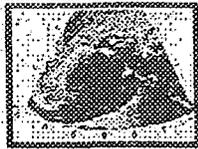


SMU Geothermal Lab



Heat Flow - A transfer of temperature

"Bringing The Earth's Energy Into Your Community"

	<p>2004 Surface Heat Flow Map: Heat flow is determined by multiplying the well temperature gradient times the thermal conductivity. In developing the contour map, areas where few heat flow data are available the contours were both computer and hand determined to match the regional and topographic configuration. This is the U.S. portion of the <u>Geothermal Map of North America, 2004</u>. In this context the words geothermal and heat flow are synonymous.</p> <p>Ranges in heat flow on this map vary from 25 to 150 mW/m^2. Note: mW = milliWatts and m = meters</p>
	<p>The Regional Heat Flow <u>data base</u> is a collection of published heat flow points prepared by David Blackwell et al. beginning in 1989 and continues to be updated. This work is completed for the Department of Energy (DOE).</p>
	<p>Alaska Surface Heat Flow: This map is an extension of the <u>Geothermal Map of North America, 2004</u>.</p>
	<p>1992 Surface Heat Flow Map: This map was part of the Geothermal Map of North America published in 1992 by the Geological Society of America (GSA) in conjunction with the GSA sponsored Decade of North American Geology (DNAG).</p> <p>Blackwell, D.D. and J.L. Steele, Geothermal Map of North America, Geol. Soc. Amer. DNAG Map No. 006, 1992.</p> <p>Blackwell, D.D., J.L. Steele and L.S. Carter, Heat flow patterns of the North American continent: A discussion of the DNAG geothermal map of North America, pp. 423-437, in D.B. Stenmoas, E.R. Engdahl, and D.D. Blackwell eds., <u>Neotectonics of North America</u>, Geol. Soc. Amer. DNAG Decade Map Volume 1, pp. 498, 1991.</p>
	<p>Detailed Western United States Heat Flow: Power plants, geothermal systems and springs are shown on this map with the regional provinces and heat flow contours for background. This information is currently being researched further by developing a detailed data base of geothermal area wells. See the <u>Geothermal Resources</u> page.</p>
	<p>Thermal Gradient: Conductivity divided into heat flow gives the mean thermal gradient. On a regional basis the gradient can vary from less than 15 to over 35°C/km. Within an individual well, gradients may vary up to 500% depending on the lithology.</p>
	<p>Temperature at 4km Depth: Using the Regional Heat Flow Database information, an evaluation and assessment of the deeper resources in the United States was completed down to 4 km depths. The deepest hole measured in the United States is approximately 9100 meters, although most wells are under 3100 meters. To determine the Earth's internal temperature at any depth below the capabilities of normal well drilling, multiple data sets</p>

G-344

	are synthesized. The data used for this figure are: thermal conductivity, thickness of sedimentary rock, geothermal gradient, heat flow and surface temperature. When sediments are less than 4 km deep, a constant basement thermal conductivity of 2.8W/m/K was used. The range of regional temperatures at 4 km is from less than 70 to over 150°C.
	Average Ground Water Temperature, Near Surface: This is a reproduction of the Map by T.E. Gass, in Geothermal Heat Pumps Geothermal Resources Council Bulletin 11(11), 3-8, 1982.
	Topography of United States

U.S. Regional Heat Flow Data Base: Detailed information on site location, well information, geology, and data, i.e., heat flow, temperature, temperature gradient, thermal conductivity, radioactive heat production, porosity, measurement comments, quality, etc. Not all sites contain information in each category. The data sets are saved using comma separated variables (*.csv) and can be easily brought into Microsoft Excel or any other spreadsheet program. There are usually three data files for each state or region. The first files were generated in 1989 for the data base creating the Decade of North America Geology (DNAG) Geothermal Map. The second set is from 1996 when the data base was officially updated for the Department of Energy. The third set is from 1999 when the Western U.S. High Temperature Geothermal data base was completed. As new data is received the files will continue to be updated. If you are aware of data that is missing or new data, please let Maria Richards know.

Related Publications:

Continental Heat Flow (3996kb pdf)

by Robert F. Roy, David D. Blackwell, and Edward R. Decker, in *The Nature of the Solid Earth*, Ed. E.C. Robertson, McGraw-Hill, New York, pp. 505-543, 1972.

Heat flow patterns of the North American continent: A discussion of the DNAG geothermal map of North America (115kb doc)

by Blackwell, D.D., J.L. Steele and L.S. Carter, in D.B. Stiemmons, E.R. Engdahl, and D.D. Blackwell eds. *Neotectonics of North America*, Geol. Soc. Amer. DNAG Decade Map Volume 1, pp. 423-437, 1991.

Thermal Structure of the Continental Crust (606kb pdf)

by David D. Blackwell, in *The Structure and Physical Properties of the Earth's Crust*, *Geophys. Mono. Ser.* 14, ed. J.G. Heacock, 169-184, AGU, Washington D.C., 1971.

Heat Flow in the Northern Basin and Range Province (204kb pdf)

by David D. Blackwell, in *The role of heat in the development of energy and mineral resources in the Northern Basin and Range province*, Geothermal Res. Council Sp. Rep. 13, 81-92, 1983.

Additional Data:

- USGS Great Basin Geothermal database
- The Global Heat Flow Database of the International Heat Flow Commission
- Geomatics Laboratory Energy and Geosciences Institute

Inflation Calculator

INFLATION ADJUSTMENT

WIND ENERGY

4-6 cents / kWh in 2000

\$4.00

in 2000

has the same buying power as

\$4.68

in 2006

= 4.7¢ / kWh in 2006

Calculate

[About this calculator](#)

Inflation Calculator

INFLATION ADJUSTMENT

WIND ENERGY

4-6 cents / kWh in 2000

\$6.00

in 2000

has the same buying power as

\$7.02

in 2006

= 7¢ / kWh in 2006

Calculate

[About this calculator](#)

Inflation Calculator

INFLATION ADJUSTMENT

PHOTOVOLTAIC CELLS

19.40 to 47.4 cents / kWh in 2003

\$ 19.40

in 2003

has the same buying power as

\$21.26

in 2006

Calculate

= 21.3 cents / kWh in 2006

[About this calculator](#)

Inflation Calculator

INFLATION ADJUSTMENT

PHOTOVOLTIC CELL

19.40 to 47.40 cents / kWh in 2003

\$ 47.40

in 2003

has the same buying power as

\$ 51.93

in 2006

= 51.9 cents / kWh in 2006

Calculate

[About this calculator](#)

Inflation Calculator

INFLATION ADJUSTMENT

SOLAR THERMAL UNIT

10.8 to 18.7 cents/kWh in 2003

\$ 10.80

in 2003

has the same buying power as

\$ 11.83

in 2006

= 11.8¢/kWh in 2006

Calculate

[About this calculator](#)

Inflation Calculator

INFLATION ADJUSTMENT

SOLAR THERMAL UNIT

19.8 to 18.7 cents/kWh in 2003

\$18.70

in 2003

has the same buying power as

\$20.49

in 2006

= 20.5 ¢/kWh in 2006

Calculate

[About this calculator](#)

Inflation Calculator

INFLATION ADJUSTMENT

Hydroelectric Power

4 to 14 cents per kWh in 2003

\$4.00

in 2003

has the same buying power as

\$4.38

in 2006

= 4.4 ¢/kWh in 2006

Calculate

[About this calculator](#)

Inflation Calculator

INFLATION ADJUSTMENT

Hydroelectric Power

4 to 14 cents per kWh in 2003

\$ 14.00

in 2003

has the same buying power as

\$15.34

in 2006

= 15.3 ¢/kWh in 2006

Calculate

[About this calculator](#)

Inflation Calculator

INFLATION ADJUSTMENT

BIOMASS GENERATOR

6.3 to 11.8 cents/kWh in 2003

\$6.30

in 2003

has the same buying power as

\$6.90

in 2006

= 6.9 ¢/kWh in 2006

Calculate

[About this calculator](#)

Inflation Calculator

INFLATION ADJUSTMENT

BIO MASS GENERATOR

6.3 to 11.8 cents/kWh in 2003

\$ 11.80

in 2003

has the same buying power as

\$ 12.93

in 2006

= 12.9 ¢/kWh in 2006

Calculate

[About this calculator](#)

Inflation Calculator

INFLATION ADJUSTMENT

Municipal Solid Waste Plant

\$ 2,500 - 4,600 dollars/kWh in 2003

\$2,500.00

in 2003

has the same buying power as

\$2,739.13

in 2006

= 2,740 \$/kWh in 2006

Calculate

[About this calculator](#)

Inflation Calculator

INFLATION ADJUSTMENT

MUNICIPAL SOLID WASTE PLANT

\$ 2500 - 4600 \$/KWH in 2002

\$ 4,600.00

in 2003

has the same buying power as

\$5,040.00

in 2006

= 5040 \$/KWH in 2006

Calculate

[About this calculator](#)

Inflation Calculator

INFLATION ADJUSTMENT

MUN. Solid Waste Generation

3.5 - 15.3 cents/kWh in 2003

\$3.50

in 2003

has the same buying power as

\$3.83

in 2006

= 3.8 ¢/kWh in 2006

Calculate

[About this calculator](#)

Inflation Calculator

INFLATION ADJUSTMENT

MUN. Solid Waste Generation

3.5 - 15.3 cents /kWh in 2003

\$ 15.30

in 2003

has the same buying power as

\$ 16.76

in 2006

= 16.8 ¢/kWh in 2006

Calculate

[About this calculator](#)

1.1 Bituminous And Subbituminous Coal Combustion

1.1.1 General

Coal is a complex combination of organic matter and inorganic mineral matter formed over eons from successive layers of fallen vegetation. Coals are classified by rank according to their progressive alteration in the natural metamorphosis from lignite to anthracite. Coal rank depends on the volatile matter, fixed carbon, inherent moisture, and oxygen, although no single parameter defines a rank. Typically, coal rank increases as the amount of fixed carbon increases and the amount of volatile matter and moisture decreases.

Bituminous coals are by far the largest group and are characterized as having lower fixed carbon and higher volatile matter than anthracite. The key distinguishing characteristics of bituminous coal are its relative volatile matter and sulfur content as well as its slagging and agglomerating characteristics. Subbituminous coals have higher moisture and volatile matter and lower sulfur content than bituminous coals and may be used as an alternative fuel in some boilers originally designed to burn bituminous coals.¹ Generally, bituminous coals have heating values of 10,500 to 14,000 British thermal units per pound (Btu/lb) on a wet, mineral-matter-free basis.² As mined, the heating values of typical U.S. bituminous coals range from 10,720 to 14,730 Btu/lb.³ The heating values of subbituminous coals range from 8,300 to 11,500 Btu/lb on a wet, mineral-matter-free basis², and from 9,420 to 10,130 Btu/lb on an as-mined basis.³ Formulae and tables for classifying coals are given in Reference 2.

1.1.2 Firing Practices⁴

Coal-fired boilers can be classified by type, fuel, and method of construction. Boiler types are identified by the heat transfer method (watertube, firetube, or cast iron), the arrangement of the heat transfer surfaces (horizontal or vertical, straight or bent tube), and the firing configuration (suspension, stoker, or fluidized bed). The most common heat transfer method for coal-fired boilers is the watertube method in which the hot combustion gases contact the outside of the heat transfer tubes, while the boiler water and steam are contained within the tubes.

Coal-fired watertube boilers include pulverized coal, cyclone, stoker, fluidized bed, and handfed units. In stoker-fired systems and most handfed units, the fuel is primarily burned on the bottom of the furnace or on a grate. In a fluidized bed combustor (FBC), the coal is introduced to a bed of either sorbent or inert material (usually sand) which is fluidized by an upward flow of air. In pulverized coal-fired (PC-fired) boilers, the fuel is pulverized to the consistency of talcum powder (i.e., at least 70 percent of the particles will pass through a 200-mesh sieve) and pneumatically injected through the burners into the furnace. Combustion in PC-fired units takes place almost entirely while the coal is suspended in the furnace volume. PC-fired boilers are classified as either dry bottom or wet bottom (also referred to as slag tap furnaces), depending on whether the ash is removed in a solid or molten state. In dry bottom furnaces, coals with high fusion temperatures are burned, resulting in dry ash. In wet bottom furnaces, coals with low fusion temperatures are used, resulting in molten ash or slag.

Depending upon the type and location of the burners and the direction of coal injection into the furnace, PC-fired boilers can also be classified into two different firing types, including wall, and tangential. Wall-fired boilers can be either single wall-fired, with burners on only one wall of the furnace firing horizontally, or opposed wall-fired, with burners mounted on two opposing walls. Tangential (or corner-fired) boilers have burners mounted in the corners of the furnace. The fuel and air are injected tangent to an imaginary circle in the plane of the boilers. Cyclone furnaces are often

categorized as PC-fired systems even though the coal is crushed to a maximum size of about 4-mesh. The coal is fed tangentially, with primary air, into a horizontal cylindrical furnace. Smaller coal particles are burned in suspension while larger particles adhere to the molten layer of slag on the combustion chamber wall. Cyclone boilers are high-temperature, wet-bottom type systems.

Stoker-fired systems account for the vast majority of coal-fired watertube boilers for industrial, commercial, and institutional applications. Most packaged stoker units designed for coal firing are small and can be divided into three groups: underfeed stokers, overfeed stokers, and spreader stokers. Underfeed stokers are generally either the horizontal-feed, side-ash-discharge type or the gravity-feed, rear-ash-discharge type. An overfeed stoker uses a moving grate assembly in which coal is fed from a hopper onto a continuous grate which conveys the fuel into the furnace. In a spreader stoker, mechanical or pneumatic feeders distribute coal uniformly over the surface of a moving grate. The injection of the fuel into the furnace and onto the grate combines suspension burning with a thin, fast-burning fuel bed. The amount of fuel burned in suspension depends primarily on fuel size and composition, and air flow velocity. Generally, fuels with finer size distributions, higher volatile matter contents, and lower moisture contents result in a greater percentage of combustion and corresponding heat release rates in suspension above the bed.

FBCs, while not constituting a significant percentage of the total boiler population, have nonetheless gained popularity in the last decade, and today generate steam for industries, cogenerators, independent power producers, and utilities. There are two major categories of FBC systems: (1) atmospheric, operating at or near ambient pressures, and (2) pressurized, operating from 4 to 30 atmospheres (60 to 450 pounds per square inch gauge). At this time, atmospheric FBCs are more advanced (or commercialized) than pressurized FBCs. The two principal types of atmospheric FBCs are bubbling bed and circulating bed. The feature that varies most fundamentally between these two types is the fluidization velocity. In the bubbling bed design, the fluidation velocity is relatively low in order to minimize solids carryover or elutriation from the combustor. Circulating FBCs, however, employ high fluidization velocities to promote the carryover or circulation of the solids. High-temperature cyclones are used in circulating FBCs and in some bubbling FBCs to capture the solid fuel and bed material for return to the primary combustion chamber. The circulating FBC maintains a continuous, high-volume recycle rate which increases the residence time compared to the bubbling bed design. Because of this feature, circulating FBCs often achieve higher combustion efficiencies and better sorbent utilization than bubbling bed units.

Small, coal-fired boilers and furnaces are found in industrial, commercial, institutional, or residential applications and are sometimes capable of being hand-fired. The most common types of firetube boilers used with coal are the horizontal return tubular (HRT), Scotch, vertical, and the firebox. Cast iron boilers are also sometimes available as coal-fired units in a handfed configuration. The HRT boilers are generally fired with gas or oil instead of coal. The boiler and furnace are contained in the same shell in a Scotch or shell boiler. Vertical firetube boilers are typically small singlepass units in which the firetubes come straight up from the water-cooled combustion chamber located at the bottom of the unit. A firebox boiler is constructed with an internal steel-encased, water-jacketed firebox. Firebox firetube boilers are also referred to as locomotive, short firebox, and compact firebox boilers and employ mechanical stokers or are hand-fired.

1.1.3 Emissions⁴

Emissions from coal combustion depend on the rank and composition of the fuel, the type and size of the boiler, firing conditions, load, type of control technologies, and the level of equipment maintenance. The major pollutants of concern from bituminous and subbituminous coal combustion are particulate matter (PM), sulfur oxides (SO_x), and nitrogen oxides (NO_x). Some unburned combustibles, including carbon monoxide (CO) and numerous organic compounds, are generally emitted even under proper boiler operating conditions.

1.1.3.1 Particulate Matter⁴ -

PM composition and emission levels are a complex function of boiler firing configuration, boiler operation, pollution control equipment, and coal properties. Uncontrolled PM emissions from coal-fired boilers include the ash from combustion of the fuel as well as unburned carbon resulting from incomplete combustion. In pulverized coal systems, combustion is almost complete; thus, the emitted PM is primarily composed of inorganic ash residues.

Coal ash may either settle out in the boiler (bottom ash) or entrained in the flue gas (fly ash). The distribution of ash between the bottom ash and fly ash fractions directly affects the PM emission rate and depends on the boiler firing method and furnace type (wet or dry bottom). Boiler load also affects the PM emissions as decreasing load tends to reduce PM emissions. However, the magnitude of the reduction varies considerably depending on boiler type, fuel, and boiler operation.

Soot blowing is also a source of intermittent PM emissions in coal-fired boilers. Steam soot and air soot blowing is periodically used to dislodge ash from heat transfer surfaces in the furnace, convective section, economizer, and air preheater.

Particulate emissions may be categorized as either filterable or condensable. Filterable emissions are generally considered to be the particles that are trapped by the glass fiber filter in the front half of a Reference Method 5 or Method 17 sampling train. Vapors and particles less than 0.3 microns pass through the filter. Condensable particulate matter is material that is emitted in the vapor state which later condenses to form homogeneous and/or heterogeneous aerosol particles. The condensable particulate emitted from boilers fueled on coal or oil is primarily inorganic in nature.

1.1.3.2 Sulfur Oxides⁴ -

Gaseous SO_x from coal combustion are primarily sulfur dioxide (SO₂), with a much lower quantity of sulfur trioxide (SO₃) and gaseous sulfates. These compounds form as the organic and pyritic sulfur in the coal are oxidized during the combustion process. On average, about 95 percent of the sulfur present in bituminous coal will be emitted as gaseous SO_x, whereas somewhat less will be emitted when subbituminous coal is fired. The more alkaline nature of the ash in some subbituminous coals causes some of the sulfur to react in the furnace to form various sulfate salts that are retained in the boiler or in the flyash.

1.1.3.3 Nitrogen Oxides⁵⁻⁶ -

NO_x emissions from coal combustion are primarily nitric oxide (NO), with only a few volume percent as nitrogen dioxide (NO₂). Nitrous oxide (N₂O) is also emitted at a few parts per million. NO_x formation results from thermal fixation of atmospheric nitrogen in the combustion flame and from oxidation of nitrogen bound in the coal. Experimental measurements of thermal NO_x formation have shown that the NO_x concentration is exponentially dependent on temperature and is proportional to nitrogen concentration in the flame, the square root of oxygen concentration in the flame, and the gas residence time.⁷ Cyclone boilers typically have high conversion of nitrogen to NO_x. Typically, only 20 to 60 percent of the fuel nitrogen is converted to NO_x. Bituminous and subbituminous coals usually

contain from 0.5 to 2 weight percent nitrogen, mainly present in aromatic ring structures. Fuel nitrogen can account for up to 80 percent of total NO_x from coal combustion.

1.1.3.4 Carbon Monoxide -

The rate of CO emissions from combustion sources depends on the fuel oxidation efficiency of the source. By controlling the combustion process carefully, CO emissions can be minimized. Thus, if a unit is operated improperly or is not well-maintained, the resulting concentrations of CO (as well as organic compounds) may increase by several orders of magnitude. Smaller boilers, heaters, and furnaces typically emit more CO and organics than larger combustors. This is because smaller units usually have less high-temperature residence time and, therefore, less time to achieve complete combustion than larger combustors. Combustion modification techniques and equipment used to reduce NO_x can increase CO emissions if the modification techniques are improperly implemented or if the equipment is improperly designed.

1.1.3.5 Organic Compounds -

As with CO emissions, the rate at which organic compounds are emitted depends on the combustion efficiency of the boiler. Therefore, combustion modifications that change combustion residence time, temperature, or turbulence may increase or decrease concentrations of organic compounds in the flue gas.

Organic emissions include volatile, semivolatile, and condensable organic compounds either present in the coal or formed as a product of incomplete combustion (PIC). Organic emissions are primarily characterized by the criteria pollutant class of unburned vapor-phase hydrocarbons. These emissions include alkanes, alkenes, aldehydes, alcohols, and substituted benzenes (e.g., benzene, toluene, xylene, and ethyl benzene).^{8,9}

Emissions of polychlorinated dibenzo-p-dioxins and polychlorinated dibenzofurans (PCDD/PCDF) also result from the combustion of coal. Of primary interest environmentally are tetrachloro- through octachloro- dioxins and furans. Dioxin and furan emissions are influenced by the extent of destruction of organics during combustion and through reactions in the air pollution control equipment. The formation of PCDD/PCDF in air pollution control equipment is primarily dependent on flue gas temperature, with maximum potential for formation occurring at flue gas temperatures of 450 degrees to 650 degrees Fahrenheit.

The remaining organic emissions are composed largely of compounds emitted from combustion sources in a condensed phase. These compounds can almost exclusively be classed into a group known as polycyclic organic matter (POM), and a subset of compounds called polynuclear aromatic hydrocarbons (PNA or PAH). Polycyclic organic matter is more prevalent in the emissions from coal combustion because of the more complex structure of coal.

1.1.3.6 Trace Metals-

Trace metals are also emitted during coal combustion. The quantity of any given metal emitted, in general, depends on:

- the physical and chemical properties of the metal itself;
- the concentration of the metal in the coal;
- the combustion conditions; and

- the type of particulate control device used, and its collection efficiency as a function of particle size.

Some trace metals become concentrated in certain particle streams from a combustor (e.g., bottom ash, collector ash, and flue gas particulate) while others do not.¹⁰ Various classification schemes have been developed to describe this partitioning behavior.¹⁰⁻¹² These classification schemes generally distinguish between:

- Class 1: Elements that are approximately equally concentrated in the fly ash and bottom ash, or show little or no small particle enrichment. Examples include manganese, beryllium, cobalt, and chromium.
- Class 2: Elements that are enriched in fly ash relative to bottom ash, or show increasing enrichment with decreasing particle size. Examples include arsenic, cadmium, lead, and antimony.
- Class 3: Elements which are emitted in the gas phase (primarily mercury and, in some cases, selenium).

Control of Class 1 metals is directly related to control of total particulate matter emissions, while control of Class 2 metals depends on collection of fine particulate. Because of variability in particulate control device efficiencies, emission rates of these metals can vary substantially. Because of the volatility of Class 3 metals, particulate controls have only a limited impact on emissions of these metals.

1.1.3.7 Acid Gases-

In addition to SO₂ and NO_x emissions, combustion of coal also results in emissions of chlorine and fluorine, primarily in the form of hydrogen chloride (HCl) and hydrogen fluoride (HF). Lesser amounts of chlorine gas and fluorine gas are also emitted. A portion of the chlorine and fluorine in the fuel may be absorbed onto fly ash or bottom ash. Both HCl and HF are water soluble and are readily controlled by acid gas scrubbing systems.

1.1.3.8 Fugitive Emissions -

Fugitive emissions are defined as pollutants which escape from an industrial process due to leakage, materials handling, inadequate operational control, transfer, or storage. The fly ash handling operations in most modern utility and industrial combustion sources consist of pneumatic systems or enclosed and hooded systems which are vented through small fabric filters or other dust control devices. The fugitive PM emissions from these systems are therefore minimal. Fugitive particulate emissions can sometimes occur during fly ash transfer operations from silos to trucks or rail cars.

1.1.3.9 Greenhouse Gases¹³⁻¹⁸ -

Carbon dioxide (CO₂), methane (CH₄), and nitrous oxide (N₂O) emissions are all produced during coal combustion. Nearly all of the fuel carbon (99 percent) in coal is converted to CO₂ during the combustion process. This conversion is relatively independent of firing configuration. Although the formation of CO acts to reduce CO₂ emissions, the amount of CO produced is insignificant compared to the amount of CO₂ produced. The majority of the fuel carbon not converted to CO₂ is entrained in bottom ash. CO₂ emissions for coal vary with carbon content, and carbon content varies between the classes of bituminous and subbituminous coals. Further, carbon content also varies within each class of coal based on the geographical location of the mine.

Formation of N₂O during the combustion process is governed by a complex series of reactions and its formation is dependent upon many factors. Formation of N₂O is minimized when combustion

temperatures are kept high (above 1575°F) and excess air is kept to a minimum (less than 1 percent). N₂O emissions for coal combustion are not significant except for fluidized bed combustion (FBC), where the emissions are typically two orders of magnitude higher than all other types of coal firing due to areas of low temperature combustion in the fuel bed.

Methane emissions vary with the type of coal being fired and firing configuration, but are highest during periods of incomplete combustion, such as the start-up or shut-down cycle for coal-fired boilers. Typically, conditions that favor formation of N₂O also favor emissions of CH₄.

1.1.4 Controls⁴

Control techniques for criteria pollutants from coal combustion may be classified into three broad categories: fuel treatment/substitution, combustion modification, and postcombustion control. Emissions of noncriteria pollutants such as particulate phase metals have been controlled through the use of post combustion controls designed for criteria pollutants. Fuel treatment primarily reduces SO₂ and includes coal cleaning using physical, chemical, or biological processes; fuel substitution involves burning a cleaner fuel. Combustion modification includes any physical or operational change in the furnace or boiler and is applied primarily for NO_x control purposes, although for small units, some reduction in PM emissions may be available through improved combustion practice. Postcombustion control employs a device after the combustion of the fuel and is applied to control emissions of PM, SO₂, and NO_x for coal combustion.

1.1.4.1 Particulate Matter Control⁴ -

The principal control techniques for PM are combustion modifications (applicable to small stoker-fired boilers) and postcombustion methods (applicable to most boiler types and sizes). Uncontrolled PM emissions from small stoker-fired and hand-feed combustion sources can be minimized by employing good combustion practices such as operating within the recommended load ranges, controlling the rate of load changes, and ensuring steady, uniform fuel feed. Proper design and operation of the combustion air delivery systems can also minimize PM emissions. The postcombustion control of PM emissions from coal-fired combustion sources can be accomplished by using one or more of the following particulate control devices:

- Electrostatic precipitator (ESP),
- Fabric filter (or baghouse),
- Wet scrubber,
- Cyclone or multiclone collector, or
- Side stream separator.

Electrostatic precipitation technology is applicable to a variety of coal combustion sources. Because of their modular design, ESPs can be applied to a wide range of system sizes and should have no adverse effect on combustion system performance. The operating parameters that influence ESP performance include fly ash mass loading, particle size distribution, fly ash electrical resistivity, and precipitator voltage and current. Other factors that determine ESP collection efficiency are collection plate area, gas flow velocity, and cleaning cycle. Data for ESPs applied to coal-fired sources show fractional collection efficiencies greater than 99 percent for fine (less than 0.1 micrometer) and coarse particles (greater than 10 micrometers). These data show a reduction in collection efficiency for particle diameters between 0.1 and 10 micrometers.

Fabric filtration has been widely applied to coal combustion sources since the early 1970s and consists of a number of filtering elements (bags) along with a bag cleaning system contained in a main shell structure incorporating dust hoppers. The particulate removal efficiency of fabric filters is

dependent on a variety of particle and operational characteristics. Particle characteristics that affect the collection efficiency include particle size distribution, particle cohesion characteristics, and particle electrical resistivity. Operational parameters that affect fabric filter collection efficiency include air-to-cloth ratio, operating pressure loss, cleaning sequence, interval between cleanings, cleaning method, and cleaning intensity. In addition, the particle collection efficiency and size distribution can be affected by certain fabric properties (e. g., structure of fabric, fiber composition, and bag properties). Collection efficiencies of fabric filters can be as high as 99.9 percent.

Wet scrubbers, including venturi and flooded disc scrubbers, tray or tower units, turbulent contact absorbers, or high-pressure spray impingement scrubbers are applicable for PM as well as SO₂ control on coal-fired combustion sources. Scrubber collection efficiency depends on particle size distribution, gas side pressure drop through the scrubber, and water (or scrubbing liquor) pressure, and can range between 95 and 99 percent for a 2-micron particle.

Cyclone separators can be installed singly, in series, or grouped as in a multicyclone or multicclone collector. These devices are referred to as mechanical collectors and are often used as a precollector upstream of an ESP, fabric filter, or wet scrubber so that these devices can be specified for lower particle loadings to reduce capital and/or operating costs. The collection efficiency of a mechanical collector depends strongly on the effective aerodynamic particle diameter. Although these devices will reduce PM emissions from coal combustion, they are relatively ineffective for collection of particles less than 10 micron (PM-10). The typical overall collection efficiency for mechanical collectors ranges from 90 to 95 percent.

The side-stream separator combines a multicyclone and a small pulse-jet baghouse to more efficiently collect small-diameter particles that are difficult to capture by a mechanical collector alone. Most applications to date for side-stream separators have been on small stoker boilers.

Atmospheric fluidized bed combustion (AFBC) boilers may tax conventional particulate control systems. The particulate mass concentration exiting AFBC boilers is typically 2 to 4 times higher than pulverized coal boilers. AFBC particles are also, on average, smaller in size, and irregularly shaped with higher surface area and porosity relative to pulverized coal ashes. The effect is a higher pressure drop. The AFBC ash is more difficult to collect in ESPs than pulverized coal ash because AFBC ash has a higher electrical resistivity and the use of multiclones for recycling, inherent with the AFBC process, tends to reduce exit gas stream particulate size.

1.1.4.2 Sulfur Oxides Control⁴ -

Several techniques are used to reduce SO_x emissions from coal combustion. Table 1.1-1 presents the techniques most frequently used. One way is to switch to lower sulfur coals, since SO_x emissions are proportional to the sulfur content of the coal. This alternative may not be possible where lower sulfur coal is not readily available or where a different grade of coal cannot be satisfactorily fired. In some cases, various coal cleaning processes may be employed to reduce the fuel sulfur content. Physical coal cleaning removes mineral sulfur such as pyrite but is not effective in removing organic sulfur. Chemical cleaning and solvent refining processes are being developed to remove organic sulfur.

Post combustion flue gas desulfurization (FGD) techniques can remove SO₂ formed during combustion by using an alkaline reagent to absorb SO₂ in the flue gas. Flue gases can be treated using wet, dry, or semi-dry desulfurization processes of either the throwaway type (in which all waste streams are discarded) or the recovery/regenerable type (in which the SO₂ absorbent is regenerated and reused). To date, wet systems are the most commonly applied. Wet systems generally use alkali slurries as the SO₂ absorbent medium and can be designed to remove greater than 90 percent of the incoming SO₂. Lime/limestone scrubbers, sodium scrubbers, and dual alkali scrubbers are among the commercially

proven wet FGD systems. The effectiveness of these devices depends not only on control device design but also on operating variables. Particulate reduction of more than 99 percent is possible with wet scrubbers, but fly ash is often collected by upstream ESPs or baghouses, to avoid erosion of the desulfurization equipment and possible interference with FGD process reactions.¹⁸ Also, the volume of scrubber sludge is reduced with separate fly ash removal, and contamination of the reagents and by-products is prevented.

The lime and limestone wet scrubbing process uses a slurry of calcium oxide or limestone to absorb SO₂ in a wet scrubber. Control efficiencies in excess of 91 percent for lime and 94 percent for limestone over extended periods are possible. Sodium scrubbing processes generally employ a wet scrubbing solution of sodium hydroxide or sodium carbonate to absorb SO₂ from the flue gas. Sodium scrubbers are generally limited to smaller sources because of high reagent costs and can have SO₂ removal efficiencies of up to 96.2 percent. The double or dual alkali system uses a clear sodium alkali solution for SO₂ removal followed by a regeneration step using lime or limestone to recover the sodium alkali and produce a calcium sulfite and sulfate sludge. SO₂ removal efficiencies of 90 to 96 percent are possible.

1.1.4.3 Nitrogen Oxide Controls⁴ -

Several techniques are used to reduce NO_x emissions from coal combustion. These techniques are summarized in Table 1.1-2. The primary techniques can be classified into one of two fundamentally different methods—combustion controls and postcombustion controls. Combustion controls reduce NO_x by suppressing NO_x formation during the combustion process, while postcombustion controls reduce NO_x emission after their formation. Combustion controls are the most widely used method of controlling NO_x formation in all types of boilers and include low excess air (LEA), burners out of service (BOOS), biased burner firing, overfire air (OFA), low NO_x burners (LNBs), and reburn. Postcombustion control methods are selective noncatalytic reduction (SNCR) and selective catalytic reduction (SCR). Combustion and postcombustion controls can be used separately or combined to achieve greater NO_x reduction from fluidized bed combustors in boilers.

Operating at LEA involves reducing the amount of combustion air to the lowest possible level while maintaining efficient and environmentally compliant boiler operation. NO_x formation is inhibited because less oxygen is available in the combustion zone. BOOS involves withholding fuel flow to all or part of the top row of burners so that only air is allowed to pass through. This method simulates air staging, or OFA conditions, and limits NO_x formation by lowering the oxygen level in the burner area. Biased burner firing involves more fuel-rich firing in the lower rows of burners than in the upper row of burners. This method provides a form of air staging and limits NO_x formation by limiting the amount of oxygen in the firing zone. These methods may change the normal operation of the boiler and the effectiveness is boiler-specific. Implementation of these techniques may also reduce operational flexibility; however, they may reduce NO_x by 10 to 20 percent from uncontrolled levels.

OFA is a technique in which a percentage of the total combustion air is diverted from the burners and injected through ports above the top burner level. OFA limits NO_x by (1) suppressing thermal NO_x by partially delaying and extending the combustion process resulting in less intense combustion and cooler flame temperatures and (2) suppressing fuel NO_x formation by reducing the concentration of air in the combustion zone where volatile fuel nitrogen is evolved. OFA can be applied for various boiler types including tangential and wall-fired, turbo, and stoker boilers and can reduce NO_x by 20 to 30 percent from uncontrolled levels.

LNBs limit NO_x formation by controlling the stoichiometric and temperature profiles of the combustion process in each burner zone. The unique design of features of an LNB may create (1) a reduced oxygen level in the combustion zone to limit fuel NO_x formation, (2) a reduced flame

temperature that limits thermal NO_x formation, and/or (3) a reduced residence time at peak temperature which also limits thermal NO_x formation.

LNBS are applicable to tangential and wall-fired boilers of various sizes but are not applicable to other boiler types such as cyclone furnaces or stokers. They have been used as a retrofit NO_x control for existing boilers and can achieve approximately 35 to 55 percent reduction from uncontrolled levels. They are also used in new boilers to meet New Source Performance Standards (NSPS) limits. LNBS can be combined with OFA to achieve even greater NO_x reduction (40 to 60 percent reduction from uncontrolled levels).

Reburn is a combustion hardware modification in which the NO_x produced in the main combustion zone is reduced in a second combustion zone downstream. This technique involves withholding up to 40 percent (at full load) of the heat input to the main combustion zone and introducing that heat input above the top row of burners to create a reburn zone. Reburn fuel (natural gas, oil, or pulverized coal) is injected with either air or flue gas to create a fuel-rich zone that reduces the NO_x created in the main combustion zone to nitrogen and water vapor. The fuel-rich combustion gases from the reburn zone are completely combusted by injecting overfire air above the reburn zone. Reburn may be applicable to many boiler types firing coal as the primary fuel, including tangential, wall-fired, and cyclone boilers. However, the application and effectiveness are site-specific because each boiler is originally designed to achieve specific steam conditions and capacity which may be altered due to reburn. Commercial experience is limited; however, this limited experience does indicate NO_x reduction of 50 to 60 percent from uncontrolled levels may be achieved.

SNCR is a postcombustion technique that involves injecting ammonia (NH_3) or urea into specific temperature zones in the upper furnace or convective pass. The ammonia or urea reacts with NO_x in the flue gas to produce nitrogen and water. The effectiveness of SNCR depends on the temperature where reagents are injected; mixing of the reagent in the flue gas; residence time of the reagent within the required temperature window; ratio of reagent to NO_x ; and the sulfur content of the fuel that may create sulfur compounds that deposit in downstream equipment. There is not as much commercial experience to base effectiveness on a wide range of boiler types; however, in limited applications, NO_x reductions of 25 to 40 percent have been achieved.

SCR is another postcombustion technique that involves injecting NH_3 into the flue gas in the presence of a catalyst to reduce NO_x to nitrogen and then water. The SCR reactor can be located at various positions in the process including before an air heater and particulate control device, or downstream of the air heater, particulate control device, and flue gas desulfurization systems. The performance of SCR is influenced by flue gas temperature, fuel sulfur content, ammonia-to- NO_x ratio, inlet NO_x concentration, space velocity, and catalyst condition. Although there is currently very limited application of SCR in the U.S. on coal-fired boilers, NO_x reductions of 75 to 86 percent have been realized on a few pilot systems.

1.1.5 Emission Factors

Emission factors for SO_x , NO_x , and CO are presented in Table 1.1-3. Tables in this section present emission factors on both a weight basis (lb/ton) and an energy basis (lb/Btu). To convert from lb/ton to lb/MMBtu, divide by a heating value of 26.0 MMBtu/ton. Because of the inherently low NO_x emission characteristics of FBCs and the potential for in-bed SO_2 capture by calcium-based sorbents, uncontrolled emission factors for this source category were not developed in the same sense as with other source categories. For NO_x emissions, the data collected from test reports were considered to be baseline (uncontrolled) if no additional add-on NO_x control system (such as ammonia injection) was operated.

For SO₂ emissions, a correlation was developed from reported data on FBCs to relate SO₂ emissions to the coal sulfur content and the calcium-to-sulfur ratio in the bed.

Filterable particulate matter and particulate matter less than, or equal to, 10 micrometers in diameter (PM-10) emission factors are presented in Table 1.1-4. Condensable particulate matter emission factors are presented in Table 1.1.5. Cumulative particle size distributions and particulate size-specific emission factors are given in Tables 1.1-6, 1.1-7, 1.1-8, 1.1-9, 1.1-10, and 1.1-11. Particulate size-specific emission factors are also presented graphically in Figures 1.1-1, 1.1-2, 1.1-3, 1.1-4, 1.1-5, and 1.1-6.

Controlled emission factors for PCDD/PCDF and PAHs are provided in Tables 1.1-12 and 1.1-13, respectively. Controlled emission factors for other organic compounds are presented in Table 1.1-14. Emission factors for hydrogen chloride and hydrogen fluoride are presented in Table 1.1-15.

Table 1.1-16 presents emission factor equations for nine trace metals from controlled and uncontrolled boilers. Table 1.1-17 presents uncontrolled emission factors for seven of the same metals, along with mercury, POM and formaldehyde. Table 1.1-18 presents controlled emission factors for 13 trace metals and includes the metals found in Tables 1.1-16 and 1.1-17. The emission factor equations in Table 1.1-16 are based on statistical correlations among measured trace element concentrations in coal, measured fractions of ash in coal, and measured particulate matter emission factors. Because these are the major parameters affecting trace metals emissions from coal combustion, it is recommended that the emission factor equations be used when the inputs to the equations are available. If the inputs to the emission factor equations are not available for a pollutant, then the emission factors provided in Table 1.1-17 and 1.1-18 for the pollutant should be used.

Greenhouse gas emission factors, including CH₄, non-methane organic compounds (NMOC), and N₂O are provided in Table 1.1-19. In addition, Table 1.1-20 provides emission factors for CO₂.

1.1.6 Updates Since the Fifth Edition

The Fifth Edition was released in January 1995. Revisions to this section since that date are summarized below. For further detail, consult the memoranda describing each supplement or the background report for this section. These and other documents can be found on the CHIEF home page (<http://www.epa.gov/ttn/chief/>).

Supplement A, February 1996

- SCC's were corrected from 1-01-002-17, 1-02-002-17, and 1-03-002-17, to 1-01-002-18, 1-02-002-18, and 1-03-002-18 in the tables with SO_x, NO_x, CO, and PM/PM10 emission factors.
- For SO_x factors, clarifications were added to the table footnotes to clarify that "S" is a weight percent and not a fraction. Similar clarification was added to the footnote for the CO₂ factor.
- For fluidized bed combustors (bubbling bed and circulating bed), the PM10 factors were replaced with footnote "m." The revised footnote "m" directs the user to the emission factor for spreader stoker with multiple cyclones and no flyash reinjection.
- In the table with filterable PM factors, the misspelling of "filterable" was corrected.
- In the cumulative particle size distribution table, text was added to the table footnotes to clarify that "A" is a weight percent and not a fraction.
- In the cumulative particle size distribution for spreader stokers, all of the factors were corrected.
- The N₂O emission factor for bubbling bed was changed from 5.9 lb/ton to 5.5 lb/ton.

Supplement B, October 1996

- Text was added concerning coal rank/classification, firing practices, emissions, and controls.
- The table for NO_x control technologies was revised to include controls for all types of coal-fired boilers.
- SO_x, NO_x, and CO emission factors were added for cell burners.
- The PM table was revised to recommend using spreader stoker PM factors for FBC units.
- Tables were added for new emission factors for polychlorinated toxics, polynuclear aromatics, organic toxics, acid gas toxics, trace metal toxics, and controlled toxics.
- N₂O emission factors were added.
- Default CO₂ emission factors were added.

Supplement E, September 1998

- The term "Filterable" was added to the PM-10 column heading of Table 1.1-4.

- Reference to condensable particulate matter was deleted from footnote b of Table 1.1-4.
- Emission factors for condensable particulate matter were added (Table 1.1-5).
- Table 1.1-7 was revised to correct a typographical errors in the ESP column.
- The zeros in Table 1.1-8 appeared to be in error. Engineering judgement was used to determine a conservative estimate.
- NO_x emission factors were updated based on data from the Acid Rain program.

Table 1.1-1. POSTCOMBUSTION SO₂ CONTROLS FOR COAL COMBUSTION SOURCES

Control Technology	Process	Typical Control Efficiencies	Remarks
Wet scrubber	Lime/limestone	80 - 95+%	Applicable to high sulfur fuels, wet sludge product
	Sodium carbonate	80 - 98%	5-430 million Btu/hr typical application range, high reagent costs
	Magnesium oxide/hydroxide	80 - 95+%	Can be regenerated
	Dual alkali	90 - 96%	Uses lime to regenerate sodium-based scrubbing liquor
Spray drying	Calcium hydroxide slurry, vaporizes in spray vessel	70 - 90%	Applicable to low and medium sulfur fuels, produces dry product
Furnace injection	Dry calcium carbonate/hydrate injection in upper furnace cavity	25 - 50%	Commercialized in Europe, several U. S. demonstration projects are completed
Duct injection	Dry sorbent injection into duct, sometimes combined with water spray	25 - 50+%	Several research and development, and demonstration projects underway, not yet commercially available in the United States.

Table 1.1-2. NO_x CONTROL OPTIONS FOR COAL-FIRED BOILERS^a

Control Technique	Description of Technique	Applicable Boiler Designs	NO _x Reduction Potential ^b (%)	Commercial Availability/R & D Status	Comments
Combustion Modifications					
Load reduction	Reduction of coal and air	Stokers	Minimal	Available	Applicable to stokers that can reduce load without increasing excess air; may cause reduction in boiler efficiency; NO _x reduction varies with percent load reduction.
Operational modifications (BOOS, LEA, BF, or combination)	Rearrangement of air or fuel in the main combustion zone	Pulverized coal boilers (some designs); Stokers (LEA only)	10 - 20	Available	Must have sufficient operational flexibility to achieve NO _x reduction potential without sacrificing boiler performance.
Overfire Air	Injection of air above main combustion zone	Pulverized coal boilers and stokers	20 - 30	Available	Must have sufficient furnace height above top row of burners in order to retrofit this technology to existing boilers.
Low NO _x Burners	New burner designs controlling air-fuel mixing	Pulverized coal boilers	35 - 55	Available	Available in new boiler designs and can be retrofit in existing boilers.
LNB with OFA	Combination of new burner designs and injection of air above main combustion zone	Pulverized coal boilers	40 - 60	Available	Available in new boiler designs and can be retrofit in existing boilers with sufficient furnace height above top row of burners.
Reburn	Injection of reburn fuel and completion air above main combustion zone	Pulverized coal boilers, cyclone furnaces	50 - 60	Commercially available but not widely demonstrated	Reburn fuel can be natural gas, fuel oil, or pulverized coal. Must have sufficient furnace height to retrofit this technology to existing boilers.

Table 1.1-2 (cont.).

Control Technique	Description of Technique	Applicable Boiler Designs	NO _x Reduction Potential ^b (%)	Commercial Availability/R & D Status	Comments
Post-Combustion Modifications					
SNCR	Injection of NH ₃ or urea in the convective pass	Pulverized coal boilers, cyclone furnaces, stokers, and fluidized bed boilers	30 - 60	Commercially available but not widely demonstrated	Applicable to new boilers or as a retrofit technology; must have sufficient residence time at correct temperature (1,750°±90°F); elaborate reagent injection system; possible load restrictions on boiler; and possible air preheater fouling by ammonium bisulfate.
SCR	Injection of NH ₃ in combination with catalyst material	Pulverized coal boilers, cyclone furnaces	75 - 85	Commercially offered, but not yet demonstrated	Applicable to new boilers or as a retrofit technology provided there is sufficient space; hot-side SCR best on low-sulfur fuel and low fly ash applications; cold-side SCR can be used on high-sulfur/high-ash applications if equipped with an upstream FGD system.
LNB with SNCR	Combination of new burner designs and injection of NH ₃ or urea	Pulverized coal boilers	50-80	Commercially offered, but not widely demonstrated as a combined technology	Same as LNB and SNCR alone.
LNB with OFA and SCR	Combination of new burner design, injection of air above combustion zone, and injection of NH ₃ or urea	Pulverized coal boiler	85-95	Commercially offered, but not widely demonstrated as a combined technology	Same as LNB, OFA, and SCR alone.

^a References 20-21.

^b NO_x reduction potential from uncontrolled levels.

Table 1.1-3. EMISSION FACTORS FOR SO_x, NO_x, AND CO
FROM BITUMINOUS AND SUBBITUMINOUS COAL COMBUSTION^a

Firing Configuration	SCC	SO _x ^b		NO _x ^c		CO ^{d,e}	
		Emission Factor (lb/ton)	EMISSION FACTOR RATING	Emission Factor (lb/ton)	EMISSION FACTOR RATING	Emission Factor (lb/ton)	EMISSION FACTOR RATING
PC, dry bottom, wall-fired ^f , bituminous Pre-NSPS ^g	1-01-002-02	38S	A	22	A	0.5	A
	1-02-002-02						
	1-03-002-06						
PC, dry bottom, wall-fired ^f , bituminous Pre-NSPS ^g with low-NO _x burner	1-01-002-02	38S	A	11	A	0.5	A
	1-02-002-02						
	1-03-002-06						
PC, dry bottom, wall-fired ^f , bituminous NSPS ^g	1-01-002-02	38S	A	12	A	0.5	A
	1-02-002-02						
	1-03-002-06						
PC, dry bottom, wall-fired ^f , sub-bituminous Pre-NSPS ^g	1-01-002-22	35S	A	12	C	0.5	A
	1-02-002-22						
	1-03-002-22						
PC, dry bottom, wall-fired ^f , sub-bituminous NSPS ^g	1-01-002-22	35S	A	7.4	A	0.5	A
	1-02-002-22						
	1-03-002-22						
PC, dry bottom, cell burner ^h fired, bituminous	1-01-002-15	38S	A	31	A	0.5	A
PC, dry bottom, cell burner fired, sub-bituminous	1-01-002-35	35S	A	14	E	0.5	A

Table 1.1-3 (cont.).

Firing Configuration	SCC	SO _x ^b		NO _x ^c		CO ^{d,e}	
		Emission Factor (lb/ton)	EMISSION FACTOR RATING	Emission Factor (lb/ton)	EMISSION FACTOR RATING	Emission Factor (lb/ton)	EMISSION FACTOR RATING
PC, dry bottom, tangentially fired, bituminous, Pre-NSPS ^g	1-01-002-12 1-02-002-12 1-03-002-16	38S	A	15	A	0.5	A
PC, dry bottom, tangentially fired, bituminous, Pre-NSPS ^g with low-NO _x burner	1-01-002-12 1-02-002-12 1-03-002-16	38S	A	9.7	A	0.5	A
PC, dry bottom, tangentially fired, bituminous, NSPS ^g	1-01-002-12 1-02-002-12 1-03-002-16	38S		10	A	0.5	A
PC, dry bottom, tangentially fired, sub-bituminous, Pre-NSPS ^g	1-01-002-26 1-02-002-26 1-03-002-26	35S	A	8.4	A	0.5	A
PC, dry bottom, tangentially fired, sub-bituminous, NSPS ^g	1-01-002-26 1-02-002-26 1-03-002-26	35S	A	7.2	A	0.5	A
PC, wet bottom, wall-fired ^f , bituminous, Pre-NSPS ^g	1-01-002-01 1-02-002-01 1-03-002-05	38S	A	31	D	0.5	A
PC, wet bottom, tangentially fired, bituminous, NSPS ^g	1-01-002-11	38S	A	14	E	0.5	A
PC, wet bottom, wall-fired sub-bituminous	1-01-002-21 1-02-002-21 1-03-002-21	35S	A	24	E	0.5	A

Table 1.1-3 (cont.).

Firing Configuration	SCC	SO _x ^b		NO _x ^c		CO ^{d,e}	
		Emission Factor (lb/ton)	EMISSION FACTOR RATING	Emission Factor (lb/ton)	EMISSION FACTOR RATING	Emission Factor (lb/ton)	EMISSION FACTOR RATING
Cyclone Furnace, bituminous	1-01-002-03 1-02-002-03 1-03-002-03	38S	A	33	A	0.5	A
Cyclone Furnace, sub-bituminous	1-01-002-23 1-02-002-23 1-03-002-23	35S	A	17	C	0.5	A
Spreader stoker, bituminous	1-01-002-04 1-02-002-04 1-03-002-09	38S	B	11	B	5	A
Spreader Stoker, sub-bituminous	1-01-002-24 1-02-002-24 1-03-002-24	35S	B	8.8	B	5	A
Overfeed stoker ^f	1-01-002-05/25 1-02-002-05/25 1-03-002-07/25	38S (35S)	B	7.5	A	6	B
Underfeed stoker	1-02-002-06 1-03-002-08	31S	B	9.5	A	11	B
Hand-fed units	1-03-002-14	31S	D	9.1	E	275	E

Table 1.1-3 (cont.).

Firing Configuration	SCC	SO _x ^b		NO _x ^c		CO ^{d,c}	
		Emission Factor (lb/ton)	EMISSION FACTOR RATING	Emission Factor (lb/ton)	EMISSION FACTOR RATING	Emission Factor (lb/ton)	EMISSION FACTOR RATING
FBC, circulating bed	1-01-002-18 1-02-002-18 1-03-002-18	C ^j	E	5.0	D	18	E
FBC, bubbling bed	1-01-002-17 1-02-002-17 1-03-002-17	C ^j	E	15.2	D	18	D

^a Factors represent uncontrolled emissions unless otherwise specified and should be applied to coal feed, as fired. SCC = Source Classification Code. To convert from lb/ton to kg/Mg, multiply by 0.5.

