existing boiler's historic emission rate (in lb/MMBtu) divided by the boiler efficiency (assumed to be 80 percent); this result is multiplied by the conversion factor of 3.413 (to convert to MWh) divided by the CHP system's power to heat ratio. CHP units that are at least 55 percent efficient, use at least 20 percent of a fuel's recovered energy for thermal, and at least 13 percent for electricity are eligible.

Additional information:
http://www.dnrec.state.de.us/air/aqm_page/docs/pdf/Final%20Regulation%201144.pdf

B.2.4 Rhode Island Distributed Generation Rule

In Rhode Island, new and existing distributed generators may be subject to emission limits (lb/MWh) pursuant to state air pollution control Regulation No. 43, established in May 2007. Using the *avoided emissions approach,* the rule allows a CHP system to account for its secondary thermal output when determining compliance with NO_x, CO, and CO_2 emission limits. The CHP system can receive emission compliance credits using the same method that Delaware uses, as noted above (assuming a boiler efficiency of 80%):

$$\text{credit } lb/MWh_{emissions} = [(\text{boiler limit } lb/MMBtu) \div (\text{boiler efficiency})] \times [3.412/(\text{power to heat ratio})]$$

A CHP system can take into account the secondary thermal output if it meets the following criteria:

- The power-to-heat ratio is between 4.0 and 0.15.
- The design system efficiency is at least 55 percent.

Additional information:
http://www.dem.ri.gov/pubs/regs/regs/air/air43_07.pdf

B.2.5 Texas Standard NO_x Permit for Distributed Generation

In May 2001, the Texas Commission on Environmental Quality (TCEQ) approved a new standard permit for emissions from small electric generating units. This new standard:

- Applies to electric generating units that were new or modified after June 2001.
- Exempts non-emitting generators from permitting.
- Does not apply to DG used to power an individual's home.
- Provides separate standards for east and west Texas.
- Differentiates by system size and capacity factor.
- Provides full credit for heat recovery in CHP projects.

The permit sets output-based limits for units in 2001 with a more stringent limit in 2005 for 10 MW or less in eastern Texas (**Table B-6**).

Table B-6. TCEQ Standard Permit for NO_x from DG

Region	10 MW or Less	>10 MW
East	Installed prior to 2005: Operating >300 hrs/yr = 0.47 lb/MWh Operating <u><</u>300 hrs/yr= 1.65 lb/MWh Installed starting 2005: Operating >300 hrs/yr = 0.14 lb/MWh Operating <u><</u>300 hrs/yr = 0.47 lb/MWh	Operating >300 hrs/yr = 0.14 lb/MWh Operating <u><</u>300 hrs/yr = 0.38 lb/MWh
West	Operating >300 hrs/yr = 3.11 lb/MWh Operating <u><</u>300 hrs/yr = 21 lb/MWh	Operating >300 hrs/yr = 0.14 lb/MWh Operating <u><</u>300 hrs/yr = 0.38 lb/MWh

The rule also sets a NO_x limit of 1.7 lb/MWh for generators burning waste gases, including landfill gas, digester gas, and oil field gas. In addition, the gas is limited to less than 1.5 grains of hydrogen sulfide or 30 grains of sulfur compounds. CHP units can subtract 1 MWh from the output calculation for each 3.413 MMBtu of thermal output produced.

Additional information:
TCEQ Air Permits Division
Texas Natural Resource Conservation Commission
P.O. Box 13087
Austin, TX 78711-3087
(512) 239-1250
airperm@tceq.texas.gov
http://www.tceq.state.tx.us/assets/public/permitting/air/NewSourceReview/Combustion/segu_final.pdf

B.2.6 Texas Permit by Rule

Texas offers a streamlined construction air permitting program, termed a permit by rule (PBR), which was issued in July 2012 for certain types of natural-gas-fired CHP systems up to 15 MW. The CHP PBR, codified in 30 TAC 106.513, allows CHP systems that meet the rule's eligibility requirements to comply with NO_x and CO emission limits using the *equivalence approach*. A CHP system can receive 100 percent credit for its secondary thermal output (at the rate of 1.0 MWh for each 3.4 million BTU of heat recovered) if "the heat recovered equals at least 20 percent of the total heat energy output of the CHP system." The permit sets output-based NO_x and CO limits for CHP units or a combination of CHP units (Table B-7).

Table B-7. TCEQ PBR for CHP

Pollutant	Emission Standard (lb/MWh)			
	CHP unit > 20 kW to <u><</u> 8 MW	CHP unit > 8 MW	Combo of CHP Units <u><</u> 8 MW at Least 900 Feet Apart	CHP Units > 8 MW at Least 900 Feet Apart
NO_x	1.0 lb/MWh	0.7 lb/MWh	1.0 lb/MWh	0.7 lb/MWh
CO	9.0 lb CO/MWh	9.0 lb/MWh	9.0 lb/MWh	9.0 lb CO/MWh

Additional information:
TCEQ Air Permits Division
Texas Natural Resource Conservation Commission
P.O. Box 13087
Austin, TX 78711-3087
(512) 239-1250
airperm@tceq.texas.gov
http://info.sos.state.tx.us/pls/pub/readtac$ext.TacPage?sl=R&app=9&p_dir=&p_rloc=&p_tloc=&p_ploc=&pg=1&p_tac=&ti=30&pt=1&ch=106&rl=513

B.2.7 Regulatory Assistance Project Model Rule for Distributed Generation

A collaborative group of state utility regulators, state air regulators, environmental organizations, and DG industry representatives, with participation from the U.S. Department of Energy (DOE) and EPA, developed a model emission rule for small DG units. Supported by DOE's Office of Distributed Energy Resources, the Regulatory Assistance Project facilitated the formation of the collaborative group as well as its deliberations. The purpose of the model rule is to facilitate the permitting of DG projects by providing a framework of underlying principles that can be uniformly adopted across the United States. The model rule was completed in February 2003.

The model rule recommends output-based emission limits for NO_x (separate standards for ozone attainment and nonattainment areas), CO, and PM. The rule also requires diesel-fueled generators to use low-sulfur highway diesel fuel. The limits are established in three phases, taking effect in 2004, 2008, and 2012. The third phase is subject to a technology review to determine whether the limits are feasible and appropriate. The limits are summarized in Table B-8.

Table B-8. RAP Model Rule Emission Limits (lb/MWh)

	NO_x Attainment	NO_x Nonattainment	CO	PM*
Phase I—2004	4	0.6	10	0.7
Phase II—2008	1.5	0.3	2	0.07
Phase III—2012**	0.15	0.15	1	0.03

* Diesel engines only.
** Subject to technology review.

Limits on CO_2 were endorsed by the collaborative group but are not part of the final recommendations. The model rule provides compliance credit for CHP facilities based on the avoided emissions from an equivalent thermal generator. It also allows credit for avoided combustion of waste and byproduct gases. There is also a section on credit for combined conventional/renewable projects, though the approach is not described in detail.

The model rule was adopted in whole or in part by a number of states, among them Connecticut, Rhode Island, Maine, Massachusetts, and Delaware.

Additional information:

Rick Weston
Regulatory Assistance Project
50 State Street, Suite 3
Montpelier, VT 05602
(802) 498-0711
http://www.google.com/url?sa=t&rct=j&q=&esrc=s&source=web&cd=1&cad=rja&uact=8&ved=0CCsQFjAA&url=http%3A%2F%2Fwww.raponline.org%2Fdocument%2Fdownload%2Fid%2F174&ei=F1dqU6G0HMiV8gHXzoGQBA&usg=AFQjCNH6kz6UMjNki-NY3sPF4oPonH6PaQ&sig2=5hbiLKTLGB1NzfS_1MEoSQ&bvm=bv.66111022,d.b2U

B.2.8 Connecticut Air Pollution Regulations 22a-174-42

The state of Connecticut finalized a rule setting output-based emission standards in 2005. The rule is based on the Regulatory Assistance Project (RAP) rule for distributed generation using the avoided emissions approach for crediting CHP. The rule regulates NO_x, PM, CO, and CO_2.

Additionally, the rule incorporates a fuel sulfur content requirement to control SO_2 emissions. The rule is based on the RAP model rule for new generators (**Table B-9**). The rule also sets less stringent limits for existing generators. The rule is applicable to generators with a nameplate capacity less than 15 MW that generate electricity for other than emergency use and have potential emissions less than 15 tons per year.

Table B-9. Connecticut Emission Standards for New Distributed Generators

Date of Installation	NO_x (lb/MWh)	PM (lb/MWh)	CO (lb/MWh)	CO_2 (lb/MWh)
On or after January 1, 2005	0.6	0.7	10	1,900
On or after May 1, 2008	0.3	0.07	2	1,900
On or after May 1, 2012	0.15	0.03	1	1,650

Table B-10. Connecticut Emission Standards for Existing Distributed Generators

NO_x (lb/MWh)	PM (lb/MWh)	CO (lb/MWh)	CO_2 (lb/MWh)
4.0	0.7	10	1,900

An owner or operator of any new or existing distributed generator subject to this section can comply with the applicable emission standards of this section by obtaining one of the following certifications:

- Certification by CARB pursuant to Title 13, sections 94200 through 94214 of the California Code of Regulations.
- Certification from the generator supplier that satisfies the requirements of this subsection.

The proposed regulation does recognize the thermal output of CHP systems based on displaced emissions as long as:

- At least 20 percent of the fuel's total recovered energy is thermal and at least 13 percent is electric, with a resulting power-to-heat ratio between 4.0 and 0.15.
- The design system efficiency is at least 55 percent.

Additional information:
Director Division of Compliance and Field Operations
Bureau of Air Management
Connecticut Department of Environmental Protection
(860) 424-3416
http://www.ct.gov/deep/lib/deep/air/regulations/mainregs/sec42.pdf

B.2.9 Maine Permit for Small-Scale Electric Generators

Maine's output-based regulation titled "Emissions from Smaller-Scale Electric Generating Resources," limits emissions of NO_x, SO_2, PM, and CO. The emission standard applies to stationary generators with a capacity equal to or greater than 50 kW installed on or after January 1, 2005. Generators that use CHP can receive credit for heat recovery to comply with the emission standards. Credit is given at the rate of 1 MWh for each 3.4 MMBtu of heat recovered. Total CHP system efficiency must be at least 55 percent. The heat recovered from a CHP unit must be at least 20 percent of the total energy output, and at least 13 percent of total output must be electric.

Table B-11. Maine Emission Standards for Non-Emergency Generators

	NO_x	PM	CO
Installed on or after January 1, 2005	4.0 lb/MWh	0.7 lb/MWh	10.0 lb/MWh
Installed on or after January 1, 2009	1.5 lb/MWh	0.07 lb/MWh	2.0 lb/MWh
Installed on or after January 1, 2013	Reserved	Reserved	Reserved

Additional information:
Eric Kennedy
Bureau of Air Quality
Maine Department of Environmental Quality
17 State House Station
Augusta, ME 04333-0017
(207) 287-5412
http://www.maine.gov/sos/cec/rules/06/096/096c148.doc

B.2.10 Massachusetts Draft 310 CMR 7.26 Engines and Combustion Turbine Certification Standards

The state of Massachusetts has released a final output-based regulation on emissions from commercial/industrial size engines and combustion turbines.[19] The proposed rule applies to engines and combustion turbines that are not subject to Prevention of Significant Deterioration or Non-Attainment Review. It includes separate standards for emergency and non-emergency units. "Emergency" is defined as not only equipment failure, but also the imminent threat of a power outage is likely due to failure of the electrical supply or when capacity deficiencies result in a deviation of voltage from the electrical supplier to the premises of 3 percent above or 5 percent below standard voltage. An emergency engine or emergency turbine cannot operate more than 300 hours per 12-month rolling period during times of emergency and for normal maintenance and testing as recommended by the manufacturer. All emergency engines with a rated power output equal to or greater than 37 kW, and emergency combustion turbines with a rated power output less than 1 MW installed after March 23, 2006, must meet the following air emission limits.