^b Expressed as SO₂, including SO₂, SO₃, and gaseous sulfates. Factors in parentheses should be used to estimate gaseous SO_x emissions for subbituminous coal. In all cases, S is weight % sulfur content of coal as fired. Emission factor would be calculated by multiplying the weight percent sulfur in the coal by the numerical value preceding S. For example, if fuel is 1.2% sulfur, then S = 1.2. On average for bituminous coal, 95% of fuel sulfur is emitted as SO₂, and only about 0.7% of fuel sulfur is emitted as SO₃ and gaseous sulfate. An equally small percent of fuel sulfur is emitted as particulate sulfate (References 22-23). Small quantities of sulfur are also retained in bottom ash. With subbituminous coal, about 10% more fuel sulfur is retained in the bottom ash and particulate because of the more alkaline nature of the coal ash. Conversion to gaseous sulfate appears about the same as for bituminous coal.

Table 1.1-3. (cont.)

- c Expressed as NO₂. Generally, 95 volume % or more of NO_x present in combustion exhaust will be in the form of NO, the rest NO₂ (Reference 6). To express factors as NO, multiply factors by 0.66. All factors represent emissions at baseline operation (i. e., 60 to 110% load and no NO_x control measures).
- d Nominal values achievable under normal operating conditions. Values 1 or 2 orders of magnitude higher can occur when combustion is not complete.
- e Emission factors for CO₂ emissions from coal combustion should be calculated using $\text{lb CO}_2/\text{ton coal} = 72.6C$, where C is the weight % carbon content of the coal. For example, if carbon content is 85%, then C equals 85.
- f Wall-fired includes front and rear wall-fired units, as well as opposed wall-fired units.
- g Pre-NSPS boilers are not subject to any NSPS. NSPS boilers are subject to Subpart D or Subpart Da. Subpart D boilers are boilers constructed after August 17, 1971 and with a heat input rate greater than 250 million Btu per hour (MMBtu/hr). Subpart Da boilers are boilers constructed after September 18, 1978 and with a heat input rate greater than 250 MMBtu/hr.
- h References 24-27.
- i Includes traveling grate, vibrating grate, and chain grate stokers.
- j SO₂ emission factors for fluidized bed combustion are a function of fuel sulfur content and calcium-to-sulfur ratio. For both bubbling bed and circulating bed design, use: $\text{lb SO}_2/\text{ton coal} = 39.6(S)(\text{Ca}/S)^{-1.9}$. In this equation, S is the weight percent sulfur in the fuel and Ca/S is the molar calcium-to-sulfur ratio in the bed. This equation may be used when the Ca/S is between 1.5 and 7. When no calcium-based sorbents are used and the bed material is inert with respect to sulfur capture, the emission factor for underfeed stokers should be used to estimate the SO₂ emissions. In this case, the emission factor ratings are E for both bubbling and circulating units.

Table 1.1-4. UNCONTROLLED EMISSION FACTORS FOR PM AND PM-10
FROM BITUMINOUS AND SUBBITUMINOUS COAL COMBUSTION^a

Firing Configuration	SCC	Filterable PM ^b		Filterable PM-10	
		Emission Factor (lb/ton)	EMISSION FACTOR RATING	Emission Factor (lb/ton)	EMISSION FACTOR RATING
PC-fired, dry bottom, wall-fired	1-01-002-02/22 1-02-002-02/22 1-03-002-06/22	10A	A	2.3A	E
PC-fired, dry bottom, tangentially fired	1-01-002-12/26 1-02-002-12/26 1-03-002-16/26	10A	B	2.3A ^c	E
PC-fired, wet bottom	1-01-002-01/21 1-02-002-01/21 1-03-002-05/21	7A ^d	D	2.6A	E
Cyclone furnace	1-01-002-03/23 1-02-002-03/23 1-03-002-03/23	2A ^d	E	0.26A	E
Spreader stoker	1-01-002-04/24 1-02-002-04/24 1-03-002-09/24	66 ^c	B	13.2	E
Spreader stoker, with multiple cyclones, and reinjection	1-01-002-04/24 1-02-002-04/24 1-03-002-09/24	17	B	12.4	E
Spreader stoker, with multiple cyclones, no reinjection	1-01-002-04/24 1-02-002-04/24 1-03-002-09/24	12	A	7.8	E

Table 1.1-4 (cont.).

Firing Configuration	SCC	Filterable PM ^b		Filterable PM-10	
		Emission Factor (lb/ton)	EMISSION FACTOR RATING	Emission Factor (lb/ton)	EMISSION FACTOR RATING
Overfeed stoker ^f	1-01-002-05/25 1-02-002-05/25 1-03-002-07/25	16 ^g	C	6.0	E
Overfeed stoker, with multiple cyclones ^f	1-01-002-05/25 1-02-002-05/25 1-03-002-07/25	9 ^h	C	5.0	E
Underfeed stoker	1-02-002-06 1-03-002-08	15 ^j	D	6.2	E
Underfeed stoker, with multiple cyclone	1-02-002-06 1-03-002-08	11 ^h	D	6.2 ^j	E
Hand-fed units	1-03-002-14	15	E	6.2 ^k	E
FBC, bubbling bed	1-01-002-17 1-02-002-17 1-03-002-17	^m	E	^m	E
FBC, circulating bed	1-01-002-18 1-02-002-18 1-03-002-18	^m	E	^m	E

^a Factors represent uncontrolled emissions unless otherwise specified and should be applied to coal feed, as fired. To convert from lb/ton to kg/Mg, multiply by 0.5. SCC = Source Classification Code.

Table 1.1-4 (cont.).

- ^b Based on EPA Method 5 (front half catch) as described in Reference 28. Where particulate is expressed in terms of coal ash content, A, factor is determined by multiplying weight % ash content of coal (as fired) by the numerical value preceding the A. For example, if coal with 8% ash is fired in a PC-fired, dry bottom unit, the PM emission factor would be 10 x 8, or 80 lb/ton.
- ^c No data found; emission factor for PC-fired dry bottom boilers used.
- ^d Uncontrolled particulate emissions, when no fly ash reinjection is employed. When control device is installed, and collected fly ash is reinjected to boiler, particulate from boiler reaching control equipment can increase up to a factor of 2.
- ^e Accounts for fly ash settling in an economizer, air heater, or breaching upstream of control device or stack. (Particulate directly at boiler outlet typically will be twice this level.) Factor should be applied even when fly ash is reinjected to boiler from air heater or economizer dust hoppers.
- ^f Includes traveling grate, vibrating grate, and chain grate stokers.
- ^g Accounts for fly ash settling in breaching or stack base. Particulate loadings directly at boiler outlet typically can be 50% higher.
- ^h See Reference 4 for discussion of apparently low multiple cyclone control efficiencies, regarding uncontrolled emissions.
- ^j Accounts for fly ash settling in breaching downstream of boiler outlet.
- ^k No data found; emission factor for underfeed stoker used.
- ^m No data found; use emission factor for spreader stoker with multiple cyclones and reinjection.

Table 1.1-5. CONDENSABLE PARTICULATE MATTER EMISSION FACTORS FOR BITUMINOUS AND SUBBITUMINOUS COAL COMBUSTION^a

Firing Configuration ^b	Controls ^c	SCC	CPM - TOT ^{d,e}		CPM - IOR ^{d,e}		CPM - ORG ^{d,e}	
			Emission Factor (lb/MMBtu)	EMISSION FACTOR RATING	Emission Factor (lb/MMBtu)	EMISSION FACTOR RATING	Emission Factor (lb/MMBtu)	EMISSION FACTOR RATING
All pulverized coal-fired boilers	All PM controls (without FGD controls)	1-01-002-01/21	0.1S-0.03 ^{f,g}	B	80% of CPM-TOT emission factor ^c	E	20% of CPM-TOT emission factor ^c	E
		1-01-002-02/22						
		1-01-002-12/26						
		1-02-002-01/21						
		1-02-002-02/22						
		1-02-002-12/26						
		1-03-002-05/06						
		1-03-002-16						
		1-03-002-21/22						
		1-03-002-26						
All pulverized coal-fired boilers	All PM controls combined with an FGD control	1-01-002-01/21	0.02 ^h	E	ND		ND	
		1-01-002-02/22						
		1-01-002-12/26						
		1-02-002-01/21						
		1-02-002-02/22						
		1-02-002-12/26						
		1-03-002-05/06						
		1-03-002-16						
		1-03-002-21/22						
		1-03-002-26						
Spreader stoker, travelling grate overfeed stoker, underfeed stoker	All PM controls, or Uncontrolled	1-01-002-04/24	0.04 ⁱ	C	80% of CPM-TOT emission factor ^g	E	20% of CPM-TOT emission factor ^g	E
		1-01-002-05/25						
		1-02-002-04/24						
		1-02-002-05/25						
		1-02-002-06						
		1-03-002-07/08						
		1-03-002-09/11						
		1-03-002-16						
		1-03-002-24/25						

Table 1.1-5 (cont.).

- ^a All condensable PM is assumed to be less than 1.0 micron in diameter.
- ^b No data are available for cyclone boilers (SCCs 1-01-002-03/23, 1-02-002-03/23, 1-03-002-23) or for atmospheric fluidized bed combustion (AFBC) boilers (SCCs 1-01B002-17, 1-02-002-17, 1-03-002-17). For cyclone boilers, use the factors provided for pulverized coal-fired boilers and applicable control devices. For AFBC boilers, use the factors provided for pulverized coal-fired boilers with PM and FGD controls.
- ^c FGD = flue gas desulfurization.
- ^d CPM-TOT = total condensable particulate matter.
CPM-IOR = inorganic condensable particulate matter.
CPM-ORG = organic condensable particulate matter.
ND = No data.
- ^e Factors should be multiplied by fuel rate on a heat input basis (MMBtu), as fired. To convert to lb/ton of bituminous coal, multiply by 26 MMBtu/ton. To convert to lb/ton of subbituminous coal, multiply by 20 MMBtu/ton.
- ^f S = coal sulfur percent by weight, as fired. For example, if the sulfur percent is 1.04, then S = 1.04. If the coal sulfur percent is 0.4 or less, use a default emission factor of 0.01 lb/MMBtu rather than the emission equation.
- ^g References 78-94.
- ^h References 95 and 96.
- ⁱ References 97-104.

Table 1.1-6. CUMULATIVE PARTICLE SIZE DISTRIBUTION AND SIZE-SPECIFIC EMISSION FACTORS FOR DRY BOTTOM BOILERS BURNING PULVERIZED BITUMINOUS AND SUBBITUMINOUS COAL^a

Particle Size ^b (μm)	Cumulative Mass % \leq Stated Size					Cumulative Emission Factor ^c (lb/ton)				
	Uncontrolled	Controlled				Uncontrolled ^d	Controlled ^e			
		Multiple Cyclones	Scrubber	ESP	Baghouse		Multiple Cyclones ^f	Scrubber ^g	ESP ^g	Baghouse ^f
15	32	54	81	79	97	3.2A	1.08A	0.48A	0.064A	0.02A
10	23	29	71	67	92	2.3A	0.58A	0.42A	0.054A	0.02A
6	17	14	62	50	77	1.7A	0.28A	0.38A	0.024A	0.02A
2.5	6	3	51	29	53	0.6A	0.06A	0.3A	0.024A	0.01A
1.25	2	1	35	17	31	0.2A	0.02A	0.22A	0.01A	0.006A
1.00	2	1	31	14	25	0.2A	0.02A	0.18A	0.01A	0.006A
0.625	1	1	20	12	14	0.10A	0.02A	0.12A	0.01A	0.002A
TOTAL	100	100	100	100	100	10A	2A	0.6A	0.08A	0.02A

^a Reference 33. Applicable Source Classification Codes are 1-01-002-02, 1-02-002-02, 1-03-002-06, 1-01-002-12, 1-02-002-12, and 1-03-002-16. To convert from lb/ton to kg/Mg, multiply by 0.5. Emission Factors are lb of pollutant per ton of coal combusted, as fired. ESP = Electrostatic precipitator.

^b Expressed as aerodynamic equivalent diameter.

^c A = coal ash weight percent, as fired. For example, if coal ash weight is 8.2%, then A = 8.2.

^d EMISSION FACTOR RATING = C.

^e Estimated control efficiency for multiple cyclones is 80%; for scrubber, 94%; for ESP, 99.2%; and for baghouse, 99.8%.

^f EMISSION FACTOR RATING = E.

^g EMISSION FACTOR RATING = D.

Table 1.1-7. CUMULATIVE PARTICLE SIZE DISTRIBUTION AND SIZE-SPECIFIC EMISSION FACTORS FOR WET BOTTOM BOILERS BURNING PULVERIZED BITUMINOUS COAL^a

EMISSION FACTOR RATING: E

Particle Size ^b (μm)	Cumulative Mass % \leq Stated Size			Cumulative Emission Factor ^c (lb/ton)		
	Uncontrolled	Controlled		Uncontrolled	Controlled ^d	
		Multiple Cyclones	ESP		Multiple Cyclones	ESP
15	40	99	83	2.8A	1.38A	0.046A
10	37	93	75	2.6A	1.3A	0.042A
6	33	84	63	2.32A	1.18A	0.036A
2.5	21	61	40	1.48A	0.86A	0.022A
1.25	6	31	17	0.42A	0.44A	0.01A
1.00	4	19	8	0.28A	0.26A	0.004A
0.625	2	— ^e	— ^e	0.14A	— ^e	— ^e
TOTAL	100	100	100	7.0A	1.4A	0.056A

^a Reference 33. Applicable Source Classification Codes are 1-01-002-01, 1-02-002-01, and 1-03-002-05. To convert from lb/ton to kg/Mg, multiply by 0.5. Emission factors are lb of pollutant per ton of coal combusted as fired. ESP = Electrostatic precipitator.

^b Expressed as aerodynamic equivalent diameter.

^c A = coal ash weight %, as fired. For example, if coal ash weight is 2.4%, then A = 2.4.

^d Estimated control efficiency for multiple cyclones is 94%, and for ESPs, 99.2%.

^e Insufficient data.

Table 1.1-8. CUMULATIVE SIZE DISTRIBUTION AND SIZE-SPECIFIC EMISSION FACTORS FOR CYCLONE FURNACES BURNING BITUMINOUS COAL^a

EMISSION FACTOR RATING: E

Particle Size ^b (μm)	Cumulative Mass % \leq Stated Size			Cumulative Emission Factor ^c (lb/ton)		
	Uncontrolled	Controlled		Uncontrolled	Controlled ^d	
		Multiple Cyclones	ESP		Multiple Cyclones	ESP
15	33	95	90	0.66A	0.114A	0.013A
10	13	94	68	0.26A	0.112A	0.011A
6	8	93	56	0.16A	0.112A	0.009A
2.5	5.5	92	36	0.11A ^e	0.11A	0.006A
1.25	5	85	22	0.10A ^e	0.10A	0.004A
1.00	5	82	17	0.10A ^e	0.10A	0.003A
0.625	0	— ^f	— ^f	0	— ^f	— ^f
TOTAL	100	100	100	2A	0.12A	0.016A

^a Reference 33. Applicable Source Classification Codes are 1-01-002-03, 1-02-002-03, and 1-03-002-03. To convert from lb/ton to kg/Mg, multiply by 0.5. Emissions are lb of pollutant per ton of coal combusted, as fired.

^b Expressed as aerodynamic equivalent diameter.

^c A = coal ash weight %, as fired. For example, if coal ash weight is 2.4%, then A = 2.4.

^d Estimated control efficiency for multiple cyclones is 94%, and for ESPs, 99.2%.

^e These values are estimates based on data from controlled source.

^f Insufficient data.

Table 1.1-9. CUMULATIVE PARTICLE SIZE DISTRIBUTION AND SIZE-SPECIFIC EMISSION FACTORS FOR SPREADER STOKERS BURNING BITUMINOUS COAL^a

Particle Size ^b (μm)	Cumulative Mass % \leq Stated Size					Cumulative Emission Factor (lb/ton)				
	Uncontrolled	Controlled				Uncontrolled ^e	Controlled			
		Multiple Cyclones ^c	Multiple Cyclones ^d	ESP	Baghouse		Multiple Cyclones ^{c,f}	Multiple Cyclones ^{d,e}	ESP ^{f,g}	Baghouse ^{c,g}
15	28	86	74	97	72	18.5	14.6	8.8	0.46	0.086
10	20	73	65	90	60	13.2	12	7.8	0.44	0.072
6	14	51	52	82	46	9.2	8.6	6.2	0.40	0.056
2.5	7	8	27	61	26	4.6	1.4	3.2	0.30	0.032
1.25	5	2	16	46	18	3.3	0.4	2.0	0.22	0.022
1.00	5	2	14	41	15	3.3	0.4	1.6	0.20	0.018
0.625	4	1	9	C ^h	7	2.6	0.2	1.0	C ^h	0.006
TOTAL	100	100	100	100	100	66.0	17.0	12.0	0.48	0.12

^a Reference 33. Applicable Source Classification Codes are 1-01-002-04, 1-02-002-04, 1-03-002-09. To convert from lb/ton to kg/Mg, multiply by 0.5. Emissions are lb of pollutant per ton of coal combusted, as fired.

^b Expressed as aerodynamic equivalent diameter.

^c With flyash reinjection.

^d Without flyash reinjection.

^e EMISSION FACTOR RATING = C.

^f EMISSION FACTOR RATING = E.

^g Estimated control efficiency for ESP is 99.22%; and for baghouse, 99.8%.

^h Insufficient data.

Table 1.1-10. CUMULATIVE PARTICLE SIZE DISTRIBUTION AND SIZE-SPECIFIC EMISSION FACTORS FOR OVERFEED STOKERS BURNING BITUMINOUS COAL^a

Particle Size ^b (μm)	Cumulative Mass % \leq Stated Size		Cumulative Emission Factor (lb/ton)			
	Uncontrolled	Multiple Cyclones Controlled	Uncontrolled		Multiple Cyclones Controlled ^c	
			Emission Factor	EMISSION FACTOR RATING	Emission Factor	EMISSION FACTOR RATING
15	49	60	7.8	C	5.4	E
10	37	55	6.0	C	5.0	E
6	24	49	3.8	C	4.4	E
2.5	14	43	2.2	C	3.8	E
1.25	13	39	2.0	C	3.6	E
1.00	12	39	2.0	C	3.6	E
0.625	— ^d	16	— ^d	C	1.4	E
TOTAL	100	100	16.0	C	9.0	E

^a Reference 33. Applicable Source Classification Codes are 1-01-002-05, 1-02-002-05, and 1-03-002-07. To convert from lb/ton to kg/Mg, multiply by 0.5. Emissions are lb of pollutant per ton of coal combusted, as fired.

^b Expressed as aerodynamic equivalent diameter.

^c Estimated control efficiency for multiple cyclones is 80%.

^d Insufficient data.

Table 1.1-11. CUMULATIVE PARTICLE SIZE DISTRIBUTION AND SIZE-SPECIFIC EMISSION FACTORS FOR UNDERFEED STOKERS BURNING BITUMINOUS COAL^a

EMISSION FACTOR RATING: C

Particle Size ^b (μm)	Cumulative Mass % ≤ Stated Size	Uncontrolled Cumulative Emission Factor ^c (lb/ton)
15	50	7.6
10	41	6.2
6	32	4.8
2.5	25	3.8
1.25	22	3.4
1.00	21	3.2
0.625	18	2.7
TOTAL	100	15.0

^a Reference 33. Applicable Source Classification Codes are 1-02-002-06 and 1-03-002-08. To convert from lb/ton to kg/Mg, multiply by 0.5. Emission factors are lb of pollutant per ton of coal combusted, as fired.

^b Expressed as aerodynamic equivalent diameter.

^c May also be used for uncontrolled hand-fired units.

Table 1.1-12 EMISSION FACTORS FOR POLYCHLORINATED
DIBENZO-P-DIOXINS AND POLYCHLORINATED DIBENZOFURANS FROM CONTROLLED
BITUMINOUS AND SUBBITUMINOUS COAL COMBUSTION

Controls	FGD-SDA with FF ^a		ESP or FF ^b	
Congener	Emission Factor ^c (lb/ton)	EMISSION FACTOR RATING	Emission Factor ^c (lb/ton)	EMISSION FACTOR RATING
2,3,7,8-TCDD	No data	---	1.43E-11	E
Total TCDD	3.93E-10	E	9.28E-11	D
Total PeCDD	7.06E-10	E	4.47E-11	D
Total HxCDD	3.00E-09	E	2.87E-11	D
Total HpCDD	1.00E-08	E	8.34E-11	D
Total OCDD	2.87E-08	E	4.16E-10	D
Total PCDD ^d	4.28E-08	E	6.66E-10	D
2,3,7,8-TCDF	No data	---	5.10E-11	D
Total TCDF	2.49E-09	E	4.04E-10	D
Total PeCDF	4.84E-09	E	3.53E-10	D
Total HxCDF	1.27E-08	E	1.92E-10	D
Total HpCDF	4.39E-08	E	7.68E-11	D
Total OCDF	1.37E-07	E	6.63E-11	D
Total PCDF ^d	2.01E-07	E	1.09E-09	D
TOTAL PCDD/PCDF	2.44E-07	E	1.76E-09	D

^a Reference 34. Factors apply to boilers equipped with both flue gas desulfurization spray dryer absorber (FGD-SDA) and a fabric filter (FF). SCCs = pulverized coal-fired, dry bottom boilers, 1-01-002-02/22, 1-02-002-02/22, and 1-03-002-06/22.

^b References 35-37. Factors apply to boilers equipped with an electrostatic precipitator (ESP) or a fabric filter. SCCs = pulverized coal-fired, dry bottom boilers, 1-01-002-02/22, 1-02-002-02/22, 1-03-002-06/22; and, cyclone boilers, 1-01-002-03/23, 1-02-002-03/23, and 1-03-002-03/23.

^c Emission factor should be applied to coal feed, as fired. To convert from lb/ton to kg/Mg, multiply by 0.5. Emissions are lb of pollutant per ton of coal combusted.

^d Total PCDD is the sum of Total TCDD through Total OCDD. Total PCDF is the sum of Total TCDF through Total OCDF.

Table 1.1-13 EMISSION FACTORS FOR POLYNUCLEAR AROMATIC HYDROCARBONS (PAH) FROM CONTROLLED COAL COMBUSTION^a

Pollutant	Emission Factor ^b (lb/ton)	EMISSION FACTOR RATING
Biphenyl	1.7E-06	D
Acenaphthene	5.1E-07	B
Acenaphthylene	2.5E-07	B
Anthracene	2.1E-07	B
Benzo(a)anthracene	8.0E-08	B
Benzo(a)pyrene	3.8E-08	D
Benzo(b,j,k)fluoranthene	1.1E-07	B
Benzo(g,h,i)perylene	2.7E-08	D
Chrysene	1.0E-07	C
Fluoranthene	7.1E-07	B
Fluorene	9.1E-07	B
Indeno(1,2,3-cd)pyrene	6.1E-08	C
Naphthalene	1.3E-05	C
Phenanthrene	2.7E-06	B
Pyrene	3.3E-07	B
5-Methyl chrysene	2.2E-08	D

^a References 35-45. Factors were developed from emissions data from six sites firing bituminous coal, four sites firing subbituminous coal, and from one site firing lignite. Factors apply to boilers utilizing both wet limestone scrubbers or spray dryers with an electrostatic precipitator (ESP) or fabric filter (FF). The factors also apply to boilers utilizing only an ESP or FF. Bituminous/subbituminous SCCs = pulverized coal-fired dry bottom boilers, 1-01-002-02/22, 1-02-002-02/22, 1-03-002-06; pulverized coal, dry bottom, tangentially-fired boilers, 1-01-002-12/26, 1-02-002-12/26, 1-03-002-16/26; and, cyclone boilers, 1-01-002-03/23, 1-02-002-03/23, and 1-03-002-03/23.

^b Emission factor should be applied to coal feed, as fired. To convert from lb/ton to kg/Mg, multiply by 0.5. Emissions are lb of pollutant per ton of coal combusted.

Table 1.1-14 EMISSION FACTORS FOR VARIOUS ORGANIC COMPOUNDS
FROM CONTROLLED COAL COMBUSTION^a

Pollutant ^b	Emission Factor ^c (lb/ton)	EMISSION FACTOR RATING
Acetaldehyde	5.7E-04	C
Acetophenone	1.5E-05	D
Acrolein	2.9E-04	D
Benzene	1.3E-03	A
Benzyl chloride	7.0E-04	D
Bis(2-ethylhexyl)phthalate (DEHP)	7.3E-05	D
Bromoform	3.9E-05	E
Carbon disulfide	1.3E-04	D
2-Chloroacetophenone	7.0E-06	E
Chlorobenzene	2.2E-05	D
Chloroform	5.9E-05	D
Cumene	5.3E-06	E
Cyanide	2.5E-03	D
2,4-Dinitrotoluene	2.8E-07	D
Dimethyl sulfate	4.8E-05	E
Ethyl benzene	9.4E-05	D
Ethyl chloride	4.2E-05	D
Ethylene dichloride	4.0E-05	E
Ethylene dibromide	1.2E-06	E
Formaldehyde	2.4E-04	A
Hexane	6.7E-05	D
Isophorone	5.8E-04	D
Methyl bromide	1.6E-04	D
Methyl chloride	5.3E-04	D
Methyl ethyl ketone	3.9E-04	D
Methyl hydrazine	1.7E-04	E
Methyl methacrylate	2.0E-05	E

Table 1.1-14 (cont.).

Pollutant ^b	Emission Factor ^c (lb/ton)	EMISSION FACTOR RATING
Methyl tert butyl ether	3.5E-05	E
Methylene chloride	2.9E-04	D
Phenol	1.6E-05	D
Propionaldehyde	3.8E-04	D
Tetrachloroethylene	4.3E-05	D
Toluene	2.4E-04	A
1,1,1-Trichloroethane	2.0E-05	E
Styrene	2.5E-05	D
Xylenes	3.7E-05	C
Vinyl acetate	7.6E-06	E

^a References 35-53. Factors were developed from emissions data from ten sites firing bituminous coal, eight sites firing subbituminous coal, and from one site firing lignite. The emission factors are applicable to boilers using both wet limestone scrubbers or spray dryers and an electrostatic precipitator (ESP) or fabric filter (FF). In addition, the factors apply to boilers utilizing only an ESP or FF. SCCs = pulverized coal-fired, dry bottom boilers, 1-01-002-02/22, 1-02-002-02/22, 1-03-002-06/22; pulverized coal, dry bottom, tangentially-fired boilers, 1-01-002-12/26, 1-02-002-12/26, 1-03-002-16/26; cyclone boilers, 1-01-002-03/23, 1-02-002-03/23, 1-03-002-03/23; and, atmospheric fluidized bed combustors, circulating bed, 1-01-002-18/38, 1-02-002-18, and 1-03-002-18.

^b Pollutants sampled for but not detected in any sampling run include: Carbon tetrachloride- 2 sites; 1,3-Dichloropropylene- 2 sites; N-nitrosodimethylamine- 2 sites; Ethylidene dichloride- 2 sites; Hexachlorobutadiene- 1 site; Hexachloroethane- 1 site; Propylene dichloride- 2 sites; 1,1,2,2-Tetrachloroethane- 2 sites; 1,1,2-Trichloroethane- 2 sites; Vinyl chloride- 2 sites; and, Hexachlorobenzene- 2 sites.

^c Emission factor should be applied to coal feed, as fired. To convert from lb/ton to kg/Mg, multiply by 0.5.

Table 1.1-15. EMISSION FACTORS FOR HYDROGEN CHLORIDE (HCl) AND HYDROGEN FLUORIDE (HF) FROM COAL COMBUSTION^a

EMISSION FACTOR RATING: B

Firing Configuration	SCC	HCl	HF
		Emission Factor (lb/ton)	Emission Factor (lb/ton)
PC-fired, dry bottom	1-01-002-02/22	1.2	0.15
	1-02-002-02/22		
	1-03-002-06/22		
PC-fired, dry bottom, tangential	1-01-002-12/26	1.2	0.15
	1-02-002-12/26		
	1-03-002-16/26		
PC-fired, wet bottom	1-01-002-01/21	1.2	0.15
	1-02-002-01/21		
	1-03-002-05/21		
Cyclone Furnace	1-01-002-03/23	1.2	0.15
	1-02-002-03/23		
	1-03-002-03/23		
Spreader Stoker	1-01-002-04/24	1.2	0.15
	1-02-002-04/24		
	1-03-002-09/24		
Overfeed Stoker	1-01-002-05/25	1.2	0.15
	1-02-002-05/25		
	1-03-002-07/25		
Underfeed Stoker	1-02-002-06	1.2	0.15
	1-03-002-08		
FBC, Bubbling Bed	1-01-002-17	1.2	0.15
	1-02-002-17		
	1-03-002-17		
FBC, Circulating Bed	1-01-002-18/38	1.2	0.15
	1-02-002-18		
	1-03-002-18		
Hand-fired	1-03-002-14	1.2	0.15

^a Reference 54. The emission factors were developed from bituminous coal, subbituminous coal, and lignite emissions data. To convert from lb/ton to kg/Mg, multiply by 0.5. The factors apply to both controlled and uncontrolled sources.

Table 1.1-16. EMISSION FACTOR EQUATIONS FOR TRACE ELEMENTS FROM COAL COMBUSTION^a

EMISSION FACTOR EQUATION RATING: A^b

Pollutant	Emission Equation (lb/10 ¹² Btu) ^c
Antimony	$0.92 * (C/A * PM)^{0.63}$
Arsenic	$3.1 * (C/A * PM)^{0.85}$
Beryllium	$1.2 * (C/A * PM)^{1.1}$
Cadmium	$3.3 * (C/A * PM)^{0.5}$
Chromium	$3.7 * (C/A * PM)^{0.58}$
Cobalt	$1.7 * (C/A * PM)^{0.69}$
Lead	$3.4 * (C/A * PM)^{0.80}$
Manganese	$3.8 * (C/A * PM)^{0.60}$
Nickel	$4.4 * (C/A * PM)^{0.48}$

^a Reference 55. The equations were developed from emissions data from bituminous coal combustion, subbituminous coal combustion, and from lignite combustion. The equations may be used to generate factors for both controlled and uncontrolled boilers. The emission factor equations are applicable to all typical firing configurations for electric generation (utility), industrial, and commercial/industrial boilers firing bituminous coal, subbituminous coal, and lignite. Thus, all SCCs for these boilers are assigned to the factors.

^b AP-42 criteria for rating emission factors were used to rate the equations.

^c The factors produced by the equations should be applied to heat input. To convert from lb/10¹² Btu to kg/joules, multiply by 4.31 x 10⁻¹⁶.

C = concentration of metal in the coal, parts per million by weight (ppmwt).

A = weight fraction of ash in the coal. For example, 10% ash is 0.1 ash fraction.

PM = Site-specific emission factor for total particulate matter, lb/10⁶ Btu.

Table 1.1-17. EMISSION FACTORS FOR TRACE ELEMENTS, POM, AND HCOH FROM UNCONTROLLED BITUMINOUS AND SUBBITUMINOUS COAL COMBUSTION^a

EMISSION FACTOR RATING: E

Firing Configuration (SCC)	Emission Factor, lb/10 ¹² Btu									
	As	Be	Cd	Cr	Pb ^b	Mn	Hg	Ni	POM	HCOH
Pulverized coal, configuration unknown (no SCC)	ND	ND	ND	1922	ND	ND	ND	ND	ND	112 ^c
Pulverized coal, wet bottom (1-01-002-01/21, 1-02-002-01/21, 1-03-002-05/21)	538	81	44-70	1020- 1570	507	808-2980	16	840-1290	ND	ND
Pulverized coal, dry bottom (1-01-002-02/22, 1-02-002-06/22, 1-03-002-06/22)	684	81	44.4	1250-157 0	507	228-2980	16	1030- 1290	2.08	ND
Pulverized coal, dry bottom, tangential (1-01-002-12/26, 1-02-002-12/26, 1-03-002-16/26)	ND	ND	ND	ND	ND	ND	ND	ND	2.4	ND
Cyclone furnace (1-01-002-03/23, 1-02-002-03/23, 1-03-002-03/23)	115	<81	28	212-1502	507	228-1300	16	174-1290	ND	ND
Stoker, configuration unknown (no SCC)	ND	73	ND	19-300	ND	2170	16	775-1290	ND	ND
Spreader stoker (1-01-002-04/24, 1-02-002-04/24, 1-03-002-09/24)	264-542	ND	21-43	942-1570	507	ND	ND	ND	ND	221 ^d
Overfeed stoker, traveling grate (1-01-002-05/25, 1-02-002-05/25, 1-03-002-07/25)	542-1030	ND	43-82	ND	507	ND	ND	ND	ND	140 ^e

^a References 56-61. The emission factors in this table represent the ranges of factors reported in the literature. If only 1 data point was found, it is still reported in this table. To convert from lb/10¹² Btu to pg/J, multiply by 0.43. SCC = Source Classification Code. ND = no data.

^b Lead emission factors were taken directly from an EPA background document for support of the National Ambient Air Quality Standards.

^c Based on 2 units; 133 x 10⁶ Btu/hr and 1550 x 10⁶ Btu/hr.

^d Based on 1 unit; 59 x 10⁶ Btu/hr.

Table 1.1-18 EMISSION FACTORS FOR TRACE METALS FROM CONTROLLED COAL COMBUSTION^a

Pollutant	Emission Factor (lb/ton) ^b	EMISSION FACTOR RATING
Antimony	1.8E-05	A
Arsenic	4.1E-04	A
Beryllium	2.1E-05	A
Cadmium	5.1E-05	A
Chromium	2.6E-04	A
Chromium (VI)	7.9E-05	D
Cobalt	1.0E-04	A
Lead	4.2E-04	A
Magnesium	1.1E-02	A
Manganese	4.9E-04	A
Mercury	8.3E-05	A
Nickel	2.8E-04	A
Selenium	1.3E-03	A

^a References 35-53, 62-70. The emission factors were developed from emissions data at eleven facilities firing bituminous coal, fifteen facilities firing subbituminous coal, and from two facilities firing lignite. The factors apply to boilers utilizing either venturi scrubbers, spray dryer absorbers, or wet limestone scrubbers with an electrostatic precipitator (ESP) or Fabric Filter (FF). In addition, the factors apply to boilers using only an ESP, FF, or venturi scrubber. SCCs = pulverized coal-fired, dry bottom boilers, 1-01-002-02/22, 1-02-002-02/22, 1-03-002-06/22; pulverized coal, dry bottom, tangentially-fired boilers, 1-01-002-12/26, 1-02-002-12/26, 1-03-002-16/26; cyclone boilers, 1-01-002-03/23, 1-02-002-03/23, 1-03-002-03/23; and, atmospheric fluidized bed combustors, circulating bed, 1-01-002-18/38, 1-02-002-18, and 1-03-002-18.

^b Emission factor should be applied to coal feed, as fired. To convert from lb/ton to kg/Mg, multiply by 0.5.

Table 1.1-19. EMISSION FACTORS FOR CH₄, TNMOC, AND N₂O FROM BITUMINOUS AND SUBBITUMINOUS COAL COMBUSTION^a

Firing Configuration	SCC	CH ₄ ^b		TNMOC ^{b,c}		N ₂ O ^d	
		Emission Factor (lb/ton)	EMISSION FACTOR RATING	Emission Factor (lb/ton)	EMISSION FACTOR RATING	Emission Factor (lb/ton)	EMISSION FACTOR RATING
PC-fired, dry bottom, wall fired	1-01-002-02/22	0.04	B	0.06	B	0.03	B
	1-02-002-02/22						
	1-03-002-06/22						
PC-fired, dry bottom, tangentially fired	1-01-002-12/26	0.04	B	0.06	B	0.08	B
	1-02-002-12/26						
	1-03-002-16/26						
PC-fired, wet bottom	1-01-002-01/21	0.05	B	0.04	B	0.08	E
	1-02-002-01/21						
	1-03-002-05/21						
Cyclone furnace	1-01-002-03/23	0.01	B	0.11	B	0.09 ^e	E
	1-02-002-03/23						
	1-03-002-03/23						
Spreader stoker	1-01-002-04/24	0.06	B	0.05	B	0.04 ^f	D
	1-02-002-04/24						
	1-03-002-09/24						
Spreader stoker, with multiple cyclones, and reinjection	1-01-002-04/24	0.06	B	0.05	B	0.04 ^f	E
	1-02-002-04/24						
	1-03-002-09/24						
Spreader stoker, with multiple cyclones, no reinjection	1-01-002-04/24	0.06	B	0.05	B	0.04 ^f	E
	1-02-002-04/24						
	1-03-002-09/24						

Table 1.1-19 (cont.).

Firing Configuration	SCC	CH ₄ ^b		TNMOC ^{b,c}		N ₂ O ^d	
		Emission Factor (lb/ton)	EMISSION FACTOR RATING	Emission Factor (lb/ton)	EMISSION FACTOR RATING	Emission Factor (lb/ton)	EMISSION FACTOR RATING
Overfeed stoker ^e	1-01-002-05/25 1-02-002-05/25 1-03-002-07/25	0.06	B	0.05	B	0.04 ^f	E
Overfeed stoker, with multiple cyclones ^e	1-01-002-05/25 1-02-002-05/25 1-03-002-07/25	0.06	B	0.05	B	0.04 ^f	E
Underfeed stoker	1-02-002-06 1-03-002-08	0.8	B	1.3	B	0.04 ^f	E
Underfeed stoker, with multiple cyclone	1-02-002-06 1-03-002-08	0.8	B	1.3	B	0.04 ^f	E
Hand-fed units	1-03-002-14	5	E	10	E	0.04 ^f	E
FBC, bubbling bed	1-01-002-17 1-02-002-17 1-03-002-17	0.06 ^h	E	0.05 ^h	E	3.5 ^h	B
FBC, circulating bed	1-01-002-18 1-02-002-18 1-03-002-18	0.06	E	0.05	E	3.5	B

^a Factors represent uncontrolled emissions unless otherwise specified and should be applied to coal feed, as fired. SCC = Source Classification Code. To convert from lb/ton to kg/Mg, multiply by 0.5.

^b Reference 32. Nominal values achievable under normal operating conditions; values 1 or 2 orders of magnitude higher can occur when combustion is not complete.

^c TNMOC are expressed as C₂ to C₁₆ alkane equivalents (Reference 71). Because of limited data, the effects of firing configuration on TNMOC emission factors could not be distinguished. As a result, all data were averaged collectively to develop a single average emission factor for pulverized coal units, cyclones, spreaders, and overfeed stokers.

^d References 14-15.

Table 1.1-20. DEFAULT CO₂ EMISSION FACTORS FOR U. S. COALS^a

EMISSION FACTOR RATING: C

Coal Type	Average %C ^b	Conversion Factor ^c	Emission Factor ^d (lb/ton coal)
Subbituminous	66.3	72.6	4810
High-volatile bituminous	75.9	72.6	5510
Medium-volatile bituminous	83.2	72.6	6040
Low-volatile bituminous	86.1	72.6	6250

^a This table should be used only when an ultimate analysis is not available. If the ultimate analysis is available, CO₂ emissions should be calculated by multiplying the %carbon (%C) by 72.6. This resultant factor would receive a quality rating of "B".

^b An average of the values given in References 2,76-77. Each of these references listed average carbon contents for each coal type (dry basis) based on extensive sampling of U.S. coals.

^c Based on the following equation:

$$\frac{44 \text{ ton CO}_2}{12 \text{ ton C}} \times 0.99 \times 2000 \frac{\text{lb CO}_2}{\text{ton CO}_2} \times \frac{1}{100\%} = 72.6 \frac{\text{lb CO}_2}{\text{ton \%C}}$$

Where:

- 44 = molecular weight of CO₂,
- 12 = molecular weight of carbon, and
- 0.99 = fraction of fuel oxidized during combustion (Reference 16).

^d To convert from lb/ton to kg/Mg, multiply by 0.5.

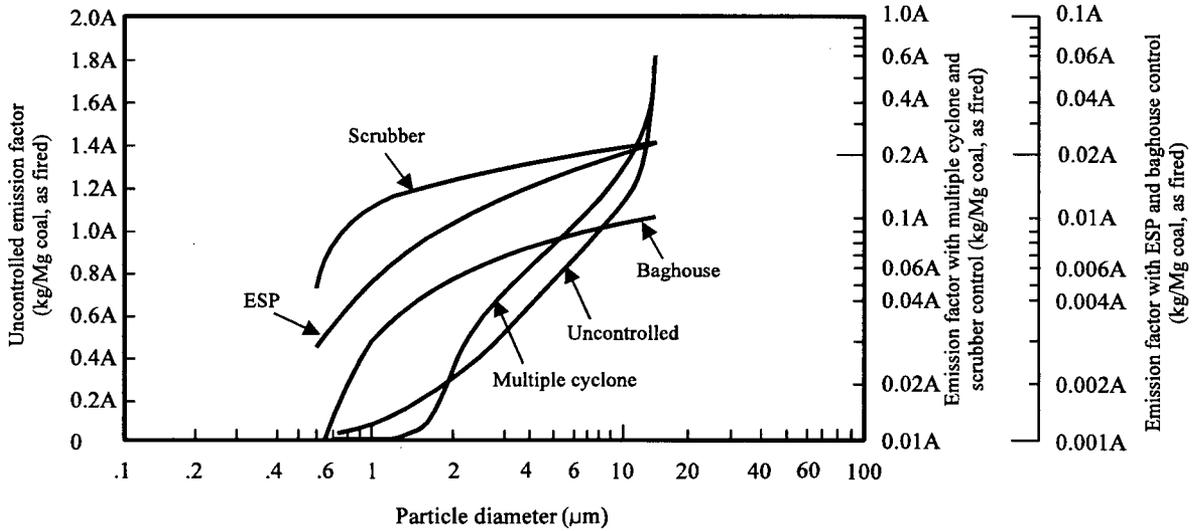


Figure 1.1-1. Cumulative size-specific emission factors for an example dry bottom boiler burning pulverized bituminous coal.

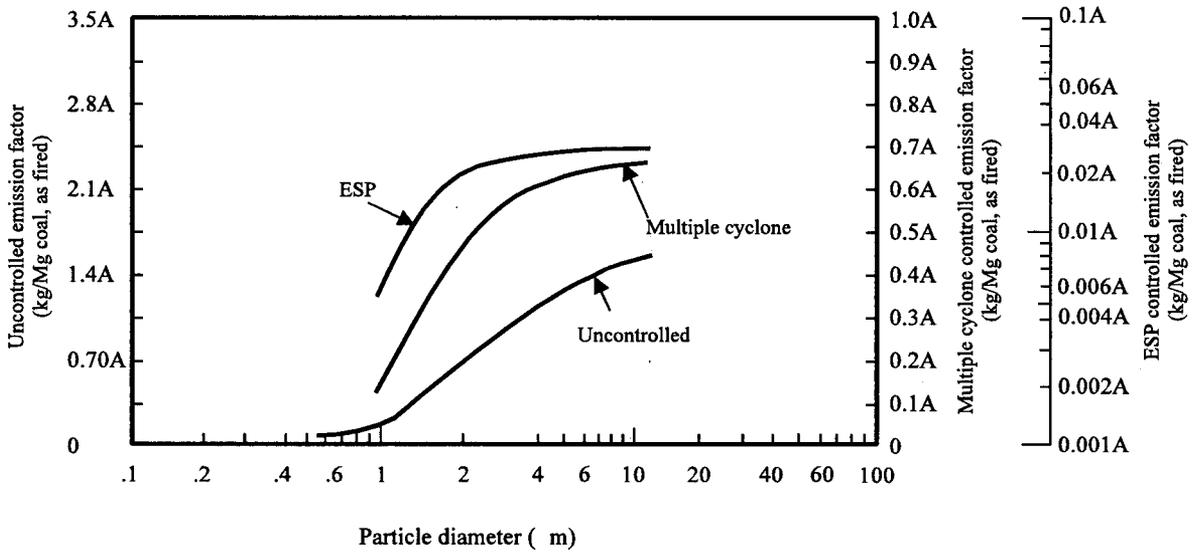


Figure 1.1-2. Cumulative size-specific emission factors for an example wet bottom boiler burning pulverized bituminous coal.

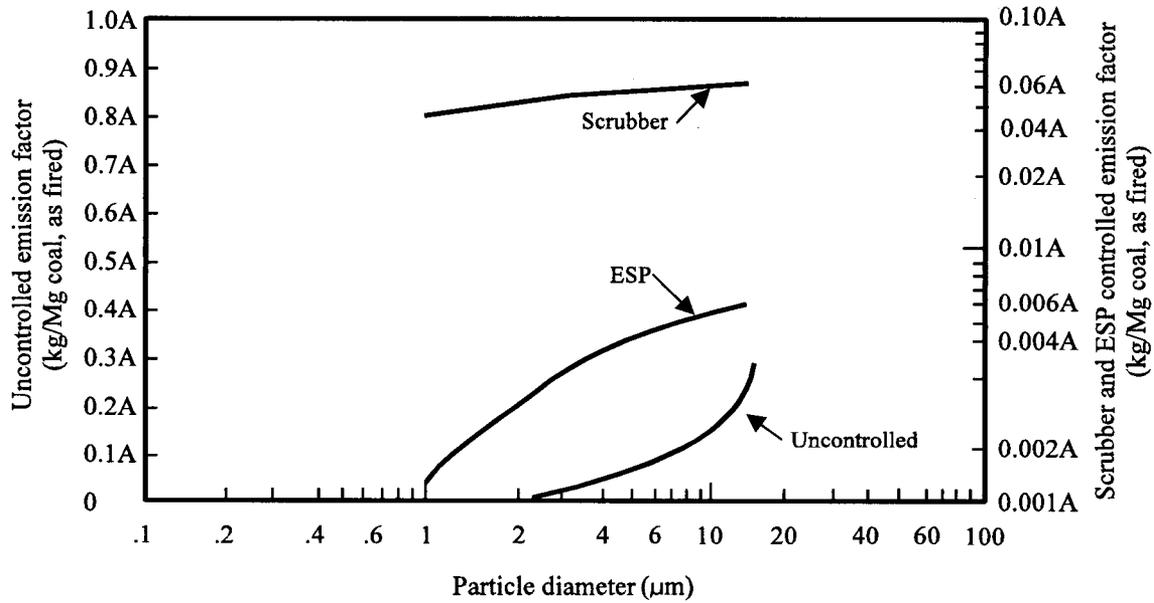


Figure 1.1-3. Cumulative size-specific emission factors for an example cyclone furnace burning bituminous coal.

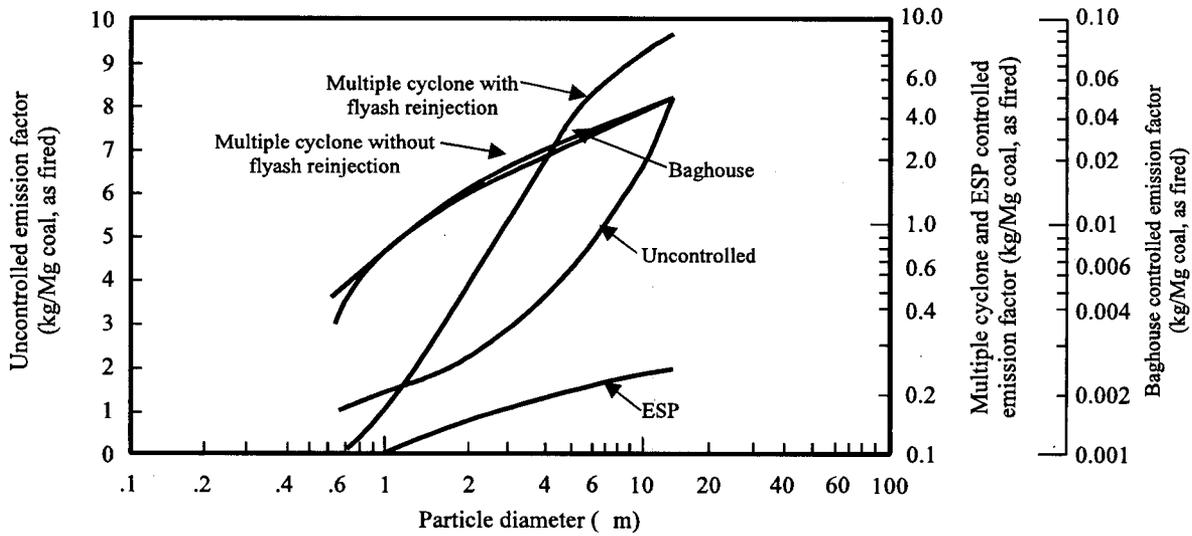


Figure 1.1-4. Cumulative size-specific emission factors for an example spreader stoker burning bituminous coal.

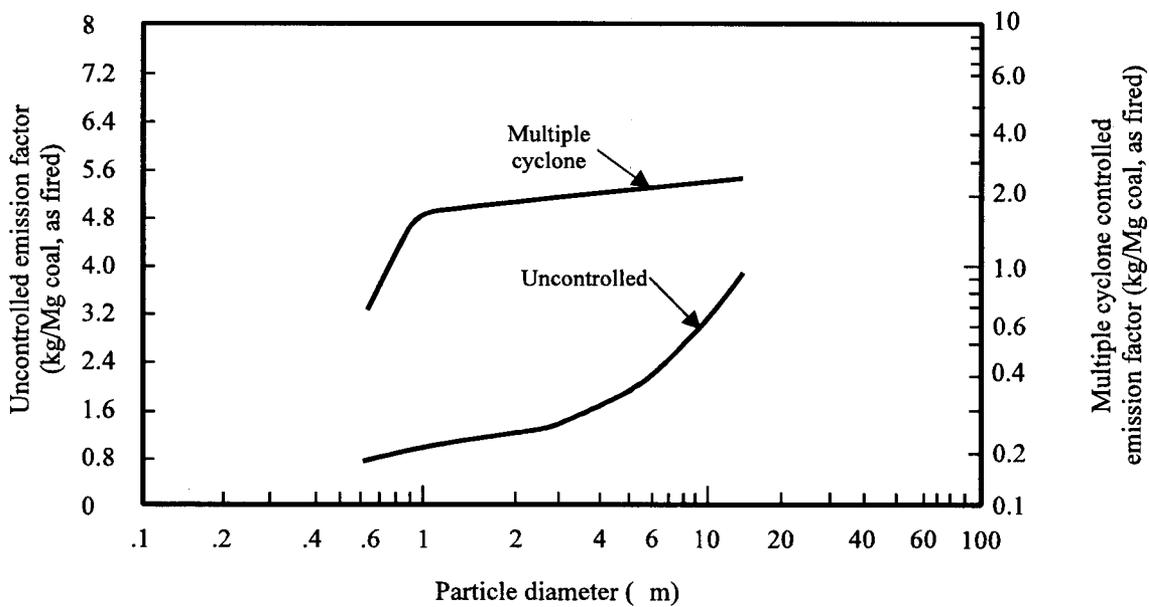


Figure 1.1-5. Cumulative size-specific emission factors for an example overfeed stoker burning bituminous coal.