Table B-12. Massachusetts Emission Limits for Emergency Engines and Turbines

Pollutant	Emission Limit
NO_x	**0.60 lb/MW-hr**

Additionally, on and after July 1, 2007, emergency engines and turbines may not accept delivery of fuel oil for burning in a unit that does not conform to EPA's sulfur limits for transportation distillate fuel (15 ppm sulfur).

Non-emergency engines are subject to declining emission output regulations through the use of three phases based on the RAP Model Rule. The first phase occurred on and after March 23, 2006. The second phase was from 2008 to 2012. The third phase is 2012 and beyond. The phase-in was intended to encourage the development and commercialization of new technologies. Table B-13 summarizes the proposed limits for non-emergency engines. Unlike the model rule, the final rule does not create or provide any recognition for concurrent emission reductions, CHP, or end-use efficiency.

An owner or operator who installs, after March 23, 2006, an engine with a rated power output equal to or greater than 50 kW or a combustion turbine with a rated power output equal to or less than 10 MW is subject to the following emission limits:

Table B-13. Massachusetts Emission Limits for Non-Emergency Engines

Installation Date	NO_x	PM (Liquid Fuel)	CO
On and after 03/23/2006	0.6 lb/MWh	0.7 lb/MWh; ≥ 1 MW 0.09 lb/MWh	10 lb/MWh
On and after 01/01/2008	0.3 lb/MWh	0.07 lb/MWh	2 lb/MWh
On and after 01/01/2012	0.15 lb/MWh	0.03 lb/MWh	1 lb/MWh

[19] *http://www.mass.gov/eea/agencies/massdep/air/approvals/stationary-engines-and-turbines.html#1*

The emission limits for turbines (Tables B-14 and B-15) are consistent with the Texas general permit for DG (See section B.2.3). They vary by generator size but are not phased in over time.

Table B-14. Massachusetts Emission Limits for Non-Emergency Turbines

Rated Power Output	NO_x	Ammonia	PM	CO
Less than 1 MW	0.47 lb/MWh	N/A	0.10 lb/MWh	0.47 lb/MWh
1 to 10 MW	Gas—0.14 lb/MWh Oil—0.34 lb/MWh	2.0 ppm at 15% O_2 dry basis	0.10 lb/MWh	Gas—0.09 lb/MWh Oil—0.18 lb/MWh

Table B-15. CO_2 Emission Limitations—Engines and Turbines

Installation Date	CO_2
On and after March 23, 2006	1,900 lb/MWh
On and after 1/1/08	1,900 lb/MWh
On and after 1/1/12	1,650 lb/MWh

Additional information:
Cynthia Greene
Business Compliance Division
Massachusetts Department of Environmental Protection
One Winter Street
Boston, MA 02108
(617) 918-1813

B.2.11 New York 6 NYCRR Part 222 Emissions from Distributed Generation

The state of New York's Department of Environmental Conservation is proposing output-based standards for NO_x. Under this proposed rule, output-based limits are proposed for "economic dispatch" engines and demand response resources in g/bhp. For combustion turbines, the emission limits are based on heat input and are expressed in ppm. Currently, there is no recognition of CHP. The proposed limits in the tables below are from a working draft released in October 2007.[20] The department has never finalized this proposed rule, but has stated in its January 2014 Regulatory Agenda that it plans on doing so soon.

NO_x emission limits under proposed Part 222 apply to "economic dispatch sources," defined as DG sources used to reduce energy costs or ensure a reliable electricity supply for facilities. The rule states that any DG source that is not an emergency-power-generating stationary internal combustion engine or a demand response source is considered to be an economic dispatch source. "Demand response sources" are also subject to output-based NO_x limits. A demand response source is defined as a "distributed generation source that operates for no more than 500 hours per year, or as limited to comply with any other applicable requirement, as a mechanical or electrical power source when the usual supply of power is unavailable and for a limited number of hours per year when called upon to

[20] *http://www.eea-inc.com/rrdb/DGRegProject/Documents/NYExpTerms222%20-%20Oct%202007%20(2).pdf*

reduce demand on the electric grid as set forth in sections of this proposed rule." Output-based limits are established for economic dispatch engines and demand response resources as follows:

Table B-16. Proposed NO_x Emission Limits

Effective Date	Technology	NOx Emission Limits g/bhp
May 1, 2009 (economic dispatch sources)	Lean burn engines—gas-fired	3.0 g/bhp
	Rich burn engines—gas-fired	2.0 g/bhp
	Oil-fired engines	7.5 g/bhp
January 1, 2010 (economic dispatch sources)	Lean burn engines—biogas-fired	3.0 g/bhp
	Rich burn engines—biogas-fired	2.0 g/bhp
May 1, 2009	Demand response resources	9.0 g/bhp

Additional Information:
Ron Stannard
New York Department of Environmental Conservation
625 Broadway
Albany, NY 12233-3251
(518) 402-8396
airregs@gw.dec.state.ny.us

B.3 Allowance Allocation in Emission Trading Programs

In emission cap and trade programs, the total tons of emissions for a given sector are capped. Allowances represent a permit to emit one ton. Allowances are allocated to the affected sources, and each source is required to hold allowances equal to its emissions during each regulated period. Sources are allowed to buy and sell allowances from each other to help them meet their compliance requirement. In themselves, these trading programs promote an output-based view on the part of affected sources. Affected sources must try to maximize their production within the overall emission cap; thus they are driven to relate their emissions directly to their productive output. However, other aspects of the program can more directly relate to output-based regulation.

In these programs, the emission allowances must be allocated to participating sources at the beginning of the program. The early cap and trade programs performed this allocation based on historical emissions or heat input. More recently, there has been interest in doing the allocation based on energy output. An output-based allocation can serve to recognize the benefits of efficient generation, end use efficiency, and renewables. Past programs that include output-based allocation are primarily state programs under the NO_x State Implementation Plan (SIP) call program, the Clean Air Interstate Rule (CAIR), and the Regional Greenhouse Gas Initiative (RGGI) as described in this section.