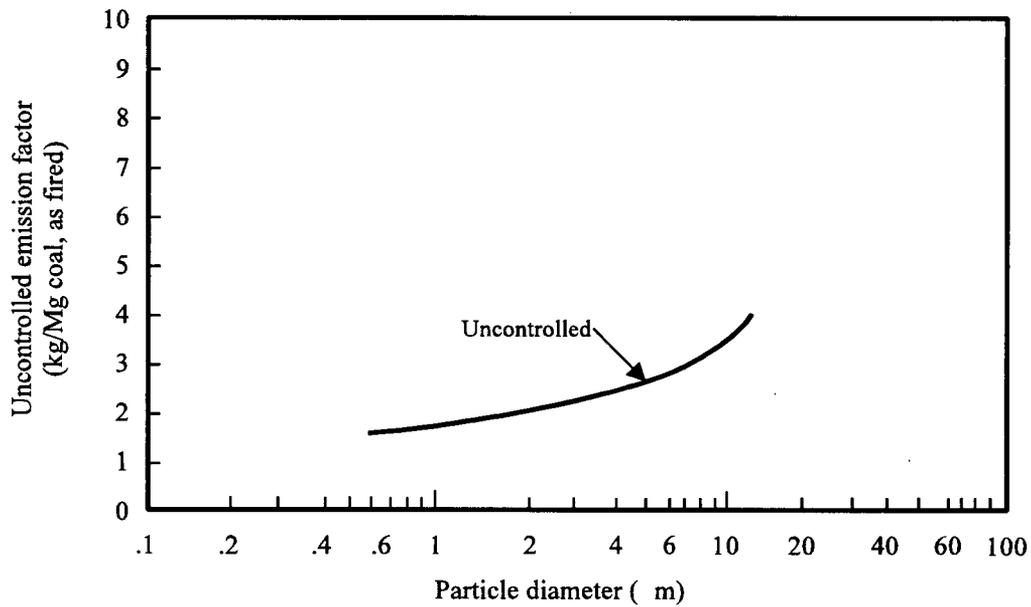


Figure 1.1-6. Cumulative size-specific emission factors for an example underfeed stoker burning bituminous coal.

References For Section 1.1

1. Bartok, B., Sarofina, A. F. (eds), *Fossil Fuel Combustion, A Source Book*, John Wiley & Sons, Inc., 1991, p. 239.
2. *Steam: It Generation And Use*, 38th Edition, Babcock and Wilcox, New York, 1975.
3. *Combustion. Fossil Power Systems. Third Edition.* Published by Combustion Engineering, Inc. Windsor, CT., 1981.
4. *Emission Factor Documentation For AP-42 Section 1.1 Bituminous and Subbituminous Coal Combustion*, U. S. Environmental Protection Agency, Research Triangle Park, NC, April 1993.
5. *Control Techniques For Nitrogen Oxides Emissions From Stationary Sources*, 2nd Edition, EPA-450/1-78-001, U. S. Environmental Protection Agency, Research Triangle Park, NC, January 1978.
6. *Review Of NO_x Emission Factors For Stationary Fossil Fuel Combustion Sources*, EPA-450/4-79-021, U. S. Environmental Protection Agency, Research Triangle Park, NC, September 1979.
7. K. J. Lim, *et al.*, *Technology Assessment Report For Industrial Boiler Applications: NO_x Combustion Modification*, EPA-600/7-79-178f, U. S. Environmental Protection Agency, Research Triangle Park, NC, December 1979.
8. Particulate Polycyclic Organic Matter, National Academy of Sciences, Washington, DC, 1972.
9. Vapor Phase Organic Pollutants- Volatile Hydrocarbons and Oxidation Products, National Academy of Sciences, Washington, DC, 1976.
10. D. H. Klein, *et al.*, "Pathways of Thirty-Seven Trace Elements Through Coal-Fired Power Plants", *Environmental Science and Technology*, 9:973-979, 1975.
11. D. G. Coles, *et al.*, "Chemical Studies of Stack Fly Ash from a Coal-Fired Power Plant", *Environmental Science and Technology*, 13:455-459, 1979.
12. S. Baig, *et al.*, *Conventional Combustion Environmental Assessment*, EPA Contract No. 68-02-3138, U. S. Environmental Protection Agency, Research Triangle Park, NC, 1981.
13. L. P. Nelson, *et al.*, *Global Combustion Sources of Nitrous Oxide Emissions*, Research Project 2333-4 Interim Report, Sacramento: Radian Corporation, 1991.
14. R. L. Peer, *et al.*, *Characterization of Nitrous Oxide Emission Sources*, U. S. Environmental Protection Agency, Office of Research and Development, Research Triangle Park, NC, 1995.
15. S. D. Piccot, *et al.*, *Emissions and Cost Estimates for Globally Significant Anthropogenic Combustion Sources of NO_x , N_2O , CH_4 , CO , and CO_2* , U. S. Environmental Protection Agency, Office of Research and Development, Research Triangle Park, NC, 1990.

16. G. Marland and R. M. Rotty, *Carbon Dioxide Emissions from Fossil Fuels: A Procedure For Estimation and Results For 1951-1981*, DOE/NBB-0036 TR-003, Carbon Dioxide Research Division, Office of Energy Research, U.S. Department of Energy, Oak Ridge, TN, 1983.
17. G. Marland and R. M. Rotty, *Carbon Dioxide Emissions from Fossil Fuels: A Procedure For Estimation and Results For 1950-1982*, *Tellus*, 36B: 232-261.
18. *Sector-Specific Issues and Reporting Methodologies Supporting the General Guidelines for the Voluntary Reporting of Greenhouse Gases under Section 1605(b) of the Energy Policy Act of 1992* (1994) DOE/PO-0028, Volume 2 of 3, U.S. Department of Energy.
19. *Control Techniques For Sulfur Dioxide Emissions From Stationary Sources, 2nd Edition*, EPA-450/3-81-004, U. S. Environmental Protection Agency, Research Triangle Park, NC, April 1981.
20. *Alternative Control Techniques Document--NO_x Emissions From Utility Boilers*, EPA-453/R-94-023, March 1994, pp. 2-15, 2-18, 5-103.
21. *Emission Factor Documentation For AP-42, Section 1.1, Bituminous and Subbituminous Coal Combustion*, Prepared by Acurex Environmental Corp., Edward Aul & Associates, Inc., E. H. Pechan And Associates, Inc., EPA Contract No. 68-D0-11210, April 1993.
22. Carlo Castaldini, and Meredith Angwin, *Boiler Design And Operating Variables Affecting Uncontrolled Sulfur Emissions From Pulverized Coal Fired Steam Generators*, EPA-450/3-77-047, U. S. Environmental Protection Agency, Research Triangle Park, NC, December 1977.
23. K. Cushing, *et al.*, "Fabric Filtration Experience Downstream From Atmospheric Fluidized Bed Combustion Boilers", Presented at the Ninth Particulate Control Symposium, October 1991.
24. Susan Stamey-Hall, *Evaluation of Nitrogen Oxide Emissions Data from TVA Coal-Fired Boilers*, EPA-600/R-92-242, U. S. Environmental Protection Agency, Research Triangle Park, NC, December 1992.
25. Joel Vatsky and Timothy W. Sweeney, *Development of an Ultra-Low No_x Pulverizer Coal Burner*, Presented at the EPA/EPRI 1991 Joint Symposium on Combustion No_x Control, March 25-28, 1991, Washington, DC.
26. T. L. Lu, R. L. Lungren, and A. Kokkinos, *Performance of a Large Cell-Burner Utility Boiler Retrofitted with Foster Wheeler Low-NO_x Burners*, Presented at the EPA/EPRI 1991 Joint Symposium on Combustion NO_x Control, March 25-28, 1991, Washington, DC.
27. *Alternative Control Techniques Document NO_x Emissions from Utility Boilers*, EPA-453/R-94-023, U. S. Environmental Protection Agency, Research Triangle Park, NC, March 1994.
28. *Standards Of Performance For New Stationary Sources*, 36 FR 24876, December 23, 1971.

29. *Field Tests Of Industrial Stoker Coal Fired Boilers For Emission Control And Efficiency Improvement - Sites L1 - 17*, EPA-600/7-81-020a, U. S. Environmental Protection Agency, Washington, DC, February 1981.
30. *Application Of Combustion Modifications To Control Pollutant Emissions From Industrial Boilers Phase I*, EPA-650/2-74-078a, U. S. Environmental Protection Agency, Washington, DC, October 1974.
31. *Source Sampling Residential Fireplaces For Emission Factor Development*, EPA-50/3-6-010, U. S. Environmental Protection Agency, Research Triangle Park, NC, November 1975.
32. *Atmospheric Emissions From Coal Combustion: An Inventory Guide*, 999-AP-24, U. S. Environmental Protection Agency, Washington, DC, April 1966.
33. *Inhalable Particulate Source Category Report For External Combustion Sources*, EPA Contract No. 68-02-3156, Acurex Corporation, Mountain View, CA, January 1985.
34. Results of the March 28, 1990 Dioxin Emission Performance Test on Unit 3 at the NSP Sherco Plant in Becker, Minnesota. Interpoll Laboratories, Inc., Circle Pines, Minnesota. July 11, 1990.
35. Field Chemical Emissions Monitoring Project: Site 22 Emissions Report. Radian Corporation, Austin, Texas. February, 1994.
36. Toxics Assessment Report. Illinois Power Company. Baldwin Power Station- Unit 2. Baldwin, Illinois. Volumes I- Main Report. Roy F. Weston, Inc. West Chester, Pennsylvania. December, 1993.
37. Toxics Assessment Report. Minnesota Power Company Boswell Energy Center- Unit 2. Cohasset, Minnesota. Volume 1-Main Report. Roy F. Weston, Inc. West Chester, Pennsylvania. December, 1993. (EPRI Report)
38. Field Chemical Emissions Monitoring Project: Site 11 Emissions Monitoring. Radian Corporation, Austin, Texas. October, 1992. (EPRI Report)
39. Field Chemical Emissions Monitoring Project: Site 21 Emissions Monitoring. Radian Corporation, Austin, Texas. August, 1993. (EPRI Report)
40. Field Chemical Emissions Monitoring Project: Site 111 Emissions Report. Radian Corporation, Austin, Texas. May, 1993. (EPRI Report)
41. Field Chemical Emissions Monitoring Project: Site 115 Emissions Report. Radian Corporation, Austin, Texas. November, 1994. (EPRI Report)
42. Draft Final Report. A Study of Toxic Emissions from a Coal-Fired Power Plant-Niles Station No. 2. Volumes One, Two, and Three. Battelle, Columbus, Ohio. December 29, 1993.
43. Draft Final Report. A Study of Toxic Emissions from a Coal-Fired Power Plant Utilizing an ESP/Wet FGD System. Volumes One, Two, and Three. Battelle, Columbus, Ohio. December 1993.

44. Assessment of Toxic Emissions From a Coal Fired Power Plant Utilizing an ESP. Final Report-Revision 1. Energy and Environmental Research Corporation, Irvine, California. December 23, 1993.
45. 500-MW Demonstration of Advanced Wall-Fired Combustion Techniques for the Reduction of Nitrogen Oxide (NOx) Emissions from Coal-Fired Boilers. Radian Corporation, Austin, Texas.
46. Results of the November 7, 1991 Air Toxic Emission Study on the Nos. 3, 4, 5 & 6 Boilers at the NSP High Bridge Plant. Interpoll Laboratories, Inc., Circle Pines, Minnesota. January 3, 1992.
47. Results of the December 1991 Air Toxic Emission Study on Units 6 & 7 at the NSP Riverside Plant. Interpoll Laboratories, Inc., Circle Pines, Minnesota. February 28, 1992.
48. Field Chemical Emissions Monitoring Project: Site 10 Emissions Monitoring. Radian Corporation, Austin, Texas. October, 1992. (EPRI Report)
49. Field Chemical Emissions Monitoring Project: Site 12 Emissions Monitoring. Radian Corporation, Austin, Texas. November, 1992. (EPRI Report)
50. Field Chemical Emissions Monitoring Project: Site 15 Emissions Monitoring. Radian Corporation, Austin, Texas. October, 1992. (EPRI Report)
51. Field Chemical Emissions Monitoring Project: Site 101 Emissions Report. Radian Corporation, Austin, Texas. October, 1994. (EPRI Report)
52. Field Chemical Emissions Monitoring Project: Site 114 Report. Radian Corporation, Austin, Texas. May, 1994. (EPRI Report)
53. Field Chemical Emissions Monitoring Report: Site 122. Final Report, Task 1 Third Draft. EPRI RP9028-10. Southern Research Institute, Birmingham, Alabama. May, 1995. (EPRI Report)
54. *Hydrogen Chloride And Hydrogen Fluoride Emission Factors For The NAPAP Inventory*, EPA-600/7-85-041, U. S. Environmental Protection Agency, October 1985.
55. *Electric Utility Trace Substances Synthesis Report, Volume 1*, Report TR-104614, Electric Power Research Institute, Palo Alto, CA, November 1994.
56. *Locating And Estimating Air Emissions From Sources Of Chromium*, EPA-450/4-84-007g, U. S. Environmental Protection Agency, July 1984.
57. *Locating And Estimating Air Emissions From Sources Of Formaldehyde*, (Revised), EPA-450/4-91-012, U. S. Environmental Protection Agency, March 1991.
58. *Estimating Air Toxics Emissions From Coal And Oil Combustion Sources*, EPA-450/2-89-001, Radian Corporation, Project Officer: Dallas W. Safriet, Research Triangle Park, NC, April 1989.
59. *Canadian Coal-Fired Plants, Phase I: Final Report And Appendices*, Report for the Canadian Electrical Association, R&D, Montreal, Quebec, Contract Number 001G194, Report by Battelle, Pacific Northwest Laboratories, Richland, WA.

60. R. Meij, Auteru dr., *The Fate Of Trace Elements At Coal-Fired Plants*, Report No. 2561-MOC 92-3641, Rapport te bestellen bij; bibliotheek N.V. KEMA, February 13, 1992.
61. *Locating And Estimating Air Emissions From Sources Of Manganese*, EPA-450/4-84-007h, September 1985.
62. Results of the September 10 and 11, 1991 Mercury Removal Tests on the Units 1 & 2, and Unit 3 Scrubber Systems at the NSP Sherco Plant in Becker, Minnesota. Interpoll Laboratories, Inc., Circle Pines, Minnesota. October 30, 1991.
63. Results of the November 5, 1991 Air Toxic Emission Study on the No. 1, 3 & 4 Boilers at the NSP Black Dog Plant. Interpoll Laboratories, Inc., Circle Pines, Minnesota. January 3, 1992.
64. Results of the January 1992 Air Toxic Emission Study on the No. 2 Boiler at the NSP Black Dog Plant. Interpoll Laboratories, Inc., Circle Pines, Minnesota. May 4, 1992.
65. Results of the May 29, 1990 Trace Metal Characterization Study on Units 1 and 2 at the Sherburne County Generating Station in Becker, Minnesota. Interpoll Laboratories, Inc., Circle Pines, Minnesota. July, 1990.
66. Results of the May 1, 1990 Trace Metal Characterization Study on Units 1 and 2 at the Sherburne County Generating Station. Interpoll Laboratories, Inc., Circle Pines, Minnesota. July 18, 1990.
67. Results of the March 1990 Trace Metal Characterization Study on Unit 3 at the Sherburne County Generating Station. Interpoll Laboratories, Circle Pines, Minnesota. June 7, 1990.
68. Field Chemical Emissions Monitoring Project: Site 19 Emissions Monitoring. Radian Corporation, Austin, Texas. April, 1993. (EPRI Report)
69. Field Chemical Emissions Monitoring Project: Site 20 Emissions Monitoring. Radian Corporation, Austin, Texas. March, 1994. (EPRI Report)
70. Characterizing Toxic Emissions from a Coal-Fired Power Plant Demonstrating the AFGD ICCT Project and a Plant Utilizing a Dry Scrubber /Baghouse System. Final Draft Report. Springerville Generating Station Unit No. 2. Southern Research Insititue, Birmingham, Alabama. December, 1993.
71. *Emissions Of Reactive Volatile Organic Compounds From Utility Boilers*, EPA-600/7-80-111, U. S. Environmental Protection Agency, Washington, DC, May 1980.
72. *EPA/IFP European Workshop On The Emission Of Nitrous Oxide For Fuel Combustion*, EPA Contract No. 68-02-4701, Rueil-Malmaison, France, June 1-2, 1988.
73. R. Clayton, *et al.*, *NO_x Field Study*, EPA-600/2-89-006, U. S. Environmental Protection Agency, Research Triangle Park, NC, February 1989.
74. L. E. Amand, and S. Anderson, "Emissions of Nitrous Oxide from Fluidized Bed Boilers", Presented at the Tenth International Conference on Fluidized Bed Combustor, San Francisco, CA, 1989.

75. *Alternative Control Techniques Document--NO_x Emissions From Utility Boilers*, EPA-453/R-94-023, Office of Air Quality Standards, Research Triangle Park, NC, 1994.
76. Alliance Technologies Corporation, *Evaluation of Significant Anthropogenic Sources of Radiatively Important Trace Gases*, U. S. Environmental Protection Agency, Office of Research and Development, Research Triangle Park, NC, 1990.
77. R. A. Winschel, Richard, "The Relationship of Carbon Dioxide Emissions with Coal Rank and Sulfur Content," *Journal of the Air and Waste Management Association*, Vol. 40, no. 6, pp. 861-865, June 1990.
78. Public Service Electric and Gas Company Mercer Generating Station Unit No. 2 Emission Compliance Test Program. November 1994.
79. Particulate Emission Study Performed for Madison Gas and Electric Company at the Blount Street Station Units 7, 8, 9 Inlets/Outlets. Mostardi-Platt Associates, Inc. December 6, 1994.
80. Particulate Emission Study Performed for Marshfield Electric and Water Department at the Wildwood Station Marshfield Wisconsin Boiler 5 Stack. Mostardi-Platt Associates, Inc. January 23-25, 1990.
81. Report on Particulate, SO₂, and NO_x Compliance Testing. Dairyland Power Cooperative J.P. Madgett Stack. Alma, Wisconsin. CAE. January 6, 1995.
82. Particulate Emissions Test Results. Portland General Electric Coal-fired Power Plant. Boardman, Oregon. SAIC, Inc. January 25, 1994.
83. Report on Compliance Testing Performed at Marshfield Electric and Water Department Wildwood Station Unit 5, Marshfield, Wisconsin. Clean Air Engineering, December 11, 1989.
84. Portland General Electric Company Boardman Coal Plant. Unit #1 Coal-fired Boiler. Boardman, Oregon. August 24-27, 1995.
85. Particulate Emission Compliance Study Performed for Portland General Electric at the Boardman Plant Unit 1 Stack. Boardman, Oregon. September 19, 1996.
86. Emissions Source Test Report. Portland General Electric Coal-Fired Power Plant. Boardman, Oregon. OMNI Environmental Services, Inc. October 17, 1990.
87. Source Emissions Test Report Compliance. Portland General Electric Coal-Fired Power Plant. Boardman, Oregon. OMNI Environmental Services. January 29, 1991.
88. Source Test Report. Particulate Emissions. Portland General Electric Coal-Fired Power Plant. Boardman, Oregon. OMNI Environmental Services, Inc. January 14, 1991.
89. Emissions Source Test Report. Portland General Electric Coal-Fired Power Plant. Boardman, Oregon. OMNI Environmental Services, Inc. April 3, 1991.
90. Source Emissions Test Report. Portland General Electric Coal-Fired Power Plant. Boardman, Oregon. OMNI Environmental Services, Inc. January 21, 1992.

91. Particulate Emissions Test Results. Portland General Electric Coal-fired Power Plant. Boardman, Oregon. OMNI Environmental Services, Inc. April 4, 1992.
92. Particulate Emissions Test Results. Portland General Electric Coal-Fired Power Plant. Boardman, Oregon. OMNI Environmental Services, Inc. September 9, 1992.
93. Particulate Emissions Test Results. Portland General Electric Coal-Fired Power Plant. Boardman, Oregon. OMNI Environmental Services, Inc. November 6, 1992.
94. Particulate Emissions Test Results. Portland General Electric Coal-Fired Power Plant. Boardman, Oregon. OMNI Environmental Services, Inc. January 26, 1993.
95. Stationary Source Sampling Report. Keystone Cogeneration Facility. Keystone Cogeneration Facility. Logan Township, NJ. November 1994.
96. Source Emissions Survey of City Public Service Board J.K. Spruce Unit Number 1 Stack. METCO Environmental. December 1992.
97. Report of Particulate Emission Testing on the Number 1 Boiler at Associated Milk Products Incorporated Located in Jim Falls, Wisconsin. Environmental Services of American, Inc. November 1994.
98. Appleton Papers, Inc. Boiler Emission Test at Appleton, WI. May 11 and 12, 1993. Badger Laboratories and Engineering.
99. Appleton Papers, Inc. Boiler Emission Test Report at Appleton, WI. Badger Laboratories and Engineering. October 11, 1993.
100. Results of a Source Emission Compliance Test on Boiler #2 at the Hills Farm Heating Plant, Madison, Wisconsin. MMT Environmental Services, Inc. January 22, 1993.
101. Results of a Source Emission Compliance Test on Boiler #2 at the Hills Farm Heating Plant, Madison, Wisconsin. MMT Environmental Services, Inc. March 2, 1995.
102. Report to Mosinee Paper Company for Particulate Matter Emission Testing. No. 6 Boiler at Mosinee, Wisconsin. May 18, 19, and 20, 1993.
103. Report to Milwaukee County for Particulate Matter Emission Test Boiler No. 21. Environmental Technology and Engineering Corporation. November 5, 1991.
104. Report on Compliance Testing Conducted at Oscar Mayer Foods Corporation, Madison, Wisconsin. Clean Air Engineering. July 21, 1989.

3.1 Stationary Gas Turbines

3.1.1 General¹

Gas turbines, also called "combustion turbines", are used in a broad scope of applications including electric power generation, cogeneration, natural gas transmission, and various process applications. Gas turbines are available with power outputs ranging in size from 300 horsepower (hp) to over 268,000 hp, with an average size of 40,200 hp.² The primary fuels used in gas turbines are natural gas and distillate (No. 2) fuel oil.³

3.1.2 Process Description^{1,2}

A gas turbine is an internal combustion engine that operates with rotary rather than reciprocating motion. Gas turbines are essentially composed of three major components: compressor, combustor, and power turbine. In the compressor section, ambient air is drawn in and compressed up to 30 times ambient pressure and directed to the combustor section where fuel is introduced, ignited, and burned. Combustors can either be annular, can-annular, or silo. An annular combustor is a doughnut-shaped, single, continuous chamber that encircles the turbine in a plane perpendicular to the air flow. Can-annular combustors are similar to the annular; however, they incorporate several can-shaped combustion chambers rather than a single continuous chamber. Annular and can-annular combustors are based on aircraft turbine technology and are typically used for smaller scale applications. A silo (frame-type) combustor has one or more combustion chambers mounted external to the gas turbine body. Silo combustors are typically larger than annular or can-annular combustors and are used for larger scale applications.

The combustion process in a gas turbine can be classified as diffusion flame combustion, or lean-premix staged combustion. In the diffusion flame combustion, the fuel/air mixing and combustion take place simultaneously in the primary combustion zone. This generates regions of near-stoichiometric fuel/air mixtures where the temperatures are very high. For lean-premix combustors, fuel and air are thoroughly mixed in an initial stage resulting in a uniform, lean, unburned fuel/air mixture which is delivered to a secondary stage where the combustion reaction takes place. Manufacturers use different types of fuel/air staging, including fuel staging, air staging, or both; however, the same staged, lean-premix principle is applied. Gas turbines using staged combustion are also referred to as Dry Low NO_x combustors. The majority of gas turbines currently manufactured are lean-premix staged combustion turbines.

Hot gases from the combustion section are diluted with additional air from the compressor section and directed to the power turbine section at temperatures up to 2600°F. Energy from the hot exhaust gases, which expand in the power turbine section, are recovered in the form of shaft horsepower. More than 50 percent of the shaft horsepower is needed to drive the internal compressor and the balance of recovered shaft horsepower is available to drive an external load.² Gas turbines may have one, two, or three shafts to transmit power between the inlet air compression turbine, the power turbine, and the exhaust turbine. The heat content of the exhaust gases exiting the turbine can either be discarded without heat recovery (simple cycle); recovered with a heat exchanger to preheat combustion air entering the combustor (regenerative cycle); recovered in a heat recovery steam generator to raise process steam, with or without supplementary firing (cogeneration); or recovered, with or without supplementary firing, to raise steam for a steam turbine Rankine cycle (combined cycle or repowering).

The simple cycle is the most basic operating cycle of gas turbines with a thermal efficiency ranging from 15 to 42 percent. The cycle thermal efficiency is defined as the ratio of useful shaft energy to fuel energy input. Simple cycle gas turbines are typically used for shaft horsepower applications without recovery of exhaust heat. For example, simple cycle gas turbines are used by electric utilities for generation of electricity during emergencies or during peak demand periods.

A regenerative cycle is a simple cycle gas turbine with an added heat exchanger. The heat exchanger uses the turbine exhaust gases to heat the combustion air which reduces the amount of fuel required to reach combustor temperatures. The thermal efficiency of a regenerative cycle is approximately 35 percent. However, the amount of fuel efficiency and saving may not be sufficient to justify the capital cost of the heat exchanger, rendering the process unattractive.

A cogeneration cycle consists of a simple cycle gas turbine with a heat recovery steam generator (HRSG). The cycle thermal efficiency can be as high as 84 percent. In a cogeneration cycle, the steam generated by the HRSG can be delivered at a variety of pressures and temperatures to other thermal processes at the site. For situations where additional steam is required, a supplementary burner, or duct burner, can be placed in the exhaust duct stream of the HRSG to meet the site's steam requirements.

A combined cycle gas turbine is a gas turbine with a HRSG applied at electric utility sites. The gas turbine drives an electric generator; and the steam from the HRSG drives a steam turbine which also drives an electric generator. A supplementary-fired boiler can be used to increase the steam production. The thermal efficiency of a combined cycle gas turbine is between 38 percent and 60 percent.

Gas turbine applications include gas and oil industry, emergency power generation facilities, independent electric power producers (IPP), electric utilities, and other industrial applications. The petroleum industry typically uses simple cycle gas turbines with a size range from 300 hp to 20,000 hp. The gas turbine is used to provide shaft horsepower for oil and gas production and transmission. Emergency power generation sites also utilize simple cycle gas turbines. Here the gas turbine is used to provide backup or emergency power to critical networks or equipment. Usually, gas turbines under 5,000 hp are used at emergency power generation sites.

Independent electrical power producers generate electricity for resale to larger electric utilities. Simple, regenerative, or combined cycle gas turbines are used at IPP; however, most installations use combined cycle gas turbines. The gas turbines used at IPP can range from 1,000 hp to over 100,000 hp. The larger electric utilities use gas turbines mostly as peaking units for meeting power demand peaks imposed by large commercial and industrial users on a daily or seasonal basis. Simple cycle gas turbines ranging from 20,000 hp to over 200,000 hp are used at these installations. Other industrial applications for gas turbines include pulp and paper, chemical, and food processing. Here, combined cycle gas turbines are used for cogeneration.

3.1.3 Emissions

The primary pollutants from gas turbine engines are nitrogen oxides (NO_x), carbon monoxide (CO), and to a lesser extent, volatile organic compounds (VOC). Particulate matter (PM) is also a primary pollutant for gas turbines using liquid fuels. Nitrogen oxide formation is strongly dependent on the high temperatures developed in the combustor. Carbon monoxide, VOC, hazardous air pollutants (HAP), and PM are primarily the result of incomplete combustion. Trace to low amounts of HAP and sulfur dioxide (SO_2) are emitted from gas turbines. Ash and metallic additives in the fuel may also contribute to PM in the exhaust. Oxides of sulfur (SO_x) will only appear in a significant quantity if heavy oils are fired

in the turbine. Emissions of sulfur compounds, mainly SO_2 , are directly related to the sulfur content of the fuel.

Available emissions data indicate that the turbine's operating load has a considerable effect on the resulting emission levels. Gas turbines are typically operated at high loads (greater than or equal to 80 percent of rated capacity) to achieve maximum thermal efficiency and peak combustor zone flame temperatures. With reduced loads (lower than 80 percent), or during periods of frequent load changes, the combustor zone flame temperatures are expected to be lower than the high load temperatures, yielding lower thermal efficiencies and more incomplete combustion. The emission factors for this sections are presented for gas turbines operating under high load conditions. Section 3.1 background information document and emissions database contain additional emissions data for gas turbines operating under various load conditions.

Gas turbines firing distillate oil may emit trace metals carried over from the metals content of the fuel. If the fuel analysis is known, the metals content of the fuel ash should be used for flue gas emission factors assuming all metals pass through the turbine.

If the HRSG is not supplementary fuel fired, the simple cycle input-specific emission factors (pounds per million British thermal units [lb/MMBtu]) will also apply to cogeneration/combined cycle systems. If the HRSG is supplementary fired, the emissions attributable to the supplementary firing must also be considered to estimate total stack emissions.

3.1.3.1 Nitrogen Oxides -

Nitrogen oxides formation occurs by three fundamentally different mechanisms. The principal mechanism with turbines firing gas or distillate fuel is thermal NO_x , which arises from the thermal dissociation and subsequent reaction of nitrogen (N_2) and oxygen (O_2) molecules in the combustion air. Most thermal NO_x is formed in high temperature stoichiometric flame pockets downstream of the fuel injectors where combustion air has mixed sufficiently with the fuel to produce the peak temperature fuel/air interface.

The second mechanism, called prompt NO_x , is formed from early reactions of nitrogen molecules in the combustion air and hydrocarbon radicals from the fuel. Prompt NO_x forms within the flame and is usually negligible when compared to the amount of thermal NO_x formed. The third mechanism, fuel NO_x , stems from the evolution and reaction of fuel-bound nitrogen compounds with oxygen. Natural gas has negligible chemically-bound fuel nitrogen (although some molecular nitrogen is present). Essentially all NO_x formed from natural gas combustion is thermal NO_x . Distillate oils have low levels of fuel-bound nitrogen. Fuel NO_x from distillate oil-fired turbines may become significant in turbines equipped with a high degree of thermal NO_x controls. Otherwise, thermal NO_x is the predominant NO_x formation mechanism in distillate oil-fired turbines.

The maximum thermal NO_x formation occurs at a slightly fuel-lean mixture because of excess oxygen available for reaction. The control of stoichiometry is critical in achieving reductions in thermal NO_x . Thermal NO_x formation also decreases rapidly as the temperature drops below the adiabatic flame temperature, for a given stoichiometry. Maximum reduction of thermal NO_x can be achieved by control of both the combustion temperature and the stoichiometry. Gas turbines operate with high overall levels of excess air, because turbines use combustion air dilution as the means to maintain the turbine inlet temperature below design limits. In older gas turbine models, where combustion is in the form of a diffusion flame, most of the dilution takes place downstream of the primary flame, which does not minimize peak temperature in the flame and suppress thermal NO_x formation.

Diffusion flames are characterized by regions of near-stoichiometric fuel/air mixtures where temperatures are very high and significant thermal NO_x is formed. Water vapor in the turbine inlet air contributes to the lowering of the peak temperature in the flame, and therefore to thermal NO_x emissions. Thermal NO_x can also be reduced in diffusion type turbines through water or steam injection. The injected water-steam acts as a heat sink lowering the combustion zone temperature, and therefore thermal NO_x . Newer model gas turbines use lean, premixed combustion where the fuel is typically premixed with more than 50 percent theoretical air which results in lower flame temperatures, thus suppressing thermal NO_x formation.

Ambient conditions also affect emissions and power output from turbines more than from external combustion systems. The operation at high excess air levels and at high pressures increases the influence of inlet humidity, temperature, and pressure.⁴ Variations of emissions of 30 percent or greater have been exhibited with changes in ambient humidity and temperature. Humidity acts to absorb heat in the primary flame zone due to the conversion of the water content to steam. As heat energy is used for water to steam conversion, the temperature in the flame zone will decrease resulting in a decrease of thermal NO_x formation. For a given fuel firing rate, lower ambient temperatures lower the peak temperature in the flame, lowering thermal NO_x significantly. Similarly, the gas turbine operating loads affect NO_x emissions. Higher NO_x emissions are expected for high operating loads due to the higher peak temperature in the flame zone resulting in higher thermal NO_x .

3.1.3.2 Carbon Monoxide and Volatile Organic Compounds -

CO and VOC emissions both result from incomplete combustion. CO results when there is insufficient residence time at high temperature or incomplete mixing to complete the final step in fuel carbon oxidation. The oxidation of CO to CO_2 at gas turbine temperatures is a slow reaction compared to most hydrocarbon oxidation reactions. In gas turbines, failure to achieve CO burnout may result from quenching by dilution air. With liquid fuels, this can be aggravated by carryover of larger droplets from the atomizer at the fuel injector. Carbon monoxide emissions are also dependent on the loading of the gas turbine. For example, a gas turbine operating under a full load will experience greater fuel efficiencies which will reduce the formation of carbon monoxide. The opposite is also true, a gas turbine operating under a light to medium load will experience reduced fuel efficiencies (incomplete combustion) which will increase the formation of carbon monoxide.

The pollutants commonly classified as VOC can encompass a wide spectrum of volatile organic compounds some of which are hazardous air pollutants. These compounds are discharged into the atmosphere when some of the fuel remains unburned or is only partially burned during the combustion process. With natural gas, some organics are carried over as unreacted, trace constituents of the gas, while others may be pyrolysis products of the heavier hydrocarbon constituents. With liquid fuels, large droplet carryover to the quench zone accounts for much of the unreacted and partially pyrolyzed volatile organic emissions.

Similar to CO emissions, VOC emissions are affected by the gas turbine operating load conditions. Volatile organic compounds emissions are higher for gas turbines operating at low loads as compared to similar gas turbines operating at higher loads.

3.1.3.3 Particulate Matter¹³ -

PM emissions from turbines primarily result from carryover of noncombustible trace constituents in the fuel. PM emissions are negligible with natural gas firing and marginally significant with distillate oil firing because of the low ash content. PM emissions can be classified as "filterable" or "condensable" PM. Filterable PM is that portion of the total PM that exists in the stack in either the solid or liquid state and

can be measured on a EPA Method 5 filter. Condensable PM is that portion of the total PM that exists as a gas in the stack but condenses in the cooler ambient air to form particulate matter. Condensable PM exists as a gas in the stack, so it passes through the Method 5 filter and is typically measured by analyzing the impingers, or "back half" of the sampling train. The collection, recovery, and analysis of the impingers is described in EPA Method 202 of Appendix M, Part 51 of the Code of Federal Regulations. Condensable PM is composed of organic and inorganic compounds and is generally considered to be all less than 1.0 micrometers in aerodynamic diameter.

3.1.3.4 Greenhouse Gases⁵⁻¹¹ -

Carbon dioxide (CO₂) and nitrous oxide (N₂O) emissions are all produced during natural gas and distillate oil combustion in gas turbines. Nearly all of the fuel carbon is converted to CO₂ during the combustion process. This conversion is relatively independent of firing configuration. Methane (CH₄) is also present in the exhaust gas and is thought to be unburned fuel in the case of natural gas or a product of combustion in the case of distillate fuel oil.

Although the formation of CO acts to reduce CO₂ emissions, the amount of CO produced is insignificant compared to the amount of CO₂ produced. The majority of the fuel carbon not converted to CO₂ is due to incomplete combustion.

Formation of N₂O during the combustion process is governed by a complex series of reactions and its formation is dependent upon many factors. However, the formation of N₂O is minimized when combustion temperatures are kept high (above 1475°F) and excess air is kept to a minimum (less than 1 percent).

3.1.3.5 HAP Emissions -

Available data indicate that emission levels of HAP are lower for gas turbines than for other combustion sources. This is due to the high combustion temperatures reached during normal operation. The emissions data also indicate that formaldehyde is the most significant HAP emitted from combustion turbines. For natural gas fired turbines, formaldehyde accounts for about two-thirds of the total HAP emissions. Polycyclic aromatic hydrocarbons (PAH), benzene, toluene, xylenes, and others account for the remaining one-third of HAP emissions. For No. 2 distillate oil-fired turbines, small amount of metallic HAP are present in the turbine's exhaust in addition to the gaseous HAP identified under gas fired turbines. These metallic HAP are carried over from the fuel constituents. The formation of carbon monoxide during the combustion process is a good indication of the expected levels of HAP emissions. Similar to CO emissions, HAP emissions increase with reduced operating loads. Typically, combustion turbines operate under full loads for greater fuel efficiency, thereby minimizing the amount of CO and HAP emissions.

3.1.4 Control Technologies¹²

There are three generic types of emission controls in use for gas turbines, wet controls using steam or water injection to reduce combustion temperatures for NO_x control, dry controls using advanced combustor design to suppress NO_x formation and/or promote CO burnout, and post-combustion catalytic control to selectively reduce NO_x and/or oxidize CO emission from the turbine. Other recently developed technologies promise significantly lower levels of NO_x and CO emissions from diffusion combustion type gas turbines. These technologies are currently being demonstrated in several installations.

Emission factors in this section have been determined from gas turbines with no add-on control devices (uncontrolled emissions). For NO_x and CO emission factors for combustion controls, such as water-steam injection, and lean pre-mix units are presented. Additional information for controlled

emissions with various add-on controls can be obtained using the section 3.1 database. Uncontrolled, lean-premix, and water injection emission factors were presented for NO_x and CO to show the effect of combustion modification on emissions.

3.1.4.1 Water Injection -

Water or steam injection is a technology that has been demonstrated to effectively suppress NO_x emissions from gas turbines. The effect of steam and water injection is to increase the thermal mass by dilution and thereby reduce peak temperatures in the flame zone. With water injection, there is an additional benefit of absorbing the latent heat of vaporization from the flame zone. Water or steam is typically injected at a water-to-fuel weight ratio of less than one.

Depending on the initial NO_x levels, such rates of injection may reduce NO_x by 60 percent or higher. Water or steam injection is usually accompanied by an efficiency penalty (typically 2 to 3 percent) but an increase in power output (typically 5 to 6 percent). The increased power output results from the increased mass flow required to maintain turbine inlet temperature at manufacturer's specifications. Both CO and VOC emissions are increased by water injection, with the level of CO and VOC increases dependent on the amount of water injection.

3.1.4.2 Dry Controls -

Since thermal NO_x is a function of both temperature (exponentially) and time (linearly), the basis of dry controls are to either lower the combustor temperature using lean mixtures of air and/or fuel staging, or decrease the residence time of the combustor. A combination of methods may be used to reduce NO_x emissions such as lean combustion and staged combustion (two stage lean/lean combustion or two stage rich/lean combustion).

Lean combustion involves increasing the air-to-fuel ratio of the mixture so that the peak and average temperatures within the combustor will be less than that of the stoichiometric mixture, thus suppressing thermal NO_x formation. Introducing excess air not only creates a leaner mixture but it also can reduce residence time at peak temperatures.

Two-stage lean/lean combustors are essentially fuel-staged, premixed combustors in which each stage burns lean. The two-stage lean/lean combustor allows the turbine to operate with an extremely lean mixture while ensuring a stable flame. A small stoichiometric pilot flame ignites the premixed gas and provides flame stability. The NO_x emissions associated with the high temperature pilot flame are insignificant. Low NO_x emission levels are achieved by this combustor design through cooler flame temperatures associated with lean combustion and avoidance of localized "hot spots" by premixing the fuel and air.

Two stage rich/lean combustors are essentially air-staged, premixed combustors in which the primary zone is operated fuel rich and the secondary zone is operated fuel lean. The rich mixture produces lower temperatures (compared to stoichiometric) and higher concentrations of CO and H₂, because of incomplete combustion. The rich mixture also decreases the amount of oxygen available for NO_x generation. Before entering the secondary zone, the exhaust of the primary zone is quenched (to extinguish the flame) by large amounts of air and a lean mixture is created. The lean mixture is pre-ignited and the combustion completed in the secondary zone. NO_x formation in the second stage are minimized through combustion in a fuel lean, lower temperature environment. Staged combustion is identified through a variety of names, including Dry-Low NO_x (DLN), Dry-Low Emissions (DLE), or SoLoNO_x.

3.1.4.3 Catalytic Reduction Systems -

Selective catalytic reduction (SCR) systems selectively reduce NO_x emissions by injecting ammonium (NH_3) into the exhaust gas stream upstream of a catalyst. Nitrogen oxides, NH_3 , and O_2 react on the surface of the catalyst to form N_2 and H_2O . The exhaust gas must contain a minimum amount of O_2 and be within a particular temperature range (typically 450°F to 850°F) in order for the SCR system to operate properly.

The temperature range is dictated by the catalyst material which is typically made from noble metals, including base metal oxides such as vanadium and titanium, or zeolite-based material. The removal efficiency of an SCR system in good working order is typically from 65 to 90 percent. Exhaust gas temperatures greater than the upper limit (850°F) cause NO_x and NH_3 to pass through the catalyst unreacted. Ammonia emissions, called NH_3 slip, may be a consideration when specifying an SCR system.

Ammonia, either in the form of liquid anhydrous ammonia, or aqueous ammonia hydroxide is stored on site and injected into the exhaust stream upstream of the catalyst. Although an SCR system can operate alone, it is typically used in conjunction with water-steam injection systems or lean-premix system to reduce NO_x emissions to their lowest levels (less than 10 ppm at 15 percent oxygen for SCR and wet injection systems). The SCR system for landfill or digester gas-fired turbines requires a substantial fuel gas pretreatment to remove trace contaminants that can poison the catalyst. Therefore, SCR and other catalytic treatments may be inappropriate control technologies for landfill or digester gas-fired turbines.

The catalyst and catalyst housing used in SCR systems tend to be very large and dense (in terms of surface area to volume ratio) because of the high exhaust flow rates and long residence times required for NO_x , O_2 , and NH_3 , to react on the catalyst. Most catalysts are configured in a parallel-plate, "honeycomb" design to maximize the surface area-to-volume ratio of the catalyst. Some SCR installations incorporate CO catalytic oxidation modules along with the NO_x reduction catalyst for simultaneous CO/ NO_x control.

Carbon monoxide oxidation catalysts are typically used on turbines to achieve control of CO emissions, especially turbines that use steam injection, which can increase the concentrations of CO and unburned hydrocarbons in the exhaust. CO catalysts are also being used to reduce VOC and organic HAPs emissions. The catalyst is usually made of a precious metal such as platinum, palladium, or rhodium. Other formulations, such as metal oxides for emission streams containing chlorinated compounds, are also used. The CO catalyst promotes the oxidation of CO and hydrocarbon compounds to carbon dioxide (CO_2) and water (H_2O) as the emission stream passes through the catalyst bed. The oxidation process takes place spontaneously, without the requirement for introducing reactants. The performance of these oxidation catalyst systems on combustion turbines results in 90-plus percent control of CO and about 85 to 90 percent control of formaldehyde. Similar emission reductions are expected on other HAP pollutants.

3.1.4.4 Other Catalytic Systems^{14,15} -

New catalytic reduction technologies have been developed and are currently being commercially demonstrated for gas turbines. Such technologies include, but are not limited to, the SCONOX and the XONON systems, both of which are designed to reduce NO_x and CO emissions. The SCONOX system is applicable to natural gas fired gas turbines. It is based on a unique integration of catalytic oxidation and absorption technology. CO and NO are catalytically oxidized to CO_2 and NO_2 . The NO_2 molecules are subsequently absorbed on the treated surface of the SCONOX catalyst. The system manufacturer guarantees CO emissions of 1 ppm and NO_x emissions of 2 ppm. The SCONOX system does not require the use of ammonia, eliminating the potential of ammonia slip conditions evident in existing SCR systems. Only limited emissions data were available for a gas turbine equipped with a SCONOX system. This data reflected HAP emissions and was not sufficient to verify the manufacturer's claims.

The XONON system is applicable to diffusion and lean-premix combustors and is currently being demonstrated with the assistance of leading gas turbine manufacturers. The system utilizes a flameless combustion system where fuel and air reacts on a catalyst surface, preventing the formation of NO_x while achieving low CO and unburned hydrocarbon emission levels. The overall combustion process consists of the partial combustion of the fuel in the catalyst module followed by completion of the combustion downstream of the catalyst. The partial combustion within the catalyst produces no NO_x, and the combustion downstream of the catalyst occurs in a flameless homogeneous reaction that produces almost no NO_x. The system is totally contained within the combustor of the gas turbine and is not a process for clean-up of the turbine exhaust. Note that this technology has not been fully demonstrated as of the drafting of this section. The catalyst manufacturer claims that gas turbines equipped with the XONON Catalyst emit NO_x levels below 3 ppm and CO and unburned hydrocarbons levels below 10 ppm. Emissions data from gas turbines equipped with a XONON Catalyst were not available as of the drafting of this section.

3.1.5 Updates Since the Fifth Edition

The Fifth Edition was released in January 1995. Revisions to this section since that date are summarized below. For further detail, consult the memoranda describing each supplement or the background report for this section. These and other documents can be found on the new EFIG home page (<http://www.epa.gov/ttn/chief>).

Supplement A, February 1996

- For the PM factors, a footnote was added to clarify that condensables and all PM from oil- and gas-fired turbines are considered PM-10.
- In the table for large uncontrolled gas turbines, a sentence was added to footnote "e" to indicate that when sulfur content is not available, 0.6 lb/10⁶ ft³ (0.0006 lb/MMBtu) can be used.

Supplement B, October 1996

- Text was revised and updated for the general section.
- Text was added regarding firing practices and process description.
- Text was revised and updated for emissions and controls.
- All factors for turbines with SCR-water injection control were corrected.
- The CO₂ factor was revised and a new set of N₂O factors were added.

Supplement F, April 2000

- Text was revised and updated for the general section.
- All emission factors were updated except for the SO₂ factor for natural gas and distillate oil turbines.

- Turbines using staged (lean-premix) combustors added to this section.
- Turbines used for natural gas transmission added to this section.
- Details for turbine operating configurations (operating cycles) added to this section.
- Information on new emissions control technologies added to this section (SCONOX and XONON).
- HAP emission factors added to this section based on over 400 data points taken from over 60 source tests.
- PM condensable and filterable emission factors for natural gas and distillate oil fired turbines were developed.
- NOx and CO emission factors for lean-premix turbines were added.
- Emission factors for landfill gas and digester gas were added.

Table 3.1-1. EMISSION FACTORS FOR NITROGEN OXIDES (NO_x) AND CARBON MONOXIDE (CO) FROM STATIONARY GAS TURBINES

Emission Factors ^a				
Turbine Type	Nitrogen Oxides		Carbon Monoxide	
Natural Gas-Fired Turbines ^b	(lb/MMBtu) ^c (Fuel Input)	Emission Factor Rating	(lb/MMBtu) ^c (Fuel Input)	Emission Factor Rating
Uncontrolled	3.2 E-01	A	8.2 E-02 ^d	A
Water-Steam Injection	1.3 E-01	A	3.0 E-02	A
Lean-Premix	9.9 E-02	D	1.5 E-02	D
Distillate Oil-Fired Turbines ^e	(lb/MMBtu) ^f (Fuel Input)	Emission Factor Rating	(lb/MMBtu) ^f (Fuel Input)	Emission Factor Rating
Uncontrolled	8.8 E-01	C	3.3 E-03	C
Water-Steam Injection	2.4 E-01	B	7.6 E-02	C
Landfill Gas-Fired Turbines ^g	(lb/MMBtu) ^h (Fuel Input)	Emission Factor Rating	(lb/MMBtu) ^h (Fuel Input)	Emission Factor Rating
Uncontrolled	1.4 E-01	A	4.4 E-01	A
Digester Gas-Fired Turbines ^j	(lb/MMBtu) ^k (Fuel Input)	Emission Factor Rating	(lb/MMBtu) ^k (Fuel Input)	Emission Factor Rating
Uncontrolled	1.6 E-01	D	1.7 E-02	D

^a Factors are derived from units operating at high loads (≥ 80 percent load) only. For information on units operating at other loads, consult the background report for this chapter (Reference 16), available at "www.epa.gov/ttn/chief".

^b Source Classification Codes (SCCs) for natural gas-fired turbines include 2-01-002-01, 2-02-002-01, 2-02-002-03, 2-03-002-02, and 2-03-002-03. The emission factors in this table may be converted to other natural gas heating values by multiplying the given emission factor by the ratio of the specified heating value to this average heating value.

^c Emission factors based on an average natural gas heating value (HHV) of 1020 Btu/scf at 60°F. To convert from (lb/MMBtu) to (lb/10⁶ scf), multiply by 1020.

^d It is recognized that the uncontrolled emission factor for CO is higher than the water-steam injection and lean-premix emission factors, which is contrary to expectation. The EPA could not identify the reason for this behavior, except that the data sets used for developing these factors are different.

^e SCCs for distillate oil-fired turbines include 2-01-001-01, 2-02-001-01, 2-02-001-03, and 2-03-001-02.

^f Emission factors based on an average distillate oil heating value of 139 MMBtu/10³ gallons. To convert from (lb/MMBtu) to (lb/10³ gallons), multiply by 139.

^g SCC for landfill gas-fired turbines is 2-03-008-01.

^h Emission factors based on an average landfill gas heating value of 400 Btu/scf at 60°F. To convert from (lb/MMBtu), to (lb/10⁶ scf) multiply by 400.

^j SCC for digester gas-fired turbine is 2-03-007-01.

^k Emission factors based on an average digester gas heating value of 600 Btu/scf at 60°F. To convert from (lb/MMBtu) to (lb/10⁶ scf) multiply by 600.

Table 3.1-2a. EMISSION FACTORS FOR CRITERIA POLLUTANTS AND GREENHOUSE GASES FROM STATIONARY GAS TURBINES

Emission Factors ^a - Uncontrolled				
Pollutant	Natural Gas-Fired Turbines ^b		Distillate Oil-Fired Turbines ^d	
	(lb/MMBtu) ^c (Fuel Input)	Emission Factor Rating	(lb/MMBtu) ^e (Fuel Input)	Emission Factor Rating
CO ₂ ^f	110	A	157	A
N ₂ O	0.003 ^g	E	ND	NA
Lead	ND	NA	1.4 E-05	C
SO ₂	0.94S ^h	B	1.01S ^h	B
Methane	8.6 E-03	C	ND	NA
VOC	2.1 E-03	D	4.1 E-04 ^j	E
TOC ^k	1.1 E-02	B	4.0 E-03 ^l	C
PM (condensable)	4.7 E-03 ^l	C	7.2 E-03 ^l	C
PM (filterable)	1.9 E-03 ^l	C	4.3 E-03 ^l	C
PM (total)	6.6 E-03 ^l	C	1.2 E-02 ^l	C

^a Factors are derived from units operating at high loads (≥ 80 percent load) only. For information on units operating at other loads, consult the background report for this chapter (Reference 16), available at "www.epa.gov/ttn/chieff". ND = No Data, NA = Not Applicable.

^b SCCs for natural gas-fired turbines include 2-01-002-01, 2-02-002-01 & 03, and 2-03-002-02 & 03.

^c Emission factors based on an average natural gas heating value (HHV) of 1020 Btu/scf at 60°F. To convert from (lb/MMBtu) to (lb/10⁶ scf), multiply by 1020. Similarly, these emission factors can be converted to other natural gas heating values.

^d SCCs for distillate oil-fired turbines are 2-01-001-01, 2-02-001-01, 2-02-001-03, and 2-03-001-02.