Some states established output-based allocations or allocation set-asides as part of their implementation of CAIR. CAIR set emissions caps for NO_x and SO_2 emissions for 27 states in the eastern United States and the District of Columbia. In its CAIR model rule, EPA outlined an allocation methodology to existing units on a heat input basis, but suggested using an output-based allocation approach to new units. States were allowed to develop their own allocation methodologies in their SIPs. A number of states did develop output-based allocation methodologies for existing units. These output-based approaches are briefly described below. On April 29, 2014, the U.S. Supreme Court issued an opinion reversing a lower court ruling that had vacated the Cross State Air Pollution Rule, intended to be the successor to CAIR. EPA has stated that CAIR remains in place at this time, and that "no immediate action from States or affected sources is expected."[21]

RGGI applies to 10 northeastern and mid-Atlantic states. The program imposes CO_2 caps on electric power generators larger than 25 MW in participating states and functions as a multi-state cap and trade program with a market-based emission trading system. As of August 2013, nine states are participating in the RGGI effort: Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island, and Vermont. (New Jersey announced its withdrawal from the program in June 2011.) The cap begins in 2009 at "current levels" and is reduced by 10 percent between 2016 and 2019. Some states developed set-aside pools of allowances that are allocated on an output basis. Most of the RGGI allowances are distributed through an auction process, but some allowances in set-aside pools are allocated on an output basis.

Some actual and proposed multi-pollutant legislation also includes output-based allocation (see sections B.4 and B.5).

B.3.1 Arkansas

Arkansas allocates allowances to existing units on an output basis as a part of CAIR.

Additional information:
http://www.adeq.state.ar.us/regs/drafts/reg19_draft_docket_06-012-R/reg19_draft_docket_06-012-R_revision_comparison_chart.pdf

B.3.2 Connecticut

Allowances for existing electric generating units in the NO_x SIP Call trading program (section 22a-174-22b) are allocated every two years based on the percentage of each unit's average electric generation during the previous two years relative to the total generation from affected units (output-based). The allocation for new units, cogenerators, and industrial boilers was based on heat input.

CHP facilities receive no special treatment.

Connecticut allocates CAIR allowances for CHP units (with an efficiency of at least 60 percent) and other facilities based on electrical output. Also, Connecticut has finalized its RGGI regulations, allocating allowances to the CHP set-aside account and early reduction account on an output basis.

Additional information:
Connecticut Department of Environmental Protection at Bureau of Air Management
79 Elm Street, 5th Floor
Hartford, CT 06106-5127
(860) 424-3000
NO_x SIP Call: *http://www.ct.gov/deep/lib/deep/air/regulations/mainregs/sec22b_repealed.pdf*
CAIR: *http://www.ct.gov/deep/lib/deep/air/regulations/mainregs/sec22c.pdf*
RGGI: *http://www.ct.gov/deep/lib/deep/air/regulations/mainregs/22a-174-31.pdf*

[21] *http://www.epa.gov/cleanairinterstaterule/*.

B.3.3 Illinois

Illinois has output-based allocations for new and existing units as well as their energy efficiency/renewable energy set-aside as a part of CAIR.

Additional information:
http://www.ipcb.state.il.us/documents/dsweb/Get/Document-58394/

B.3.4 Indiana

Indiana has established output-based regulations for new units and those that are eligible for the energy efficiency/renewable energy set-aside under CAIR.

Additional information:
http://www.in.gov/legislative/iac/T03260/A00240.PDF

B.3.5 Massachusetts

Allocations of allowances for the NO_x SIP Call trading program are revised annually, three years ahead of the compliance year. Allocation for electric generators is based on the average of the two highest years of generation (output) in the fourth, fifth, and sixth years before the allocation year. Allocation for industrial boilers is based on the two highest years of steam output in the fourth, fifth, and sixth years before the allocation year. Sources with both electric and thermal output (including CHP facilities) receive allocations for both output streams.

Massachusetts' CAIR rule employs useful output, including the thermal output of CHP, to allocate emission allowances to affected sources (generators > 25 MW). This approach provides a significant economic incentive for CHP within the emission cap. Additionally, early reduction credits under the state's RGGI rule will be allocated on an output basis.

Additional information:
Bill Lamkin
Massachusetts Department of Environmental Protection
One Winter Street
Boston, MA 02108-4746
(978) 694-3294
NO_x SIP Call: *http://www.mass.gov/eea/docs/dep/air/laws/output.doc*
CAIR: *http://www.mass.gov/eea/docs/dep/service/regulations/310cmr07.pdf*
RGGI: *http://www.mass.gov/eea/agencies/massdep/air/regulations/310-cmr-7-00-air-pollution-control-regulation.html*

B.3.6 Missouri

Missouri has output-based allocations under its NO_x SIP Call for its energy efficiency/renewable energy set-aside. Energy efficiency projects receive allowances based on the number of kWh saved, zero-emitting technologies receive allowances based on electrical output, and CHP systems receive allocations based on the difference between NO_x emissions from the CHP system and the NO_x emissions that would have resulted from a business-as-usual equivalent.

Additional information:
http://www.dnr.mo.gov/env/apcp/reghaze/appendix-v.pdf

B.3.7 New Hampshire

New Hampshire has had a NO_x cap and trade program since the ozone season starting in 2003 (NH CAR Env-A 3207). The allowances for the first three years of the program were allocated to electric generating units based on historical generation with some modifications to allow for new units. Starting in 2006, allocations were based directly on generation output.

There is no special treatment for CHP facilities.

Additional information:
Joe Fontaine
Air Resources Division
New Hampshire Department of Environmental Services
P.O. Box 95
Concord, NH 03302-0095
(800) 271-6794
jfontaine@des.state.nh.us

B.3.8 New Jersey

The New Jersey allocation system for NO_x allowances under the SIP Call (NJ AC Title 7, chapter 27, subchapter 31) treated sources differently depending on their emission rate.

Allocations are done annually three years in advance. Allowances for sources with an emission rate less than or equal to 0.15 $lb/MMBtu_{heat\ input}$ are based on actual emissions. Allowances for sources with an emission rate greater than 0.15 $lb/MMBtu_{heat\ input}$ are allocated based on output. For electric generating units, the allocation is 1.5 lb/MWh times the average of the two highest years' electrical generation outputs in the three ozone seasons before the allocation. For industrial boilers, the allocation was 0.44 $lb/MMBtu_{heat\ output}$ times the average of the two highest years' heat outputs for the three ozone seasons before the allocation.

New Jersey has output-based regulations for new and existing units as well as its energy efficiency/renewable energy set-asides as a part of CAIR.

Additional information:
Air Quality Management, Bureau of Regulatory Development
New Jersey Department of Environmental Protection
401 East State Street, 7th Floor
P.O. Box 418
Trenton, NJ 08625-0418
(609) 292-6710
http://www.state.nj.us/dep/aqm/

B.3.9 New York

New York allocates allowances under its RGGI early reduction set-aside account on an output basis (see Part 242: CO_2 Budget Trading Program).

Additional information:
New York State Department of Environmental Conservation
625 Broadway
Albany, New York 12233-0001
(518) 402-8452
DARWeb@gw.dec.state.ny.us
http://www.dec.ny.gov/regs/2492.html

B.3.10 Ohio

In July 2002, the Ohio EPA established a program for issuing credits to energy efficiency/renewable energy (EE/RE) and innovative technology (IT) projects in its NO_x Budget Trading Program. The rule set aside NO_x allowances for EE/RE and IT projects. Demand-side programs such as lighting retrofits could also receive credits. The program ended when CAIR started in 2009. However, Ohio has an EE/RE set-aside with output-based allocations under CAIR.

Additional information:
http://codes.ohio.gov/oac/3745-109-17

B.3.11 Pennsylvania

Pennsylvania allocates CAIR allowances to existing and new units on an output basis.

Additional information:
http://www.pacode.com/secure/data/025/chapter145/subchapDtoc.html

B.3.12 Wisconsin

Wisconsin has output-based regulations for new and existing units as well as its energy efficiency/renewable energy set-asides as a part of CAIR.

Additional information:
http://docs.legis.wisconsin.gov/code/admin_code/nr/400/432.pdf

B.4 State Multi-Pollutant Programs

Several states have recently implemented multi-pollutant regulations for power generators. These regulations comprise integrated emission reduction programs for power generators. Some are cap and trade programs, while others are conventional emission rate limit programs. Several programs include output-based approaches to regulation.

B.4.1 Massachusetts Multi-Pollutant Program

Massachusetts had a multi-pollutant regulation (310 CMR 7.29) for SO_2, NO_x, mercury (Hg), and CO_2 from older coal-fired power plants in the state that applied to emissions that occurred prior to 2009. The regulation set output-based emission limits for NO_x, SO_2, CO_2, and Hg (Table B-17). The regulation targeted specific coal-fired plants, including Brayton Point, Canal Electric, Mount Tom, Mystic Station, Salem Harbor Station, and Somerset Station.

The NO_x emission standard was 1.5 lb/MWh rolling annual average (beginning October 2004), with an additional 3.0 lb/MWh monthly average that took effect in October 2006. The limit of 1.5 lb/MWh is the nominal level established for the ozone season by the NO_x SIP Call, but this regulation expanded compliance with the SIP Call standard to a year-round requirement, rather than the ozone season. It also set a fixed standard rather than a cap and trade program. Compliance dates were moved two years in the future for units that were approved for major modifications or repowering before 2003.

that the rem

Table B-17. Massachusetts Multi-Pollutant Program Emission Limits

Effective Date	Emission Limits (lb/MWh, Rolling 12-Month Average)			
	NO_x	SO_2	CO_2	Mercury
2002	—	—	—	See limits below
2004	1.5	6.0	Historical emissions	
2006	1.5*	3.0**	1,800	

* Must also meet 3.0 lb/MWh monthly average.
** Must also meet 6.0 lb/MWh monthly average.

SO_2 emission standards were 6.0 lb/MWh (as of October 2004). Early reduction credits could be generated by participating facilities and used by these facilities to meet emissions above the 6.0 lb/MWh annual level. Beginning in October 2006, the standard dropped to 3.0 lb/MWh (rolling annual) and 6.0 lb/MWh (monthly). Title IV SO_2 allowances could be purchased and used for compliance with the 3.0 lb/MWh standard but were discounted at a 3:1 ratio. Title IV allowances used for this purpose were required to be excess allowances above those used to comply with the federal requirements. These standards reduced nominal emission levels allowed under Title IV by half and set specific limits. Compliance dates were moved to 2008 for units that were approved for major modifications or repowering before 2003.

CO_2 emissions from 2004 to 2006 could exceed historical annual emissions from a facility. Beginning in 2006, facilities were required to have an average emission rate not greater than 1,800 lb/MWh (annual average). The average emission rate was calculated by dividing pounds of CO_2 emitted by net electrical output. Compliance with these standards was required to be demonstrated by using offsite reductions or sequestration to offset emissions.

Mercury emission limits were set in January 2002 at the average historical annual emission level from a facility. This average was calculated using the results of stack tests. The Massachusetts Department of Environmental Protection (DEP) first completed an evaluation of the technological and economic feasibility of controlling and eliminating emissions of mercury from the combustion of solid fossil fuel in December 2002. In 2004, DEP released a draft proposal for mercury emission regulations.

The mercury regulations affected four large coal-burning power plants, which contributed 17 percent of the point source mercury emissions in Massachusetts. DEP concluded a mercury feasibility report in 2003 by finding that there is strong evidence oval of 85 to 90 percent of mercury in flue gas is technologically and economically feasible for coal-fired power plants.

The regulations contain output-based mercury rate limitations that were implemented in two phases (Table B-18). Under the first phase of the mercury reductions, each utility had a choice between a minimum 85 percent removal of mercury from inlet levels measured in 2001–2002 or a maximum Hg emission rate of 0.0075 pounds per net gigawatt-hour of electricity generated, calculated as a rolling annual average. This standard took effect January 1, 2008.