^e Emission factors based on an average distillate oil heating value of 139 MMBtu/10³ gallons. To convert from (lb/MMBtu) to (lb/10³ gallons), multiply by 139.

^f Based on 99.5% conversion of fuel carbon to CO₂ for natural gas and 99% conversion of fuel carbon to CO₂ for distillate oil. CO₂ (Natural Gas) [lb/MMBtu] = (0.0036 scf/Btu)(%CON)(C)(D), where %CON = weight percent conversion of fuel carbon to CO₂, C = carbon content of fuel by weight, and D = density of fuel. For natural gas, C is assumed at 75%, and D is assumed at 4.1 E+04 lb/10⁶scf. For distillate oil, CO₂ (Distillate Oil) [lb/MMBtu] = (26.4 gal/MMBtu) (%CON)(C)(D), where C is assumed at 87%, and the D is assumed at 6.9 lb/gallon.

^g Emission factor is carried over from the previous revision to AP-42 (Supplement B, October 1996) and is based on limited source tests on a single turbine with water-steam injection (Reference 5).

^h All sulfur in the fuel is assumed to be converted to SO₂. S = percent sulfur in fuel. Example, if sulfur content in the fuel is 3.4 percent, then S = 3.4. If S is not available, use 3.4 E-03 lb/MMBtu for natural gas turbines, and 3.3 E-02 lb/MMBtu for distillate oil turbines (the equations are more accurate).

^j VOC emissions are assumed equal to the sum of organic emissions.

^k Pollutant referenced as THC in the gathered emission tests. It is assumed as TOC, because it is based on EPA Test Method 25A.

^l Emission factors are based on combustion turbines using water-steam injection.

Table 3.1-2b. EMISSION FACTORS FOR CRITERIA POLLUTANTS AND GREENHOUSE GASES FROM STATIONARY GAS TURBINES

Emission Factors ^a - Uncontrolled				
Pollutants	Landfill Gas-Fired Turbines ^b		Digester Gas-Fired Turbines ^d	
	(lb/MMBtu) ^c	Emission Factor Rating	(lb/MMBtu) ^e	Emission Factor Rating
CO ₂ ^f	50	D	27	C
Lead	ND	NA	< 3.4 E-06 ^g	D
PM-10	2.3 E-02	B	1.2 E-02	C
SO ₂	4.5 E-02	C	6.5 E-03	D
VOC ^h	1.3 E-02	B	5.8 E-03	D

^a Factors are derived from units operating at high loads (≥ 80 percent load) only. For information on units operating at other loads, consult the background report for this chapter (Reference 16), available at "www.epa.gov/ttn/chief". ND = No Data, NA = Not Applicable.

^b SCC for landfill gas-fired turbines is 2-03-008-01.

^c Emission factors based on an average landfill gas heating value (HHV) of 400 Btu/scf at 60°F. To convert from (lb/MMBtu) to (lb/10⁶ scf), multiply by 400.

^d SCC for digester gas-fired turbine include 2-03-007-01.

^e Emission factors based on an average digester gas heating value of 600 Btu/scf at 60°F. To convert from (lb/MMBtu) to (lb/10⁶ scf), multiply by 600.

^f For landfill gas and digester gas, CO₂ is presented in test data as volume percent of the exhaust stream (4.0 percent to 4.5 percent).

^g Compound was not detected. The presented emission value is based on one-half of the detection limit.

^h Based on adding the formaldehyde emissions to the NMHC.

Table 3.1-3. EMISSION FACTORS FOR HAZARDOUS AIR POLLUTANTS FROM NATURAL GAS-FIRED STATIONARY GAS TURBINES^a

Emission Factors ^b - Uncontrolled		
Pollutant	Emission Factor (lb/MMBtu) ^c	Emission Factor Rating
1,3-Butadiene ^d	< 4.3 E-07	D
Acetaldehyde	4.0 E-05	C
Acrolein	6.4 E-06	C
Benzene ^e	1.2 E-05	A
Ethylbenzene	3.2 E-05	C
Formaldehyde ^f	7.1 E-04	A
Naphthalene	1.3 E-06	C
PAH	2.2 E-06	C
Propylene Oxide ^d	< 2.9 E-05	D
Toluene	1.3 E-04	C
Xylenes	6.4 E-05	C

^a SCC for natural gas-fired turbines include 2-01-002-01, 2-02-002-01, 2-02-002-03, 2-03-002-02, and 2-03-002-03. Hazardous Air Pollutants as defined in Section 112 (b) of the *Clean Air Act*.

^b Factors are derived from units operating at high loads (≥ 80 percent load) only. For information on units operating at other loads, consult the background report for this chapter (Reference 16), available at "www.epa.gov/ttn/chief".

^c Emission factors based on an average natural gas heating value (HHV) of 1020 Btu/scf at 60°F. To convert from (lb/MMBtu) to (lb/10⁶ scf), multiply by 1020. These emission factors can be converted to other natural gas heating values by multiplying the given emission factor by the ratio of the specified heating value to this heating value.

^d Compound was not detected. The presented emission value is based on one-half of the detection limit.

^e Benzene with SCONOX catalyst is 9.1 E-07, rating of D.

^f Formaldehyde with SCONOX catalyst is 2.0 E-05, rating of D.

Table 3.1-4. EMISSION FACTORS FOR HAZARDOUS AIR POLLUTANTS FROM DISTILLATE OIL-FIRED STATIONARY GAS TURBINES^a

Emission Factors ^b - Uncontrolled		
Pollutant	Emission Factor (lb/MMBtu) ^c	Emission Factor Rating
1,3-Butadiene ^d	< 1.6 E-05	D
Benzene	5.5 E-05	C
Formaldehyde	2.8 E-04	B
Naphthalene	3.5 E-05	C
PAH	4.0 E-05	C

^a SCCs for distillate oil-fired turbines include 2-01-001-01, 2-02-001-01, 2-02-001-03, and 2-03-001-02. Hazardous Air Pollutants as defined in Section 112 (b) of the *Clean Air Act*.

^b Factors are derived from units operating at high loads (≥ 80 percent load) only. For information on units operating at other loads, consult the background report for this chapter (Reference 16), available at "www.epa.gov/ttn/chief".

^c Emission factors based on an average distillate oil heating value (HHV) of 139 MMBtu/10³ gallons. To convert from (lb/MMBtu) to (lb/10³ gallons), multiply by 139.

^d Compound was not detected. The presented emission value is based on one-half of the detection limit.

Table 3.1-5. EMISSION FACTORS FOR METALLIC HAZARDOUS AIR POLLUTANTS FROM DISTILLATE OIL-FIRED STATIONARY GAS TURBINES^a

Emission Factors ^b - Uncontrolled		
Pollutant	Emission Factor (lb/MMBtu) ^c	Emission Factor Rating
Arsenic ^d	< 1.1 E-05	D
Beryllium ^d	< 3.1 E-07	D
Cadmium	4.8 E-06	D
Chromium	1.1 E-05	D
Lead	1.4 E-05	D
Manganese	7.9 E-04	D
Mercury	1.2 E-06	D
Nickel ^d	< 4.6 E-06	D
Selenium ^d	< 2.5 E-05	D

^a SCCs for distillate oil-fired turbines include 2-01-001-01, 2-02-001-01, 2-02-001-03, and 2-03-001-02. Hazardous Air Pollutants as defined in Section 112 (b) of the *Clean Air Act*.

^b Factors are derived from units operating at high loads (≥ 80 percent load) only. For information on units operating at other loads, consult the background report for this chapter (Reference 16), available at "www.epa.gov/ttn/chief".

^c Emission factors based on an average distillate oil heating value (HHV) of 139 MMBtu/10³ gallons. To convert from (lb/MMBtu) to (lb/10³ gallons), multiply by 139.

^d Compound was not detected. The presented emission value is based on one-half of the detection limit.

Table 3.1-6. EMISSION FACTORS FOR HAZARDOUS AIR POLLUTANTS FROM LANDFILL GAS-FIRED STATIONARY GAS TURBINES^a

Emission Factors ^b - Uncontrolled		
Pollutant	Emission Factor (lb/MMBtu) ^c	Emission Factor Rating
Acetonitrile ^d	< 1.2E-05	D
Benzene	2.1E-05	B
Benzyl Chloride ^d	< 1.2 E-05	D
Carbon Tetrachloride ^d	< 1.8 E-06	D
Chlorobenzene ^d	< 2.9 E-06	D
Chloroform ^d	< 1.4 E-06	D
Methylene Chloride	2.3 E-06	D
Tetrachloroethylene ^d	< 2.5 E-06	D
Toluene	1.1 E-04	B
Trichloroethylene ^d	< 1.9 E-06	D
Vinyl Chloride ^d	< 1.6 E-06	D
Xylenes	3.1 E-05	B

^a SCC for landfill gas-fired turbines is 2-03-008-01. Hazardous Air Pollutants as defined in Section 112 (b) of the *Clean Air Act*.

^b Factors are derived from units operating at high loads (≥ 80 percent load) only. For information on units operating at other loads, consult the background report for this chapter (Reference 16), available at "www.epa.gov/ttn/chief".

^c Emission factors based on an average landfill gas heating value (HHV) of 400 Btu/scf at 60°F. To convert from (lb/MMBtu) to (lb/10⁶ scf), multiply by 400.

^d Compound was not detected. The presented emission value is based on one-half of the detection limit.

Table 3.1-7. EMISSION FACTORS FOR HAZARDOUS AIR POLLUTANTS FROM DIGESTER GAS-FIRED STATIONARY GAS TURBINES^a

Emission Factors ^b - Uncontrolled		
Pollutant	Emission Factor (lb/MMBtu) ^c	Emission Factor Ratings
1,3-Butadiene ^d	< 9.8 E-06	D
1,4-Dichlorobenzene ^d	< 2.0 E-05	D
Acetaldehyde	5.3 E-05	D
Carbon Tetrachloride ^d	< 2.0 E-05	D
Chlorobenzene ^d	< 1.6 E-05	D
Chloroform ^d	< 1.7 E-05	D
Ethylene Dichloride ^d	< 1.5 E-05	D
Formaldehyde	1.9 E-04	D
Methylene Chloride ^d	< 1.3 E-05	D
Tetrachloroethylene ^d	< 2.1 E-05	D
Trichloroethylene ^d	< 1.8 E-05	D
Vinyl Chloride ^d	< 3.6 E-05	D
Vinylidene Chloride ^d	< 1.5 E-05	D

^a SCC for digester gas-fired turbines is 2-03-007-01. Hazardous Air Pollutants as defined in Section 112 (b) of the *Clean Air Act*.

^b Factors are derived from units operating at high loads (≥ 80 percent load) only. For information on units operating at other loads, consult the background report for this chapter (Reference 16), available at "www.epa.gov/ttn/chief".

^c Emission factors based on an average digester gas heating value (HHV) of 600 Btu/scf at 60°F. To convert from (lb/MMBtu) to (lb/10⁶ scf), multiply by 600.

^d Compound was not detected. The presented emission value is based on one-half of the detection limit.

Table 3.1-8. EMISSION FACTORS FOR METALLIC HAZARDOUS AIR POLLUTANTS FROM DIGESTER GAS-FIRED STATIONARY GAS TURBINES^a

Emission Factors ^b - Uncontrolled		
Pollutant	Emission Factor (lb/MMBtu) ^c	Emission Factor Rating
Arsenic ^d	< 2.3 E-06	D
Cadmium ^d	< 5.8 E-07	D
Chromium ^d	< 1.2 E-06	D
Lead ^d	< 3.4 E-06	D
Nickel	2.0 E-06	D
Selenium	1.1 E-05	D

^a SCC for digester gas-fired turbines is 2-03-007-01. Hazardous Air Pollutants as defined in Section 112 (b) of the *Clean Air Act*.

^b Factors are derived from units operating at high loads (≥ 80 percent load) only. For information on units operating at other loads, consult the background report for this chapter (Reference 16), available at "www.epa.gov/ttn/chiep".

^c Emission factor based on an average digester gas heating value (HHV) of 600 Btu/scf at 60°F. To convert from (lb/MMBtu) to (lb/10⁶ scf), multiply by 600.

^d Compound was not detected. The presented emission value is based on one-half of the detection limit.

References For Section 3.1

1. *Alternative Control Techniques Document - NO_x Emissions from Stationary Gas Turbines*, EPA 453/R-93-007, January 1993.
2. C. C. Shih, *et al.*, *Emissions Assessment Of Conventional Stationary Combustion Systems, Vol. II: Internal Combustion Sources*, EPA-600/7-79-029c, U. S. Environmental Protection Agency, Cincinnati, OH, February 1979.
3. *Final Report - Gas Turbine Emission Measurement Program*, GASLTR787, General Applied Science Laboratories, Westbury, NY, August 1974.
4. *Standards Support And Environmental Impact Statement, Volume 1: Proposed Standards Of Performance For Stationary Gas Turbines*, EPA-450/2-77-017a, U. S. Environmental Protection Agency, Research Triangle Park, NC, September 1977.
5. L. P. Nelson, *et al.*, *Global Combustion Sources Of Nitrous Oxide Emissions*, Research Project 2333-4 Interim Report, Sacramento: Radian Corporation, 1991.
6. R. L. Peer, *et al.*, *Characterization Of Nitrous Oxide Emission Sources*, U. S. Environmental Protection Agency, Office of Research and Development, Research Triangle Park, NC, 1995.
7. S. D. Piccot, *et al.*, *Emissions And Cost Estimates For Globally Significant Anthropogenic Combustion Sources Of NO_x, N₂O, CH₄, CO, And CO₂*, U. S. Environmental Protection Agency, Office of Research and Development, Research Triangle Park, NC, 1990.
8. G. Marland and R. M. Rotty, *Carbon Dioxide Emissions From Fossil Fuels: A Procedure For Estimation And Results For 1951-1981*, DOE/NBB-0036 TR-003, Carbon Dioxide Research Division, Office of Energy Research, U. S. Department of Energy, Oak Ridge, TN, 1983.
9. G. Marland and R. M. Rotty, *Carbon Dioxide Emissions From Fossil Fuels: A Procedure For Estimation And Results For 1950-1982*, Tellus 36B:232-261, 1984.
10. *Inventory Of U. S. Greenhouse Gas Emissions And Sinks: 1990-1991*, EPA-230-R-96-006, U. S. Environmental Protection Agency, Washington, DC, November 1995.
11. *IPCC Guidelines For National Greenhouse Gas Inventories Workbook*, Intergovernmental Panel on Climate Change/Organization for Economic Cooperation and Development, Paris, France, 1995.
12. L. M. Campbell and G. S. Shareef, *Sourcebook: NO_x Control Technology Data*, Radian Corp., EPA-600/2-91-029, Air and Energy Engineering Research Laboratory, U. S. Environmental Protection Agency, Research Triangle Park, July 1991.
13. *In-stack Condensable Particulate Matter Measurement and Permitting Issues for Maryland Power Plants*, Maryland Department of Natural Resource, Prepared by Versar, INC, January 1998.

14. *Catalysts for Power Generation, The SCONOX System.* Goal Line Environmental Technologies, www.glet.com/gl_prod_SCONOX.htm, March 1998.
15. Information form Chuck Solt of Catalytica Combustion Systems, Inc., to EPA, XONON Flameless Combustion, January 1996.
16. *Emission Factor Documentation of AP-42 Section 3.1, Stationary Combustion Turbines,* EPA Contract No. 68-D7-0070, Alpha-Gamma Technologies Inc., Raleigh, North Carolina, April 2000.

April 17, 2001

Review of Potential Efficiency Improvements at Coal-Fired Power Plants

Introduction

The Clean Air Markets Division, U.S. Environmental Protection Agency requested that Perrin Quarles Associates, Inc., perform a review of readily available data on potential and actual efficiency improvements at coal-fired utilities. The objective was to identify heat rate reductions or efficiency improvements that have taken place due to either optimization efforts at existing utility boilers or due to the use of newer advanced technologies for coal combustion.

A unit's efficiency in this context refers to its thermal efficiency and is defined as a percentage determined by the electrical energy export divided by the fuel energy input. Fuel energy input can be defined either on a higher heating value (HHV) or lower heating value (LHV) basis. HHV is the full energy content of a fuel including the latent heat of vaporization of water, while LHV excludes the energy in the water vapor from the fuels hydrogen. The HHV will be about 5 to 10 percent higher than LHV. In the United States, fuel energy content is generally measured in terms of HHV, and HHV is used in Energy Information Agency statistics. Internationally, LHV is more often used. For this report, all efficiencies are reported on an HHV basis. Efficiency is also commonly represented by the heat rate, which is the reciprocal of the thermal efficiency and is described in the units of Btu/kWh.

This document discusses the range of heat rates and efficiencies associated with coal-fired power plants including the improved heat rates that have been achieved at some of the more recently constructed state-of-the-art coal-fired facilities. The following is a general discussion of this issue in the context of several different types of coal-fired plants. Note that the information in this report is based on a search of documents currently available on the Internet. More extensive research that may lead to additional data and supporting documentation could entail contacting EIA at DOE or individual facilities for additional information, particularly with respect to actual heat rates or efficiency percentages.

Conventional Pulverized Coal Plants

Current Heat Rates

Unit efficiency, or heat rate, is a function of unit design, size, capacity factor, the fuel fired, maintenance condition of the unit, and operating and ambient conditions (cooling water temperature). Existing pulverized coal boilers operating today in the U.S. use subcritical or supercritical steam cycles. A supercritical steam cycle normally operates above the water critical temperature (705 F) and critical pressure (3210 psia) where water can exist only in the gaseous phase. Subcritical systems historically have achieved thermal efficiencies of 33 to 34 percent (10,300 Btu/kWh to 10,000 Btu/kWh). Supercritical systems achieve thermal efficiencies 3 to 5 percent higher than subcritical

systems.¹ Table 1 summarizes heat rate data for the 25 best performing utility coal-fired plants, and 50 best performing utility company coal-fired fleets in the U.S. The data were prepared for Electric Light and Power's annual top 100 utility operating report.²

Table 1: Best Coal Fired Heat Rates – U.S. Utilities

	Lowest Reported Annual Average Heat Rate (Btu/kWh)	Highest Reported Annual Average Heat Rate (Btu/kWh)	Average of the Reported Annual Average Heat Rates (Btu/kWh)
25 Best Performing Coal-Fired Plants	8996	9486	9309
50 Best Performing Coal-Fired Fleets	9382	10,146	9854
<i>Data on heat rates are taken from Electric Light and Power's annual top 100 utility operating report (EL&P, 1999), and were prepared by Navigant Consulting. Heat rates are from 1998 or 1997. The report noted that utility methods for determining the heat rate values are inconsistent.</i>			

Heat Rate Improvements at Existing Plants

Many conventional pulverized coal-fired power plants have made improvements to their systems that have, in turn, led to improvements in the plant's efficiency or heat rate. The extent to which heat rates can be improved at existing plants is estimated to be at best 3 to 5 percent.³ This is because heat rate is primarily dependent on unit design, fuel, and capacity factor, and the design of a plant can not be changed once built. The literature reviewed reported heat rate improvements consistent with the 3 to 5 percent improvement estimate.

Table 2 summarizes some of the potential actions that could be taken to improve plant efficiencies. Even though these data are based on the higher moisture "brown coal" or lignite typically used only in certain areas, such as Australia, Germany, Russia, and certain portions of the U.S., some of the actions may also be applied in the context of the lower moisture "black coal" or bituminous that is typically used in the U.S. These actions include those that would help restore the plant to its design conditions, change existing operational settings, or install retrofit improvements.

¹Kitto, J.B., Babcock & Wilcox, *Developments in Pulverized Coal-Fired Boiler Technology*, presented to the Missouri Valley Electric Association Engineering Conference, April 1996. <http://www.babcock.com/pgg/tt/pdf/BR-1610.pdf>

²Burr, M. T., Holding companies rule; top 10 sell 28% of U.S. electricity, Electric Light and Power, October 1999.

³Levy, E. and N. Sarunac, *Technical Review of EPA's Proposed Output Monitoring System*, Lehigh University Energy Research Center, September 2000.

Table 2: Measures that may Improve the Efficiency of Coal-Fired Power Plants⁴

Action	Efficiency Improvement (%)
Restore Plant to Design Conditions	
Minimize boiler tramp air	0.42
Reinstate any feedheaters out of service	0.46 - 1.97
Refurbish feedheaters	0.84
Reduce steam leaks	1.1
Reduce turbine gland leakage	0.84
Changes to Operational Settings	
Low excess air operation	1.22
Improved combustion control	0.84
Retrofit Improvements	
Extra airheater surface in the boiler	2.1
Install new high efficiency turbine blades	0.98
Install variable speed drives**	1.97
Install on-line condenser cleaning system	0.84
Install new cooling tower film pack**	1.97
Install intermittent energisation to ESPs	0.32

* Note that the efficiency improvements expected as a result of implementation of these actions may not be additive and the feasibility and improvements associated with each action may vary based on plant configuration.

** The expected efficiency improvements associated with these actions may be overestimated.

Wisconsin Electric Power Company (WEPCO) has implemented a number of actions to improve the efficiency or heat rate at certain coal-fired plants, some of which are included in Table 2 above. The efficiency improvements as reported in the Climate Challenge Participation Accord between WEPCO and the Department of Energy (DOE) are summarized in Table 3. Efficiency improvements over a 5 year period ranged from 2.3 percent to 4.1 percent. In the Accord, WEPCO also committed to other efforts to improve heat rates including: various equipment control upgrades such as distributed control systems, precipitators and turbine controls; metering upgrades; boiler chemical cleaning; feedwater heater improvements; reduced condenser air in-leakage; and reduced

⁴Sinclair Knight Merz Pty. Ltd., *Integrating Consultancy - Efficiency Standards for Power Generation*, Australian Greenhouse Office, January 2000, p. 38.
http://www.greenhouse.gov.au/markets/gen_eff/skmreport.pdf

thermal losses. WEPCO estimated a 0.5 percent annual company-wide heat rate improvement due to these additional efforts over a period from 1995 - 2000.

Table 3: Example Heat Rate Improvements at Wisconsin Electric Plants Due to Operational Changes (1990 - 1994)⁵

Plant	Original Heat Rate (Btu/kWh HHV)	Improved Heat Rate (Btu/kWh HHV)	Efficiency Increase (%)	Description of Efficiency Improvement Projects
Oak Creek	9,802	9,424	3.9	Variable pressure operation, distributed control system, retractable turbine packing, variable speed drives on the forced and induced draft fans, reduced air in-leakage, feedwater heater replacements, increased availability and capacity factor and precipitator energy management system
Pleasant Prairie	11,157	10,796	3.2	Variable pressure operation, unit and equipment performance monitoring, retractable turbine packing, reduced air in-leakage, increased availability and variable speed drive make-up water pumps
Presque Isle	11,565	11,089	4.1	Retractable turbine packing, increased availability and capacity factor, reduced air in-leakage, reduced excess boiler O ₂ , boiler chemical cleaning, CO monitors on the boiler, improved turbine pressure and updated or additional instrumentation

⁵Wisconsin Electric Power Company Climate Challenge Participation Accord (agreement with DOE), Appendix A (Wisconsin Energy Emission Reduction/Sequestration Project Descriptions), Section 2 - Supply Side Energy Efficiency.
http://www.eren.doe.gov/climatechallenge/cc_accordxWISCEL.htm

**Table 3: Example Heat Rate Improvements at Wisconsin Electric Plants
 Due to Operational Changes (1990 - 1994) (cont.)**

Plant	Original Heat Rate (Btu/kWh HHV)	Improved Heat Rate (Btu/kWh HHV)	Efficiency Increase (%)	Description of Efficiency Improvement Projects
Valley	13,938	13,623	2.3	Last row turbine blade replacement, retractable turbine packing, variable speed drives for the forced and induced draft fans, superheater surface change, reduced air in-leakage, reduced pulverizer primary air velocity and increased availability and capacity factor

PQA has previously reviewed literature for CAMD on NO_x reductions and efficiency improvements resulting from the installation of combustion optimization software, such as NeuSIGHT, ULTRAMAX, and GNOCIS. The software works with a boiler's digital control system to optimize and control boiler settings. Efficiency improvements from the combustion optimization ranged from 0.3 to 3 percent.⁶

New Pulverized Coal Plants

In addition to the potential for efficiency improvements at existing conventional pulverized coal-fired plants through operational changes and equipment upgrades, there is also the potential for dramatically reduced heat rates through the use of pulverized coal-fired power plants built with more advanced technologies.

A Low Emissions Boiler System (LEBS) based on the direct combustion of pulverized coal emphasizes improvements in technology and processes that are already widely accepted. These types of facilities include a high-efficiency pulverized coal boiler integrated with other more efficient combustion techniques and advancements in emission control technologies. The more advanced versions of these facilities may achieve up to 44 percent efficiency and are expected to be currently commercially available.⁷

In the context of these newer units, a 400 MW pulverized coal power plant design based on the utilization of pulverized coal feeding a conventional steam boiler and steam

⁶Perrin Quarles Associates, Inc., *Review of Utility Coal-Fired Boiler Optimization Papers*, Appendix, August 2000.

⁷Lester, E., *Minimization of Global Climate Change Using Clean Coal Technology*, American Institute of Chemical Engineers, August 1998, p. 5.
<http://www.aiche.org/government/pdfdocs/cleancoal.pdf>

turbine, as well as state-of-the-art technology and components currently available in the market, could achieve heat rates as low as 8,251 Btu/kWh, depending on the specific design of the facility. Design data for these types of facilities are summarized in Table 4 below.

Table 4: Heat Rate Data for Subcritical, Supercritical, and Ultra-Supercritical Coal-Fired Power Plants (Design Data Based on a 400 MW Facility)⁸

Type of Plant	Steam Pressure (psig)	Steam Temperature (F)	Expected Heat Rate (Btu/kWh)
Subcritical (conventional pulverized coal plant with emission control systems to meet current air quality standards)	2400 psig	1000F/1000F	9,077
Supercritical (single reheat configuration with emissions control systems to meet air quality standards expected in 2005)	3500 psig	1050F/1050F	8,568
Ultra-Supercritical (double reheat configuration with emissions control systems to meet air quality standards expected in 2010)	4500 psig	1100F/1100F/1100F	8,251

Another source includes data from coal-fired plants in North America, Europe, and Japan, and cites the best practice thermal efficiency rates at 37.7 percent and 41.7 percent for subcritical and supercritical plants, respectively, for facilities similar in size to those referenced above.⁹

An examination of this new generation of coal burning plants internationally have revealed that several are capable of achieving efficiencies above 40 percent through the use of low condenser pressures, high steam pressures and temperatures, double reheat cycles, up to ten stages of feed heating and other changes to station parameters and

⁸U.S. Department of Energy, Office of Fossil Energy, *Market Based Advanced Coal Power Systems*, Section 3 -- Pulverized Coal-Fired Plants, May 1999, DOE/FE-0400, p. 3.1-5, 3.2-2, and 3.3-2.
http://www.fetc.doe.gov/coal_power/special_rpts/market_systems/market_sys.html

⁹Sinclair Knight Merz Pty. Ltd., *Integrating Consultancy -- Efficiency Standards for Power Generation*, Australian Greenhouse Office, January 2000, p. 6.

configuration of equipment. These plants and their corresponding efficiencies are summarized in Table 5 below.

**Table 5 - International "Black Coal" Power Plants
 with High Design Thermal Efficiencies¹⁰**

Plant	Online	Size (MW)	Steam Temperature (F)	Design Thermal Efficiency (%) HHV
Staudinger 5	1992	550	1004/1040	41.1*
Rostock	1994	550	1004/1040	42
Esbjerg	1992	400	1036/1040	43.2*
Nordjylland-svaerket	1998	400	1076/1076/1076 (double reheat cycle)	44.9
Lubeck	1998	440	1076/1112	43.6
Bexbach II	2002 (projected)	750	1067/1103	44.2

* Note that these estimated thermal efficiencies have been confirmed through testing and/or operating experience.

Combined Cycle Operations at Coal-Fired Power Plants

Coal-fired power plants have historically been limited to the simple cycle method. However, recent technological developments have led to the capability of powering "combined-cycle" generators. Under DOE Initiatives, two new technologies -- Pressurized Fluid Bed Combustion and Integrated Gasification Combined Cycle (IGCC) -- have allowed for combined cycle operations in the context of coal-fired facilities. These facilities have dramatically improved efficiencies or heat rates as compared to conventional pulverized coal-fired facilities.

Pressurized Fluid Bed Combustor

One study examined the efficiency benefits of using more advanced technologies such as the pressurized fluid bed combustor. Using a standard pulverized coal plant (294 MW with a heat rate of 9009 Btu/kWh) as a reference point, the efficiency benefits of using more advanced technologies were evaluated. A facility similar to the reference plant that utilizes a pressurized fluid bed combustor system may be able to achieve heat rates between 7,040 Btu/kWh and 8,679 Btu/kWh depending on the type of technology. A "bubbling bed" pressurized fluid bed combustor could lead to a heat rate of about 8,679 Btu/kWh, while a "first generation" or "second generation" pressurized fluid bed

¹⁰Sinclair Knight Merz Pty. Ltd., p. 59.

combustor could lead to heat rates of 8,506 Btu/kWh and 7,040 Btu/kWh, respectively.¹¹ Another DOE study also confirms heat rates in this range for a pressurized fluid bed combustor.¹²

Combustors the size of 70 to 80 MW have been in operation for a number of years. Recently, some larger combustors have been constructed. A 350 MW combustor is under construction in Japan and the expected efficiency is 41 percent. There is the potential to reach 43 percent in future plants. However, based on operational data from one existing plant, the overall net efficiency is approximately 38.2 percent.¹³

Integrated Gasification Combined Cycle

The DOE/Parsons study referenced above also examined the benefits of using an Integrated Gasification Combined Cycle (IGCC) system, which is capable of achieving heat rates between 7,374 Btu/kWh and 7,581 Btu/kWh, depending again, on the type of technology used.¹⁴

There have been some successful examples of plants that have recently demonstrated the IGCC technology. The Wabash River Coal Gasification Power Plant in West Terre Haute, IN and the Polk Power Plant in Polk County, Florida are two IGCC systems that have been successful at improving efficiencies. The Wabash River project repowered the oldest of six pulverized coal units using a "next-generating" coal gasifier, an advanced gas turbine and a heat-recovery steam generator. The 265 MW unit began operation in December 1995 and the design heat rate for the repowered unit is 9,034 Btu/kWh (approximately 38 percent efficiency).¹⁵ The Polk Power Plant has a similar efficiency estimated at 39.7 percent and the heat rate is estimated at approximately 8,600 Btu/kWh.¹⁶

¹¹Bonk, D., and M. Freier, U.S. Department of Energy, and Buchanan, et. al., Parsons Power, *Assessment of Opportunities for Advanced Technology Repowering*, p. 3. , Proceedings of the Advanced Coal Based and Environmental Systems Conference, Pittsburgh, July 22 - 24, 1997. http://www.fetc.doe.gov/publications/proceedings/97/97ps/ps_pdf/PS1-7.PDF

¹²*Market Based Advanced Coal Power Systems*, Section 5 -- Circulating Pressurized Fluid Bed Combustor, U.S. Department of Energy, May 1999, p.5-5.

¹³Sinclair Knight Merz Pty. Ltd., pp. 59-60, 66-67.

¹⁴Bonk, D. and M. Freier, and Buchanan, et. al., p. 3-4.

¹⁵*DOE Fossil Energy Techline*, "Fourth Clean Coal Plant to Win Powerplant Award Sets Record Operation for Coal Gasifier in Early 1997." February 18, 1997. http://www.fe.doe.gov/techline/tl_wab96.html

¹⁶*Clean Coal Today*, "Tampa Electric's Greenfield IGCC Ready for Demonstration," Office of Fossil Energy, U.S. Department of Energy, DOE/FE-0215 P-24, No. 24, Winter 1996.

Recent data on actual operational results shows that these facilities have achieved efficiencies that are similar to the design values. The overall net thermal efficiency for the Wabash River IGCC facility has been 39.7 percent.¹⁷ The overall net thermal efficiency for the Polk Power Station has been 36.5 percent with an overall heat rate of 9350 Btu/kWh. The efficiency for the Polk Station has been slightly lower than expected due to problems with the gasifier and low carbon conversion. These and other issues have been recently addressed and certain operational changes are expected to lead to a thermal efficiency of around 38 percent.¹⁸

One study notes that the efficiency of IGCC plants is expected to be around 42 percent and there is the potential to achieve 49 percent when higher efficiency gas turbines become available.¹⁹ One DOE study estimates the thermal efficiency of an IGCC plant slightly lower at 40.1 percent with a heat rate of 8,522 Btu/kWh. This estimate assumes a 540 MW facility with a plant configuration based on the technology demonstrated at the Wabash IGCC facility but incorporates a new steam turbine. However, this study also describes IGCC facilities of similar size based on more advanced technologies (some of which are not yet commercially available) that could achieve an efficiency and heat rate of up to 49.7 percent and 6,870 Btu/kWh, respectively.²⁰

¹⁷"The Wabash River Coal Gasification Repowering Project - An Update," *Clean Coal Technology*, Topical Report #20, September 2000.
<http://www.lanl.gov/projects/cctc/topicalreports/documents/topical20.pdf>

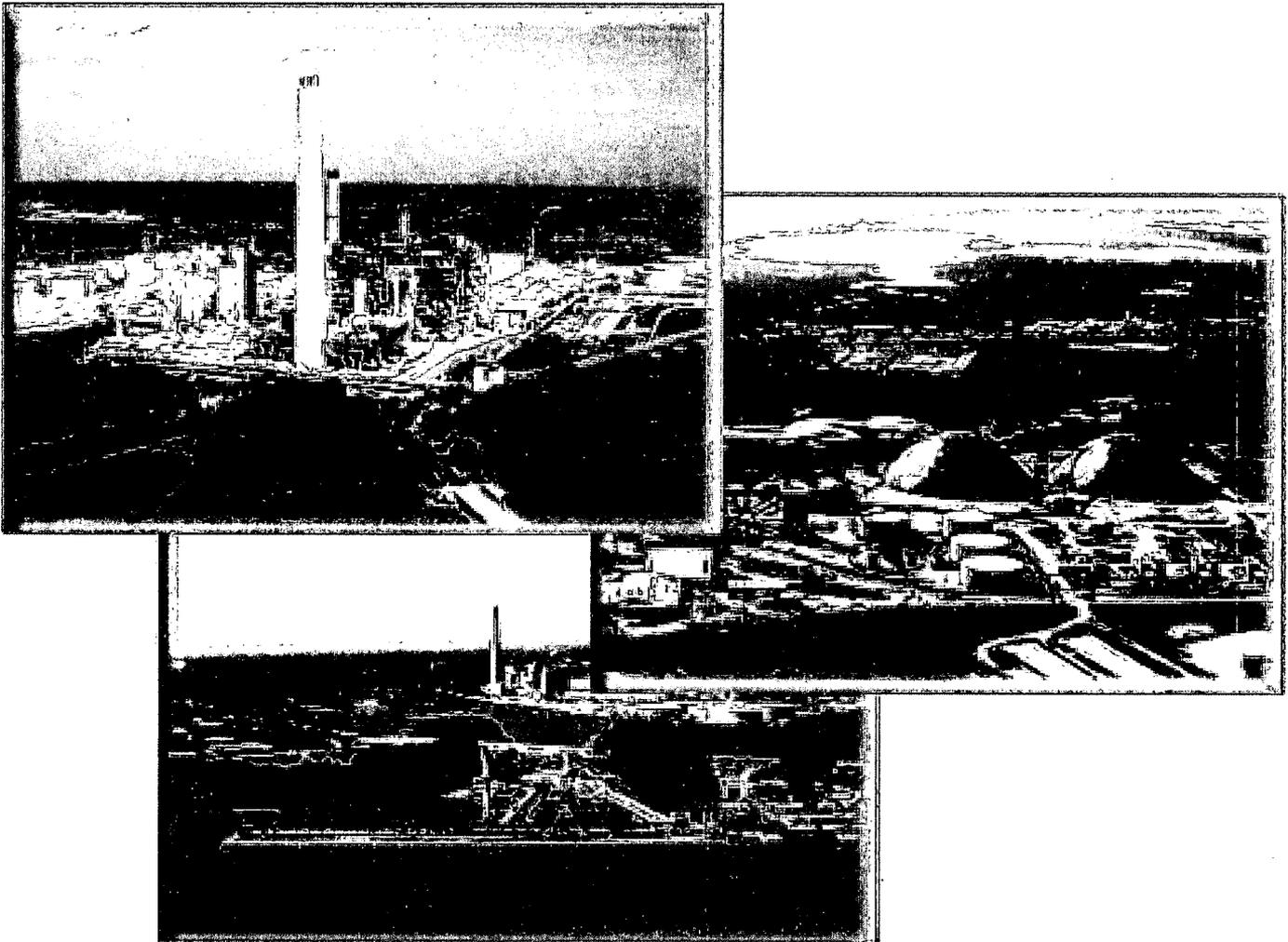
¹⁸"Tampa Electric Integrated Gasification Combined-Cycle Project - An Update," *Clean Coal Technology*, Topical Report #19, July 2000.
<http://www.lanl.gov/projects/cctc/topicalreports/documents/topical19.pdf>

¹⁹Sinclair Knight Merz Pty. Ltd., pp. 59, 66.

²⁰*Market Based Advanced Coal Power Systems*, Section 4 -- Integrated Gasification Combined Cycle, DOE, May 1999, p. 4.3-5.

Sec 9.2 Ref 40

CLEAN COAL TECHNOLOGY



The JEA Large-Scale CFB Combustion Demonstration Project

The JEA Large-Scale CFB Combustion Demonstration Project

A report on a project conducted jointly under
a Cooperative Agreement between:
The U.S. Department of Energy and JEA



Cover Picture:

**Three views of JEA
Northside Station,
Jacksonville, Florida**



The JEA Large-Scale CFB Combustion Demonstration Project

Executive Summary	1
Background	2
Project Description.....	3
Process Description.....	5
Environmental Considerations.....	7
Project Cost.....	9
Project History	11
Project Objectives	16
Project Scope	17
Fluidized Bed Combustion Systems	19
Demonstration Test Program	23
Operating Results.....	23
Awards	24
Commercial Applications.....	24
Conclusions.....	24
Bibliography	25
List of Acronyms and Abbreviations	26
Contacts for CCT Projects and U.S. DOE CCT Program.....	28

Executive Summary

The Clean Coal Technology (CCT) Demonstration Program is a government and industry co-funded effort to demonstrate a new generation of innovative coal utilization processes in a series of facilities built across the country. These projects are carried out on a commercial scale to prove technical feasibility and provide the information required for future applications.

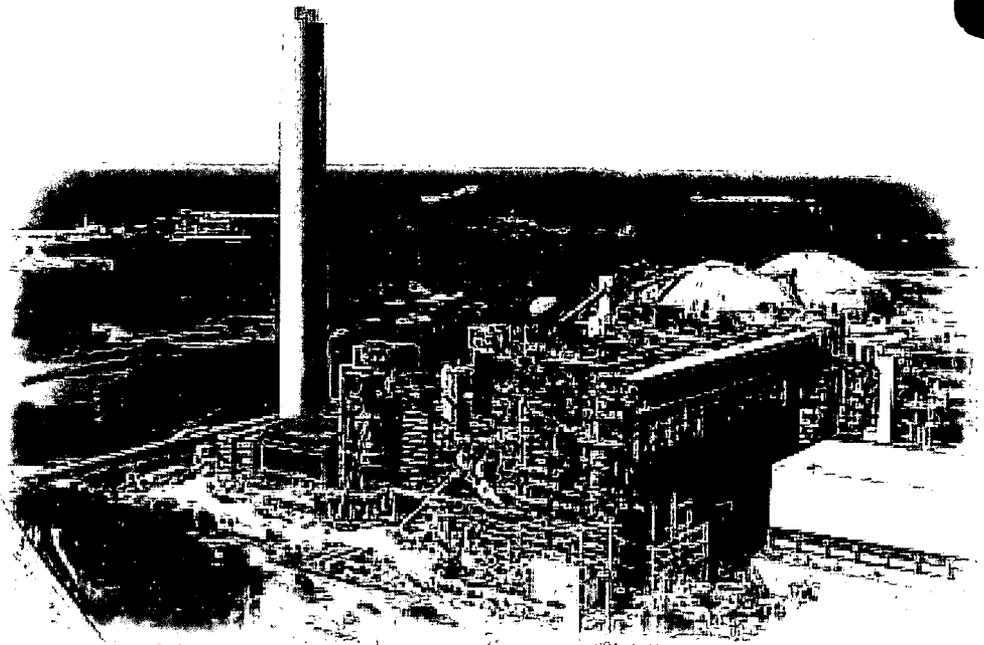
The goal of the CCT Program is to furnish the marketplace with a number of advanced, more efficient coal-based technologies that meet strict environmental standards. Use of these technologies is intended to minimize the economic and environmental barriers that limit the full utilization of coal.

To achieve this goal, beginning in 1985, a multi-phased effort consisting of five separate solicitations was administered by the U.S. Department of Energy's (DOE) National Energy Technology Laboratory (NETL). Projects selected through these solicitations have demonstrated technology options with the potential to meet the needs of energy markets while satisfying relevant environmental requirements.

Part of this Program is the demonstration of advanced electric power generation technologies, including circulating fluidized bed combustion (CFB). This report discusses the JEA Large-Scale CFB Combustion Demonstration Project which is testing the CFB concept using inexpensive feedstocks such as high sulfur coal and coal fuel blends.

The project is being conducted at the Northside Generating Station of JEA (formerly Jacksonville Electric Authority) in Jacksonville, Florida, and JEA is the project Participant. Foster Wheeler Energy Corporation, the technology supplier, is an additional team member.

To date, the JEA Project has operated CFBs to generate electricity at a scale larger than previously demonstrated. The boilers at the Northside Station are the largest CFBs in the world. Power production on coal feed meets the target goal of 297.5 MWe gross (265 MWe net). Emissions of atmospheric pollutants are below the stringent limits set for this project. A two-year demonstration test program is planned to evaluate the operational and environmental performance of the CFB system.



JEA plant with CFB boilers in center and fuel storage domes in background

The JEA Large-Scale CFB Combustion Demonstration Project

Background

The Clean Coal Technology (CCT) Demonstration Program, sponsored by the U.S. Department of Energy (DOE) and administered by the National Energy Technology Laboratory (NETL), has been conducted since 1985 to develop innovative, environmentally friendly coal utilization processes for the world energy marketplace.

The CCT Program, which is co-funded by industry and government, involves a series of demonstration projects that provide data for design, construction, operation, and technical/economic evaluation of full-scale applications. The goal of the CCT Program is to enhance the utilization of coal as a major energy source.

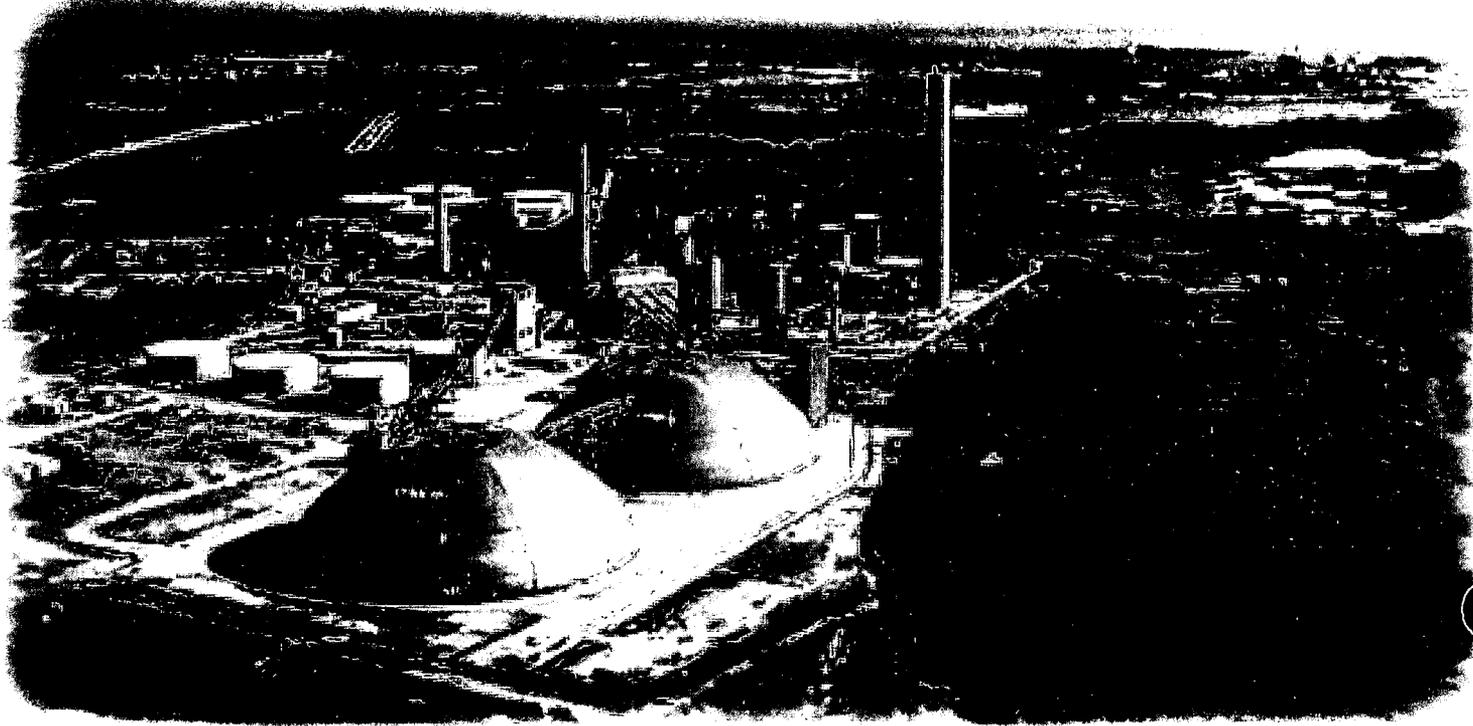
Fluidized Bed Combustion

Among the technologies being demonstrated in the CCT Program is fluidized bed combustion (FBC). FBC is an advanced electric power generation process that minimizes the formation of gaseous pollutants by controlling coal combustion parameters and by injecting a sorbent (such as crushed limestone) into the combustion chamber along with the fuel. In the

JEA project described in this report, the fuel is coal or a blend of coal and petroleum coke. Crushed fuel mixed with the sorbent is fluidized on jets of air in the combustion chamber. Sulfur released from the fuel as sulfur dioxide (SO_2) is captured by the sorbent in the bed to form a solid compound that is removed with the ash. The resultant by-product is a dry, benign solid that can be disposed of easily or used in agricultural and construction applications. More than 90% of the sulfur in the fuel is captured in this process.

An additional environmental benefit of FBC power plants results from their relatively low operating temperature, which significantly reduces formation of nitrogen oxides (NO_x).

Five FBC demonstration projects are included in the CCT Program under Advanced Electric Power Generation: (1) the JEA Large-Scale CFB Combustion Demonstration Project, (2) the Nucla CFB Demonstration Project, (3) the Tidd PFBC Demonstration Project, (4) the McIntosh Unit 4A PCFB Demonstration Project, and (5) the McIntosh Unit 4B Topped PCFB Demonstration Project. This Topical Report describes the JEA project.



Panoramic view of JEA site

Project Description

The JEA Large-Scale CFB Combustion Demonstration Project consists of installing a new 300-MWe (297.5-MWe nameplate) atmospheric circulating fluidized bed (ACFB) boiler in conjunction with an existing turbine generator at JEA's Northside Generating Station (Unit 2) in Jacksonville, Florida. In parallel with this project, JEA replaced the Unit 1 oil/gas fired boiler with an identical ACFB unit. Unit 1 continues to use its existing turbine generator.

These boilers are designed to burn fuel blends consisting of coal and petroleum coke,

thereby greatly reducing plant fuel costs and maintaining fuel flexibility while meeting stringent emissions limits. These units are the world's largest ACFB boilers.

In this project, the existing Unit 2 turbine generator was upgraded, and other existing balance-of-plant (BOP) equipment and systems were either upgraded or replaced. The existing turbine building and some piping systems were re-utilized.

Steam from the combustor is used in an existing General Electric 297.5-MWe (nameplate) turbine to produce electric power. With parasitic power consuming 32.5 MWe, net power output is 265 MWe.

JEA Large-Scale CFB Combustion Demonstration Project

Project Participants and Responsibilities

JEA

- Overall project and construction management
- Funding (\$234 million)
- Environmental permitting

U.S. DOE

- Funding (\$75 million)
- Technology support/dissemination

Foster Wheeler Energy Corporation (Clinton, NJ)

- Design and supply of CFBs
- Engineering/procurement/construction for the extended boiler island, including CFBs, scrubbers, fabric filters, stack, and fuel and limestone preparation facilities

Black & Veatch (Kansas City, MO)

- Design of BOP and materials handling systems

Zachry Construction Corporation (San Antonio, TX)

- Procurement and construction of BOP system upgrades and replacements, including condensate, feedwater, and circulating water systems; water and wastewater treatment systems; distributed control system; station electric distribution system; and substation equipment

Fluor Global Services (Irvine, CA)

- Upgrade/uprate of turbine/generators
- Procurement and construction of materials handling systems, including continuous ship unloader (purchased by JEA), pier, conveyors, fuel storage domes, and fuel and limestone reclaim equipment

Project Participant

The Participant is JEA, who provided the host site. An additional team member is Foster Wheeler Energy Corporation (FWEC), who supplied the ACFB technology.

Fuel Supply

Coal feed is an Eastern bituminous coal having a sulfur content of 3.39 wt%. Petroleum coke having a sulfur content as high as 8% also serves as feed, either alone or in combination with coal.

Project Scale

The JEA project represents a scale-up of previous ACFB installations. The Nucla project, completed in 1992, had a capacity of 100 MWe (net) and the Tidd project, completed in 1995, had a capacity of 70 MWe (net). The McIntosh Unit 4A project (currently on hold) is designed for a capacity of 137 MWe (net), and the McIntosh Unit 4B project (also on hold) has a design capacity of an additional 103 MWe (net). At a nominal design capacity of 300 MWe gross (265 MWe net), the JEA project is the largest scale demonstration of FBC technology to date.

Jacksonville

A half century after Ponce de Leon claimed Florida for Spain, Frenchman Jean Ribault sailed into the St. Johns River to establish Fort Caroline for French Huguenot settlers. Within several years, Spanish forces from the military garrison at St. Augustine would destroy this small settlement.

In 1821, Spain ceded Florida to the United States, and one year later Isaiah D. Hart surveyed the village. He named it Jacksonville for General Andrew Jackson, the territory's first military governor.

Today, located at the crossroads of two transcontinental highways, Jacksonville is one of the Nation's largest cities in land area (841 square miles), a major port, site of Navy bases, and home of the NFL Jacksonville Jaguars, a Mayo Clinic medical center, and the Jacksonville Zoological Gardens. The area boasts beautiful beaches and numerous waterways for over 700,000 residents.

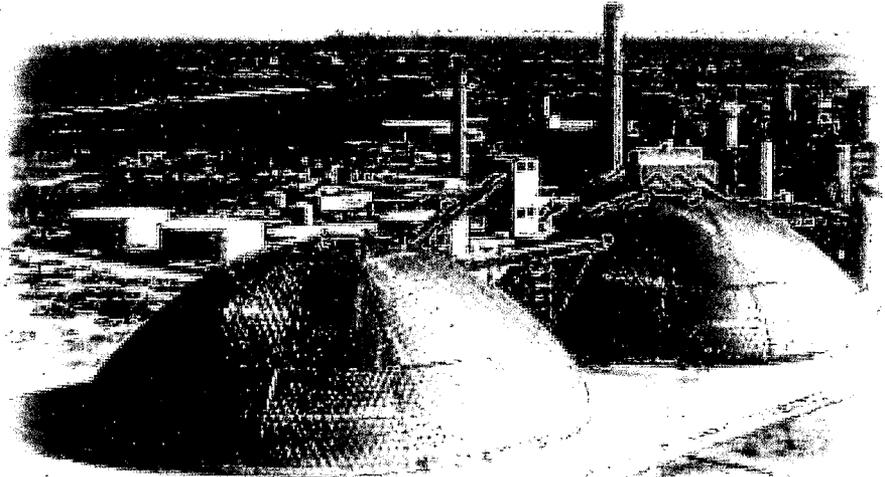
Process Description

Coal fuel blends, along with primary air and a solid sorbent such as limestone, are introduced into the lower part of the combustor, where initial combustion occurs. As the fuel particles decrease in size due to combustion, they are carried higher in the combustor where secondary air is introduced. As the particles continue to be reduced in size the fuel, along with some of the sorbent, is carried out of the combustor, collected in a cyclone separator, and recycled to the lower portion of the combustor. Primary removal of sulfur is achieved by reaction with the sorbent in the bed. Additional SO₂ removal is achieved through the use of a downstream polishing scrubber using a spray dryer absorber (SDA). Fabric filters are used for particulate control.

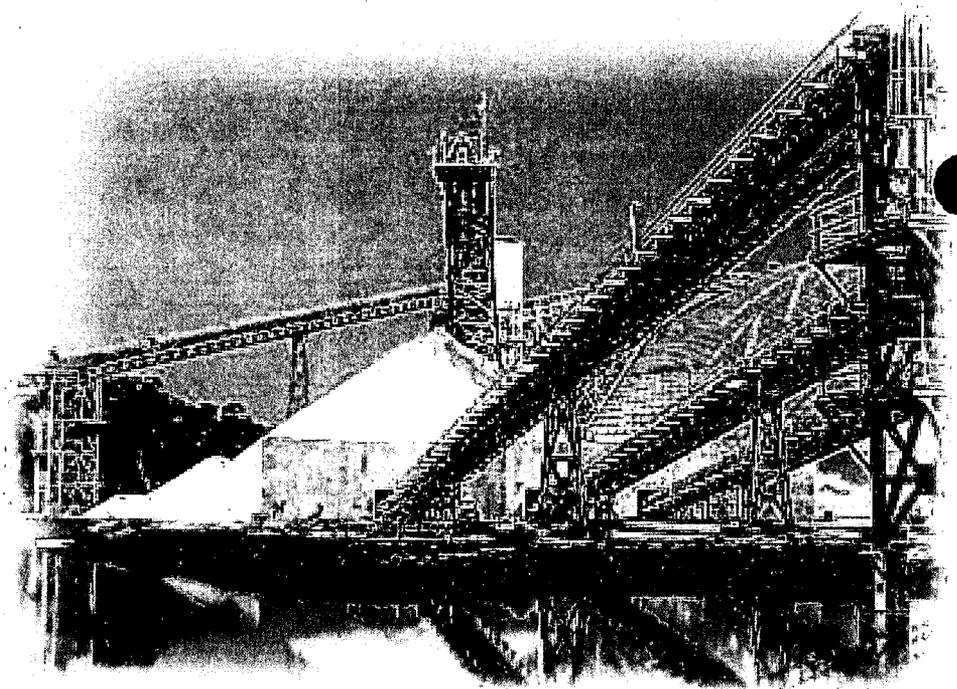
Furnace temperature is maintained in the range of 1500 to 1700°F by efficient heat transfer between the fluid bed and the water walls in the boiler. This relatively low operating temperature inherently results in appreciably lower NO_x emissions compared with PC-fired power plants. However, the project also includes a new selective non-catalytic reduction (SNCR) system, using reaction with ammonia to further reduce NO_x emissions to very low levels as required by the stringent environmental regulations for the JEA project.

Steam is generated in tubes placed along the walls of the combustor and superheated in tube bundles placed downstream of the particulate separator to protect against erosion. The system produces approximately 2 million lb/hr of main steam at 2,500 psig and 1,000°F, and 1.73 million lb/hr of reheat steam at 548 psig and 1,000°F. The steam flows to the turbine/generator, where electric power is produced. The design heat rate is 9,950 Btu/kWh (34% overall thermal efficiency, higher heating value basis).

The JEA CCT project incorporates several advanced features including a patented integrated recycle heat exchanger (INTREX™) in the furnace.



Two 400-foot diameter by 140-foot high aluminum geodesic domes for fuel storage



Limestone conveyors

Details of the JEA Project Systems

Limestone Preparation System

The limestone preparation system grinds and dries raw limestone and pneumatically transports it to the limestone storage silo for each Unit. The limestone grinding system consists of three rod mills with accessories. The mills are sized for grinding limestone at a maximum feed size of 1 inch to a product size of -2000 microns (approximately 1/16 inch), meeting the CFB desired product distribution curve, with a residual moisture content of 1% maximum.

Three pneumatic transfer systems are provided to convey the prepared limestone from the preparation building to the unit's silo. Each silo has a bin vent filter to control dust emissions. Each system is sized for 50 tons per hour (tph) capacity and is capable of transferring limestone to either Unit 1 or 2.

The control system for the limestone preparation system uses a programmable logic controller (PLC) with a cathode ray tube (CRT)-based operator interface located in the material handling control room. A digital communication interface is furnished to tie this local control system into the plant's distributed control system (DCS).

Air Quality Control System

To optimize overall plant performance, a polishing SO₂ scrubber was included in the design. The polishing scrubber is an SDA/baghouse combination. The SDA utilizes a dual fluid nozzle atomized with air, and the baghouse is a pulse-jet design. A key feature of the polishing scrubber is a recycle system which adds fly ash to the reagent feed, thus utilizing the unreacted lime in the fly ash from the CFB boiler and reducing the amount of fresh lime required.

The polishing scrubber for each unit, provided by Wheelabrator Air Pollution Control, consists of:

- A two-fluid nozzle SDA
- A medium-pressure pulse jet fabric filter (FF)
- A feed slurry preparation system
- A common sorbent preparation system, consisting of a lime storage silo, redundant vertical ball mill slaking systems, and redundant transfer/storage tanks and pumps
- A common air compressor system to provide atomizing air for the SDA, dried pulse air for the FF, and instrument air. The compressors are provided with a closed loop

cooling system. Waste heat from the compressor is used to preheat the reuse water feed to the SDA feed slurry system.

Turbine Generator and Balance of Plant Systems

The Units 1 and 2 turbine generators were upgraded to maximize output and improve turbine heat rate as much as practical. The high pressure/intermediate pressure rotor, diaphragms, and inner casing were replaced with a GE Dense Pack design, which added four stages to the turbine and increased turbine efficiency. The normal operating throttle pressure was also increased from 2400 psig to 2500 psig. In addition, the original mechanical linkage type turbine control system was replaced with a state-of-the-art Mark VI electrohydraulic control system to allow better response to load changes and for complete integrated control, protection, and monitoring of the turbine generator and accessories. A new brushless excitation system was also installed on each generator, and a new turbine lube-oil conditioner was installed (Unit 2 only).

Unit 2 was originally designed to provide power to the JEA grid at 138 kV. However, to better interface with present and future grid capabilities, the output from Unit 2 was increased to 230 kV. This required replacement of the generator step-up transformer and associated substation upgrades.

The once-through circulating water system was upgraded by replacing the original 90% copper/10% nickel heat-transfer surfaces in the condenser damaged by erosion/corrosion with modular bundles consisting of titanium tubes welded to solid titanium tubesheets. The existing circulating water pumps were replaced with larger capacity pumps. The traveling screens were replaced with those that have man-made basket material to increase their life. Debris filters were added to minimize condenser tube pluggage and possible damage. A sodium hypochlorite shock-treatment system was installed to prevent sea life from adhering to the titanium components of the condenser.

Upgrades to the condensate system in Units 1 and 2 included upgrading the condensate pumps and condensate booster pumps, replacement of the steam packing exhausters, replacement of the LP feedwater heaters, including replacement of the tube bundle in the lowest pressure heater (located in the condenser neck), replacement of the deaerator and storage tank, installation of a new con-

continued on page 8

Environmental Considerations

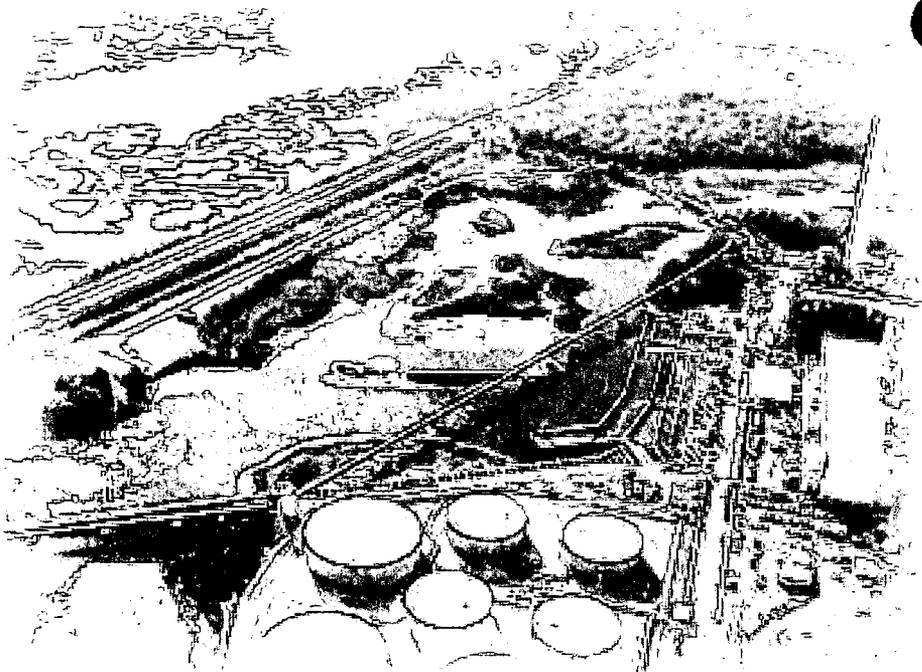
The JEA project site is located in North Jacksonville, an environmentally sensitive area surrounded by wetlands. A major goal of the project is to minimize emissions of solid, liquid and gaseous wastes. JEA is committed to making Jacksonville "the premier city in the Southeast in which to live and do business." Through consultation with community and environmental groups including the Sierra Club Northeast Florida Group, JEA agreed to emissions limits that are significantly lower than those specified by current EPA regulations.

Sierra Club Agreement

As part of the agreement with the Sierra Club, baseline stack emission rates at JEA for Units 1, 2, and 3 in 1994-1995, in tons/yr of certain substances, were identified. Target annual emissions rates representing a 10% reduction in each of these components were calculated, and a penalty of \$1000/ton was established for any emissions exceeding these rates regardless of whether such emissions are allowable under any permit or authorization. Payments are to be made to the Jacksonville Environmental Protection Board, earmarked for public environmental education. The stack emissions involved in this agreement are NO_x, SO₂, particulate matter, CO, and volatile organic compounds (VOCs). In addition, the utility negotiated limits for trace metals.

JEA also agreed to reduce groundwater consumption by at least 10%, and a penalty of \$1000/million gallons was established for any groundwater usage at JEA exceeding the agreed upon rate of 208.4 million gallons/yr, regardless of whether such usage is allowable under any permit or authorization.

These reductions in stack emissions and groundwater consumption are especially significant in light of the fact that total power production at JEA after repowering is about 2.7 times as great as the baseline level.



Wetlands adjoining the JEA Plant site

Timucuan Ecological and Historic Preserve

Designated February 16, 1988

The 46,000 acre Timucuan Ecological and Historic Preserve was established in 1988 to protect one of the last unspoiled coastal wetlands on the Atlantic Coast and to preserve historic and prehistoric sites within the area. The estuarine

ecosystem includes salt marsh, coastal dunes, and hardwood hammock as well as salt, fresh, and brackish waters. All of these are rich in native vegetation and animal life.

The Preserve was inhabited by the native Timucuan people for over 4,000 years before the arrival of the first Europeans. The Timucuan Preserve has within its boundaries federal, state, and city park lands and over 300 private landowners.



densate polisher (Unit 2 only), and installation of new chemical feed systems (Unit 2 only). The new feedwater heaters included Type 304 N stainless steel tubes (welded to tubesheets), instead of the aluminum brass tubes rolled into the tubesheets of the original heaters.

Upgrades to the feedwater system in Unit 2 included replacement of the HP feedwater heaters, upgrading of boiler feed pumps and fluid drives, and replacement of the boiler feed pump drive motor. Again, the new feedwater heaters included Type 304 N stainless steel tubes (welded to tubesheets), instead of the aluminum brass tubes rolled into the tubesheets of the original heaters.

The capability of existing piping systems and components was reviewed to confirm adequacy for the new operating and design conditions, and where necessary they were upgraded or replaced. Existing 2-inch and larger valves in Unit 2 were either refurbished or replaced. Nearly all 2-inch and smaller piping and valves in Unit 2 were replaced. Essentially all instrumentation in Unit 2 was replaced.

The original control systems in Units 1 and 2 were replaced with a new DCS provided by ABB Inc, to provide control, monitoring, and protection of the boiler, turbine interfaces, and BOP systems. Foster Wheeler provided the logic design for the CFB boiler, and Black & Veatch provided the logic design for the BOP systems, including provisions for turbine water induction prevention. ABB provided the programming to implement the logic design for the boiler and BOP systems.

The Units 1 and 2 auxiliary electric systems (switchgear and motor control centers) were replaced because of equipment obsolescence. All power and control wiring was replaced due to the age of the wiring and because the existing control wiring was not segregated from the power wiring, thus not meeting the requirements of the new DCS.

Other miscellaneous modifications included the installation of additional air dryers and screw-type air compressors as well as the installation of titanium plate-type heat exchangers for the Unit 2 closed cooling water system, similar to those previously installed in Unit 1.

Fuel Handling System

The function of the fuel handling system is to receive petroleum coke, coal, and limestone and convey it to stock-out and storage areas. The materials are reclaimed and conveyed to the in-plant fuel silos and to

the limestone preparation system for limestone sorbent.

Receiving System

Solid fuels and limestone are received at the Northside river terminal. A new 800-ft dock and over 2 miles of new belt conveyors were installed as part of the project. Fuels are delivered in 60,000-ton capacity ships and limestone in 40,000-ton ships. The fuel ships are unloaded by a state-of-the-art continuous bucket type unloader rated at 1,666 tph for coal and 1,500 tph for petroleum coke. The unloader is guided by a sophisticated electronic control system. Limestone is unloaded at a rate of 2,800 tph.

Solid fuels are stored in two 400-ft diameter by 140-ft high geodesic domes, made of aluminum, having a capacity of 60,000 tons. These domes serve to keep the fuel dry and to reduce fugitive dust emissions as well as storm water runoff. They are built with only outside support structures to eliminate pyramiding of coal dust in the interior.

Reclaim Systems

The reclaim systems used for moving feed materials from storage to the boilers are redundant. Each storage facility can provide sufficient reclaim rate for the two operating units. With two storage domes and two stacker/reclaimers, the coal and petroleum coke can be blended. Each reclaim system can deliver coal or petroleum coke at a rate of up to 600 tph.

Common Equipment

Dust suppression systems are provided at all material transfer points. The systems are of the foam type and directly control dust emissions at all transfer areas except the crusher building and the area adjacent to and above the in-plant storage silos, which have dust collectors. Reuse water is used for the foam type dust suppression system.

Dust collection systems collect and return the dust to the surge bins, or downstream of the collection points in the case of the collection points in the crusher building. The dust collected in the in-plant storage silo area is returned to one of two in-plant fuel storage silos.

A PLC based control system controls the fuel handling system and is provided with remote control for belt conveyors and associated equipment and necessary interlock control for the conveyors and machines (ship unloader and stacker/reclaimers).

continued on page 10

Emissions Targets

Design emission rate for NO_x is 0.09 lb/million Btu, which is achieved by the use of relatively low operating temperatures in the CFB coupled with post-combustion reduction of NO_x via SNCR.

For SO₂, the design emission rate is 0.15 lb/million Btu, which is achieved through the use of a sorbent for sulfur capture in the combustor, coupled with scrubbing of the flue gas.

For particulate matter having a diameter of 10 microns (µm) or less (PM₁₀), the design emission rate is 0.011 lb/million Btu. Fabric filters are used to achieve this low level of particulate emissions.

Fugitive emissions are controlled by minimizing the number of bulk material transfer points, enclosing conveyors and drop points, enclosing the fuel storage area, and using wet suppression for particulates.

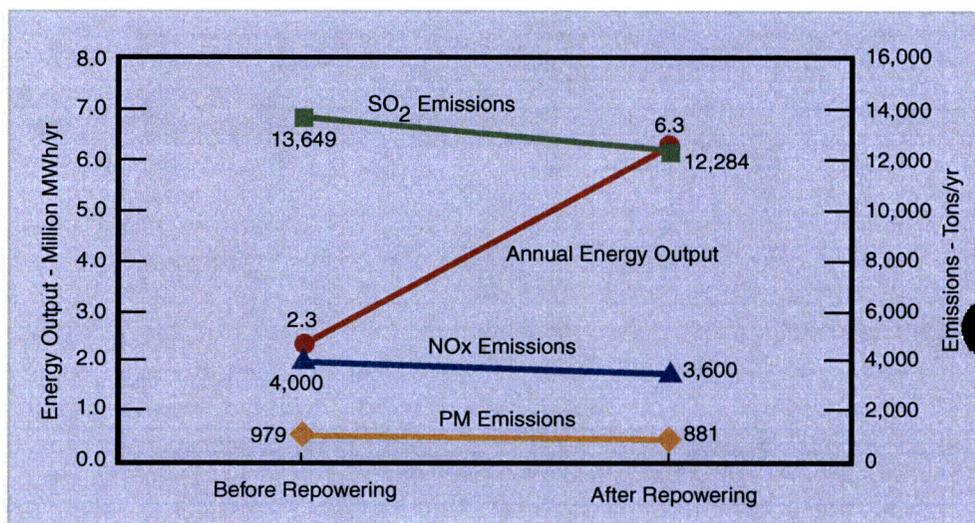
The reduction in groundwater consumption is achieved by using treated wastewater from a nearby municipal facility for certain plant applications.

Project Cost

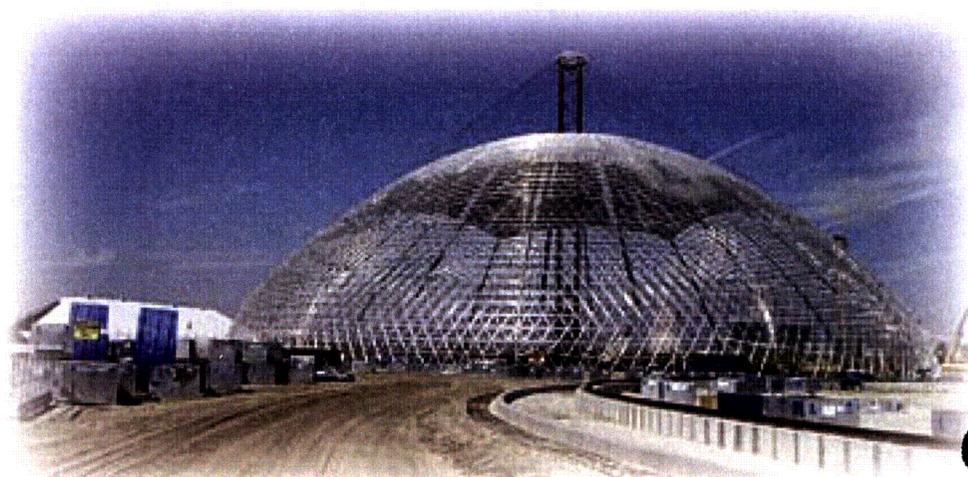
The estimated cost of the JEA Large-Scale CFB Combustion Demonstration Project is \$309 million, of which the Participant provided \$234 million (76%) and DOE provided \$75 million (24%). The repowering of Unit 1, which is not cost shared by DOE, is not included in this cost figure.

Stack Emission Rates in Sierra Club Agreement

Parameter	Existing Facility Units 1 and 3, tons/yr	Reductions from 1994/1995 Base-line, tons/yr (10% reduction)	Proposed Facility Units 1, 2, and 3, tons/yr
NO _x	4,000	400	3,600
SO ₂	13,649	1,365	12,284
Particulate Matter	979	98	881
CO	--	--	3,066
VOC (computed as 4% of CO)	--	--	123



Comparison of anticipated annual energy output and emissions before and after repowering



Fuel storage dome under construction

Ash Handling System

The ash handling system transports bed ash from the outlets of the stripper coolers to the bed ash silos, and fly ash from the economizer, air heater hoppers, and baghouse hoppers to the fly ash silos. Two sets of ash handling systems and associated equipment are provided, one for Unit 1 and the other for Unit 2. The bed ash mechanical conveying system and fly ash vacuum conveying system in turn consist of two fully independent parallel lines. Normally any one line is in operation and the other is an installed spare; however, in an emergency upset condition, both lines can be operated simultaneously.

The bed ash and fly ash from the ash silos is slurried using reclaimed water, mixed together, and pumped as a dense slurry to the by-product storage area.

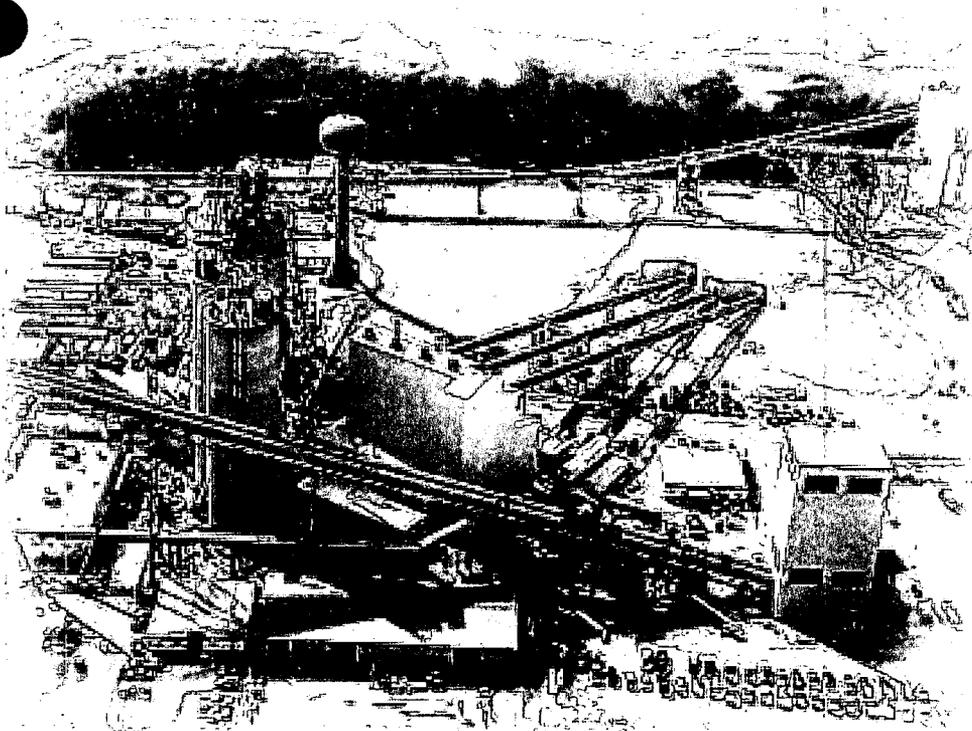
Reuse Water System

Reuse water is domestic wastewater that has been treated and disinfected to a high degree and reused for beneficial purposes. The reuse water used at Northside

Generating Station is obtained from the District II Water Reclamation Facility, transported via an eight-mile pipeline. The wastewater is treated through primary, secondary and advanced treatment. During primary treatment, large solids are removed. Secondary treatment uses microorganisms to remove the remaining solids and organic material.

After secondary treatment, the wastewater travels through cloth membrane filters, with a pore size of approximately 10 microns, to remove virtually all remaining solids. During advanced or final treatment, the wastewater is disinfected using chlorine or ultraviolet light to destroy bacteria, viruses and other pathogens.

Consumption of reuse water is expected to be more than 1 million gallons/day when all three units are operating. The reuse water is used for circulating water pump seals, boiler/precipitation area drains, polishing scrubbers, ash slurry preparation, and fuel handling dust suppression and wash down. Future uses may include irrigation.



Limestone preparation system

Project History

DOE selected the Large-Scale CFB Combustion Demonstration Project in June 1989 as part of Round I of the CCT Program. After a number of host sites were considered, the project was resited in August 1997 to Jacksonville, Florida. The Cooperative Agreement was signed in September 1997.

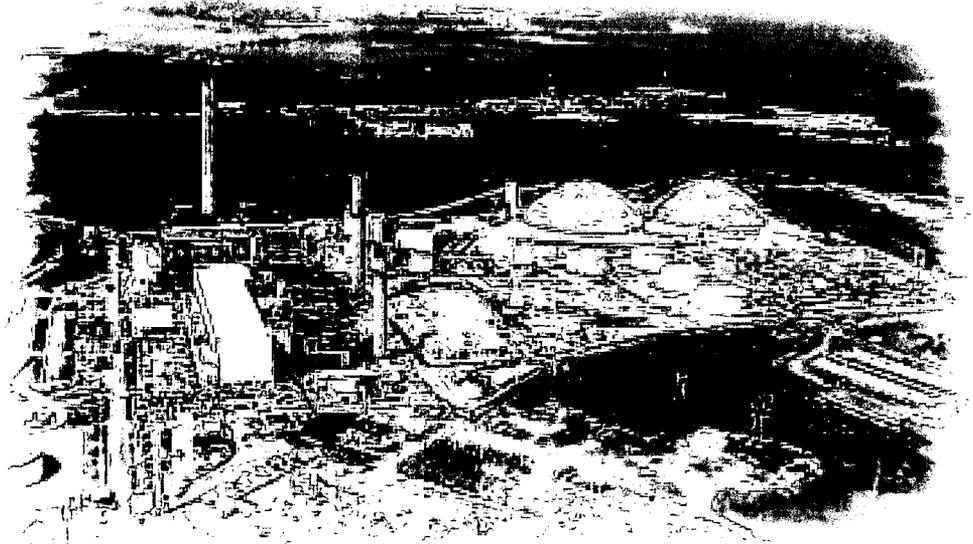
The Environmental Impact Statement for the Jacksonville site, as required by the National Environmental Policy Act, was completed in December 2001.

JEA Background

JEA is the largest municipal power company in Florida and the eighth largest municipal utility in the United States. JEA currently serves nearly 350,000 customers and is experiencing a load growth rate of more than 3% per year. Most municipal utilities in the United States do not generate their own power. Those that do so are relatively small, generating 25 MWe or less. Many of these small utilities use diesel engines for power generation. JEA is one of very few municipal utilities having an installed capacity of greater than 300 MWe.

Prior to the Large-Scale CFB Demonstration Project, JEA's Northside Station consisted of three oil/gas fired steam electric generating units. Units 1 and 2 were each nominally rated at 275 MWe and Unit 3 at 518 MWe. Units 1 & 3 had been in service since 1966 and 1977 respectively. Unit 2 was completed in 1972, but had been inoperable since about 1983 due to major boiler problems.

As part of its Integrated Resource Planning Study in 1996, JEA concluded that additional base load capacity was needed to support Jacksonville's growing need for energy. With demand growing, JEA executives saw that the utility's ability to generate all of the electricity required by its customers—something JEA had done for 100 years—would be compromised early in the 21st century unless it soon began planning new facilities.



The optimum source for that additional capacity was determined to be repowering Unit 2 with a state-of-the-art ACFB boiler fueled by coal fuel blends. To provide the project with an overall environmental benefit, increase the economies of scale, and further diversify JEA's fuel mix, a decision was made to repower Unit 1 with an identical ACFB boiler as well. The DOE cost sharing does not cover the Unit 1 repowering.

The environmental benefits include a reduction in emissions of NO_x, SO₂, and particulate matter by at least 10% compared to 1994/1995 levels. As a result of increased generating capacity and improved capacity factor, total power production was planned to increase from about 2.3 million MWh/yr to about 6.3 million MWh/yr, an increase of about 170%. An additional economic benefit results from the fact that, prior to the repowering project, Units 1 and 3 fired relatively high cost fuels, resulting in limited dispatch of these units. As a result of the repowering, both Unit 1 and Unit 2 are now capable of firing relatively low cost solid fuels. The use of these fuels, which can be delivered by ship, takes full advantage of JEA's existing strategic assets including access to the St. Johns River.

continued on page 14

Process Flowsheet

Coal or coal fuel blends are crushed to about ¼ inch diameter and mixed with limestone crushed to the size of sand. The fuel is gravimetrically metered and swept with heated combustion air into the base of the combustor. Limestone is injected into the same area of the combustor by the use of positive displacement blowers.

As the solid mixture rises, it ignites and begins a controlled "slow burn." The slow burn process maintains temperatures below 1600°F across a large area, minimizing the production of pollutants. At temperatures above 1600°F, production of NO_x increases significantly.

As the fuel particles burn, they become lighter and, with the help of additional air that constantly turns the particles over in a fluid-like motion, they are carried higher in the combustor. The limestone absorbs about 90% of the sulfur in the fuel (as SO₂).

At the cyclone inlet located at the top of the combustor, aqueous ammonia is injected into the flue gas to further reduce NO_x produced in the furnace, converting it to molecular N₂. The cyclones provide for efficient mixing of the flue gas and ammonia as well as sufficient residence time at the optimum operating temperature for effective NO_x reduction.

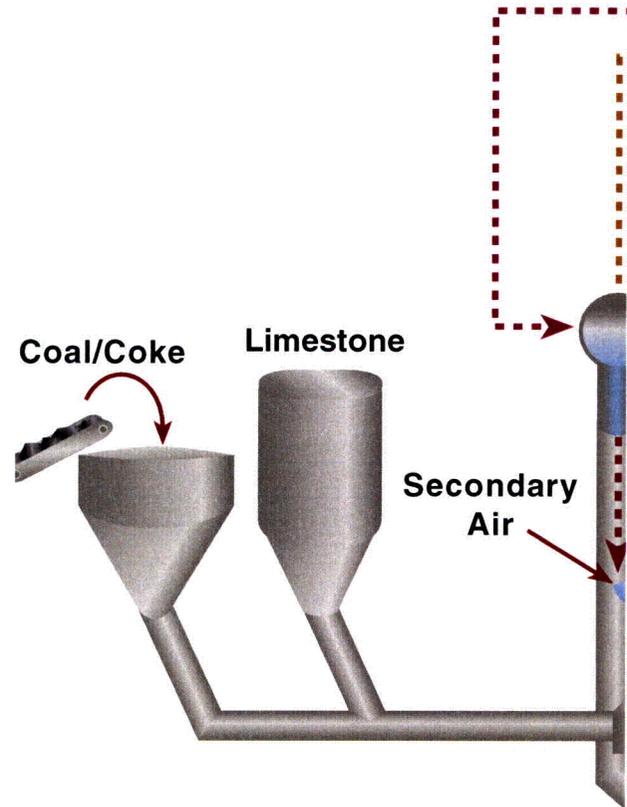
The hot ash and limestone pass through the INTREX™ exchanger before being recycled to the bottom of the combustor. In the INTREX™ exchanger, superheated steam is produced in tubes over which the hot ash returning to the combustor flows.

The steam flows into the cyclone inlet panels, through the cyclone walls, into the convection cage wall, through the primary superheater, and into the intermediate and finishing superheaters which reside within the INTREX™ exchanger. Solid material, consisting primarily of ash and CaSO₄, is removed from the bottom of the combustor and sent to by-product storage.

The hot gases leaving the top of the cyclone enter additional reheater/superheater tubes that also generate steam for the turbines. The still hot flue gas is used to preheat the main combustion air before it is introduced to the bottom of the furnace.

After the reheater/superheater, the flue gas enters an air quality control system, where it travels downward through a polishing scrubber that applies a lime slurry to absorb SO₂. Following the scrubber, the flue gas passes through a baghouse containing fabric filters to further clean the gas before it is sent up the stack. The collected particulates, which are sent to by-product storage, include trace metals captured in the fabric filters.

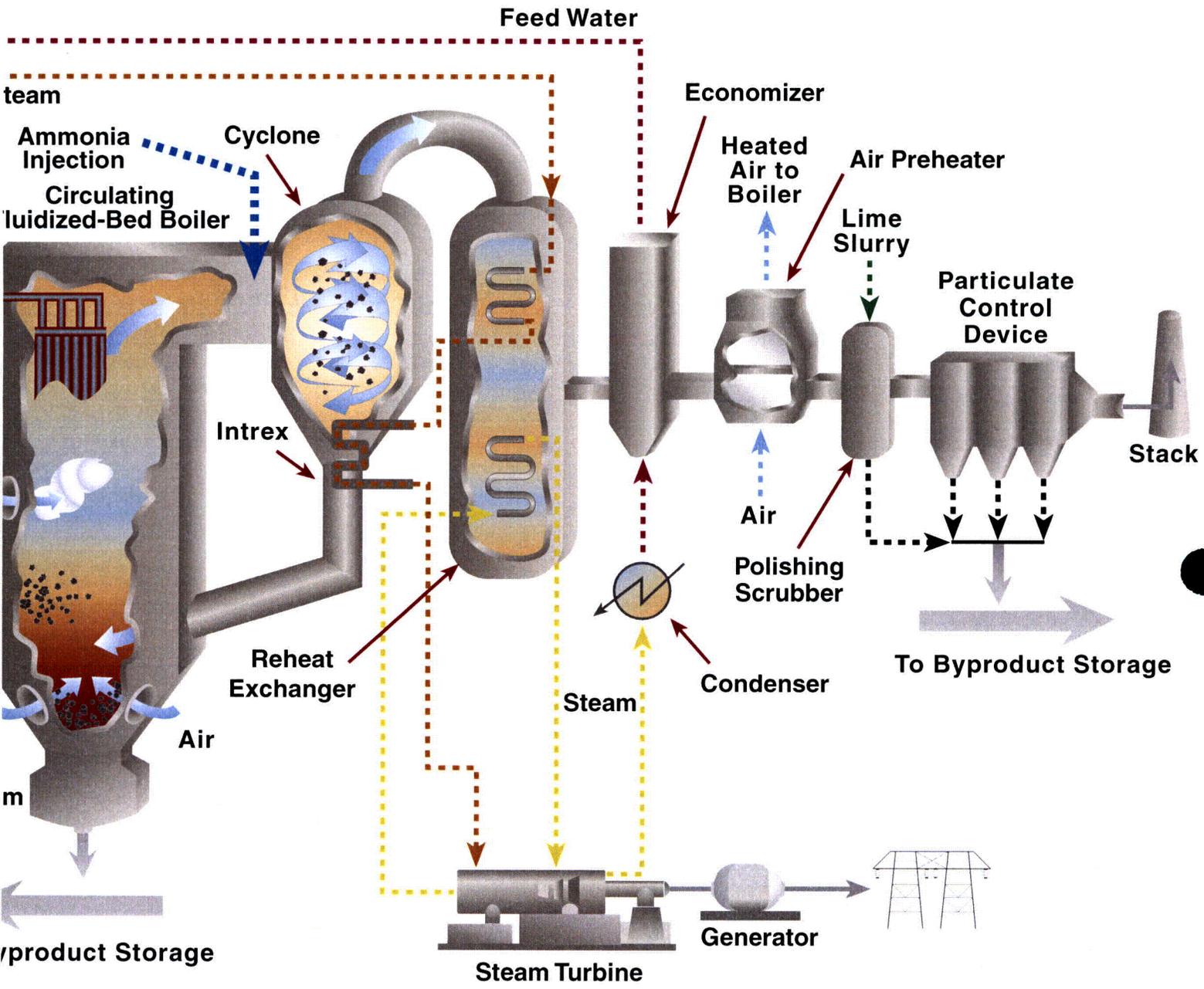
JEA Large



- Air
- High Pressure Steam
- Lower Pressure Steam
- Water
- Particulate
- Lime Slurry

A
Bot
As
To l

Scale CFB Combustion Demonstration Project



Fluidized Bed Combustion

Fluidized bed combustion (FBC) is one of the major technologies being developed under Advanced Electric Power Generation in DOE's CCT Program. FBC reduces emissions of SO₂ and NO_x by controlling combustion parameters and by injecting a sorbent, such as crushed limestone, into the combustion chamber along with the coal.

Pulverized coal mixed with the limestone is fluidized on jets of air in the combustion chamber. Sulfur released from the coal as SO₂ is captured by the sorbent in the bed to form a solid calcium compound that is removed with the ash. The resultant by-product is a dry, benign solid that can be disposed of easily or used in agricultural and construction applications. More than 90% of the SO₂ can be captured in this manner.

At combustion temperatures of 1,400 to 1600°F, the fluidized mixing of the fuel and sorbent enhances both combustion and sulfur capture. The operating temperature range is much lower than that of a conventional pulverized-coal boiler and below the temperature at which thermal NO_x is formed. In fact, NO_x emissions from FBC units are about 70 to 80% lower than those for conventional boilers. Thus, FBC units substantially reduce both SO₂ and NO_x emissions. Also, FBC has the capability of using high-ash coal, whereas conventional pulverized-coal units must limit ash content in the coal to relatively low levels.

Two parallel paths have been pursued in FBC development—bubbling and circulating beds. Bubbling FBCs use a dense fluid bed and low fluidization velocity to effect good heat transfer and mitigate erosion of an in-bed heat exchanger. Circulating FBCs use a relatively high fluidization velocity that entrains the bed material, in conjunction with hot cyclones, to separate and recirculate the bed material from the flue gas before it passes to a heat exchanger. Hybrid systems have evolved from these two basic approaches.

Fluidized bed combustion can be either atmospheric (AFBC) or pressurized (PFBC). As implied by the name, AFBC operates at atmospheric pressure. PFBCs, which operate at pressures 6 to 16 times higher, offer higher efficiency by expanding the hot combustion products through a gas turbine and utilizing the steam generated within the combustor to operate a steam turbine. Consequently, operating costs and waste are reduced relative to AFBC, as well as boiler size per unit of power output.

Second-generation PFBC integrates the combustor with a pyrolyzer (coal gasifier) to fuel a gas turbine (topping cycle), and the waste heat is used to generate steam for a steam turbine (bottoming cycle). The inherent efficiency of the gas turbine and waste heat recovery in this combined-cycle mode significantly increases overall efficiency. Such advanced PFBC systems have the potential for overall thermal efficiencies approaching 50%.

Since PFBCs have not yet been demonstrated on a commercial scale, AFBCs were chosen for the JEA project.

Natural gas was rejected as an option because northeastern Florida was served by only one pipeline at that time. Orimulsion was not considered seriously because it was not held in high regard by regulatory authorities and it did not offer a cost advantage.

In early 1997, detailed condition assessments of Unit 1 and Unit 2 BOP equipment and systems were conducted by JEA and Black & Veatch. The results of that study indicated that both Unit 1 and Unit 2 were good candidates for repowering and were capable of operating for many more years, provided various equipment and system upgrades were made.

In April 1997, JEA approved the project and authorized staff to begin working with Foster Wheeler (FW) on contract negotiations and environmental permitting.

Project Organization

JEA contracted with Foster Wheeler Energy Corporation (FWEC) to provide the design and supply of the ACFB boilers. Foster Wheeler USA (FWUSA) provided engineering, procurement, and construction management services for installation of the boilers and for furnishing and erecting the air pollution control systems, stack, limestone preparation system, and ash handling system. Foster Wheeler Environmental Corporation, a subsidiary of FWUSA, was also contracted to provide environmental permitting services.

The remaining portions of the project were implemented by JEA staff, supplemented by Black & Veatch through a pre-existing alliance with JEA for engineering services. Procurement, construction and related services were provided through other pre-existing

alliances between JEA and Zachry Construction Corporation, Fluor Global Services, W.W. Gay Mechanical Contractor, Inc., and Williams Industrial Services Inc. This work included upgrades of the existing turbine island equipment, construction of the receiving and handling facilities for the fuel and reagent required for solid fuel firing, upgrading of the electrical switchyard facilities, and construction of an ash management system.

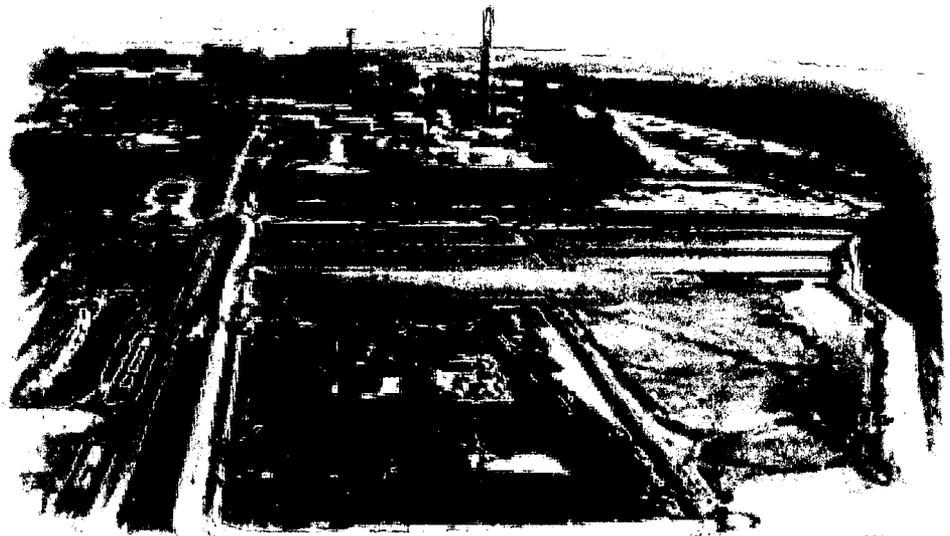
Project Status

Environmental permitting work was initiated by FW in the latter part of 1997. This work and associated preliminary engineering proceeded through 1998 and into early 1999. FW began detailed engineering for the boiler island, including the air quality control system, stack, and limestone preparation system, in December 1998. Black & Veatch began detailed engineering for BOP systems, including the fuel handling system, in February 1999. Permits necessary to begin construction were issued in July 1999, with site clearing and construction beginning in August 1999.

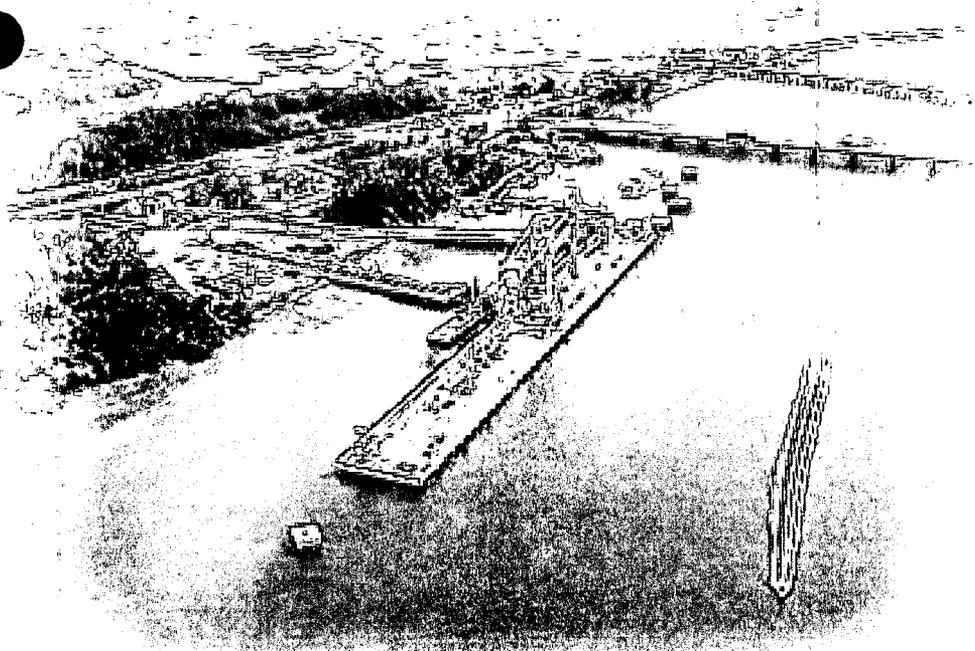
Initial synchronization was achieved for Unit 2 on February 19, 2002, and for Unit 1 on May 29, 2002. The JEA project will include two years of demonstration test runs, during which a variety of coal fuel blends will be fired.

Design Parameters

Fuel Specifications	Coal	Petroleum Coke
Heating Value, Btu/lb	>11,600	>13,000
Sulfur, %	0.5-4.5	3.0-8.0
Ash, %	7-15	<3
Volatile Matter, %	30-60	>7
Steam Flow and Conditions	Reheat	Main
Flow, 1000 lb/hr	1994	1773
Pressure, psi	2,500	548
Temperature, °F	1,000	1,000



JEA plant view from by-product storage area



Project Objectives

The JEA project objectives are (1) to demonstrate ACFB technology at 297.5 MWe gross (265 MWe net), representing a scale-up from previously constructed facilities; (2) to verify expectations of the technology's economic, environmental, and technical performance to provide potential users with the data necessary for evaluating large-scale ACFBs as a commercial alternative; (3) to accomplish greater than 90% SO₂ removal; and (4) to reduce NO_x emissions by 60% compared with conventional pulverized-coal (PC) fired boilers not equipped with post-combustion NO_x removal.

Initial Performance Results

Emissions	Guarantee Value	100% Coal Test	100% Coke Test
SO ₂ , lb/10 ⁶ Btu	<0.15	0.00-0.04	0.03-0.13
NO _x , lb/10 ⁶ Btu	<0.09	0.04-0.06	0.02
CO, lb/10 ⁶ Btu	<0.22	0.044-0.054	0.013-0.015
Particulates, lb/10 ⁶ Btu	<0.011	0.004	0.007
PM ₁₀ , lb/10 ⁶ Btu	<0.011	0.006	0.0044
SO ₃ , lb/hr	1.1	0.43	0.00
Fluoride, lb/hr	0.43	0.29	0.261
Lead, lb/hr	0.070	0.015	0.016
Mercury, lb/hr	0.03	0.0027	0.0008
VOC, lb/hr	14.0	<0.1	<0.1
Opacity, %	<10	0.36-1.12	0.21-2.64
Ammonia Slip, ppm	40	0.9	n/a
Boiler Parameters			
Steam Flow, 1000 lb/hr	>1794	1950	1937
Main Steam Temperature, °F	>980	996	992
Reheat Steam Temperature, °F	>980	1001	993
Main Steam - Reheat Steam Temperature, °F	<30	6	5
Boiler Efficiency, %	81.8	88.2	92.0

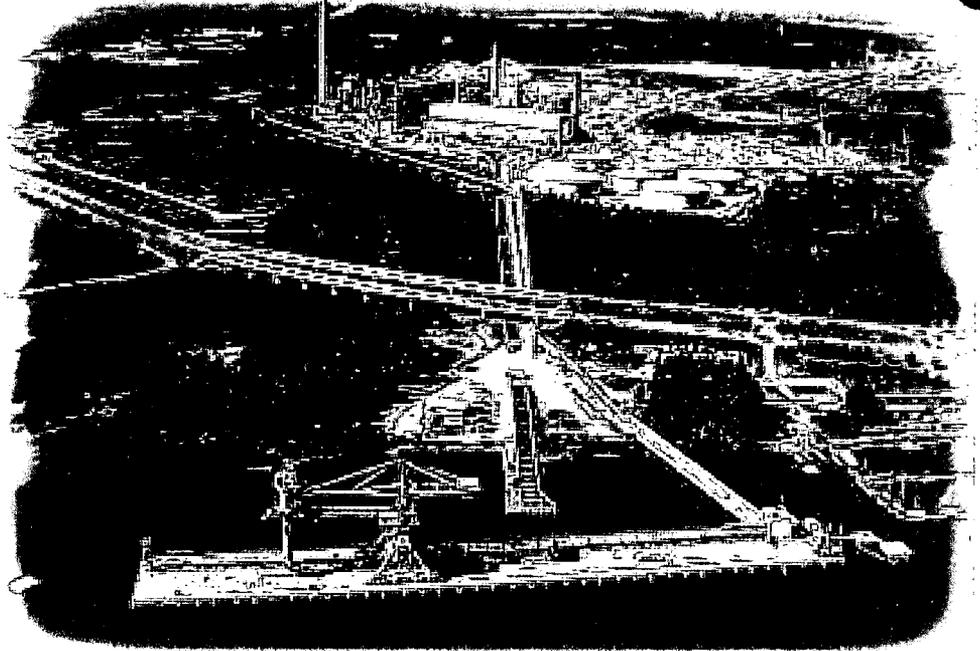
Project Scope

The JEA project involves the construction and operation of a new 300-MWe ACFB boiler fired with coal fuel blends to repower an existing steam turbine. ACFB boilers are capable of removing about 90% of the SO₂ generated, using limestone at a design Ca/S ratio of <2/1. Greater percentage removal can be achieved by increasing the Ca/S ratio, but the added cost for limestone sorbent becomes prohibitive. To optimize the overall economics and to meet environmental requirements, a polishing scrubber was included in the JEA project. This added feature is required when firing higher sulfur fuels, including petroleum coke containing up to 8.0% sulfur.

A key feature of the polishing scrubber is a recycle system which adds fly ash to the lime sorbent, thereby taking advantage of the unreacted lime in the fly ash to reduce the amount of fresh lime required. The resulting savings in sorbent and ash disposal costs offset the added capital and operating costs for the scrubber. In addition, the scrubber offers reductions in emissions of trace elements. The JEA installation represents the first use of a polishing scrubber in conjunction with a CFB in the United States.

As indicated previously, the project includes an SNCR system to reduce NO_x emissions to the very low levels required. A new baghouse was installed to achieve over 99.8% reduction in particulate emissions.

In addition to the ACFB combustor itself and the air pollution control systems, new equipment for the project includes an approximately 500-ft high stack as well as handling systems for fuel, limestone, and ash. This includes facilities for delivery of solid fuel to the site by ship. The project also required overhaul and/or modifications of existing systems such as the steam turbines, condensate and feedwater systems, circulating water systems, water treatment systems, plant electrical distribution systems, the switchyard, and the plant control systems.