Table B-18. Massachusetts' Proposed Mercury Emission Regulations

Phase	Mercury Limit
Phase 1—Effective January 1, 2008, or 15 months after the Phase I NO_x and SO_2 compliance dates	85% Hg removal efficiency or maximum emission limit of 0.0075 lb/GWhnet
Phase 2—Effective October 1, 2012	95% Hg removal efficiency or maximum emission limit of 0.0025 lb/GWhnet

Under the second phase, each utility has a choice between a minimum 95 percent removal of mercury from inlet levels measured in 2001–2002 or a maximum Hg emission rate of 0.0025 pounds per net gigawatt-hour of electricity generated, calculated as a rolling annual average. This standard took effect October 1, 2012, with the first annual average calculated for the October 1, 2012, to September 30, 2013, period.

The inlet levels measured in 2001–2002 were used as the basis of the removal standard so that a facility could not increase overall emissions by meeting the removal efficiency standard based on a higher inlet measurement. The department did allow some flexibility for compliance. Through December 31, 2009, compliance with the mercury emission rate limitations must be demonstrated by using offsite reductions to offset excess emissions. The rule did allow averaging between a facility's units, but not between facilities.

Emission averaging among boilers within a plant was allowed for all standards. Early reduction credits could be created to meet the SO_2 standards.

Additional information:
Sharon Weber
Massachusetts Department of Environmental Protection
One Winter Street
Boston, MA 02108-4746
Sharon.weber@state.ma.us
http://www.mass.gov/eea/docs/dep/service/regulations/310cmr07.pdf

B.4.2 New Hampshire Multi-Pollutant Program

On May 8, 2002, New Hampshire passed a multi-pollutant law, known as the Clean Power Act, for existing fossil fuel power plants. The rule specifies emission reduction requirements for four pollutants (SO_2, NO_x, mercury, and CO_2). This law was aimed at controlling emissions from three plants: Merrimack Station in Bow, Schiller Station in Portsmouth, and Newington Station in Newington. The language, however, is somewhat vague and could include other existing units.

The law sets annual emission caps. Allowances are allocated to the plants on an output basis, and trading is allowed for SO_2, NO_x, and CO_2. Mercury reduction provisions were adopted in 2006. Caps were as follows:

- SO_2 emissions: 7,289 tpy. This was a 75 percent reduction from 2000 levels by the end of 2006.

- NO_x emissions: 3,644 tpy. This was a 70 percent reduction from early 2000 levels by the end of 2006.
- CO_2 emissions: 5,046,055 tpy. This reduction will put emissions at 7 percent below 1990 levels by 2010.

Amendments were adopted in 2006 to incorporate provisions for mercury reductions. Mercury trading was prohibited, but provisions were added to allow mercury credits to be converted to SO_2 allowances and used for compliance in that trading program.

Affected units are required to file compliance plans to meet the requirements of the Clean Power Act and to describe monitoring and reporting procedures for mercury content in emissions. Caps are met through reductions or trading. Allowances from federal and regional trading programs may be used as well, but mercury credits from other programs are only valid for reductions above the level required by federal limits. An SO_2 allowance from an upwind state was upgraded by 25 percent, meaning 0.8 tons purchased from an upwind state are credited as 1.0 allowances by the state. Discrete NO_x emission reduction credits may not be used for compliance from May to September. Credit is given for early reductions of CO_2 and mercury. Voluntary expenditures for energy efficiency, renewable energy, and conservation programs are provided allowances equivalent to the cost of the renewable, efficiency, and conservation programs.

Compliance with the law began in 2007.

The regulation determined the annual allocation approach as follows, beginning in 2006:

- SO_2—baseline power generation (in the year 1999) multiplied by 3 lb/MWh.
- NO_x—baseline power generation (in 1999) multiplied by 1.5 lb/MWh.
- CO_2—93 percent of 1990 emissions.
- Mercury—emission cap of 82 lb.

Individual unit allocations for NO_X and SO_2 are based on the unit's average electrical output from two years prior multiplied by the emission factors above. In 2008, HB 1434 amended the Act to include RGGI for further CO_2 reductions.

Additional information:
Joe Fontaine
Air Resources Division
New Hampshire Department of Environmental Services
P.O. Box 95
Concord, NH 03302-0095
(800) 498-6868
http://des.nh.gov/organization/divisions/air/tsb/tps/aetp/categories/overview.htm

B.5 Emission Performance Standards

Several states have developed programs to set emission performance standards for retail sellers of electricity. These output-based programs apply to all sellers, including those using non-combustion generation. "Emission performance standards" (EPS), as discussed in this section, refers to a state rule limiting the average emissions of the entire generation portfolio of a retail seller of electricity.

Massachusetts initially proposed an EPS with restructuring legislation, requiring the establishment of an EPS for at least one pollutant by May 2003. The principle is that each retail seller of electricity must meet certain emission limits in lb/MWh for its portfolio of electricity. These limits extend to all sellers and all sources of electricity, including those outside the state. This raises some complicated issues of tracking of electricity sales, emissions, and even limits on interstate commerce. After Massachusetts passed its EPS language, Connecticut and New Jersey passed similar language. These programs, however, were contingent on adoption of similar programs by other states in the region which never occurred.

In 1999, the Northeast States for Coordinated Air Use Management (NESCAUM) sponsored the development of a model rule approach to an EPS that would address some of the critical issues and allow states to implement such a program consistently. A stakeholder group was convened to discuss these issues and a proposed model approach was released.[22]

Under the rule, any electric generating unit that sells electricity in a state would be subject to the performance standards. The proposed standards are listed in Table B-19.

Table B-19. NESCAUM Model Rule Emission Performance Standards

Pollutant	Emissions (lb/MWh)
NO_x	1
SO_2	4
CO_2	1,100
CO	Reserved
Mercury	Each retail supplier is limited to no more than the actual emission rate for the reporting calendar year.

CHP units would be assigned an emission rate calculated by allocating emissions on a pro rata basis between electric energy output and thermal energy output multiplied by CHP factor. The factor is initially set at 50 percent.

B.5.1 California

In September 2006, Governor Schwarzenegger signed SB 1368, creating an emission performance standard for electric generation. Utilities may not enter into long-term purchase agreements for baseload generation unless emissions from the plant do not exceed those of a combined-cycle natural gas plant, set at 1,100 pounds of carbon dioxide per MWh.[23]

B.5.2 New York

In June 2012, New York adopted an emission performance standard. The rule, 6 NYCRR Part 251, went into effect on July 12, 2012; it applies to new power plants with capacity of at least 25 MW and capacity additions of at least 25 MW at existing power plants. Unlike emission performance standards in other states, the New York rule adopts carbon limits for not only baseload plants (925 lb per MWh or 120 lb

[22] *http://www.nescaum.org/pdf/EPSRuleFINAL.pdf*.
[23] *http://www.c2es.org/sites/default/modules/usmap/pdf.php?file=5889*.

per million Btu) but also for simple cycle combustion turbines (1450 lb per MWh or 160 lb per million Btu).

B.5.3 Oregon

SB 101, signed in July 2009, applies a different performance standard to all baseload power plants. Generators of baseload power must have emissions equal to or less than 1,100 pounds of GHGs per MWh, and utilities may only make long-term purchase agreements for baseload power with generators that meet this standard. This bill addresses all baseload power, including coal plants (there is only one coal-fired power plant in Oregon), whereas an earlier bill, HB 3283, applied only to baseload gas plants and other non-baseload facilities. The rule does exempt certain facilities, including CHP in operation prior to July 1, 2010, unless subject to a new long-term financial commitment. SB 101 does not have any provisions for compliance through offsets.

B.5.4 Washington

SB 6001, enacted on May 3, 2007, issued an emission performance standard for baseload electric generation. Electric utilities may not enter into long-term purchase agreements for baseload generation unless the power plant emits less than 1,100 pounds of GHGs per MWh.

B.5.5 NSPS for New Power Plants

In January 2014, EPA proposed NSPS regulations to limit CO_2 emissions from *new* electric generating units, using combustion turbines and steam boilers (EPA proposes including these requirements either in NSPS Subparts Da and KKKK,[24] or in a new subpart TTTT).[25] The 2014 proposal replaced previous proposals issued in 2012 and 2013 and reflects public comments received on the previous version. The latest proposal includes separate standards for natural-gas-fired turbines and coal-fired units.[26] The revised proposed NSPS regulations apply to new electric utility steam generating units, including CHP, where the facility has more than 73 MW (250 MMBtu/hr) design heat input and supplies more than one-third of its potential electric output and more than 219,000 MWh net electric output to the grid per year.[27] The standards propose output-based emission limits (lb of CO_2/MWh), and are as follows:[28]

1. Fossil-fuel-fired boilers and integrated gasification combined cycle units (coal-fired):
   - 1,100 lb CO_2/MWh gross over a 12-operating month period, or
   - 1,000–1,050 lb CO_2/MWh gross over an 84-operating-month (seven-year) period.
2. Natural-gas-fired stationary combustion turbine units:
   - 1,000 lb CO_2/MWh gross for larger units (> 850 mmBtu/hr)
   - 1,100 lb CO_2/MWh gross for smaller units (≤ 850 mmBtu/hr)

[24] EPA. Subpart Da—Standards of Performance for Electric Utility Steam Generating Units. *http://www.ecfr.gov/cgi-bin/text-idx?c=ecfr;sid=032e902341db8873af7fe153511e9f67;rgn=div6;view=text;node=40%3A7.0.1.1.1.10;idno=40;cc=ecfr*.
EPA. Subpart KKKK—Standards of Performance for Stationary Combustion Turbines. *http://www.ecfr.gov/cgi-bin/text-idx?c=ecfr;sid=86adad5cd90377b914f73235b8506ef6;rgn=div6;view=text;node=40%3A7.0.1.1.1.99;idno=40;cc=ecfr*.
[25] EPA. 2013. Standards of Performance for Greenhouse Gas Emissions from New Stationary Source: Electric Utility Generating Units. Proposed Rule. *http://www2.epa.gov/sites/production/files/2013-09/documents/20130920proposal.pdf*.
[26] EPA. 2013. 2013 Proposed Carbon Pollution Standard for New Power Plants. *http://www2.epa.gov/carbon-pollution-standards/2013-proposed-carbon-pollution-standard-new-power-plants*.
[27] EPA. 2013. Standards of Performance for Greenhouse Gas Emissions from New Stationary Source: Electric Utility Generating Units. Proposed Rule. *http://www2.epa.gov/sites/production/files/2013-09/documents/20130920proposal.pdf*.
[28] Ibid.

The public comment period for the proposed rule for new power plants ended on May 9, 2014. EPA has started the rulemaking process for *existing* power plants in compliance with Section 111(d) of the CAA; a proposed rule is planned by June 2, 2014, to be finalized by June 1, 2015, and states are to submit their implementation plans by June 30, 2016.

A unit-specific, output-based emission limit such as lb CO_2/MWh can be set for CHP, to recognize both electrical and thermal outputs. The equivalence approach has been applied in the existing boiler or turbine NSPS for NO_x and the ICI Boiler MACT and proposed for CO_2 under 111(b). However, the avoided emissions approach is another alternative.

B.5.6 Proposed NSPS for New Stationary EGUs, Section 111(b) of the CAA[29]

Standard

- Output-based—
  - Coal: 1,100 lb CO_2/MWh gross for coal (over a 12-month operating period), or 1,000–1,050 lb CO_2/MWh gross for coal (over an 84-month, seven-year operating period).
  - Gas: 1,000 lb CO_2/MWh gross for larger gas units (> 850 mmBtu/hr); 1,100 lb CO_2/MWh gross for smaller gas units ($\leq$ 850 mmBtu/hr).

Applicability

- In the proposed regulation, a "combined heat and power facility" (also known as "cogeneration") is an electric generating unit that that use a steam-generating unit or stationary combustion turbine to simultaneously produce both electric (or mechanical) and useful thermal energy from the same primary energy source.