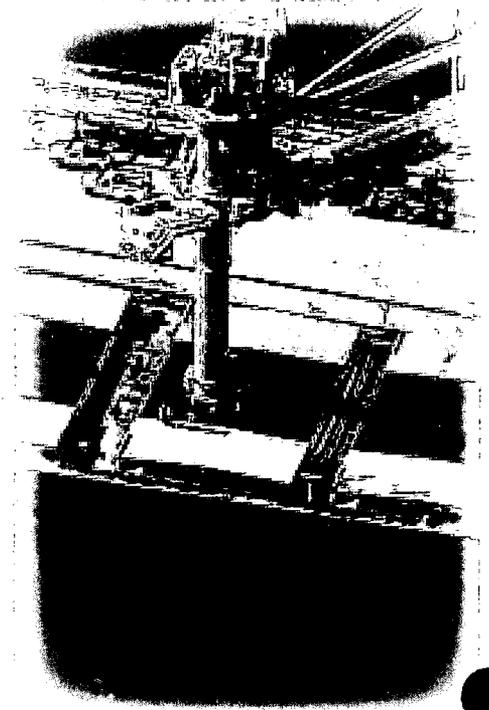


JEA plant with ship unloading dock in foreground

A significant aspect of the JEA project design is that many of the boiler components are at the leading edge of technology, but have been applied successfully in commercial service at least once before. Integrating all these components while significantly scaling up boiler size is a major project accomplishment.

Wherever possible, existing facilities and infrastructure were used. These include the intake and discharge system for cooling water, the wastewater treatment system, and the electric transmission lines and towers.

Project activities include engineering and design, permitting, procurement, construction, startup, and a twenty-four month demonstration of the commercial feasibility of the technology. During the demonstration test program, Unit 2 will be operated on several different types of coal fuel blends to enhance the viability of the technology. Upon completion of the demonstration test program, Unit 2 will continue in commercial operation. As long as petroleum coke is less expensive than coal, it will continue to be the preferred fuel for the JEA plant.



Fuel unloader at dock

Advantages of CFB Boilers

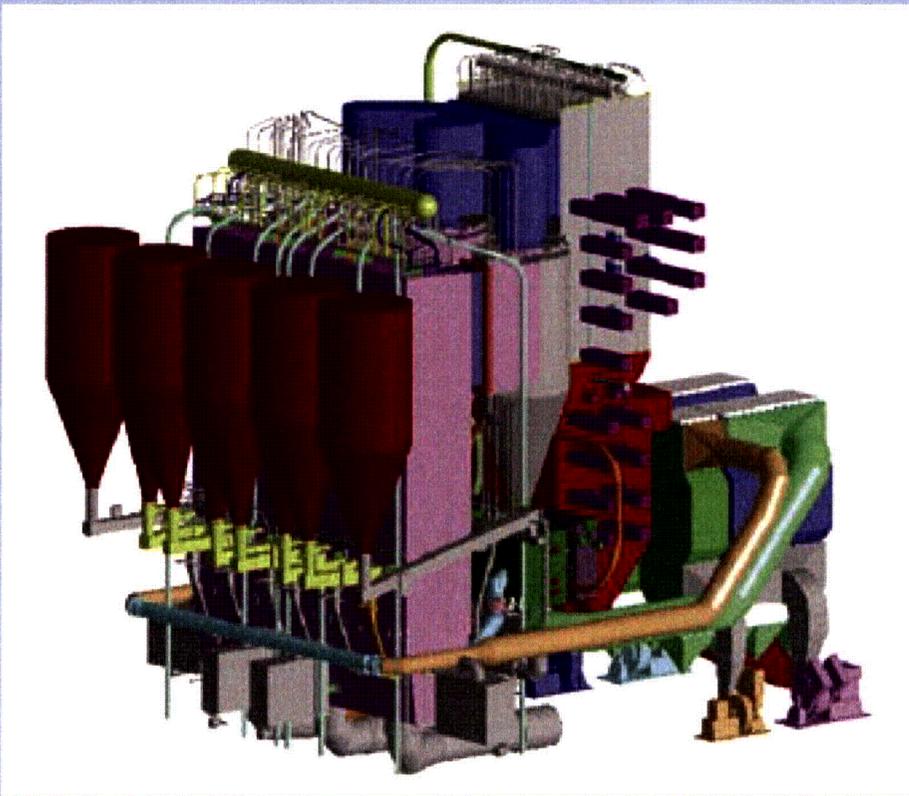
Combustion efficiency is improved in circulating fluidized bed (CFB) boilers compared to bubbling bed boilers. This is primarily because the elutriated particles are separated from the flue gas in cyclone collectors (hot cyclones with vortex finders) and returned to the furnace for further exposure to combustion

temperature and high turbulence. This fact results in an increase of up to 4% in overall combustion efficiency. The particles captured in the cyclone collectors make up the circulating bed material within the "hot loop." The hot loop is a term given for the circulating path of bed material inside the boiler.

Other advantages of CFB boilers over conventional PC-fired boilers are:

- Lower capital cost
- Ability to burn a wide range of low- to high-grade fuels
- Increased sulfur capture with less limestone consumption and low SO₂ emissions
- Lower operating temperatures compared with other types of boilers, thereby reducing slag formation and excess stack emissions
- Improved heat transfer with the increase in residence time for fuel and limestone
- Lower NO_x emissions because of low operating temperatures

Lower operating temperatures mean fewer pollutants and less equipment needed to clean up the combustion process while burning a variety of fuels. The ratios between operating gas velocity and minimum solids entrainment velocity allow turndown ratios as high as four to one. Operation over a wide range of boiler loads is possible without starting and stopping burners and auxiliary equipment.



Schematic diagram of CFB boiler at JEA

Fluidized Bed Combustion Systems

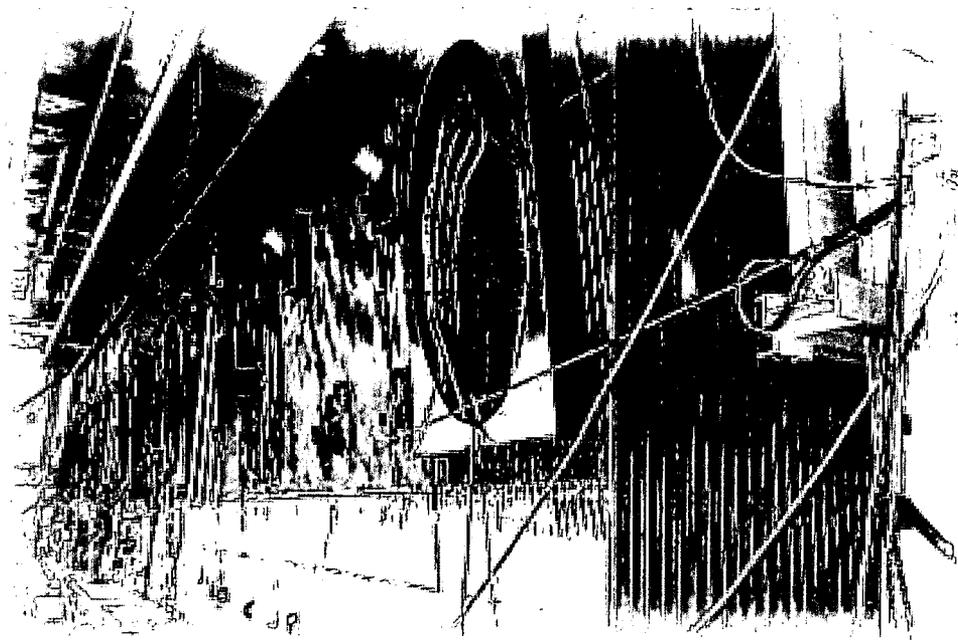
The ACFB boiler technology selected for the JEA project is an advanced method for utilizing coal and other solid fuels in an environmentally acceptable manner. The low combustion temperature allows SO₂ capture via limestone injection while minimizing NO_x emissions. The technology provides the capability to burn a wide range of coal fuel blends. Presently, there are two types of fluidized bed boilers in commercial operation: bubbling bed and circulating bed.

Bubbling Bed Boilers

In the bubbling bed type boiler, a layer of solid particles (mostly limestone, sand, ash and calcium sulfate) is contained on a grid near the bottom of the boiler. This layer is maintained in a turbulent state as low velocity air is forced into the bed from a plenum chamber beneath the grid. Fuel is added to this bed and combustion takes place. Normally, raw fuel in the bed does not exceed 2% of the total bed inventory. Velocity of the combustion air is kept at a minimum, yet high enough to maintain turbulence in the bed. Velocity is not high enough to carry significant quantities of solid particles out of the furnace.

This turbulent mixing of air and fuel results in a residence time of up to five seconds. The combination of turbulent mixing and residence time permits bubbling bed boilers to operate at a furnace temperature below 1650°F. At this temperature, the presence of limestone mixed with fuel in the furnace achieves greater than 90% sulfur removal.

Boiler efficiency is the percentage of total energy in the fuel that is used to produce steam. Combustion efficiency is the percentage of complete combustion of carbon



CFB boiler under construction

in the fuel. Incomplete combustion results in the formation of carbon monoxide (CO) plus unburned carbon in the solid particles leaving the furnace. In a typical bubbling bed fluidized boiler, combustion efficiency can be as high as 92%. This is a good figure, but is lower than that achieved by pulverized coal or cyclone-fired boilers. In addition, some fuels that are very low in volatile matter cannot be completely burned within the available residence time in bubbling bed-type boilers.

Circulating Fluidized Bed Boilers

The need to improve combustion efficiency (which also increases overall boiler efficiency and reduces operating costs) and the desire to burn a much wider range of fuels has led to the development and application of the CFB boiler. Through the years, boiler suppliers have been increasing the size of these high-efficiency steam generators. FW has designed (but not built) CFB boilers that are capable of producing 400 MWe of power.

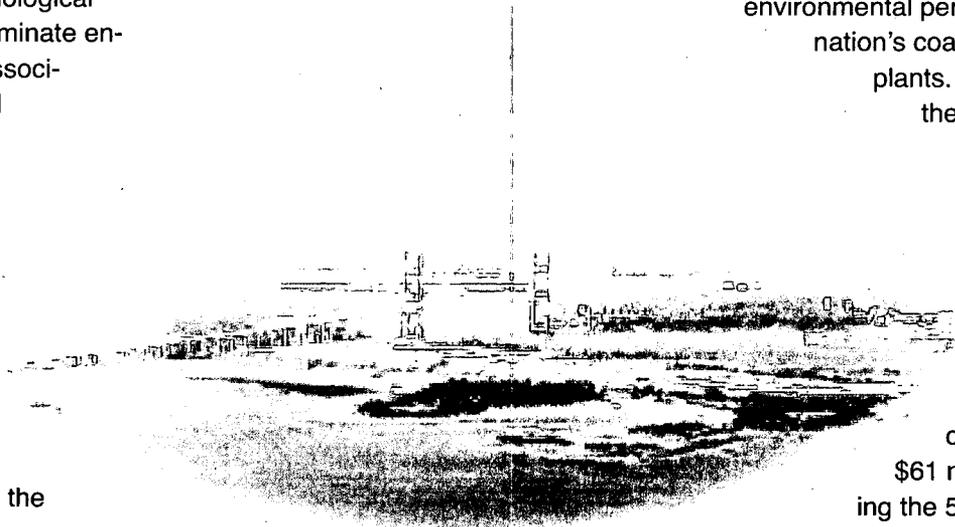
continued on page 21

The Clean Coal Technology Program

The Clean Coal Technology (CCT) Program is a unique partnership between the federal government and industry that has as its primary goal the successful introduction of new clean coal utilization technologies into the energy marketplace. With its roots in the acid rain debate of the 1980s, the program has met its early objective of broadening the range of technological solutions available to eliminate environmental concerns associated with the use of coal for electric power production. As the program has evolved, it has expanded to address the need for new, high-efficiency power generating technologies that will allow coal to continue to be a fuel option well into the 21st century.

Begun in 1985 and expanded in 1987 consistent with the recommendations of the U.S. and Canadian Special Envoys on Acid Rain, the program has been implemented through a series of five nationwide competitive solicitations, or rounds. Each solicitation was associated with specific government funding and program objectives. After five rounds, the CCT Program comprises a total of 38 projects located in 18 states with a total investment value of over \$5.2 billion. DOE's share of the total project costs is about \$1.8 billion, or approximately 34% of the total. The projects' industrial participants (i.e., the non-DOE participants) are providing the remainder—about \$3.5 billion.

Processes being demonstrated under the CCT Program have established a technology base that will enable the nation to meet more stringent energy and environmental goals. Also ready is a new generation of technologies that can produce electricity and other commodities, such as steam and synthesis gas, at high efficiencies consistent with concerns about global climate change.



Most of the CCT demonstrations are being conducted at commercial scale, in actual user environments, and under circumstances typical of commercial operations. These features allow the potential of the technologies to be evaluated in their intended commercial applications.

Each application addresses one of the following four market sectors:

- Advanced electric power generation
- Environmental control devices
- Coal processing for clean fuels
- Industrial applications

Given its programmatic success, the CCT Program serves as a model for other cooperative government/industry

programs aimed at introducing new technologies into the commercial marketplace.

Two follow-on programs have been developed that build on the successes of the CCT Program. The Power Plant Improvement Initiative (PPII) is a cost shared program, patterned after the CCT Program, directed toward improved reliability and environmental performance of the

nation's coal-burning power plants. Authorized by

the U.S. Congress

in 2001, the PPII

involves eight projects having a total cost of \$95 million.

Private sector sponsors are expected to

contribute nearly

\$61 million, exceed-

ing the 50% private sec-

tor cost sharing mandated by

Congress. Most of the PPII projects focus on technologies enabling coal-fired power plants to meet increasingly stringent environmental regulations at the lowest possible cost.

The second program is the Clean Coal Power Initiative (CCPI), also patterned on the CCT Program, authorized in early 2002. Valued at \$330 million for the initial stage, this initiative will accelerate the commercial deployment of technology advancements that result in efficiency, environmental and economic improvement compared with available state-of-the-art alternatives. Proposals submitted under the CCPI are currently being evaluated.

CFBs offer a number of advantages:

Fuel Flexibility – The relatively low furnace temperatures are below the ash softening temperature for nearly all fuels. As a result, furnace design is independent of ash characteristics, thus allowing a given furnace to handle a wide range of fuels.

Low SO₂ Emissions – Limestone is an effective sulfur sorbent in the temperature range of 1500 to 1700°F. SO₂ removal efficiency of 90% has been demonstrated with good sorbent utilization.

Low NO_x Emissions – The combination of low furnace temperatures and staging of air feed to the furnace produces very low NO_x emissions.

High Combustion Efficiency – The long solids residence time in the furnace resulting from the collection/recirculation of solids via the cyclone, plus the vigorous solids/gas contact in the furnace caused by the fluidization air flow, results in high combustion efficiency, even with difficult-to-burn fuels.

Characteristics of CFB Boilers

In the furnace of a circulating fluidized bed boiler, gas velocity is increased to more than that in a bubbling bed boiler. This increase in velocity causes the dense mixture of solids (fuel, limestone and ash) to be carried up through the furnace. There is a minimum gas entrainment velocity required for the particles to lift and separate (elutriate) and flow up, through and out of the furnace.

Reaching this entrainment velocity marks the change from a bubbling bed boiler to a circulating bed boiler. At approximately 500°F bed temperature, air flows are above minimum and the entrainment velocity is reached.

Solids move up through the furnace at lower velocities than the air and gas mixture. This fact, coupled with the elongated furnace in a CFB boiler and recirculating bed material, allows particle residence times of up to several minutes in the furnace. During this long residence period, the crushed fuel particles

are consumed in the combustion process.

The fuel is reduced in size during the combustion process and thoroughly mixed with limestone and the balance of the bed material. This action produces the “fines” (small particles of bed material) necessary to have circulating bed material in the “hot loop.” Long residence time, coupled with small particle size and high turbulence, results in a better sulfur removal rate with less limestone than in a bubbling fluidized bed boiler. In addition, higher gas velocity produces heat transfer rates that are greater than in the bubbling bed.

In normal operation there is no defined fixed bed depth in a CFB boiler. There are different densities of circulating bed material depending on the weight of the particles. Heavy particles stay in the lower region of the furnace. As the height within the furnace increases, the smaller bed particles (less dense) enter the circulation path of the hot loop. When the particles break down enough, they are carried out of the hot loop (circulating path) with the flue gas as fly ash.



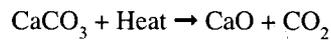
New 500-foot stack in foreground, with inset showing the stack interior

Sulfur Removal in CFB Boilers

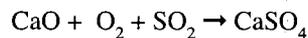
Most of the sulfur in the fuel combines chemically with oxygen during the combustion process to form SO_2 and, to a limited extent, sulfur trioxide (SO_3). These sulfur oxides must be removed from the flue gas to comply with environmental regulations.

The mechanism for removing SO_2 with limestone is as follows:

Calcination of limestone:



Reaction with sulfur oxides (sulfation):



The product, CaSO_4 , is an inert substance known as gypsum. Limestone continuously reacts with the fuel at normal operating temperatures. The sulfation reaction requires that there always be an excess of limestone. The amount of excess limestone required depends on several factors, such as the amount of sulfur in the fuel, the temperature of the bed material in the furnace, and the physical and chemical characteristics of the limestone (reactivity).

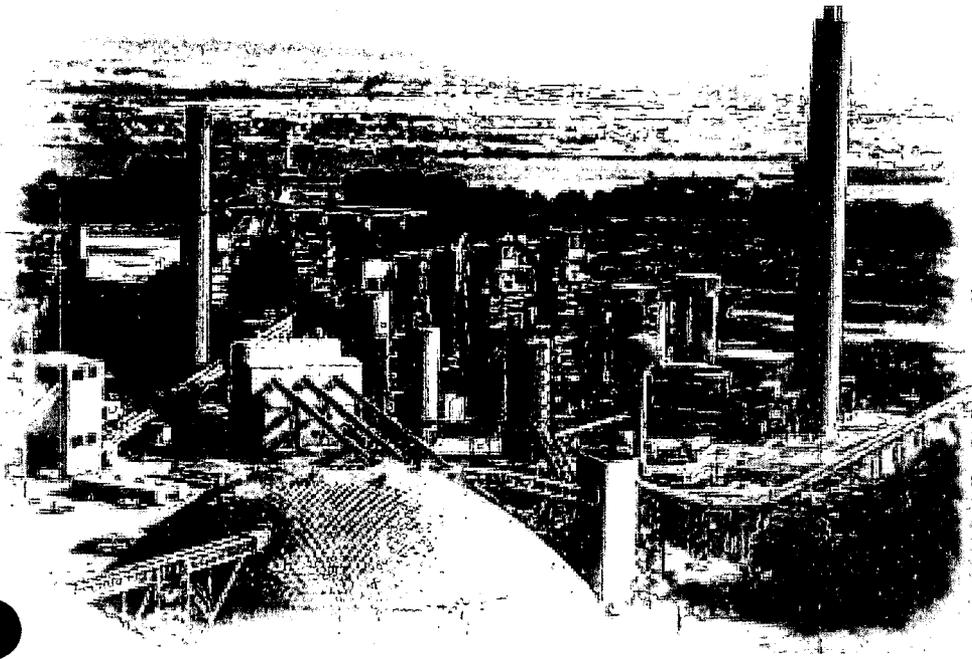
The ideal reaction temperature range is 1500 to 1700°F.

There is little limestone reaction when the bed temperature is below 1500°F or above 1700°F. Within the optimum temperature range, about 90% of the SO_2 can be removed at an acceptable Ca/S ratio. Outside this temperature range, significant increases in limestone feed rate are required to maintain emission levels within regulated limits.

The CFB bed material typically contains limestone products as the predominant component, with smaller amounts of fuel, ash and impurities (for example, rocks or tramp iron). Calcium oxide content rises with decreasing fuel sulfur content and high removal rates. The ash content increases with higher ash fuels and those that are less friable, i.e., brittle.

Fresh limestone enters the furnace and, at the normal operating temperature, calcines by liberating CO_2 . It then absorbs SO_2 from the burning fuel that sulfates the limestone, converting limestone to gypsum. In the calcining stage, limestone is physically weak and is easily decrepitated (crumbled) into dust and carried out of the bed (elutriated) by the furnace draft.

With a sulfur content in the fuel of 2.5% or more, enough SO_2 is produced during combustion that the limestone can readily sulfate (combine with the SO_2). This strengthens the limestone and reduces loss of limestone from decrepitation and elutriation. A low sulfur content can lead to loss of limestone through attrition. This loss must be compensated for by increasing limestone feed to maintain bed inventory and SO_2 capture. Gypsum and some excess limestone are carried out of the CFB furnace and trapped by the downstream flue gas cleanup equipment.



Demonstration Test Program

The demonstration test program will be conducted in accordance with the plan developed in coordination with DOE. The test program consists of the following major components.

Operational Testing will be performed to:

- Demonstrate unit functionality
- Establish initial operating, maintenance and inspection criteria
- Establish constraints related to dispatch of the unit
- Demonstrate continuous full- and part-load capability and performance

Operational testing includes a series of operability, reliability, and performance tests.

Operability involves tests of cold startups, warm startups, hot restarts, dispatch, minimum stable load, and operation at maximum continuous rating.

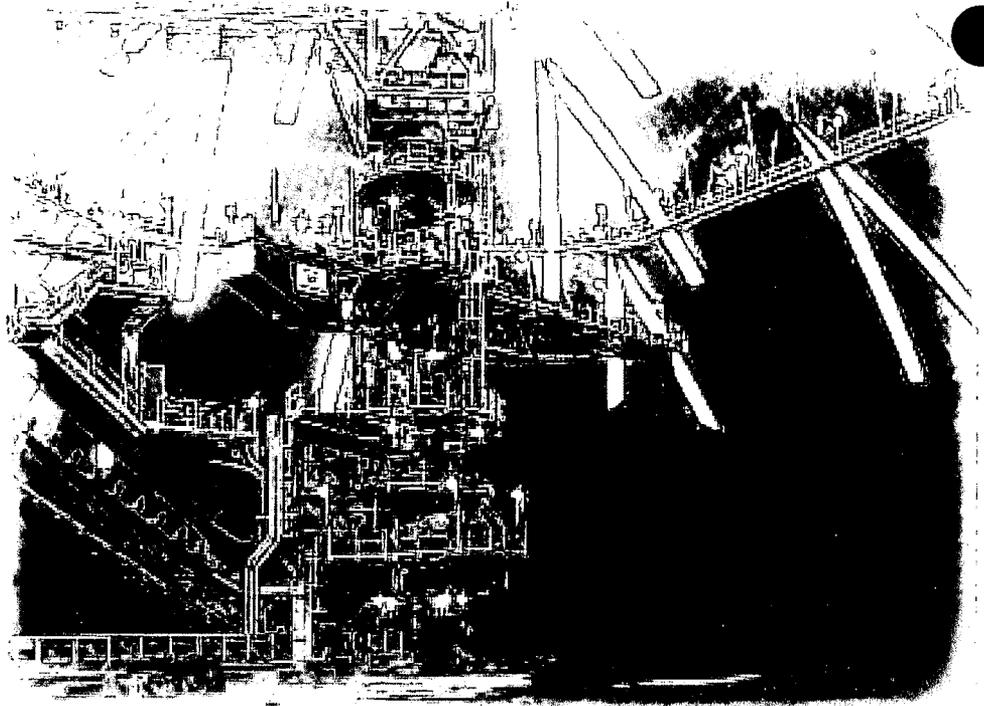
Reliability testing includes availability, capacity factor, and forced outage rate.

Performance testing will be conducted in conjunction with fuel flexibility testing, which involves burning four different fuels and fuel blends. The specific fuels to be tested are as follows:

- 100% Pittsburgh No. 8 high-sulfur coal
- 90% petroleum coke and 10% Pittsburgh No. 8 high-sulfur coal
- 50% petroleum coke and 50% Pittsburgh No. 8 high-sulfur coal
- 100% Illinois No. 6 high-sulfur coal

Fuel Flexibility Testing includes boiler capacity and controllability, load following capability, bed/cyclone agglomeration potential, and air quality control system performance.

Long Term Durability Testing consists of reviewing significant maintenance issues experienced with major equipment throughout the demonstration period.

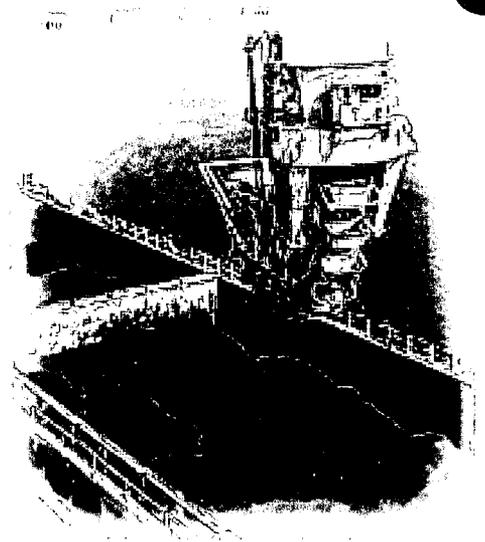


Interior of fuel storage dome

Operating Results

The JEA Unit 2 CFB boiler has operated at full load, achieving rated output in May 2002. The unit can maintain operation on both coal and coal fuel blends. However, satisfactory operation on 100% petroleum coke has not yet been demonstrated. One major problem when operating on 100% petroleum coke has been plugging in the hot gas path, specifically in the cyclone and the INTREX™ heat exchanger. Steps are being taken to remedy this situation.

Initial results indicate that the JEA plant is capable of meeting emissions guarantees when operating on both coal and coal fuel blends.





JEA receives the *Power* magazine 2002 Powerplant award. On hand for the award ceremony were (left to right): Mike Hightower, JEA's Board Chairman; Joey Duncan, JEA's Project Manager; the Honorable Corrine Brown, U.S. House of Representatives; Rita Bajura, Director of U.S. DOE's National Energy Technology Laboratory; and Bob Schwieger, *Power* magazine consulting editor

Awards

The JEA project received the 2002 Powerplant Award from *Power* magazine. This award recognizes outstanding achievement in "the development of a successful repowering strategy for converting existing oil/gas-fired steam plants to solid fuels to increase efficiency while reducing both emissions and the cost of electricity."

Bob Dyr, JEA's Boiler Island Project Manager, was presented the Engineer of the Year award by the Florida Engineers Society in 2002 for outstanding technical achievement, on behalf of the project team.

Commercial Applications

ACFB technology has potential application in both the industrial and utility sectors, for use in repowering existing plants as well as in new facilities. ACFB is attractive for both baseload and dispatchable power applications because it can be efficiently turned down to as low as 25% of full load. While the efficiency of ACFB is on a par with conventional PC-fired plants, the advantage of ACFB is that coal of any sulfur or ash content can be used, and any type or size unit can be repowered.

In repowering applications, an existing plant area is used, and coal- and waste-handling equipment as well as steam turbine equipment are retained, thereby extending the life of the plant.

In its commercial configuration, ACFB technology offers several potential benefits compared with conventional PC-fired systems:

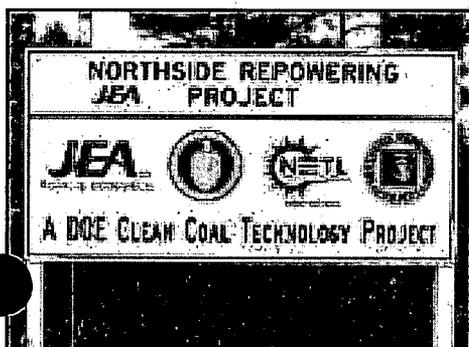
- Lower capital costs
- Reduced SO₂ and NO_x emissions at lower cost
- Higher combustion efficiency
- A high degree of fuel flexibility, including use of renewable fuels
- Dry, granular solid by-product material that is easily disposed of or sold.

Recently, two other commercial scale ACFB projects in the U.S. have been announced, one at Reliant Energy's Seward Station in Pennsylvania and the other at Tractabel's Red Hills Station in Mississippi.

Conclusions

The JEA Large-Scale CFB Combustion Demonstration Project is demonstrating the commercial application of this advanced technology for generating electricity. The two boilers at the Northside Station are the largest CFBs in the world burning coal fuel blends. Despite the large furnace size, solids distribution is good, lending confidence to the CFB design.

Power production from each boiler on coal feed meets the target goal of 297.5 MWe gross (265 MWe net). Emissions of atmospheric pollutants are below the stringent requirements set for the project.



Bibliography

P.T. Nielsen, J.L. Hebb, R. Aquino, and S.L. Darling, "Large-Scale CFB Combustion Demonstration Project," Sixth Clean Coal Technology Conference (Reno NV), May 1998.

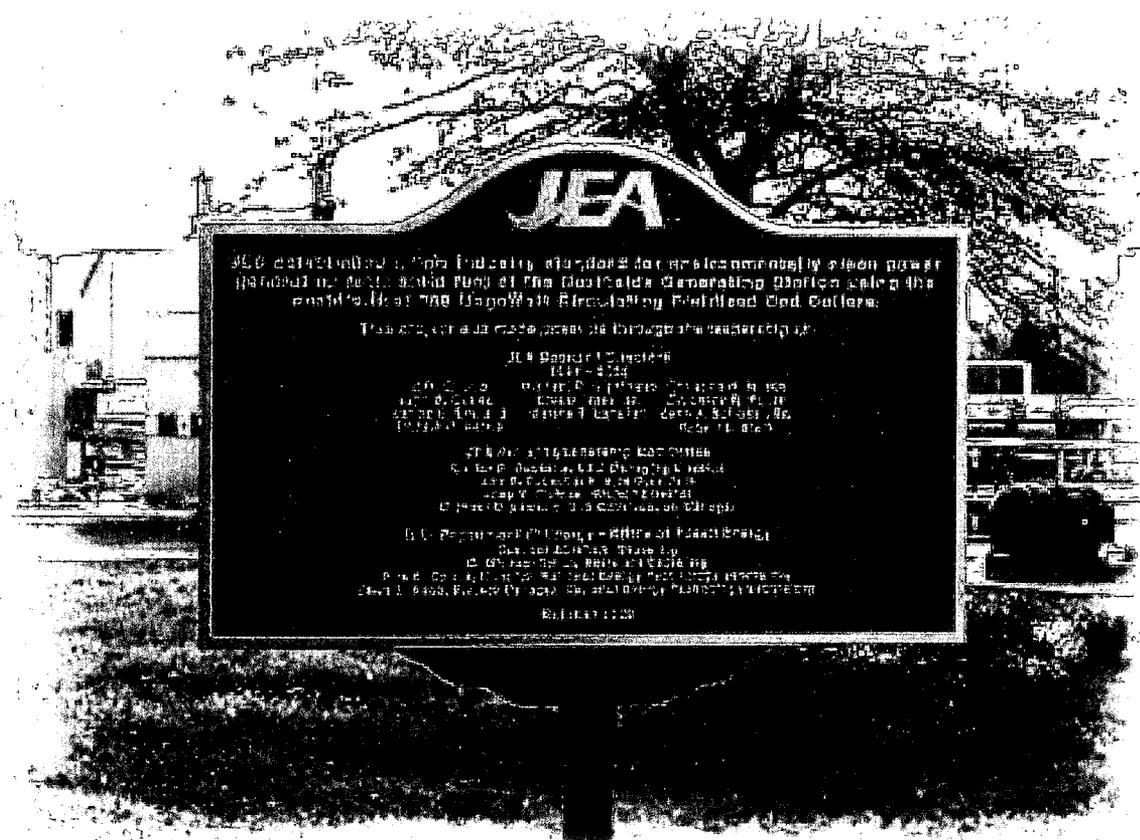
U.S. Department of Energy, Clean Coal Technology Demonstration Program -- Program Update 2000, July 2002.

R. Dyr and G. Graham, "The Northside 1 and 2 Repowering Project: An Overview," 7th Foster Wheeler Fluidized Bed Customer Conference, San Diego CA, August 14-16, 2002.

R. Schwieger, "Northside's CFB Repowering Halves Power Cost, Reduces Emissions," Power, September 2002, p. 20.

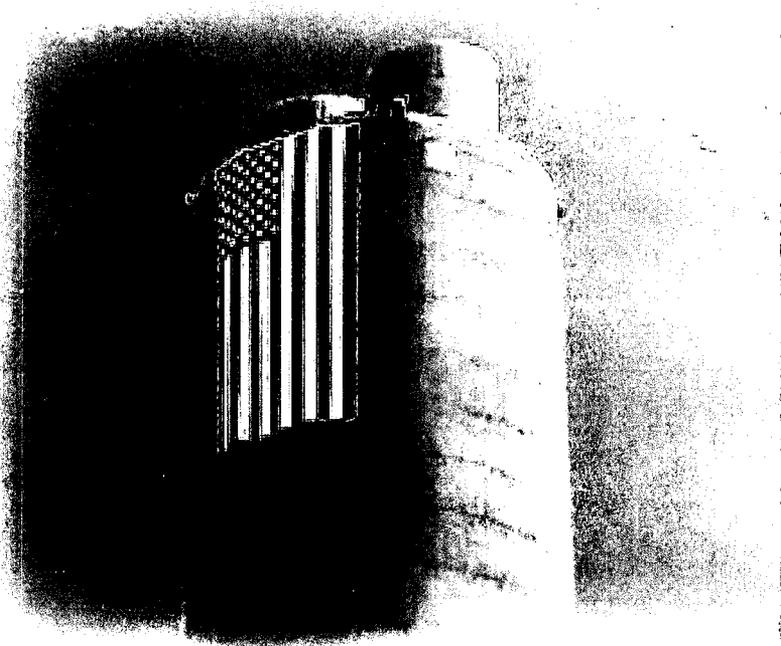
R.A. Dyr and A.L. Compaan, "JEA Northside Repowering: 2002 Powerplant of the Year," presented at FMEA 2002 Energy Connections Workshop and Trade Show, St. Petersburg FL, October 15-17, 2002.

JEA, "Public Design Report for the JEA Large-Scale CFB Combustion Demonstration Project," March 2003.



List of Acronyms and Abbreviations

ACFB	atmospheric circulating fluidized bed
AFBC	atmospheric fluidized bed combustor
AQCS	air quality control system
BOP	balance of plant
Btu	British thermal unit
CaCO ₃	calcium carbonate
CaO	calcium oxide
Ca(OH) ₂	calcium hydroxide
CaSO ₄	calcium sulfate
CAAA	Clean Air Act Amendments of 1990
CCPI	Clean Coal Power Initiative
CCT	Clean Coal Technology
CFB	circulating fluidized bed
CO ₂	carbon dioxide
CRT	cathode ray tube
DCS	distributed control system
DOE	U.S. Department of Energy
EPA	U.S. Environmental Protection Agency
FBC	fluidized bed combustion
FF	fabric filters



Stack shortly after 9/11/2001

kWh..... kilowatt hour
micron one millionth of a meter
MCR..... maximum continuous rating
MgCO₃ magnesium carbonate
Mg(OH)₂ magnesium hydroxide
MWe..... megawatts of electric power
MWh megawatt hours of electric power
NETL..... National Energy Technology Laboratory
NO_x..... nitrogen oxides
PC..... pulverized coal
PFBC..... pressurized fluidized bed combustor
PLC programmable logic controller
PM..... particulate matter
PM₁₀ particulate matter having a diameter of 10 microns (μm) or less
PPII..... Power Plant Improvement Initiative
psig..... pressure, pounds per square inch (gauge)
SDA..... spray dryer absorber
SO₂ sulfur dioxide
SO₃ sulfur trioxide
tph..... tons/hr
VOC volatile organic compound
wt % percent by weight

Sunset at JEA



To Receive Additional Information

To be placed on the Department of Energy's distribution list for future information on the Clean Coal Technology Program, the demonstration projects it is financing, or other Fossil Energy Programs, please contact:

Robert C. Porter

Director, Office of Communication
U.S. Department of Energy, FE-5
1000 Independence Ave SW
Washington DC 20585
(202) 586-6503
(202) 586-5146 fax
robert.porter@hq.doe.gov

Otis Mills

Public Information Office
U.S. Department of Energy
National Energy
Technology Laboratory
P.O. Box 10940
Pittsburgh PA 15236-0940
(412) 386-5890
(412) 386-6195 fax
otis.mills@netl.doe.gov

Contacts for CCT Projects and U.S. DOE CCT Program

Participant Contact

Joey V. Duncan

JEA Project General Manager
(904) 714-4831
duncjv@jea.com

U.S. Department of Energy Contacts

George Lynch

U.S. Department of Energy, FE-24
Germantown MD 20874-1290
(301) 903-9434
(301) 903-2713 fax
george.lynch@hq.doe.gov

Jerry L. Hebb, P.E.

Project Manager
National Energy Technology Laboratory
P.O. Box 10940
Pittsburgh PA 15236-0940
(412) 386-6079
(412) 386-4775 fax
jerry.hebb@netl.doe.gov

**This report is available on the Internet at
www.netl.doe.gov. Select Links, then Clean
Coal Technology Compendium**

NETL web page on FBC:

www.netl.doe.gov/coalpower/combustion

**JEA website:
www.jea.com**

1.1 Bituminous And Subbituminous Coal Combustion

1.1.1 General

Coal is a complex combination of organic matter and inorganic mineral matter formed over eons from successive layers of fallen vegetation. Coals are classified by rank according to their progressive alteration in the natural metamorphosis from lignite to anthracite. Coal rank depends on the volatile matter, fixed carbon, inherent moisture, and oxygen, although no single parameter defines a rank. Typically, coal rank increases as the amount of fixed carbon increases and the amount of volatile matter and moisture decreases.

Bituminous coals are by far the largest group and are characterized as having lower fixed carbon and higher volatile matter than anthracite. The key distinguishing characteristics of bituminous coal are its relative volatile matter and sulfur content as well as its slagging and agglomerating characteristics. Subbituminous coals have higher moisture and volatile matter and lower sulfur content than bituminous coals and may be used as an alternative fuel in some boilers originally designed to burn bituminous coals.¹ Generally, bituminous coals have heating values of 10,500 to 14,000 British thermal units per pound (Btu/lb) on a wet, mineral-matter-free basis.² As mined, the heating values of typical U.S. bituminous coals range from 10,720 to 14,730 Btu/lb.³ The heating values of subbituminous coals range from 8,300 to 11,500 Btu/lb on a wet, mineral-matter-free basis², and from 9,420 to 10,130 Btu/lb on an as-mined basis.³ Formulae and tables for classifying coals are given in Reference 2.

1.1.2 Firing Practices⁴

Coal-fired boilers can be classified by type, fuel, and method of construction. Boiler types are identified by the heat transfer method (watertube, firetube, or cast iron), the arrangement of the heat transfer surfaces (horizontal or vertical, straight or bent tube), and the firing configuration (suspension, stoker, or fluidized bed). The most common heat transfer method for coal-fired boilers is the watertube method in which the hot combustion gases contact the outside of the heat transfer tubes, while the boiler water and steam are contained within the tubes.

Coal-fired watertube boilers include pulverized coal, cyclone, stoker, fluidized bed, and handfed units. In stoker-fired systems and most handfed units, the fuel is primarily burned on the bottom of the furnace or on a grate. In a fluidized bed combustor (FBC), the coal is introduced to a bed of either sorbent or inert material (usually sand) which is fluidized by an upward flow of air. In pulverized coal-fired (PC-fired) boilers, the fuel is pulverized to the consistency of talcum powder (i.e., at least 70 percent of the particles will pass through a 200-mesh sieve) and pneumatically injected through the burners into the furnace. Combustion in PC-fired units takes place almost entirely while the coal is suspended in the furnace volume. PC-fired boilers are classified as either dry bottom or wet bottom (also referred to as slag tap furnaces), depending on whether the ash is removed in a solid or molten state. In dry bottom furnaces, coals with high fusion temperatures are burned, resulting in dry ash. In wet bottom furnaces, coals with low fusion temperatures are used, resulting in molten ash or slag.

Depending upon the type and location of the burners and the direction of coal injection into the furnace, PC-fired boilers can also be classified into two different firing types, including wall, and tangential. Wall-fired boilers can be either single wall-fired, with burners on only one wall of the furnace firing horizontally, or opposed wall-fired, with burners mounted on two opposing walls. Tangential (or corner-fired) boilers have burners mounted in the corners of the furnace. The fuel and air are injected tangent to an imaginary circle in the plane of the boilers. Cyclone furnaces are often

categorized as PC-fired systems even though the coal is crushed to a maximum size of about 4-mesh. The coal is fed tangentially, with primary air, into a horizontal cylindrical furnace. Smaller coal particles are burned in suspension while larger particles adhere to the molten layer of slag on the combustion chamber wall. Cyclone boilers are high-temperature, wet-bottom type systems.

Stoker-fired systems account for the vast majority of coal-fired watertube boilers for industrial, commercial, and institutional applications. Most packaged stoker units designed for coal firing are small and can be divided into three groups: underfeed stokers, overfeed stokers, and spreader stokers. Underfeed stokers are generally either the horizontal-feed, side-ash-discharge type or the gravity-feed, rear-ash-discharge type. An overfeed stoker uses a moving grate assembly in which coal is fed from a hopper onto a continuous grate which conveys the fuel into the furnace. In a spreader stoker, mechanical or pneumatic feeders distribute coal uniformly over the surface of a moving grate. The injection of the fuel into the furnace and onto the grate combines suspension burning with a thin, fast-burning fuel bed. The amount of fuel burned in suspension depends primarily on fuel size and composition, and air flow velocity. Generally, fuels with finer size distributions, higher volatile matter contents, and lower moisture contents result in a greater percentage of combustion and corresponding heat release rates in suspension above the bed.

FBCs, while not constituting a significant percentage of the total boiler population, have nonetheless gained popularity in the last decade, and today generate steam for industries, cogenerators, independent power producers, and utilities. There are two major categories of FBC systems: (1) atmospheric, operating at or near ambient pressures, and (2) pressurized, operating from 4 to 30 atmospheres (60 to 450 pounds per square inch gauge). At this time, atmospheric FBCs are more advanced (or commercialized) than pressurized FBCs. The two principal types of atmospheric FBCs are bubbling bed and circulating bed. The feature that varies most fundamentally between these two types is the fluidization velocity. In the bubbling bed design, the fluidation velocity is relatively low in order to minimize solids carryover or elutriation from the combustor. Circulating FBCs, however, employ high fluidization velocities to promote the carryover or circulation of the solids. High-temperature cyclones are used in circulating FBCs and in some bubbling FBCs to capture the solid fuel and bed material for return to the primary combustion chamber. The circulating FBC maintains a continuous, high-volume recycle rate which increases the residence time compared to the bubbling bed design. Because of this feature, circulating FBCs often achieve higher combustion efficiencies and better sorbent utilization than bubbling bed units.

Small, coal-fired boilers and furnaces are found in industrial, commercial, institutional, or residential applications and are sometimes capable of being hand-fired. The most common types of firetube boilers used with coal are the horizontal return tubular (HRT), Scotch, vertical, and the firebox. Cast iron boilers are also sometimes available as coal-fired units in a handfed configuration. The HRT boilers are generally fired with gas or oil instead of coal. The boiler and furnace are contained in the same shell in a Scotch or shell boiler. Vertical firetube boilers are typically small singlepass units in which the firetubes come straight up from the water-cooled combustion chamber located at the bottom of the unit. A firebox boiler is constructed with an internal steel-encased, water-jacketed firebox. Firebox firetube boilers are also referred to as locomotive, short firebox, and compact firebox boilers and employ mechanical stokers or are hand-fired.

1.1.3 Emissions⁴

Emissions from coal combustion depend on the rank and composition of the fuel, the type and size of the boiler, firing conditions, load, type of control technologies, and the level of equipment maintenance. The major pollutants of concern from bituminous and subbituminous coal combustion are particulate matter (PM), sulfur oxides (SO_x), and nitrogen oxides (NO_x). Some unburned combustibles, including carbon monoxide (CO) and numerous organic compounds, are generally emitted even under proper boiler operating conditions.

1.1.3.1 Particulate Matter⁴ -

PM composition and emission levels are a complex function of boiler firing configuration, boiler operation, pollution control equipment, and coal properties. Uncontrolled PM emissions from coal-fired boilers include the ash from combustion of the fuel as well as unburned carbon resulting from incomplete combustion. In pulverized coal systems, combustion is almost complete; thus, the emitted PM is primarily composed of inorganic ash residues.

Coal ash may either settle out in the boiler (bottom ash) or entrained in the flue gas (fly ash). The distribution of ash between the bottom ash and fly ash fractions directly affects the PM emission rate and depends on the boiler firing method and furnace type (wet or dry bottom). Boiler load also affects the PM emissions as decreasing load tends to reduce PM emissions. However, the magnitude of the reduction varies considerably depending on boiler type, fuel, and boiler operation.

Soot blowing is also a source of intermittent PM emissions in coal-fired boilers. Steam soot and air soot blowing is periodically used to dislodge ash from heat transfer surfaces in the furnace, convective section, economizer, and air preheater.

Particulate emissions may be categorized as either filterable or condensable. Filterable emissions are generally considered to be the particles that are trapped by the glass fiber filter in the front half of a Reference Method 5 or Method 17 sampling train. Vapors and particles less than 0.3 microns pass through the filter. Condensable particulate matter is material that is emitted in the vapor state which later condenses to form homogeneous and/or heterogeneous aerosol particles. The condensable particulate emitted from boilers fueled on coal or oil is primarily inorganic in nature.

1.1.3.2 Sulfur Oxides⁴ -

Gaseous SO_x from coal combustion are primarily sulfur dioxide (SO₂), with a much lower quantity of sulfur trioxide (SO₃) and gaseous sulfates. These compounds form as the organic and pyritic sulfur in the coal are oxidized during the combustion process. On average, about 95 percent of the sulfur present in bituminous coal will be emitted as gaseous SO_x, whereas somewhat less will be emitted when subbituminous coal is fired. The more alkaline nature of the ash in some subbituminous coals causes some of the sulfur to react in the furnace to form various sulfate salts that are retained in the boiler or in the flyash.

1.1.3.3 Nitrogen Oxides⁵⁻⁶ -

NO_x emissions from coal combustion are primarily nitric oxide (NO), with only a few volume percent as nitrogen dioxide (NO₂). Nitrous oxide (N₂O) is also emitted at a few parts per million. NO_x formation results from thermal fixation of atmospheric nitrogen in the combustion flame and from oxidation of nitrogen bound in the coal. Experimental measurements of thermal NO_x formation have shown that the NO_x concentration is exponentially dependent on temperature and is proportional to nitrogen concentration in the flame, the square root of oxygen concentration in the flame, and the gas residence time.⁷ Cyclone boilers typically have high conversion of nitrogen to NO_x. Typically, only 20 to 60 percent of the fuel nitrogen is converted to NO_x. Bituminous and subbituminous coals usually

contain from 0.5 to 2 weight percent nitrogen, mainly present in aromatic ring structures. Fuel nitrogen can account for up to 80 percent of total NO_x from coal combustion.

1.1.3.4 Carbon Monoxide -

The rate of CO emissions from combustion sources depends on the fuel oxidation efficiency of the source. By controlling the combustion process carefully, CO emissions can be minimized. Thus, if a unit is operated improperly or is not well-maintained, the resulting concentrations of CO (as well as organic compounds) may increase by several orders of magnitude. Smaller boilers, heaters, and furnaces typically emit more CO and organics than larger combustors. This is because smaller units usually have less high-temperature residence time and, therefore, less time to achieve complete combustion than larger combustors. Combustion modification techniques and equipment used to reduce NO_x can increase CO emissions if the modification techniques are improperly implemented or if the equipment is improperly designed.

1.1.3.5 Organic Compounds -

As with CO emissions, the rate at which organic compounds are emitted depends on the combustion efficiency of the boiler. Therefore, combustion modifications that change combustion residence time, temperature, or turbulence may increase or decrease concentrations of organic compounds in the flue gas.

Organic emissions include volatile, semivolatile, and condensable organic compounds either present in the coal or formed as a product of incomplete combustion (PIC). Organic emissions are primarily characterized by the criteria pollutant class of unburned vapor-phase hydrocarbons. These emissions include alkanes, alkenes, aldehydes, alcohols, and substituted benzenes (e.g., benzene, toluene, xylene, and ethyl benzene).^{8,9}

Emissions of polychlorinated dibenzo-p-dioxins and polychlorinated dibenzofurans (PCDD/PCDF) also result from the combustion of coal. Of primary interest environmentally are tetrachloro- through octachloro- dioxins and furans. Dioxin and furan emissions are influenced by the extent of destruction of organics during combustion and through reactions in the air pollution control equipment. The formation of PCDD/PCDF in air pollution control equipment is primarily dependent on flue gas temperature, with maximum potential for formation occurring at flue gas temperatures of 450 degrees to 650 degrees Fahrenheit.

The remaining organic emissions are composed largely of compounds emitted from combustion sources in a condensed phase. These compounds can almost exclusively be classed into a group known as polycyclic organic matter (POM), and a subset of compounds called polynuclear aromatic hydrocarbons (PNA or PAH). Polycyclic organic matter is more prevalent in the emissions from coal combustion because of the more complex structure of coal.

1.1.3.6 Trace Metals-

Trace metals are also emitted during coal combustion. The quantity of any given metal emitted, in general, depends on:

- the physical and chemical properties of the metal itself;
- the concentration of the metal in the coal;
- the combustion conditions; and

- the type of particulate control device used, and its collection efficiency as a function of particle size.

Some trace metals become concentrated in certain particle streams from a combustor (e.g., bottom ash, collector ash, and flue gas particulate) while others do not.¹⁰ Various classification schemes have been developed to describe this partitioning behavior.¹⁰⁻¹² These classification schemes generally distinguish between:

- Class 1: Elements that are approximately equally concentrated in the fly ash and bottom ash, or show little or no small particle enrichment. Examples include manganese, beryllium, cobalt, and chromium.
- Class 2: Elements that are enriched in fly ash relative to bottom ash, or show increasing enrichment with decreasing particle size. Examples include arsenic, cadmium, lead, and antimony.
- Class 3: Elements which are emitted in the gas phase (primarily mercury and, in some cases, selenium).

Control of Class 1 metals is directly related to control of total particulate matter emissions, while control of Class 2 metals depends on collection of fine particulate. Because of variability in particulate control device efficiencies, emission rates of these metals can vary substantially. Because of the volatility of Class 3 metals, particulate controls have only a limited impact on emissions of these metals.

1.1.3.7 Acid Gases-

In addition to SO₂ and NO_x emissions, combustion of coal also results in emissions of chlorine and fluorine, primarily in the form of hydrogen chloride (HCl) and hydrogen fluoride (HF). Lesser amounts of chlorine gas and fluorine gas are also emitted. A portion of the chlorine and fluorine in the fuel may be absorbed onto fly ash or bottom ash. Both HCl and HF are water soluble and are readily controlled by acid gas scrubbing systems.

1.1.3.8 Fugitive Emissions -

Fugitive emissions are defined as pollutants which escape from an industrial process due to leakage, materials handling, inadequate operational control, transfer, or storage. The fly ash handling operations in most modern utility and industrial combustion sources consist of pneumatic systems or enclosed and hooded systems which are vented through small fabric filters or other dust control devices. The fugitive PM emissions from these systems are therefore minimal. Fugitive particulate emissions can sometimes occur during fly ash transfer operations from silos to trucks or rail cars.

1.1.3.9 Greenhouse Gases¹³⁻¹⁸ -

Carbon dioxide (CO₂), methane (CH₄), and nitrous oxide (N₂O) emissions are all produced during coal combustion. Nearly all of the fuel carbon (99 percent) in coal is converted to CO₂ during the combustion process. This conversion is relatively independent of firing configuration. Although the formation of CO acts to reduce CO₂ emissions, the amount of CO produced is insignificant compared to the amount of CO₂ produced. The majority of the fuel carbon not converted to CO₂ is entrained in bottom ash. CO₂ emissions for coal vary with carbon content, and carbon content varies between the classes of bituminous and subbituminous coals. Further, carbon content also varies within each class of coal based on the geographical location of the mine.

Formation of N₂O during the combustion process is governed by a complex series of reactions and its formation is dependent upon many factors. Formation of N₂O is minimized when combustion

temperatures are kept high (above 1575°F) and excess air is kept to a minimum (less than 1 percent). N₂O emissions for coal combustion are not significant except for fluidized bed combustion (FBC), where the emissions are typically two orders of magnitude higher than all other types of coal firing due to areas of low temperature combustion in the fuel bed.

Methane emissions vary with the type of coal being fired and firing configuration, but are highest during periods of incomplete combustion, such as the start-up or shut-down cycle for coal-fired boilers. Typically, conditions that favor formation of N₂O also favor emissions of CH₄.

1.1.4 Controls⁴

Control techniques for criteria pollutants from coal combustion may be classified into three broad categories: fuel treatment/substitution, combustion modification, and postcombustion control. Emissions of noncriteria pollutants such as particulate phase metals have been controlled through the use of post combustion controls designed for criteria pollutants. Fuel treatment primarily reduces SO₂ and includes coal cleaning using physical, chemical, or biological processes; fuel substitution involves burning a cleaner fuel. Combustion modification includes any physical or operational change in the furnace or boiler and is applied primarily for NO_x control purposes, although for small units, some reduction in PM emissions may be available through improved combustion practice. Postcombustion control employs a device after the combustion of the fuel and is applied to control emissions of PM, SO₂, and NO_x for coal combustion.

1.1.4.1 Particulate Matter Control⁴ -

The principal control techniques for PM are combustion modifications (applicable to small stoker-fired boilers) and postcombustion methods (applicable to most boiler types and sizes). Uncontrolled PM emissions from small stoker-fired and hand-feed combustion sources can be minimized by employing good combustion practices such as operating within the recommended load ranges, controlling the rate of load changes, and ensuring steady, uniform fuel feed. Proper design and operation of the combustion air delivery systems can also minimize PM emissions. The postcombustion control of PM emissions from coal-fired combustion sources can be accomplished by using one or more of the following particulate control devices:

- Electrostatic precipitator (ESP),
- Fabric filter (or baghouse),
- Wet scrubber,
- Cyclone or multiclone collector, or
- Side stream separator.

Electrostatic precipitation technology is applicable to a variety of coal combustion sources. Because of their modular design, ESPs can be applied to a wide range of system sizes and should have no adverse effect on combustion system performance. The operating parameters that influence ESP performance include fly ash mass loading, particle size distribution, fly ash electrical resistivity, and precipitator voltage and current. Other factors that determine ESP collection efficiency are collection plate area, gas flow velocity, and cleaning cycle. Data for ESPs applied to coal-fired sources show fractional collection efficiencies greater than 99 percent for fine (less than 0.1 micrometer) and coarse particles (greater than 10 micrometers). These data show a reduction in collection efficiency for particle diameters between 0.1 and 10 micrometers.

Fabric filtration has been widely applied to coal combustion sources since the early 1970s and consists of a number of filtering elements (bags) along with a bag cleaning system contained in a main shell structure incorporating dust hoppers. The particulate removal efficiency of fabric filters is

dependent on a variety of particle and operational characteristics. Particle characteristics that affect the collection efficiency include particle size distribution, particle cohesion characteristics, and particle electrical resistivity. Operational parameters that affect fabric filter collection efficiency include air-to-cloth ratio, operating pressure loss, cleaning sequence, interval between cleanings, cleaning method, and cleaning intensity. In addition, the particle collection efficiency and size distribution can be affected by certain fabric properties (e. g., structure of fabric, fiber composition, and bag properties). Collection efficiencies of fabric filters can be as high as 99.9 percent.

Wet scrubbers, including venturi and flooded disc scrubbers, tray or tower units, turbulent contact absorbers, or high-pressure spray impingement scrubbers are applicable for PM as well as SO₂ control on coal-fired combustion sources. Scrubber collection efficiency depends on particle size distribution, gas side pressure drop through the scrubber, and water (or scrubbing liquor) pressure, and can range between 95 and 99 percent for a 2-micron particle.

Cyclone separators can be installed singly, in series, or grouped as in a multicyclone or multiclone collector. These devices are referred to as mechanical collectors and are often used as a precollector upstream of an ESP, fabric filter, or wet scrubber so that these devices can be specified for lower particle loadings to reduce capital and/or operating costs. The collection efficiency of a mechanical collector depends strongly on the effective aerodynamic particle diameter. Although these devices will reduce PM emissions from coal combustion, they are relatively ineffective for collection of particles less than 10 micron (PM-10). The typical overall collection efficiency for mechanical collectors ranges from 90 to 95 percent.

The side-stream separator combines a multicyclone and a small pulse-jet baghouse to more efficiently collect small-diameter particles that are difficult to capture by a mechanical collector alone. Most applications to date for side-stream separators have been on small stoker boilers.

Atmospheric fluidized bed combustion (AFBC) boilers may tax conventional particulate control systems. The particulate mass concentration exiting AFBC boilers is typically 2 to 4 times higher than pulverized coal boilers. AFBC particles are also, on average, smaller in size, and irregularly shaped with higher surface area and porosity relative to pulverized coal ashes. The effect is a higher pressure drop. The AFBC ash is more difficult to collect in ESPs than pulverized coal ash because AFBC ash has a higher electrical resistivity and the use of multiclones for recycling, inherent with the AFBC process, tends to reduce exit gas stream particulate size.

1.1.4.2 Sulfur Oxides Control⁴ -

Several techniques are used to reduce SO_x emissions from coal combustion. Table 1.1-1 presents the techniques most frequently used. One way is to switch to lower sulfur coals, since SO_x emissions are proportional to the sulfur content of the coal. This alternative may not be possible where lower sulfur coal is not readily available or where a different grade of coal cannot be satisfactorily fired. In some cases, various coal cleaning processes may be employed to reduce the fuel sulfur content. Physical coal cleaning removes mineral sulfur such as pyrite but is not effective in removing organic sulfur. Chemical cleaning and solvent refining processes are being developed to remove organic sulfur.

Post combustion flue gas desulfurization (FGD) techniques can remove SO₂ formed during combustion by using an alkaline reagent to absorb SO₂ in the flue gas. Flue gases can be treated using wet, dry, or semi-dry desulfurization processes of either the throwaway type (in which all waste streams are discarded) or the recovery/regenerable type (in which the SO₂ absorbent is regenerated and reused). To date, wet systems are the most commonly applied. Wet systems generally use alkali slurries as the SO₂ absorbent medium and can be designed to remove greater than 90 percent of the incoming SO₂. Lime/limestone scrubbers, sodium scrubbers, and dual alkali scrubbers are among the commercially

proven wet FGD systems. The effectiveness of these devices depends not only on control device design but also on operating variables. Particulate reduction of more than 99 percent is possible with wet scrubbers, but fly ash is often collected by upstream ESPs or baghouses, to avoid erosion of the desulfurization equipment and possible interference with FGD process reactions.¹⁸ Also, the volume of scrubber sludge is reduced with separate fly ash removal, and contamination of the reagents and by-products is prevented.

The lime and limestone wet scrubbing process uses a slurry of calcium oxide or limestone to absorb SO₂ in a wet scrubber. Control efficiencies in excess of 91 percent for lime and 94 percent for limestone over extended periods are possible. Sodium scrubbing processes generally employ a wet scrubbing solution of sodium hydroxide or sodium carbonate to absorb SO₂ from the flue gas. Sodium scrubbers are generally limited to smaller sources because of high reagent costs and can have SO₂ removal efficiencies of up to 96.2 percent. The double or dual alkali system uses a clear sodium alkali solution for SO₂ removal followed by a regeneration step using lime or limestone to recover the sodium alkali and produce a calcium sulfite and sulfate sludge. SO₂ removal efficiencies of 90 to 96 percent are possible.

1.1.4.3 Nitrogen Oxide Controls⁴ -

Several techniques are used to reduce NO_x emissions from coal combustion. These techniques are summarized in Table 1.1-2. The primary techniques can be classified into one of two fundamentally different methods—combustion controls and postcombustion controls. Combustion controls reduce NO_x by suppressing NO_x formation during the combustion process, while postcombustion controls reduce NO_x emission after their formation. Combustion controls are the most widely used method of controlling NO_x formation in all types of boilers and include low excess air (LEA), burners out of service (BOOS), biased burner firing, overfire air (OFA), low NO_x burners (LNBS), and reburn. Postcombustion control methods are selective noncatalytic reduction (SNCR) and selective catalytic reduction (SCR). Combustion and postcombustion controls can be used separately or combined to achieve greater NO_x reduction from fluidized bed combustors in boilers.

Operating at LEA involves reducing the amount of combustion air to the lowest possible level while maintaining efficient and environmentally compliant boiler operation. NO_x formation is inhibited because less oxygen is available in the combustion zone. BOOS involves withholding fuel flow to all or part of the top row of burners so that only air is allowed to pass through. This method simulates air staging, or OFA conditions, and limits NO_x formation by lowering the oxygen level in the burner area. Biased burner firing involves more fuel-rich firing in the lower rows of burners than in the upper row of burners. This method provides a form of air staging and limits NO_x formation by limiting the amount of oxygen in the firing zone. These methods may change the normal operation of the boiler and the effectiveness is boiler-specific. Implementation of these techniques may also reduce operational flexibility; however, they may reduce NO_x by 10 to 20 percent from uncontrolled levels.

OFA is a technique in which a percentage of the total combustion air is diverted from the burners and injected through ports above the top burner level. OFA limits NO_x by (1) suppressing thermal NO_x by partially delaying and extending the combustion process resulting in less intense combustion and cooler flame temperatures and (2) suppressing fuel NO_x formation by reducing the concentration of air in the combustion zone where volatile fuel nitrogen is evolved. OFA can be applied for various boiler types including tangential and wall-fired, turbo, and stoker boilers and can reduce NO_x by 20 to 30 percent from uncontrolled levels.

LNBS limit NO_x formation by controlling the stoichiometric and temperature profiles of the combustion process in each burner zone. The unique design of features of an LNB may create (1) a reduced oxygen level in the combustion zone to limit fuel NO_x formation, (2) a reduced flame

temperature that limits thermal NO_x formation, and/or (3) a reduced residence time at peak temperature which also limits thermal NO_x formation.

LNBS are applicable to tangential and wall-fired boilers of various sizes but are not applicable to other boiler types such as cyclone furnaces or stokers. They have been used as a retrofit NO_x control for existing boilers and can achieve approximately 35 to 55 percent reduction from uncontrolled levels. They are also used in new boilers to meet New Source Performance Standards (NSPS) limits. LNBS can be combined with OFA to achieve even greater NO_x reduction (40 to 60 percent reduction from uncontrolled levels).

Reburn is a combustion hardware modification in which the NO_x produced in the main combustion zone is reduced in a second combustion zone downstream. This technique involves withholding up to 40 percent (at full load) of the heat input to the main combustion zone and introducing that heat input above the top row of burners to create a reburn zone. Reburn fuel (natural gas, oil, or pulverized coal) is injected with either air or flue gas to create a fuel-rich zone that reduces the NO_x created in the main combustion zone to nitrogen and water vapor. The fuel-rich combustion gases from the reburn zone are completely combusted by injecting overfire air above the reburn zone. Reburn may be applicable to many boiler types firing coal as the primary fuel, including tangential, wall-fired, and cyclone boilers. However, the application and effectiveness are site-specific because each boiler is originally designed to achieve specific steam conditions and capacity which may be altered due to reburn. Commercial experience is limited; however, this limited experience does indicate NO_x reduction of 50 to 60 percent from uncontrolled levels may be achieved.

SNCR is a postcombustion technique that involves injecting ammonia (NH_3) or urea into specific temperature zones in the upper furnace or convective pass. The ammonia or urea reacts with NO_x in the flue gas to produce nitrogen and water. The effectiveness of SNCR depends on the temperature where reagents are injected; mixing of the reagent in the flue gas; residence time of the reagent within the required temperature window; ratio of reagent to NO_x ; and the sulfur content of the fuel that may create sulfur compounds that deposit in downstream equipment. There is not as much commercial experience to base effectiveness on a wide range of boiler types; however, in limited applications, NO_x reductions of 25 to 40 percent have been achieved.

SCR is another postcombustion technique that involves injecting NH_3 into the flue gas in the presence of a catalyst to reduce NO_x to nitrogen and then water. The SCR reactor can be located at various positions in the process including before an air heater and particulate control device, or downstream of the air heater, particulate control device, and flue gas desulfurization systems. The performance of SCR is influenced by flue gas temperature, fuel sulfur content, ammonia-to- NO_x ratio, inlet NO_x concentration, space velocity, and catalyst condition. Although there is currently very limited application of SCR in the U.S. on coal-fired boilers, NO_x reductions of 75 to 86 percent have been realized on a few pilot systems.

1.1.5 Emission Factors

Emission factors for SO_x , NO_x , and CO are presented in Table 1.1-3. Tables in this section present emission factors on both a weight basis (lb/ton) and an energy basis (lb/Btu). To convert from lb/ton to lb/MMBtu, divide by a heating value of 26.0 MMBtu/ton. Because of the inherently low NO_x emission characteristics of FBCs and the potential for in-bed SO_2 capture by calcium-based sorbents, uncontrolled emission factors for this source category were not developed in the same sense as with other source categories. For NO_x emissions, the data collected from test reports were considered to be baseline (uncontrolled) if no additional add-on NO_x control system (such as ammonia injection) was operated.

For SO₂ emissions, a correlation was developed from reported data on FBCs to relate SO₂ emissions to the coal sulfur content and the calcium-to-sulfur ratio in the bed.

Filterable particulate matter and particulate matter less than, or equal to, 10 micrometers in diameter (PM-10) emission factors are presented in Table 1.1-4. Condensable particulate matter emission factors are presented in Table 1.1.5. Cumulative particle size distributions and particulate size-specific emission factors are given in Tables 1.1-6, 1.1-7, 1.1-8, 1.1-9, 1.1-10, and 1.1-11. Particulate size-specific emission factors are also presented graphically in Figures 1.1-1, 1.1-2, 1.1-3, 1.1-4, 1.1-5, and 1.1-6.

Controlled emission factors for PCDD/PCDF and PAHs are provided in Tables 1.1-12 and 1.1-13, respectively. Controlled emission factors for other organic compounds are presented in Table 1.1-14. Emission factors for hydrogen chloride and hydrogen fluoride are presented in Table 1.1-15.

Table 1.1-16 presents emission factor equations for nine trace metals from controlled and uncontrolled boilers. Table 1.1-17 presents uncontrolled emission factors for seven of the same metals, along with mercury, POM and formaldehyde. Table 1.1-18 presents controlled emission factors for 13 trace metals and includes the metals found in Tables 1.1-16 and 1.1-17. The emission factor equations in Table 1.1-16 are based on statistical correlations among measured trace element concentrations in coal, measured fractions of ash in coal, and measured particulate matter emission factors. Because these are the major parameters affecting trace metals emissions from coal combustion, it is recommended that the emission factor equations be used when the inputs to the equations are available. If the inputs to the emission factor equations are not available for a pollutant, then the emission factors provided in Table 1.1-17 and 1.1-18 for the pollutant should be used.

Greenhouse gas emission factors, including CH₄, non-methane organic compounds (NMOC), and N₂O are provided in Table 1.1-19. In addition, Table 1.1-20 provides emission factors for CO₂.

1.1.6 Updates Since the Fifth Edition

The Fifth Edition was released in January 1995. Revisions to this section since that date are summarized below. For further detail, consult the memoranda describing each supplement or the background report for this section. These and other documents can be found on the CHIEF home page (<http://www.epa.gov/ttn/chief/>).

Supplement A, February 1996

- SCC's were corrected from 1-01-002-17, 1-02-002-17, and 1-03-002-17, to 1-01-002-18, 1-02-002-18, and 1-03-002-18 in the tables with SO_x, NO_x, CO, and PM/PM10 emission factors.
- For SO_x factors, clarifications were added to the table footnotes to clarify that "S" is a weight percent and not a fraction. Similar clarification was added to the footnote for the CO₂ factor.
- For fluidized bed combustors (bubbling bed and circulating bed), the PM10 factors were replaced with footnote "m." The revised footnote "m" directs the user to the emission factor for spreader stoker with multiple cyclones and no flyash reinjection.
- In the table with filterable PM factors, the misspelling of "filterable" was corrected.
- In the cumulative particle size distribution table, text was added to the table footnotes to clarify that "A" is a weight percent and not a fraction.
- In the cumulative particle size distribution for spreader stokers, all of the factors were corrected.
- The N₂O emission factor for bubbling bed was changed from 5.9 lb/ton to 5.5 lb/ton.

Supplement B, October 1996

- Text was added concerning coal rank/classification, firing practices, emissions, and controls.
- The table for NO_x control technologies was revised to include controls for all types of coal-fired boilers.
- SO_x, NO_x, and CO emission factors were added for cell burners.
- The PM table was revised to recommend using spreader stoker PM factors for FBC units.
- Tables were added for new emission factors for polychlorinated toxics, polynuclear aromatics, organic toxics, acid gas toxics, trace metal toxics, and controlled toxics.
- N₂O emission factors were added.
- Default CO₂ emission factors were added.

Supplement E, September 1998

- The term "Filterable" was added to the PM-10 column heading of Table 1.1-4.

- Reference to condensable particulate matter was deleted from footnote b of Table 1.1-4.
- Emission factors for condensable particulate matter were added (Table 1.1-5).
- Table 1.1-7 was revised to correct a typographical errors in the ESP column.
- The zeros in Table 1.1-8 appeared to be in error. Engineering judgement was used to determine a conservative estimate.
- NO_x emission factors were updated based on data from the Acid Rain program.

Table 1.1-1. POSTCOMBUSTION SO₂ CONTROLS FOR COAL COMBUSTION SOURCES

Control Technology	Process	Typical Control Efficiencies	Remarks
Wet scrubber	Lime/limestone	80 - 95+%	Applicable to high sulfur fuels, wet sludge product
	Sodium carbonate	80 - 98%	5-430 million Btu/hr typical application range, high reagent costs
	Magnesium oxide/hydroxide	80 - 95+%	Can be regenerated
	Dual alkali	90 - 96%	Uses lime to regenerate sodium-based scrubbing liquor
Spray drying	Calcium hydroxide slurry, vaporizes in spray vessel	70 - 90%	Applicable to low and medium sulfur fuels, produces dry product
Furnace injection	Dry calcium carbonate/hydrate injection in upper furnace cavity	25 - 50%	Commercialized in Europe, several U. S. demonstration projects are completed
Duct injection	Dry sorbent injection into duct, sometimes combined with water spray	25 - 50+%	Several research and development, and demonstration projects underway, not yet commercially available in the United States.

Table 1.1-2. NO_x CONTROL OPTIONS FOR COAL-FIRED BOILERS^a

Control Technique	Description of Technique	Applicable Boiler Designs	NO _x Reduction Potential ^b (%)	Commercial Availability/R & D Status	Comments
Combustion Modifications					
Load reduction	Reduction of coal and air	Stokers	Minimal	Available	Applicable to stokers that can reduce load without increasing excess air; may cause reduction in boiler efficiency; NO _x reduction varies with percent load reduction.
Operational modifications (BOOS, LEA, BF, or combination)	Rearrangement of air or fuel in the main combustion zone	Pulverized coal boilers (some designs); Stokers (LEA only)	10 - 20	Available	Must have sufficient operational flexibility to achieve NO _x reduction potential without sacrificing boiler performance.
Overfire Air	Injection of air above main combustion zone	Pulverized coal boilers and stokers	20 - 30	Available	Must have sufficient furnace height above top row of burners in order to retrofit this technology to existing boilers.
Low NO _x Burners	New burner designs controlling air-fuel mixing	Pulverized coal boilers	35 - 55	Available	Available in new boiler designs and can be retrofit in existing boilers.
LNB with OFA	Combination of new burner designs and injection of air above main combustion zone	Pulverized coal boilers	40 - 60	Available	Available in new boiler designs and can be retrofit in existing boilers with sufficient furnace height above top row of burners.
Reburn	Injection of reburn fuel and completion air above main combustion zone	Pulverized coal boilers, cyclone furnaces	50 - 60	Commercially available but not widely demonstrated	Reburn fuel can be natural gas, fuel oil, or pulverized coal. Must have sufficient furnace height to retrofit this technology to existing boilers.

Table 1.1-2 (cont.).

Control Technique	Description of Technique	Applicable Boiler Designs	NO _x Reduction Potential ^b (%)	Commercial Availability/R & D Status	Comments
Post-Combustion Modifications					
SNCR	Injection of NH ₃ or urea in the convective pass	Pulverized coal boilers, cyclone furnaces, stokers, and fluidized bed boilers	30 - 60	Commercially available but not widely demonstrated	Applicable to new boilers or as a retrofit technology; must have sufficient residence time at correct temperature (1,750°±90°F); elaborate reagent injection system; possible load restrictions on boiler; and possible air preheater fouling by ammonium bisulfate.
SCR	Injection of NH ₃ in combination with catalyst material	Pulverized coal boilers, cyclone furnaces	75 - 85	Commercially offered, but not yet demonstrated	Applicable to new boilers or as a retrofit technology provided there is sufficient space; hot-side SCR best on low-sulfur fuel and low fly ash applications; cold-side SCR can be used on high-sulfur/high-ash applications if equipped with an upstream FGD system.
LNB with SNCR	Combination of new burner designs and injection of NH ₃ or urea	Pulverized coal boilers	50-80	Commercially offered, but not widely demonstrated as a combined technology	Same as LNB and SNCR alone.
LNB with OFA and SCR	Combination of new burner design, injection of air above combustion zone, and injection of NH ₃ or urea	Pulverized coal boiler	85-95	Commercially offered, but not widely demonstrated as a combined technology	Same as LNB, OFA, and SCR alone.

^a References 20-21.

^b NO_x reduction potential from uncontrolled levels.

Table 1.1-3. EMISSION FACTORS FOR SO_x, NO_x, AND CO
FROM BITUMINOUS AND SUBBITUMINOUS COAL COMBUSTION^a

Firing Configuration	SCC	SO _x ^b		NO _x ^c		CO ^{d,e}	
		Emission Factor (lb/ton)	EMISSION FACTOR RATING	Emission Factor (lb/ton)	EMISSION FACTOR RATING	Emission Factor (lb/ton)	EMISSION FACTOR RATING
PC, dry bottom, wall-fired ^f , bituminous Pre-NSPS ^g	1-01-002-02 1-02-002-02 1-03-002-06	38S	A	22	A	0.5	A
PC, dry bottom, wall-fired ^f , bituminous Pre-NSPS ^g with low-NO _x burner	1-01-002-02 1-02-002-02 1-03-002-06	38S	A	11	A	0.5	A
PC, dry bottom, wall-fired ^f , bituminous NSPS ^g	1-01-002-02 1-02-002-02 1-03-002-06	38S	A	12	A	0.5	A
PC, dry bottom, wall-fired ^f , sub-bituminous Pre-NSPS ^g	1-01-002-22 1-02-002-22 1-03-002-22	35S	A	12	C	0.5	A
PC, dry bottom, wall fired ^f , sub-bituminous NSPS ^g	1-01-002-22 1-02-002-22 1-03-002-22	35S	A	7.4	A	0.5	A
PC, dry bottom, cell burner ^h fired, bituminous	1-01-002-15	38S	A	31	A	0.5	A
PC, dry bottom, cell burner fired, sub-bituminous	1-01-002-35	35S	A	14	E	0.5	A

Table 1.1-3 (cont.).

Firing Configuration	SCC	SO _x ^b		NO _x ^c		CO ^{de}	
		Emission Factor (lb/ton)	EMISSION FACTOR RATING	Emission Factor (lb/ton)	EMISSION FACTOR RATING	Emission Factor (lb/ton)	EMISSION FACTOR RATING
PC, dry bottom, tangentially fired, bituminous, Pre-NSPS ^g	1-01-002-12 1-02-002-12 1-03-002-16	38S	A	15	A	0.5	A
PC, dry bottom, tangentially fired, bituminous, Pre-NSPS ^g with low-NO _x burner	1-01-002-12 1-02-002-12 1-03-002-16	38S	A	9.7	A	0.5	A
PC, dry bottom, tangentially fired, bituminous, NSPS ^g	1-01-002-12 1-02-002-12 1-03-002-16	38S	A	10	A	0.5	A
PC, dry bottom, tangentially fired, sub-bituminous, Pre-NSPS ^g	1-01-002-26 1-02-002-26 1-03-002-26	35S	A	8.4	A	0.5	A
PC, dry bottom, tangentially fired, sub-bituminous, NSPS ^g	1-01-002-26 1-02-002-26 1-03-002-26	35S	A	7.2	A	0.5	A
PC, wet bottom, wall-fired ^f , bituminous, Pre-NSPS ^g	1-01-002-01 1-02-002-01 1-03-002-05	38S	A	31	D	0.5	A
PC, wet bottom, tangentially fired, bituminous, NSPS ^g	1-01-002-11	38S	A	14	E	0.5	A
PC, wet bottom, wall-fired sub-bituminous	1-01-002-21 1-02-002-21 1-03-002-21	35S	A	24	E	0.5	A

Table 1.1-3 (cont.).

Firing Configuration	SCC	SO _x ^b		NO _x ^c		CO ^{d,e}	
		Emission Factor (lb/ton)	EMISSION FACTOR RATING	Emission Factor (lb/ton)	EMISSION FACTOR RATING	Emission Factor (lb/ton)	EMISSION FACTOR RATING
Cyclone Furnace, bituminous	1-01-002-03 1-02-002-03 1-03-002-03	38S	A	33	A	0.5	A
Cyclone Furnace, sub-bituminous	1-01-002-23 1-02-002-23 1-03-002-23	35S	A	17	C	0.5	A
Spreader stoker, bituminous	1-01-002-04 1-02-002-04 1-03-002-09	38S	B	11	B	5	A
Spreader Stoker, sub-bituminous	1-01-002-24 1-02-002-24 1-03-002-24	35S	B	8.8	B	5	A
Overfeed stoker ⁱ	1-01-002-05/25 1-02-002-05/25 1-03-002-07/25	38S (35S)	B	7.5	A	6	B
Underfeed stoker	1-02-002-06 1-03-002-08	31S	B	9.5	A	11	B
Hand-fed units	1-03-002-14	31S	D	9.1	E	275	E

Table 1.1-3 (cont.).

Firing Configuration	SCC	SO _x ^b		NO _x ^c		CO ^{d,e}	
		Emission Factor (lb/ton)	EMISSION FACTOR RATING	Emission Factor (lb/ton)	EMISSION FACTOR RATING	Emission Factor (lb/ton)	EMISSION FACTOR RATING
FBC, circulating bed	1-01-002-18 1-02-002-18 1-03-002-18	C ^j	E	5.0	D	18	E
FBC, bubbling bed	1-01-002-17 1-02-002-17 1-03-002-17	C ^j	E	15.2	D	18	D

^a Factors represent uncontrolled emissions unless otherwise specified and should be applied to coal feed, as fired. SCC = Source Classification Code. To convert from lb/ton to kg/Mg, multiply by 0.5.

^b Expressed as SO₂, including SO₂, SO₃, and gaseous sulfates. Factors in parentheses should be used to estimate gaseous SO_x emissions for subbituminous coal. In all cases, S is weight % sulfur content of coal as fired. Emission factor would be calculated by multiplying the weight percent sulfur in the coal by the numerical value preceding S. For example, if fuel is 1.2% sulfur, then S = 1.2. On average for bituminous coal, 95% of fuel sulfur is emitted as SO₂, and only about 0.7% of fuel sulfur is emitted as SO₃ and gaseous sulfate. An equally small percent of fuel sulfur is emitted as particulate sulfate (References 22-23). Small quantities of sulfur are also retained in bottom ash. With subbituminous coal, about 10% more fuel sulfur is retained in the bottom ash and particulate because of the more alkaline nature of the coal ash. Conversion to gaseous sulfate appears about the same as for bituminous coal.

Table 1.1-3. (cont.)

- c Expressed as NO₂. Generally, 95 volume % or more of NO_x present in combustion exhaust will be in the form of NO, the rest NO₂ (Reference 6). To express factors as NO, multiply factors by 0.66. All factors represent emissions at baseline operation (i. e., 60 to 110% load and no NO_x control measures).
- d Nominal values achievable under normal operating conditions. Values 1 or 2 orders of magnitude higher can occur when combustion is not complete.
- e Emission factors for CO₂ emissions from coal combustion should be calculated using $\text{lb CO}_2/\text{ton coal} = 72.6C$, where C is the weight % carbon content of the coal. For example, if carbon content is 85%, then C equals 85.
- f Wall-fired includes front and rear wall-fired units, as well as opposed wall-fired units.
- g Pre-NSPS boilers are not subject to any NSPS. NSPS boilers are subject to Subpart D or Subpart Da. Subpart D boilers are boilers constructed after August 17, 1971 and with a heat input rate greater than 250 million Btu per hour (MMBtu/hr). Subpart Da boilers are boilers constructed after September 18, 1978 and with a heat input rate greater than 250 MMBtu/hr.
- h References 24-27.
- i Includes traveling grate, vibrating grate, and chain grate stokers.
- j SO₂ emission factors for fluidized bed combustion are a function of fuel sulfur content and calcium-to-sulfur ratio. For both bubbling bed and circulating bed design, use: $\text{lb SO}_2/\text{ton coal} = 39.6(S)(\text{Ca}/S)^{-1.9}$. In this equation, S is the weight percent sulfur in the fuel and Ca/S is the molar calcium-to-sulfur ratio in the bed. This equation may be used when the Ca/S is between 1.5 and 7. When no calcium-based sorbents are used and the bed material is inert with respect to sulfur capture, the emission factor for underfeed stokers should be used to estimate the SO₂ emissions. In this case, the emission factor ratings are E for both bubbling and circulating units.

Table 1.1-4. UNCONTROLLED EMISSION FACTORS FOR PM AND PM-10
FROM BITUMINOUS AND SUBBITUMINOUS COAL COMBUSTION^a

Firing Configuration	SCC	Filterable PM ^b		Filterable PM-10	
		Emission Factor (lb/ton)	EMISSION FACTOR RATING	Emission Factor (lb/ton)	EMISSION FACTOR RATING
PC-fired, dry bottom, wall-fired	1-01-002-02/22	10A	A	2.3A	E
	1-02-002-02/22				
	1-03-002-06/22				
PC-fired, dry bottom, tangentially fired	1-01-002-12/26	10A	B	2.3A ^c	E
	1-02-002-12/26				
	1-03-002-16/26				
PC-fired, wet bottom	1-01-002-01/21	7A ^d	D	2.6A	E
	1-02-002-01/21				
	1-03-002-05/21				
Cyclone furnace	1-01-002-03/23	2A ^d	E	0.26A	E
	1-02-002-03/23				
	1-03-002-03/23				
Spreader stoker	1-01-002-04/24	66 ^e	B	13.2	E
	1-02-002-04/24				
	1-03-002-09/24				
Spreader stoker, with multiple cyclones, and reinjection	1-01-002-04/24	17	B	12.4	E
	1-02-002-04/24				
	1-03-002-09/24				
Spreader stoker, with multiple cyclones, no reinjection	1-01-002-04/24	12	A	7.8	E
	1-02-002-04/24				
	1-03-002-09/24				

Table 1.1-4 (cont.).

Firing Configuration	SCC	Filterable PM ^b		Filterable PM-10	
		Emission Factor (lb/ton)	EMISSION FACTOR RATING	Emission Factor (lb/ton)	EMISSION FACTOR RATING
Overfeed stoker ^f	1-01-002-05/25 1-02-002-05/25 1-03-002-07/25	16 ^g	C	6.0	E
Overfeed stoker, with multiple cyclones ^f	1-01-002-05/25 1-02-002-05/25 1-03-002-07/25	9 ^h	C	5.0	E
Underfeed stoker	1-02-002-06 1-03-002-08	15 ⁱ	D	6.2	E
Underfeed stoker, with multiple cyclone	1-02-002-06 1-03-002-08	11 ^h	D	6.2 ^j	E
Hand-fed units	1-03-002-14	15 ^m	E	6.2 ^k	E
FBC, bubbling bed	1-01-002-17 1-02-002-17 1-03-002-17	^m	E	^m	E
FBC, circulating bed	1-01-002-18 1-02-002-18 1-03-002-18	^m	E	^m	E

^a Factors represent uncontrolled emissions unless otherwise specified and should be applied to coal feed, as fired. To convert from lb/ton to kg/Mg, multiply by 0.5. SCC = Source Classification Code.

Table 1.1-4 (cont.).

- ^b Based on EPA Method 5 (front half catch) as described in Reference 28. Where particulate is expressed in terms of coal ash content, A, factor is determined by multiplying weight % ash content of coal (as fired) by the numerical value preceding the A. For example, if coal with 8% ash is fired in a PC-fired, dry bottom unit, the PM emission factor would be 10 x 8, or 80 lb/ton.
- ^c No data found; emission factor for PC-fired dry bottom boilers used.
- ^d Uncontrolled particulate emissions, when no fly ash reinjection is employed. When control device is installed, and collected fly ash is reinjected to boiler, particulate from boiler reaching control equipment can increase up to a factor of 2.
- ^e Accounts for fly ash settling in an economizer, air heater, or breaching upstream of control device or stack. (Particulate directly at boiler outlet typically will be twice this level.) Factor should be applied even when fly ash is reinjected to boiler from air heater or economizer dust hoppers.
- ^f Includes traveling grate, vibrating grate, and chain grate stokers.
- ^g Accounts for fly ash settling in breaching or stack base. Particulate loadings directly at boiler outlet typically can be 50% higher.
- ^h See Reference 4 for discussion of apparently low multiple cyclone control efficiencies, regarding uncontrolled emissions.
- ^j Accounts for fly ash settling in breaching downstream of boiler outlet.
- ^k No data found; emission factor for underfeed stoker used.
- ^m No data found; use emission factor for spreader stoker with multiple cyclones and reinjection.

Table 1.1-5. CONDENSABLE PARTICULATE MATTER EMISSION FACTORS FOR BITUMINOUS AND SUBBITUMINOUS COAL COMBUSTION^a

Firing Configuration ^b	Controls ^c	SCC	CPM - TOT ^{d,e}		CPM - IOR ^{d,e}		CPM - ORG ^{d,e}	
			Emission Factor (lb/MMBtu)	EMISSION FACTOR RATING	Emission Factor (lb/MMBtu)	EMISSION FACTOR RATING	Emission Factor (lb/MMBtu)	EMISSION FACTOR RATING
All pulverized coal-fired boilers	All PM controls (without FGD controls)	1-01-002-01/21	0.1S-0.03 ^{f,g}	B	80% of CPM-TOT emission factor ^c	E	20% of CPM-TOT emission factor ^c	E
		1-01-002-02/22						
		1-01-002-12/26						
		1-02-002-01/21						
		1-02-002-02/22						
		1-02-002-12/26						
		1-03-002-05/06						
		1-03-002-16						
		1-03-002-21/22						
1-03-002-26								
All pulverized coal-fired boilers	All PM controls combined with an FGD control	1-01-002-01/21	0.02 ^h	E	ND		ND	
		1-01-002-02/22						
		1-01-002-12/26						
		1-02-002-01/21						
		1-02-002-02/22						
		1-02-002-12/26						
		1-03-002-05/06						
		1-03-002-16						
		1-03-002-21/22						
1-03-002-26								
Spreader stoker, travelling grate overfeed stoker, underfeed stoker	All PM controls, or Uncontrolled	1-01-002-04/24	0.04 ⁱ	C	80% of CPM-TOT emission factor ^e	E	20% of CPM-TOT emission factor ^e	E
		1-01-002-05/25						
		1-02-002-04/24						
		1-02-002-05/25						
		1-02-002-06						
		1-03-002-07/08						
		1-03-002-09/11						
		1-03-002-16						
		1-03-002-24/25						

Table 1.1-5 (cont.).

- ^a All condensable PM is assumed to be less than 1.0 micron in diameter.
- ^b No data are available for cyclone boilers (SCCs 1-01-002-03/23, 1-02-002-03/23, 1-03-002-23) or for atmospheric fluidized bed combustion (AFBC) boilers (SCCs 1-01B002-17, 1-02-002-17, 1-03-002-17). For cyclone boilers, use the factors provided for pulverized coal-fired boilers and applicable control devices. For AFBC boilers, use the factors provided for pulverized coal-fired boilers with PM and FGD controls.
- ^c FGD = flue gas desulfurization.
- ^d CPM-TOT = total condensable particulate matter.
CPM-IOR = inorganic condensable particulate matter.
CPM-ORG = organic condensable particulate matter.
ND = No data.
- ^e Factors should be multiplied by fuel rate on a heat input basis (MMBtu), as fired. To convert to lb/ton of bituminous coal, multiply by 26 MMBtu/ton. To convert to lb/ton of subbituminous coal, multiply by 20 MMBtu/ton.
- ^f S = coal sulfur percent by weight, as fired. For example, if the sulfur percent is 1.04, then S = 1.04. If the coal sulfur percent is 0.4 or less, use a default emission factor of 0.01 lb/MMBtu rather than the emission equation.
- ^g References 78-94.
- ^h References 95 and 96.
- ⁱ References 97-104.

Table 1.1-6. CUMULATIVE PARTICLE SIZE DISTRIBUTION AND SIZE-SPECIFIC EMISSION FACTORS FOR DRY BOTTOM BOILERS BURNING PULVERIZED BITUMINOUS AND SUBBITUMINOUS COAL^a

Particle Size ^b (μm)	Cumulative Mass % \leq Stated Size					Cumulative Emission Factor ^c (lb/ton)				
	Uncontrolled	Controlled				Uncontrolled ^d	Controlled ^e			
		Multiple Cyclones	Scrubber	ESP	Baghouse		Multiple Cyclones ^f	Scrubber ^g	ESP ^g	Baghouse ^f
15	32	54	81	79	97	3.2A	1.08A	0.48A	0.064A	0.02A
10	23	29	71	67	92	2.3A	0.58A	0.42A	0.054A	0.02A
6	17	14	62	50	77	1.7A	0.28A	0.38A	0.024A	0.02A
2.5	6	3	51	29	53	0.6A	0.06A	0.3A	0.024A	0.01A
1.25	2	1	35	17	31	0.2A	0.02A	0.22A	0.01A	0.006A
1.00	2	1	31	14	25	0.2A	0.02A	0.18A	0.01A	0.006A
0.625	1	1	20	12	14	0.10A	0.02A	0.12A	0.01A	0.002A
TOTAL	100	100	100	100	100	10A	2A	0.6A	0.08A	0.02A

^a Reference 33. Applicable Source Classification Codes are 1-01-002-02, 1-02-002-02, 1-03-002-06, 1-01-002-12, 1-02-002-12, and 1-03-002-16. To convert from lb/ton to kg/Mg, multiply by 0.5. Emission Factors are lb of pollutant per ton of coal combusted, as fired. ESP = Electrostatic precipitator.

^b Expressed as aerodynamic equivalent diameter.

^c A = coal ash weight percent, as fired. For example, if coal ash weight is 8.2%, then A = 8.2.

^d EMISSION FACTOR RATING = C.

^e Estimated control efficiency for multiple cyclones is 80%; for scrubber, 94%; for ESP, 99.2%; and for baghouse, 99.8%.

^f EMISSION FACTOR RATING = E.

^g EMISSION FACTOR RATING = D.

Table 1.1-7. CUMULATIVE PARTICLE SIZE DISTRIBUTION AND SIZE-SPECIFIC EMISSION FACTORS FOR WET BOTTOM BOILERS BURNING PULVERIZED BITUMINOUS COAL^a

EMISSION FACTOR RATING: E

Particle Size ^b (μm)	Cumulative Mass % \leq Stated Size			Cumulative Emission Factor ^c (lb/ton)		
	Uncontrolled	Controlled		Uncontrolled	Controlled ^d	
		Multiple Cyclones	ESP		Multiple Cyclones	ESP
15	40	99	83	2.8A	1.38A	0.046A
10	37	93	75	2.6A	1.3A	0.042A
6	33	84	63	2.32A	1.18A	0.036A
2.5	21	61	40	1.48A	0.86A	0.022A
1.25	6	31	17	0.42A	0.44A	0.01A
1.00	4	19	8	0.28A	0.26A	0.004A
0.625	2	— ^e	— ^e	0.14A	— ^e	— ^e
TOTAL	100	100	100	7.0A	1.4A	0.056A

^a Reference 33. Applicable Source Classification Codes are 1-01-002-01, 1-02-002-01, and 1-03-002-05. To convert from lb/ton to kg/Mg, multiply by 0.5. Emission factors are lb of pollutant per ton of coal combusted as fired. ESP = Electrostatic precipitator.

^b Expressed as aerodynamic equivalent diameter.

^c A = coal ash weight %, as fired. For example, if coal ash weight is 2.4%, then A = 2.4.

^d Estimated control efficiency for multiple cyclones is 94%, and for ESPs, 99.2%.

^e Insufficient data.

Table 1.1-8. CUMULATIVE SIZE DISTRIBUTION AND SIZE-SPECIFIC EMISSION FACTORS FOR CYCLONE FURNACES BURNING BITUMINOUS COAL^a

EMISSION FACTOR RATING: E

Particle Size ^b (μm)	Cumulative Mass % \leq Stated Size			Cumulative Emission Factor ^c (lb/ton)		
	Uncontrolled	Controlled		Uncontrolled	Controlled ^d	
		Multiple Cyclones	ESP		Multiple Cyclones	ESP
15	33	95	90	0.66A	0.114A	0.013A
10	13	94	68	0.26A	0.112A	0.011A
6	8	93	56	0.16A	0.112A	0.009A
2.5	5.5	92	36	0.11A ^e	0.11A	0.006A
1.25	5	85	22	0.10A ^e	0.10A	0.004A
1.00	5	82	17	0.10A ^e	0.10A	0.003A
0.625	0	— ^f	— ^f	0	— ^f	— ^f
TOTAL	100	100	100	2A	0.12A	0.016A

^a Reference 33. Applicable Source Classification Codes are 1-01-002-03, 1-02-002-03, and 1-03-002-03. To convert from lb/ton to kg/Mg, multiply by 0.5. Emissions are lb of pollutant per ton of coal combusted, as fired.

^b Expressed as aerodynamic equivalent diameter.

^c A = coal ash weight %, as fired. For example, if coal ash weight is 2.4%, then A = 2.4.

^d Estimated control efficiency for multiple cyclones is 94%, and for ESPs, 99.2%.

^e These values are estimates based on data from controlled source.

^f Insufficient data.

Table 1.1-9. CUMULATIVE PARTICLE SIZE DISTRIBUTION AND SIZE-SPECIFIC EMISSION FACTORS FOR SPREADER STOKERS BURNING BITUMINOUS COAL^a

Particle Size ^b (μm)	Cumulative Mass % \leq Stated Size					Cumulative Emission Factor (lb/ton)				
	Uncontrolled	Controlled				Uncontrolled ^c	Controlled			
		Multiple Cyclones ^c	Multiple Cyclones ^d	ESP	Baghouse		Multiple Cyclones ^{c,f}	Multiple Cyclones ^{d,e}	ESP ^{f,g}	Baghouse ^{c,g}
15	28	86	74	97	72	18.5	14.6	8.8	0.46	0.086
10	20	73	65	90	60	13.2	12	7.8	0.44	0.072
6	14	51	52	82	46	9.2	8.6	6.2	0.40	0.056
2.5	7	8	27	61	26	4.6	1.4	3.2	0.30	0.032
1.25	5	2	16	46	18	3.3	0.4	2.0	0.22	0.022
1.00	5	2	14	41	15	3.3	0.4	1.6	0.20	0.018
0.625	4	1	9	C ^h	7	2.6	0.2	1.0	C ^h	0.006
TOTAL	100	100	100	100	100	66.0	17.0	12.0	0.48	0.12

^a Reference 33. Applicable Source Classification Codes are 1-01-002-04, 1-02-002-04, 1-03-002-09. To convert from lb/ton to kg/Mg, multiply by 0.5. Emissions are lb of pollutant per ton of coal combusted, as fired.

^b Expressed as aerodynamic equivalent diameter.

^c With flyash reinjection.

^d Without flyash reinjection.

^e EMISSION FACTOR RATING = C.

^f EMISSION FACTOR RATING = E.

^g Estimated control efficiency for ESP is 99.22%; and for baghouse, 99.8%.

^h Insufficient data.

Table 1.1-10. CUMULATIVE PARTICLE SIZE DISTRIBUTION AND SIZE-SPECIFIC EMISSION FACTORS FOR OVERFEED STOKERS BURNING BITUMINOUS COAL^a

Particle Size ^b (μm)	Cumulative Mass % \leq Stated Size		Cumulative Emission Factor (lb/ton)			
	Uncontrolled	Multiple Cyclones Controlled	Uncontrolled		Multiple Cyclones Controlled ^c	
			Emission Factor	EMISSION FACTOR RATING	Emission Factor	EMISSION FACTOR RATING
15	49	60	7.8	C	5.4	E
10	37	55	6.0	C	5.0	E
6	24	49	3.8	C	4.4	E
2.5	14	43	2.2	C	3.8	E
1.25	13	39	2.0	C	3.6	E
1.00	12	39	2.0	C	3.6	E
0.625	— ^d	16	— ^d	C	1.4	E
TOTAL	100	100	16.0	C	9.0	E

^a Reference 33. Applicable Source Classification Codes are 1-01-002-05, 1-02-002-05, and 1-03-002-07. To convert from lb/ton to kg/Mg, multiply by 0.5. Emissions are lb of pollutant per ton of coal combusted, as fired.

^b Expressed as aerodynamic equivalent diameter.

^c Estimated control efficiency for multiple cyclones is 80%.

^d Insufficient data.

Table 1.1-11. CUMULATIVE PARTICLE SIZE DISTRIBUTION AND SIZE-SPECIFIC EMISSION FACTORS FOR UNDERFEED STOKERS BURNING BITUMINOUS COAL^a

EMISSION FACTOR RATING: C

Particle Size ^b (μm)	Cumulative Mass % ≤ Stated Size	Uncontrolled Cumulative Emission Factor ^c (lb/ton)
15	50	7.6
10	41	6.2
6	32	4.8
2.5	25	3.8
1.25	22	3.4
1.00	21	3.2
0.625	18	2.7
TOTAL	100	15.0

^a Reference 33. Applicable Source Classification Codes are 1-02-002-06 and 1-03-002-08. To convert from lb/ton to kg/Mg, multiply by 0.5. Emission factors are lb of pollutant per ton of coal combusted, as fired.

^b Expressed as aerodynamic equivalent diameter.

^c May also be used for uncontrolled hand-fired units.

Table 1.1-12 EMISSION FACTORS FOR POLYCHLORINATED DIBENZO-P-DIOXINS AND POLYCHLORINATED DIBENZOFURANS FROM CONTROLLED BITUMINOUS AND SUBBITUMINOUS COAL COMBUSTION

Controls	FGD-SDA with FF ^a		ESP or FF ^b	
Congener	Emission Factor ^c (lb/ton)	EMISSION FACTOR RATING	Emission Factor ^c (lb/ton)	EMISSION FACTOR RATING
2,3,7,8-TCDD	No data	---	1.43E-11	E
Total TCDD	3.93E-10	E	9.28E-11	D
Total PeCDD	7.06E-10	E	4.47E-11	D
Total HxCDD	3.00E-09	E	2.87E-11	D
Total HpCDD	1.00E-08	E	8.34E-11	D
Total OCDD	2.87E-08	E	4.16E-10	D
Total PCDD ^d	4.28E-08	E	6.66E-10	D
2,3,7,8-TCDF	No data	---	5.10E-11	D
Total TCDF	2.49E-09	E	4.04E-10	D
Total PeCDF	4.84E-09	E	3.53E-10	D
Total HxCDF	1.27E-08	E	1.92E-10	D
Total HpCDF	4.39E-08	E	7.68E-11	D
Total OCDF	1.37E-07	E	6.63E-11	D
Total PCDF ^d	2.01E-07	E	1.09E-09	D
TOTAL PCDD/PCDF	2.44E-07	E	1.76E-09	D

^a Reference 34. Factors apply to boilers equipped with both flue gas desulfurization spray dryer absorber (FGD-SDA) and a fabric filter (FF). SCCs = pulverized coal-fired, dry bottom boilers, 1-01-002-02/22, 1-02-002-02/22, and 1-03-002-06/22.

^b References 35-37. Factors apply to boilers equipped with an electrostatic precipitator (ESP) or a fabric filter. SCCs = pulverized coal-fired, dry bottom boilers, 1-01-002-02/22, 1-02-002-02/22, 1-03-002-06/22; and, cyclone boilers, 1-01-002-03/23, 1-02-002-03/23, and 1-03-002-03/23.

^c Emission factor should be applied to coal feed, as fired. To convert from lb/ton to kg/Mg, multiply by 0.5. Emissions are lb of pollutant per ton of coal combusted.

^d Total PCDD is the sum of Total TCDD through Total OCDD. Total PCDF is the sum of Total TCDF through Total OCDF.

Table 1.1-13 EMISSION FACTORS FOR POLYNUCLEAR AROMATIC HYDROCARBONS (PAH) FROM CONTROLLED COAL COMBUSTION^a

Pollutant	Emission Factor ^b (lb/ton)	EMISSION FACTOR RATING
Biphenyl	1.7E-06	D
Acenaphthene	5.1E-07	B
Acenaphthylene	2.5E-07	B
Anthracene	2.1E-07	B
Benzo(a)anthracene	8.0E-08	B
Benzo(a)pyrene	3.8E-08	D
Benzo(b,j,k)fluoranthene	1.1E-07	B
Benzo(g,h,i)perylene	2.7E-08	D
Chrysene	1.0E-07	C
Fluoranthene	7.1E-07	B
Fluorene	9.1E-07	B
Indeno(1,2,3-cd)pyrene	6.1E-08	C
Naphthalene	1.3E-05	C
Phenanthrene	2.7E-06	B
Pyrene	3.3E-07	B
5-Methyl chrysene	2.2E-08	D

^a References 35-45. Factors were developed from emissions data from six sites firing bituminous coal, four sites firing subbituminous coal, and from one site firing lignite. Factors apply to boilers utilizing both wet limestone scrubbers or spray dryers with an electrostatic precipitator (ESP) or fabric filter (FF). The factors also apply to boilers utilizing only an ESP or FF. Bituminous/subbituminous SCCs = pulverized coal-fired dry bottom boilers, 1-01-002-02/22, 1-02-002-02/22, 1-03-002-06; pulverized coal, dry bottom, tangentially-fired boilers, 1-01-002-12/26, 1-02-002-12/26, 1-03-002-16/26; and, cyclone boilers, 1-01-002-03/23, 1-02-002-03/23, and 1-03-002-03/23.

^b Emission factor should be applied to coal feed, as fired. To convert from lb/ton to kg/Mg, multiply by 0.5. Emissions are lb of pollutant per ton of coal combusted.