- EPA proposes that CHP facilities meeting the general applicability criteria should be subject to the same requirements as electric-only generators. The proposed CO_2 standards of performance apply to a facility that supplies more than one-third of its potential electricity output and more than 219,000 MWh "net electric output" to the grid per year. The current definition of net electric output for purposes of criteria pollutants is "the gross electric sales to the utility power distribution system minus purchased power on a calendar year basis."

- Owners/operators of a CHP facility under common ownership with an adjacent facility using the thermal output from the CHP facility (i.e., the thermal host) may subtract power purchased by the adjacent facility on an annual basis when determining applicability. However, third-party CHP developers would not be able to benefit from the "minus purchased power on a calendar year basis" provision in the definition of net electric output when determining applicability, since the CHP facility and the thermal host(s) are not under common ownership.

Options for Codifying the Requirements

- EPA is considering two options—either proposing a new subpart TTTT to include the GHG standards of performance or codifying the standards in existing 40 CFR part 60 subparts Da (boilers) and KKKK (turbines).

[29] EPA. 2014. Proposed Rule. Standards of Performance for New GHG Emissions from New Stationary Sources: Electric Utility Generating Units. Proposed Rule. 79 FR 1430.

Credit for CHP

- CHP systems in which at least 20 percent of the total gross useful energy output consists of electric or direct mechanical output and 20 percent of the total gross useful energy output consists of useful thermal output, on a rolling three-calendar-year basis, are to receive similar credit as in subpart Da and proposed amendments to subpart KKKK (77 FR 52554).

- The electric output of a CHP system is to be credited at 95 percent (to account for a 5 percent transmission loss).

- The thermal output of a CHP system is to be credited at 75 percent based on an equivalence approach; thermal energy qualifies that is not used to generate additional electric or mechanical output or to enhance the performance of the unit (e.g., steam delivered to an industrial process for a heating application)

Additional information:
Mr. Christian Fellner
Energy Strategies Group
Sector Policies and Programs Division (D243-01)
U.S. EPA
Research Triangle Park, NC 27711
(919) 541-4003
http://www2.epa.gov/carbon-pollution-standards/2013-proposed-carbon-pollution-standard-new-power-plants

B.5.7 Boiler MACT Regulations

In December 2012, EPA finalized "National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters." This rule is commonly referred to as the "Boiler MACT." It impacts large boilers and process heaters at industrial, commercial, and institutional facilities that have the potential to emit 10 tons per year (tpy) or more of any single hazardous air pollutant (HAP), or a combination of such pollutants in excess of 25 tpy. The covered pollutants include CO (as a surrogate for organic HAP), hydrogen chloride, Hg, filterable PM, or total selected metals. Existing sources must comply with the standards by January 31, 2016; however, if needed, may request from their permitting authority an additional year to comply.

Under the rule, all boilers must follow work practice standards that include annual boiler tune-ups and a one-time energy assessment. These work practice standards complete the compliance obligation for natural-gas-fired boilers and existing small (<10 million Btu per hour heat input) coal- and oil-fired boilers; however, large coal and oil-fired boilers must meet the emission limits specified in the rule. The rule presents an opportunity for major source sites with coal- and oil-fired boilers to consider switching to natural gas, and subsequently to consider natural-gas-fired CHP,[30] instead of installing costly emission controls to comply with the rule. The compliance date for existing major sources is January 31, 2016; existing sources that install CHP can have until January 31, 2017 (sources may request an additional year to comply if they need the time to install controls or to repower; this includes the installation of CHP, waste heat recovery, or gas pipeline or fuel feeding infrastructure).

[30] *http://www.epa.gov/chp/documents/boiler_opportunity.pdf*.

The Boiler MACT has alternative output-based limits for all pollutants, and the thermal and electric output are used to calculate compliance. The output-based limits are an alternative “applicable only to boilers and process heaters that generate steam.” The limits are expressed in lb/MMBtu of steam output. “Steam output,” in the context of CHP, means “For a boiler that cogenerates process steam and electricity (also known as combined heat and power), the total energy output, which is the sum of the energy content of the steam exiting the turbine and sent to process in MMBtu and the energy of the electricity generated converted to MMBtu at a rate of 10,000 Btu per kilowatt-hour generated (10 MMBtu per megawatt-hour).”

Additional information:
Mr. Brian Shrager
Energy Strategies Group
Sector Policies and Programs Division
Office of Air Quality Planning and Standards
U.S. EPA
Research Triangle Park, NC 27711
(919) 541-7689
shrager.brian@epa.gov
http://www.epa.gov/ttn/atw/boiler/fr23de11major.pdf

B.6 New Source Review

NSR requires a case-by-case determination of BACT for new and modified emission sources. It is one of the most important components of environmental permitting. Although there has been significant interest in developing an output-based approach to NSR, such an approach has yet to be developed. Recently, NSR for combustion sources has been based on determination of the best add-on control, regardless of the baseline efficiency. Although EPA guidance (*New Source Review Workshop Manual, October 1990*) allows states to consider the baseline emission levels, most states have not done so. The manual states:

In many cases, a given production process or emissions unit can be made to be inherently less polluting (e.g., the use of water-based versus solvent-based paints in a coating operation or a coal-fired boiler designed to have a low emission factor for NO_x). In such cases, the ability of design considerations to make the process inherently less polluting must be considered as a control alternative for the source.

Permit levels resulting from NSR determinations could be expressed in output-based format rather than conventional input-based or concentration-based units. This would allow some consistency in measurement. However, it would not integrate efficiency into the actual determination of control requirements.

While there is continuing discussion of how to address this issue within the existing structure of NSR, one state, Connecticut, has directly addressed the possibility in its regulations. The state’s revised NSR regulation (22a-174-3a, effective March 15, 2002) specifically allows for BACT to be determined on an output basis, though it does not specify how it would be done.

Additional information:

Chris Nelson
Connecticut Department of Environmental Protection at Bureau of Air Management
79 Elm Street, 5th Floor
Hartford, CT 06106-5127
(860) 424-3454
http://www.ct.gov/deep/lib/deep/air/regulations/mainregs/sec3a.pdf