Table 1.1-14 EMISSION FACTORS FOR VARIOUS ORGANIC COMPOUNDS
FROM CONTROLLED COAL COMBUSTION^a

Pollutant ^b	Emission Factor ^c (lb/ton)	EMISSION FACTOR RATING
Acetaldehyde	5.7E-04	C
Acetophenone	1.5E-05	D
Acrolein	2.9E-04	D
Benzene	1.3E-03	A
Benzyl chloride	7.0E-04	D
Bis(2-ethylhexyl)phthalate (DEHP)	7.3E-05	D
Bromoform	3.9E-05	E
Carbon disulfide	1.3E-04	D
2-Chloroacetophenone	7.0E-06	E
Chlorobenzene	2.2E-05	D
Chloroform	5.9E-05	D
Cumene	5.3E-06	E
Cyanide	2.5E-03	D
2,4-Dinitrotoluene	2.8E-07	D
Dimethyl sulfate	4.8E-05	E
Ethyl benzene	9.4E-05	D
Ethyl chloride	4.2E-05	D
Ethylene dichloride	4.0E-05	E
Ethylene dibromide	1.2E-06	E
Formaldehyde	2.4E-04	A
Hexane	6.7E-05	D
Isophorone	5.8E-04	D
Methyl bromide	1.6E-04	D
Methyl chloride	5.3E-04	D
Methyl ethyl ketone	3.9E-04	D
Methyl hydrazine	1.7E-04	E
Methyl methacrylate	2.0E-05	E

Table 1.1-14 (cont.).

Pollutant ^b	Emission Factor ^c (lb/ton)	EMISSION FACTOR RATING
Methyl tert butyl ether	3.5E-05	E
Methylene chloride	2.9E-04	D
Phenol	1.6E-05	D
Propionaldehyde	3.8E-04	D
Tetrachloroethylene	4.3E-05	D
Toluene	2.4E-04	A
1,1,1-Trichloroethane	2.0E-05	E
Styrene	2.5E-05	D
Xylenes	3.7E-05	C
Vinyl acetate	7.6E-06	E

^a References 35-53. Factors were developed from emissions data from ten sites firing bituminous coal, eight sites firing subbituminous coal, and from one site firing lignite. The emission factors are applicable to boilers using both wet limestone scrubbers or spray dryers and an electrostatic precipitator (ESP) or fabric filter (FF). In addition, the factors apply to boilers utilizing only an ESP or FF. SCCs = pulverized coal-fired, dry bottom boilers, 1-01-002-02/22, 1-02-002-02/22, 1-03-002-06/22; pulverized coal, dry bottom, tangentially-fired boilers, 1-01-002-12/26, 1-02-002-12/26, 1-03-002-16/26; cyclone boilers, 1-01-002-03/23, 1-02-002-03/23, 1-03-002-03/23; and, atmospheric fluidized bed combustors, circulating bed, 1-01-002-18/38, 1-02-002-18, and 1-03-002-18.

^b Pollutants sampled for but not detected in any sampling run include: Carbon tetrachloride- 2 sites; 1,3-Dichloropropylene- 2 sites; N-nitrosodimethylamine- 2 sites; Ethylidene dichloride- 2 sites; Hexachlorobutadiene- 1 site; Hexachloroethane- 1 site; Propylene dichloride- 2 sites; 1,1,2,2-Tetrachloroethane- 2 sites; 1,1,2-Trichloroethane- 2 sites; Vinyl chloride- 2 sites; and, Hexachlorobenzene- 2 sites.

^c Emission factor should be applied to coal feed, as fired. To convert from lb/ton to kg/Mg, multiply by 0.5.

Table 1.1-15. EMISSION FACTORS FOR HYDROGEN CHLORIDE (HCl) AND HYDROGEN FLUORIDE (HF) FROM COAL COMBUSTION^a

EMISSION FACTOR RATING: B

Firing Configuration	SCC	HCl	HF
		Emission Factor (lb/ton)	Emission Factor (lb/ton)
PC-fired, dry bottom	1-01-002-02/22	1.2	0.15
	1-02-002-02/22		
	1-03-002-06/22		
PC-fired, dry bottom, tangential	1-01-002-12/26	1.2	0.15
	1-02-002-12/26		
	1-03-002-16/26		
PC-fired, wet bottom	1-01-002-01/21	1.2	0.15
	1-02-002-01/21		
	1-03-002-05/21		
Cyclone Furnace	1-01-002-03/23	1.2	0.15
	1-02-002-03/23		
	1-03-002-03/23		
Spreader Stoker	1-01-002-04/24	1.2	0.15
	1-02-002-04/24		
	1-03-002-09/24		
Overfeed Stoker	1-01-002-05/25	1.2	0.15
	1-02-002-05/25		
	1-03-002-07/25		
Underfeed Stoker	1-02-002-06	1.2	0.15
	1-03-002-08		
FBC, Bubbling Bed	1-01-002-17	1.2	0.15
	1-02-002-17		
	1-03-002-17		
FBC, Circulating Bed	1-01-002-18/38	1.2	0.15
	1-02-002-18		
	1-03-002-18		
Hand-fired	1-03-002-14	1.2	0.15

^a Reference 54. The emission factors were developed from bituminous coal, subbituminous coal, and lignite emissions data. To convert from lb/ton to kg/Mg, multiply by 0.5. The factors apply to both controlled and uncontrolled sources.

Table 1.1-16. EMISSION FACTOR EQUATIONS FOR TRACE ELEMENTS FROM COAL COMBUSTION^a

EMISSION FACTOR EQUATION RATING: A^b

Pollutant	Emission Equation (lb/10 ¹² Btu) ^c
Antimony	0.92 * (C/A * PM) ^{0.63}
Arsenic	3.1 * (C/A * PM) ^{0.85}
Beryllium	1.2 * (C/A * PM) ^{1.1}
Cadmium	3.3 * (C/A * PM) ^{0.5}
Chromium	3.7 * (C/A * PM) ^{0.58}
Cobalt	1.7 * (C/A * PM) ^{0.69}
Lead	3.4 * (C/A * PM) ^{0.80}
Manganese	3.8 * (C/A * PM) ^{0.60}
Nickel	4.4 * (C/A * PM) ^{0.48}

^a Reference 55. The equations were developed from emissions data from bituminous coal combustion, subbituminous coal combustion, and from lignite combustion. The equations may be used to generate factors for both controlled and uncontrolled boilers. The emission factor equations are applicable to all typical firing configurations for electric generation (utility), industrial, and commercial/industrial boilers firing bituminous coal, subbituminous coal, and lignite. Thus, all SCCs for these boilers are assigned to the factors.

^b AP-42 criteria for rating emission factors were used to rate the equations.

^c The factors produced by the equations should be applied to heat input. To convert from lb/10¹² Btu to kg/joules, multiply by 4.31 x 10⁻¹⁶.

C = concentration of metal in the coal, parts per million by weight (ppmwt).

A = weight fraction of ash in the coal. For example, 10% ash is 0.1 ash fraction.

PM = Site-specific emission factor for total particulate matter, lb/10⁶ Btu.

Table 1.1-17. EMISSION FACTORS FOR TRACE ELEMENTS, POM, AND HCOH FROM UNCONTROLLED BITUMINOUS AND SUBBITUMINOUS COAL COMBUSTION^a

EMISSION FACTOR RATING: E

Firing Configuration (SCC)	Emission Factor, lb/10 ¹² Btu									
	As	Be	Cd	Cr	Pb ^b	Mn	Hg	Ni	POM	HCOH
Pulverized coal, configuration unknown (no SCC)	ND	ND	ND	1922	ND	ND	ND	ND	ND	112 ^c
Pulverized coal, wet bottom (1-01-002-01/21, 1-02-002-01/21, 1-03-002-05/21)	538	81	44-70	1020- 1570	507	808-2980	16	840-1290	ND	ND
Pulverized coal, dry bottom (1-01-002-02/22, 1-02-002-06/22, 1-03-002-06/22)	684	81	44.4	1250-157 0	507	228-2980	16	1030- 1290	2.08	ND
Pulverized coal, dry bottom, tangential (1-01-002-12/26, 1-02-002-12/26, 1-03-002-16/26)	ND	ND	ND	ND	ND	ND	ND	ND	2.4	ND
Cyclone furnace (1-01-002-03/23, 1-02-002-03/23, 1-03-002-03/23)	115	<81	28	212-1502	507	228-1300	16	174-1290	ND	ND
Stoker, configuration unknown (no SCC)	ND	73	ND	19-300	ND	2170	16	775-1290	ND	ND
Spreader stoker (1-01-002-04/24, 1-02-002-04/24, 1-03-002-09/24)	264-542	ND	21-43	942-1570	507	ND	ND	ND	ND	221 ^d
Overfeed stoker, traveling grate (1-01-002-05/25, 1-02-002-05/25, 1-03-002-07/25)	542-1030	ND	43-82	ND	507	ND	ND	ND	ND	140 ^c

^a References 56-61. The emission factors in this table represent the ranges of factors reported in the literature. If only 1 data point was found, it is still reported in this table. To convert from lb/10¹² Btu to pg/J, multiply by 0.43. SCC = Source Classification Code. ND = no data.

^b Lead emission factors were taken directly from an EPA background document for support of the National Ambient Air Quality Standards.

^c Based on 2 units; 133 x 10⁶ Btu/hr and 1550 x 10⁶ Btu/hr.

^d Based on 1 unit; 59 x 10⁶ Btu/hr.

Table 1.1-18 EMISSION FACTORS FOR TRACE METALS FROM CONTROLLED COAL COMBUSTION^a

Pollutant	Emission Factor (lb/ton) ^b	EMISSION FACTOR RATING
Antimony	1.8E-05	A
Arsenic	4.1E-04	A
Beryllium	2.1E-05	A
Cadmium	5.1E-05	A
Chromium	2.6E-04	A
Chromium (VI)	7.9E-05	D
Cobalt	1.0E-04	A
Lead	4.2E-04	A
Magnesium	1.1E-02	A
Manganese	4.9E-04	A
Mercury	8.3E-05	A
Nickel	2.8E-04	A
Selenium	1.3E-03	A

^a References 35-53, 62-70. The emission factors were developed from emissions data at eleven facilities firing bituminous coal, fifteen facilities firing subbituminous coal, and from two facilities firing lignite. The factors apply to boilers utilizing either venturi scrubbers, spray dryer absorbers, or wet limestone scrubbers with an electrostatic precipitator (ESP) or Fabric Filter (FF). In addition, the factors apply to boilers using only an ESP, FF, or venturi scrubber. SCCs = pulverized coal-fired, dry bottom boilers, 1-01-002-02/22, 1-02-002-02/22, 1-03-002-06/22; pulverized coal, dry bottom, tangentially-fired boilers, 1-01-002-12/26, 1-02-002-12/26, 1-03-002-16/26; cyclone boilers, 1-01-002-03/23, 1-02-002-03/23, 1-03-002-03/23; and, atmospheric fluidized bed combustors, circulating bed, 1-01-002-18/38, 1-02-002-18, and 1-03-002-18.

^b Emission factor should be applied to coal feed, as fired. To convert from lb/ton to kg/Mg, multiply by 0.5.

Table 1.1-19. EMISSION FACTORS FOR CH₄, TNMOC, AND N₂O FROM BITUMINOUS AND SUBBITUMINOUS COAL COMBUSTION^a

Firing Configuration	SCC	CH ₄ ^b		TNMOC ^{b,c}		N ₂ O ^d	
		Emission Factor (lb/ton)	EMISSION FACTOR RATING	Emission Factor (lb/ton)	EMISSION FACTOR RATING	Emission Factor (lb/ton)	EMISSION FACTOR RATING
PC-fired, dry bottom, wall fired	1-01-002-02/22	0.04	B	0.06	B	0.03	B
	1-02-002-02/22						
	1-03-002-06/22						
PC-fired, dry bottom, tangentially fired	1-01-002-12/26	0.04	B	0.06	B	0.08	B
	1-02-002-12/26						
	1-03-002-16/26						
PC-fired, wet bottom	1-01-002-01/21	0.05	B	0.04	B	0.08	E
	1-02-002-01/21						
	1-03-002-05/21						
Cyclone furnace	1-01-002-03/23	0.01	B	0.11	B	0.09 ^e	E
	1-02-002-03/23						
	1-03-002-03/23						
Spreader stoker	1-01-002-04/24	0.06	B	0.05	B	0.04 ^f	D
	1-02-002-04/24						
	1-03-002-09/24						
Spreader stoker, with multiple cyclones, and reinjection	1-01-002-04/24	0.06	B	0.05	B	0.04 ^f	E
	1-02-002-04/24						
	1-03-002-09/24						
Spreader stoker, with multiple cyclones, no reinjection	1-01-002-04/24	0.06	B	0.05	B	0.04 ^f	E
	1-02-002-04/24						
	1-03-002-09/24						

Table 1.1-19 (cont.).

Firing Configuration	SCC	CH ₄ ^b		TNMOC ^{b,c}		N ₂ O ^d	
		Emission Factor (lb/ton)	EMISSION FACTOR RATING	Emission Factor (lb/ton)	EMISSION FACTOR RATING	Emission Factor (lb/ton)	EMISSION FACTOR RATING
Overfeed stoker ^e	1-01-002-05/25 1-02-002-05/25 1-03-002-07/25	0.06	B	0.05	B	0.04 ^f	E
Overfeed stoker, with multiple cyclones ^e	1-01-002-05/25 1-02-002-05/25 1-03-002-07/25	0.06	B	0.05	B	0.04 ^f	E
Underfeed stoker	1-02-002-06 1-03-002-08	0.8	B	1.3	B	0.04 ^f	E
Underfeed stoker, with multiple cyclone	1-02-002-06 1-03-002-08	0.8	B	1.3	B	0.04 ^f	E
Hand-fed units	1-03-002-14	5	E	10	E	0.04 ^f	E
FBC, bubbling bed	1-01-002-17 1-02-002-17 1-03-002-17	0.06 ^h	E	0.05 ^h	E	3.5 ^h	B
FBC, circulating bed	1-01-002-18 1-02-002-18 1-03-002-18	0.06	E	0.05	E	3.5	B

^a Factors represent uncontrolled emissions unless otherwise specified and should be applied to coal feed, as fired. SCC = Source Classification Code. To convert from lb/ton to kg/Mg, multiply by 0.5.

^b Reference 32. Nominal values achievable under normal operating conditions; values 1 or 2 orders of magnitude higher can occur when combustion is not complete.

^c TNMOC are expressed as C₂ to C₁₆ alkane equivalents (Reference 71). Because of limited data, the effects of firing configuration on TNMOC emission factors could not be distinguished. As a result, all data were averaged collectively to develop a single average emission factor for pulverized coal units, cyclones, spreaders, and overfeed stokers.

^d References 14-15.

Table 1.1-20. DEFAULT CO₂ EMISSION FACTORS FOR U. S. COALS^a

EMISSION FACTOR RATING: C

Coal Type	Average %C ^b	Conversion Factor ^c	Emission Factor ^d (lb/ton coal)
Subbituminous	66.3	72.6	4810
High-volatile bituminous	75.9	72.6	5510
Medium-volatile bituminous	83.2	72.6	6040
Low-volatile bituminous	86.1	72.6	6250

^a This table should be used only when an ultimate analysis is not available. If the ultimate analysis is available, CO₂ emissions should be calculated by multiplying the %carbon (%C) by 72.6. This resultant factor would receive a quality rating of "B".

^b An average of the values given in References 2,76-77. Each of these references listed average carbon contents for each coal type (dry basis) based on extensive sampling of U.S. coals.

^c Based on the following equation:

$$\frac{44 \text{ ton CO}_2}{12 \text{ ton C}} \times 0.99 \times 2000 \frac{\text{lb CO}_2}{\text{ton CO}_2} \times \frac{1}{100\%} = 72.6 \frac{\text{lb CO}_2}{\text{ton \%C}}$$

Where:

- 44 = molecular weight of CO₂,
- 12 = molecular weight of carbon, and
- 0.99 = fraction of fuel oxidized during combustion (Reference 16).

^d To convert from lb/ton to kg/Mg, multiply by 0.5.

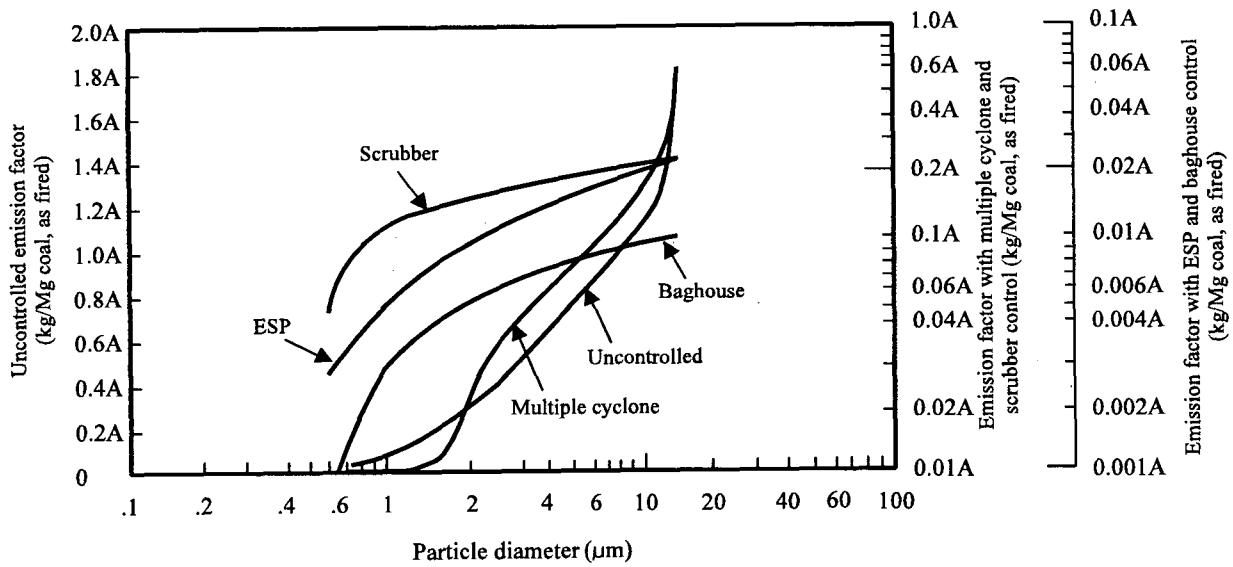


Figure 1.1-1. Cumulative size-specific emission factors for an example dry bottom boiler burning pulverized bituminous coal.

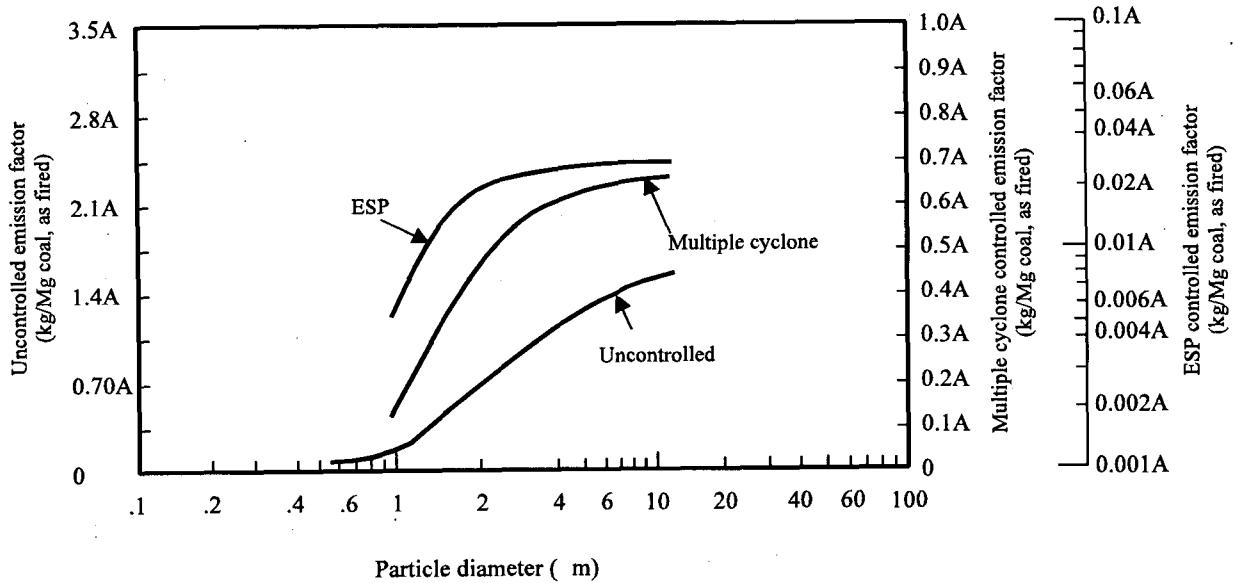


Figure 1.1-2. Cumulative size-specific emission factors for an example wet bottom boiler burning pulverized bituminous coal.

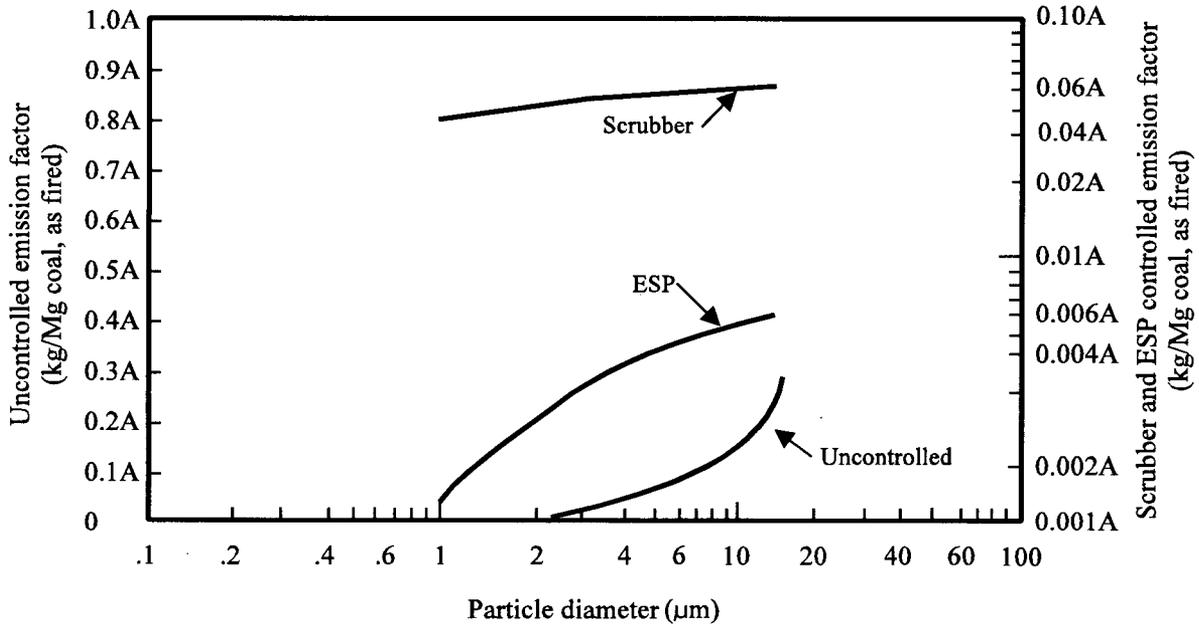


Figure 1.1-3. Cumulative size-specific emission factors for an example cyclone furnace burning bituminous coal.

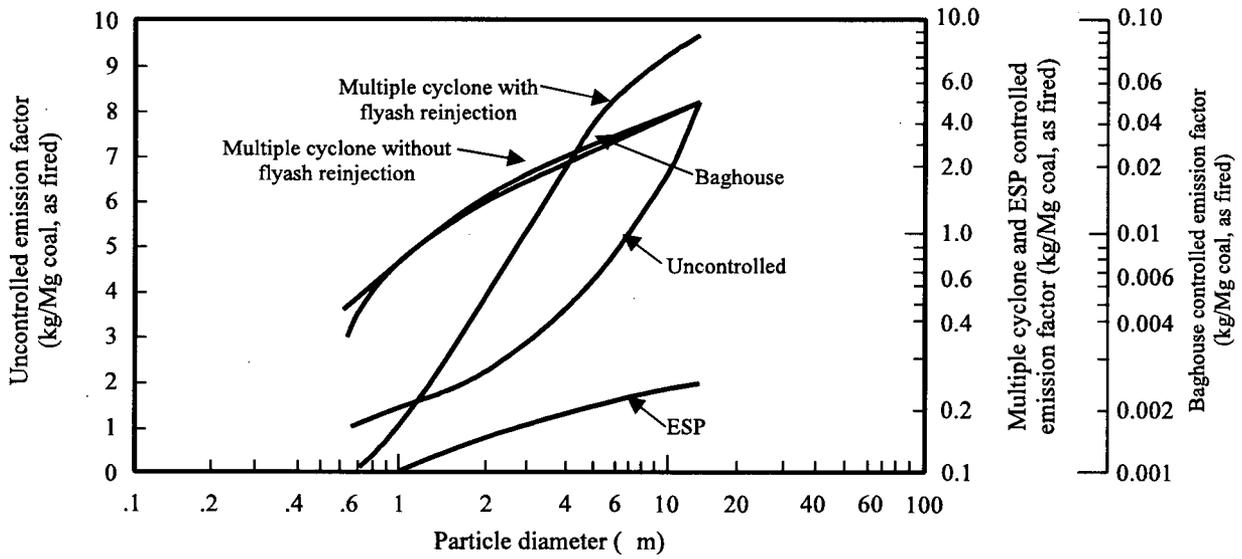


Figure 1.1-4. Cumulative size-specific emission factors for an example spreader stoker burning bituminous coal.

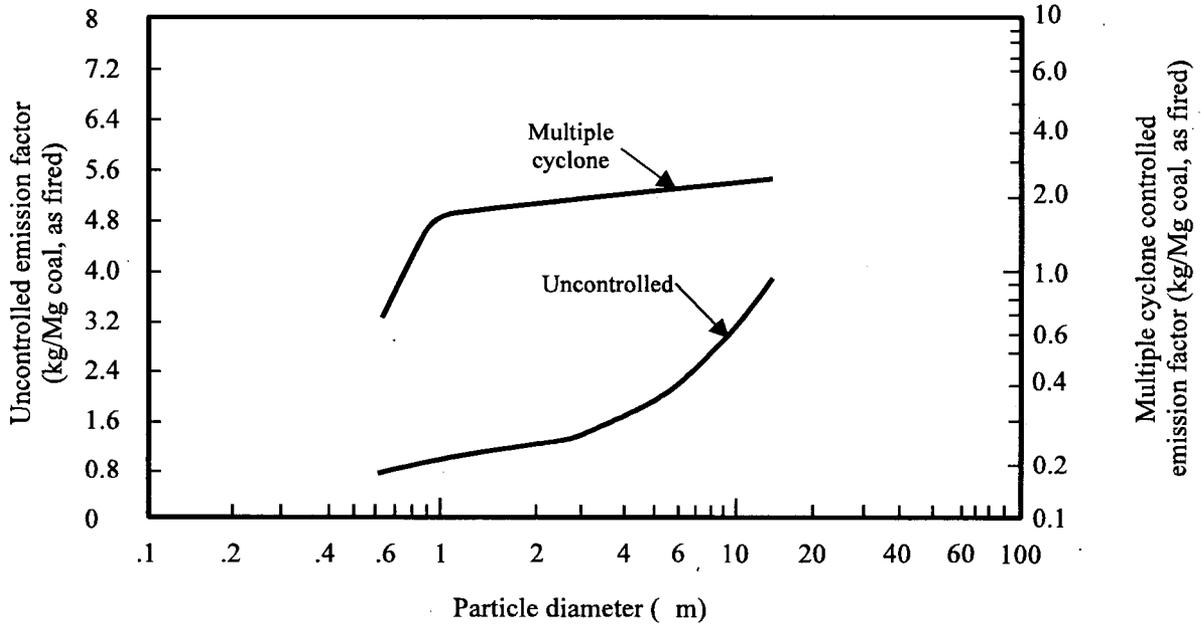


Figure 1.1-5. Cumulative size-specific emission factors for an example overfeed stoker burning bituminous coal.

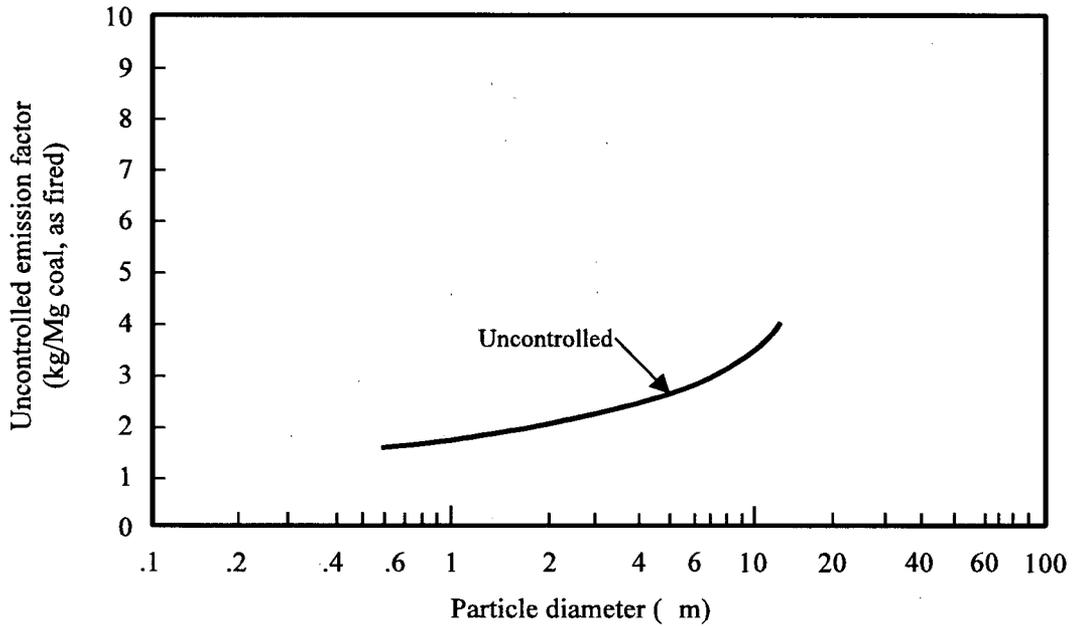


Figure 1.1-6. Cumulative size-specific emission factors for an example underfeed stoker burning bituminous coal.

References For Section 1.1

1. Bartok, B., Sarofina, A. F. (eds), *Fossil Fuel Combustion, A Source Book*, John Wiley & Sons, Inc., 1991, p. 239.
2. *Steam: It Generation And Use*, 38th Edition, Babcock and Wilcox, New York, 1975.
3. *Combustion. Fossil Power Systems. Third Edition.* Published by Combustion Engineering, Inc. Windsor, CT., 1981.
4. *Emission Factor Documentation For AP-42 Section 1.1 Bituminous and Subbituminous Coal Combustion*, U. S. Environmental Protection Agency, Research Triangle Park, NC, April 1993.
5. *Control Techniques For Nitrogen Oxides Emissions From Stationary Sources*, 2nd Edition, EPA-450/1-78-001, U. S. Environmental Protection Agency, Research Triangle Park, NC, January 1978.
6. *Review Of NO_x Emission Factors For Stationary Fossil Fuel Combustion Sources*, EPA-450/4-79-021, U. S. Environmental Protection Agency, Research Triangle Park, NC, September 1979.
7. K. J. Lim, *et al.*, *Technology Assessment Report For Industrial Boiler Applications: NO_x Combustion Modification*, EPA-600/7-79-178f, U. S. Environmental Protection Agency, Research Triangle Park, NC, December 1979.
8. Particulate Polycyclic Organic Matter, National Academy of Sciences, Washington, DC, 1972.
9. Vapor Phase Organic Pollutants- Volatile Hydrocarbons and Oxidation Products, National Academy of Sciences, Washington, DC, 1976.
10. D. H. Klein, *et al.*, "Pathways of Thirty-Seven Trace Elements Through Coal-Fired Power Plants", *Environmental Science and Technology*, 9:973-979, 1975.
11. D. G. Coles, *et al.*, "Chemical Studies of Stack Fly Ash from a Coal-Fired Power Plant", *Environmental Science and Technology*, 13:455-459, 1979.
12. S. Baig, *et al.*, *Conventional Combustion Environmental Assessment*, EPA Contract No. 68-02-3138, U. S. Environmental Protection Agency, Research Triangle Park, NC, 1981.
13. L. P. Nelson, *et al.*, *Global Combustion Sources of Nitrous Oxide Emissions*, Research Project 2333-4 Interim Report, Sacramento: Radian Corporation, 1991.
14. R. L. Peer, *et al.*, *Characterization of Nitrous Oxide Emission Sources*, U. S. Environmental Protection Agency, Office of Research and Development, Research Triangle Park, NC, 1995.
15. S. D. Piccot, *et al.*, *Emissions and Cost Estimates for Globally Significant Anthropogenic Combustion Sources of NO_x, N₂O, CH₄, CO, and CO₂*, U. S. Environmental Protection Agency, Office of Research and Development, Research Triangle Park, NC, 1990.

16. G. Marland and R. M. Rotty, *Carbon Dioxide Emissions from Fossil Fuels: A Procedure For Estimation and Results For 1951-1981*, DOE/NBB-0036 TR-003, Carbon Dioxide Research Division, Office of Energy Research, U.S. Department of Energy, Oak Ridge, TN, 1983.
17. G. Marland and R. M. Rotty, *Carbon Dioxide Emissions from Fossil Fuels: A Procedure For Estimation and Results For 1950-1982*, *Tellus*, 36B: 232-261.
18. *Sector-Specific Issues and Reporting Methodologies Supporting the General Guidelines for the Voluntary Reporting of Greenhouse Gases under Section 1605(b) of the Energy Policy Act of 1992* (1994) DOE/PO-0028, Volume 2 of 3, U.S. Department of Energy.
19. *Control Techniques For Sulfur Dioxide Emissions From Stationary Sources, 2nd Edition*, EPA-450/3-81-004, U. S. Environmental Protection Agency, Research Triangle Park, NC, April 1981.
20. *Alternative Control Techniques Document--NO_x Emissions From Utility Boilers*, EPA-453/R-94-023, March 1994, pp. 2-15, 2-18, 5-103.
21. *Emission Factor Documentation For AP-42, Section 1.1, Bituminous and Subbituminous Coal Combustion*, Prepared by Acurex Environmental Corp., Edward Aul & Associates, Inc., E. H. Pechan And Associates, Inc., EPA Contract No. 68-D0-11210, April 1993.
22. Carlo Castaldini, and Meredith Angwin, *Boiler Design And Operating Variables Affecting Uncontrolled Sulfur Emissions From Pulverized Coal Fired Steam Generators*, EPA-450/3-77-047, U. S. Environmental Protection Agency, Research Triangle Park, NC, December 1977.
23. K. Cushing, *et al.*, "Fabric Filtration Experience Downstream From Atmospheric Fluidized Bed Combustion Boilers", Presented at the Ninth Particulate Control Symposium, October 1991.
24. Susan Stamey-Hall, *Evaluation of Nitrogen Oxide Emissions Data from TVA Coal-Fired Boilers*, EPA-600/R-92-242, U. S. Environmental Protection Agency, Research Triangle Park, NC, December 1992.
25. Joel Vatsky and Timothy W. Sweeney, *Development of an Ultra-Low No_x Pulverizer Coal Burner*, Presented at the EPA/EPRI 1991 Joint Symposium on Combustion No_x Control, March 25-28, 1991, Washington, DC.
26. T. L. Lu, R. L. Lungren, and A. Kokkinos, *Performance of a Large Cell-Burner Utility Boiler Retrofitted with Foster Wheeler Low-NO_x Burners*, Presented at the EPA/EPRI 1991 Joint Symposium on Combustion NO_x Control, March 25-28, 1991, Washington, DC.
27. *Alternative Control Techniques Document NO_x Emissions from Utility Boilers*, EPA-453/R-94-023, U. S. Environmental Protection Agency, Research Triangle Park, NC, March 1994.
28. *Standards Of Performance For New Stationary Sources*, 36 FR 24876, December 23, 1971.

29. *Field Tests Of Industrial Stoker Coal Fired Boilers For Emission Control And Efficiency Improvement - Sites L1 17*, EPA-600/7-81-020a, U. S. Environmental Protection Agency, Washington, DC, February 1981.
30. *Application Of Combustion Modifications To Control Pollutant Emissions From Industrial Boilers Phase I*, EPA-650/2-74-078a, U. S. Environmental Protection Agency, Washington, DC, October 1974.
31. *Source Sampling Residential Fireplaces For Emission Factor Development*, EPA-50/3-6-010, U. S. Environmental Protection Agency, Research Triangle Park, NC, November 1875.
32. *Atmospheric Emissions From Coal Combustion: An Inventory Guide*, 999-AP-24, U. S. Environmental Protection Agency, Washington, DC, April 1966.
33. *Inhalable Particulate Source Category Report For External Combustion Sources*, EPA Contract No. 68-02-3156, Acurex Corporation, Mountain View, CA, January 1985.
34. Results of the March 28, 1990 Dioxin Emission Performance Test on Unit 3 at the NSP Sherco Plant in Becker, Minnesota. Interpoll Laboratories, Inc., Circle Pines, Minnesota. July 11, 1990.
35. Field Chemical Emissions Monitoring Project: Site 22 Emissions Report. Radian Corporation, Austin, Texas. February, 1994.
36. Toxics Assessment Report. Illinois Power Company. Baldwin Power Station- Unit 2. Baldwin, Illinois. Volumes I- Main Report. Roy F. Weston, Inc. West Chester, Pennsylvania. December, 1993.
37. Toxics Assessment Report. Minnesota Power Company Boswell Energy Center- Unit 2. Cohasset, Minnesota. Volume 1-Main Report. Roy F. Weston, Inc. West Chester, Pennsylvania. December, 1993. (EPRI Report)
38. Field Chemical Emissions Monitoring Project: Site 11 Emissions Monitoring. Radian Corporation, Austin, Texas. October, 1992. (EPRI Report)
39. Field Chemical Emissions Monitoring Project: Site 21 Emissions Monitoring. Radian Corporation, Austin, Texas. August, 1993. (EPRI Report)
40. Field Chemical Emissions Monitoring Project: Site 111 Emissions Report. Radian Corporation, Austin, Texas. May, 1993. (EPRI Report)
41. Field Chemical Emissions Monitoring Project: Site 115 Emissions Report. Radian Corporation, Austin, Texas. November, 1994. (EPRI Report)
42. Draft Final Report. A Study of Toxic Emissions from a Coal-Fired Power Plant-Niles Station No. 2. Volumes One, Two, and Three. Battelle, Columbus, Ohio. December 29, 1993.
43. Draft Final Report. A Study of Toxic Emissions from a Coal-Fired Power Plant Utilizing an ESP/Wet FGD System. Volumes One, Two, and Three. Battelle, Columbus, Ohio. December 1993.

44. Assessment of Toxic Emissions From a Coal Fired Power Plant Utilizing an ESP. Final Report-Revision 1. Energy and Environmental Research Corporation, Irvine, California. December 23, 1993.
45. 500-MW Demonstration of Advanced Wall-Fired Combustion Techniques for the Reduction of Nitrogen Oxide (NOx) Emissions from Coal-Fired Boilers. Radian Corporation, Austin, Texas.
46. Results of the November 7, 1991 Air Toxic Emission Study on the Nos. 3, 4, 5 & 6 Boilers at the NSP High Bridge Plant. Interpoll Laboratories, Inc., Circle Pines, Minnesota. January 3, 1992.
47. Results of the December 1991 Air Toxic Emission Study on Units 6 & 7 at the NSP Riverside Plant. Interpoll Laboratories, Inc., Circle Pines, Minnesota. February 28, 1992.
48. Field Chemical Emissions Monitoring Project: Site 10 Emissions Monitoring. Radian Corporation, Austin, Texas. October, 1992. (EPRI Report)
49. Field Chemical Emissions Monitoring Project: Site 12 Emissions Monitoring. Radian Corporation, Austin, Texas. November, 1992. (EPRI Report)
50. Field Chemical Emissions Monitoring Project: Site 15 Emissions Monitoring. Radian Corporation, Austin, Texas. October, 1992. (EPRI Report)
51. Field Chemical Emissions Monitoring Project: Site 101 Emissions Report. Radian Corporation, Austin, Texas. October, 1994. (EPRI Report)
52. Field Chemical Emissions Monitoring Project: Site 114 Report. Radian Corporation, Austin, Texas. May, 1994. (EPRI Report)
53. Field Chemical Emissions Monitoring Report: Site 122. Final Report, Task 1 Third Draft. EPRI RP9028-10. Southern Research Institute, Birmingham, Alabama. May, 1995. (EPRI Report)
54. *Hydrogen Chloride And Hydrogen Fluoride Emission Factors For The NAPAP Inventory*, EPA-600/7-85-041, U. S. Environmental Protection Agency, October 1985.
55. *Electric Utility Trace Substances Synthesis Report, Volume 1*, Report TR-104614, Electric Power Research Institute, Palo Alto, CA, November 1994.
56. *Locating And Estimating Air Emissions From Sources Of Chromium*, EPA-450/4-84-007g, U. S. Environmental Protection Agency, July 1984.
57. *Locating And Estimating Air Emissions From Sources Of Formaldehyde*, (Revised), EPA-450/4-91-012, U. S. Environmental Protection Agency, March 1991.
58. *Estimating Air Toxics Emissions From Coal And Oil Combustion Sources*, EPA-450/2-89-001, Radian Corporation, Project Officer: Dallas W. Safriet, Research Triangle Park, NC, April 1989.
59. *Canadian Coal-Fired Plants, Phase I: Final Report And Appendices*, Report for the Canadian Electrical Association, R&D, Montreal, Quebec, Contract Number 001G194, Report by Battelle, Pacific Northwest Laboratories, Richland, WA.

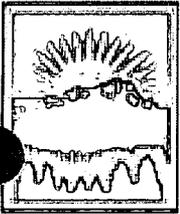
60. R. Meij, Auferu dr., *The Fate Of Trace Elements At Coal-Fired Plants*, Report No. 2561-MOC 92-3641, Rapport te bestellen bij; bibliotheek N.V. KEMA, February 13, 1992.
61. *Locating And Estimating Air Emissions From Sources Of Manganese*, EPA-450/4-84-007h, September 1985.
62. Results of the September 10 and 11, 1991 Mercury Removal Tests on the Units 1 & 2, and Unit 3 Scrubber Systems at the NSP Sherco Plant in Becker, Minnesota. Interpoll Laboratories, Inc., Circle Pines, Minnesota. October 30, 1991.
63. Results of the November 5, 1991 Air Toxic Emission Study on the No. 1, 3 & 4 Boilers at the NSP Black Dog Plant. Interpoll Laboratories, Inc., Circle Pines, Minnesota. January 3, 1992.
64. Results of the January 1992 Air Toxic Emission Study on the No. 2 Boiler at the NSP Black Dog Plant. Interpoll Laboratories, Inc., Circle Pines, Minnesota. May 4, 1992.
65. Results of the May 29, 1990 Trace Metal Characterization Study on Units 1 and 2 at the Sherburne County Generating Station in Becker, Minnesota. Interpoll Laboratories, Inc., Circle Pines, Minnesota. July, 1990.
66. Results of the May 1, 1990 Trace Metal Characterization Study on Units 1 and 2 at the Sherburne County Generating Station. Interpoll Laboratories, Inc., Circle Pines, Minnesota. July 18, 1990.
67. Results of the March 1990 Trace Metal Characterization Study on Unit 3 at the Sherburne County Generating Station. Interpoll Laboratories, Circle Pines, Minnesota. June 7, 1990.
68. Field Chemical Emissions Monitoring Project: Site 19 Emissions Monitoring. Radian Corporation, Austin, Texas. April, 1993. (EPRI Report)
69. Field Chemical Emissions Monitoring Project: Site 20 Emissions Monitoring. Radian Corporation, Austin, Texas. March, 1994. (EPRI Report)
70. Characterizing Toxic Emissions from a Coal-Fired Power Plant Demonstrating the AFGD ICCT Project and a Plant Utilizing a Dry Scrubber /Baghouse System. Final Draft Report. Springerville Generating Station Unit No. 2. Southern Research Insititute, Birmingham, Alabama. December, 1993.
71. *Emissions Of Reactive Volatile Organic Compounds From Utility Boilers*, EPA-600/7-80-111, U. S. Environmental Protection Agency, Washington, DC, May 1980.
72. *EPA/IFP European Workshop On The Emission Of Nitrous Oxide For Fuel Combustion*, EPA Contract No. 68-02-4701, Rueil-Malmaison, France, June 1-2, 1988.
73. R. Clayton, *et al.*, *NO_x Field Study*, EPA-600/2-89-006, U. S. Environmental Protection Agency, Research Triangle Park, NC, February 1989.
74. L. E. Amand, and S. Anderson, "Emissions of Nitrous Oxide from Fluidized Bed Boilers", Presented at the Tenth International Conference on Fluidized Bed Combustor, San Francisco, CA, 1989.

75. *Alternative Control Techniques Document--NO_x Emissions From Utility Boilers*, EPA-453/R-94-023, Office of Air Quality Standards, Research Triangle Park, NC, 1994.
76. Alliance Technologies Corporation, *Evaluation of Significant Anthropogenic Sources of Radiatively Important Trace Gases*, U. S. Environmental Protection Agency, Office of Research and Development, Research Triangle Park, NC, 1990.
77. R. A. Winschel, Richard, "The Relationship of Carbon Dioxide Emissions with Coal Rank and Sulfur Content," *Journal of the Air and Waste Management Association*, Vol. 40, no. 6, pp. 861-865, June 1990.
78. Public Service Electric and Gas Company Mercer Generating Station Unit No. 2 Emission Compliance Test Program. November 1994.
79. Particulate Emission Study Performed for Madison Gas and Electric Company at the Blount Street Station Units 7, 8, 9 Inlets/Outlets. Mostardi-Platt Associates, Inc. December 6, 1994.
80. Particulate Emission Study Performed for Marshfield Electric and Water Department at the Wildwood Station Marshfield Wisconsin Boiler 5 Stack. Mostardi-Platt Associates, Inc. January 23-25, 1990.
81. Report on Particulate, SO₂, and NO_x Compliance Testing. Dairyland Power Cooperative J.P. Madgett Stack. Alma, Wisconsin. CAE. January 6, 1995.
82. Particulate Emissions Test Results. Portland General Electric Coal-fired Power Plant. Boardman, Oregon. SAIC, Inc. January 25, 1994.
83. Report on Compliance Testing Performed at Marshfield Electric and Water Department Wildwood Station Unit 5, Marshfield, Wisconsin. Clean Air Engineering, December 11, 1989.
84. Portland General Electric Company Boardman Coal Plant. Unit #1 Coal-fired Boiler. Boardman, Oregon. August 24-27, 1995.
85. Particulate Emission Compliance Study Performed for Portland General Electric at the Boardman Plant Unit 1 Stack. Boardman, Oregon. September 19, 1996.
86. Emissions Source Test Report. Portland General Electric Coal-Fired Power Plant. Boardman, Oregon. OMNI Environmental Services, Inc. October 17, 1990.
87. Source Emissions Test Report Compliance. Portland General Electric Coal-Fired Power Plant. Boardman, Oregon. OMNI Environmental Services. January 29, 1991.
88. Source Test Report. Particulate Emissions. Portland General Electric Coal-Fired Power Plant. Boardman, Oregon. OMNI Environmental Services, Inc. January 14, 1991.
89. Emissions Source Test Rpeort. Portland General Electric Coal-Fired Power Plant. Boardman, Oregon. OMNI Environmental Services, Inc. April 3, 1991.
90. Source Emissions Test Report. Portland General Electric Coal-Fired Power Plant. Boardman, Oregon. OMNI Environmental Services, Inc. January 21, 1992.

91. Particulate Emissions Test Results. Portland General Electric Coal-fired Power Plant. Boardman, Oregon. OMNI Environmental Services, Inc. April 4, 1992.
92. Particulate Emissions Test Results. Portland General Electric Coal-Fired Power Plant. Boardman, Oregon. OMNI Environmental Services, Inc. September 9, 1992.
93. Particulate Emissions Test Results. Portland General Electric Coal-Fired Power Plant. Boardman, Oregon. OMNI Environmental Services, Inc. November 6, 1992.
94. Particulate Emissions Test Results. Portland General Electric Coal-Fired Power Plant. Boardman, Oregon. OMNI Environmental Services, Inc. January 26, 1993.
95. Stationary Source Sampling Report. Keystone Cogeneration Facility. Keystone Cogeneration Facility. Logan Township, NJ. November 1994.
96. Source Emissions Survey of City Public Service Board J.K. Spruce Unit Number 1 Stack. METCO Environmental. December 1992.
97. Report of Particulate Emission Testing on the Number 1 Boiler at Associated Milk Products Incorporated Located in Jim Falls, Wisconsin. Environmental Services of American, Inc. November 1994.
98. Appleton Papers, Inc. Boiler Emission Test at Appleton, WI. May 11 and 12, 1993. Badger Laboratories and Engineering.
99. Appleton Papers, Inc. Boiler Emission Test Report at Appleton, WI. Badger Laboratories and Engineering. October 11, 1993.
100. Results of a Source Emission Compliance Test on Boiler #2 at the Hills Farm Heating Plant, Madison, Wisconsin. MMT Environmental Services, Inc. January 22, 1993.
101. Results of a Source Emission Compliance Test on Boiler #2 at the Hills Farm Heating Plant, Madison, Wisconsin. MMT Environmental Services, Inc. March 2, 1995.
102. Report to Mosinee Paper Company for Particulate Matter Emission Testing. No. 6 Boiler at Mosinee, Wisconsin. May 18, 19, and 20, 1993.
103. Report to Milwaukee County for Particulate Matter Emission Test Boiler No. 21. Environmental Technology and Engineering Corporation. November 5, 1991.
104. Report on Compliance Testing Conducted at Oscar Mayer Foods Corporation, Madison, Wisconsin. Clean Air Engineering. July 21, 1989.

Sec 9.2 Ref 42

Clean and Diversified Energy Initiative



WESTERN GOVERNORS' ASSOCIATION

Solar Task Force Report

January 2006

Western Governors' Association Clean and Diversified Energy Initiative

Solar Task Force Report

The Western Governors' Association's Clean and Diversified Energy Advisory Committee (CDEAC) commissioned this task force report in February 2005. Members of the Task Force are listed below. This is one of several task force reports presented to the CDEAC on December 8, 2005 and accepted for further consideration as the CDEAC develops recommendations for the Governors. While this task force report represents the consensus views of the members, it does not represent the adopted policy of WGA or the CDEAC. At their Annual Meeting in June, 2006, Western Governors will consider and adopt a broad range of recommendations for increasing the development of clean and diverse energy, improving the efficient use of energy and ensuring adequate transmission. The CDEAC commends the Task Force for its thorough analysis and thoughtful recommendations.

Members of the Solar Task Force

Glenn Hamer (Chair)	First Solar (CDEAC member)
Fred Morse	Morse Associates, Inc.
Steve Chadima	Energy Innovations, Inc.
David Kearney	Kearney & Associates
Don Aitken	Donald Aitken Associates
Mitch Apper	Sunergy Systems
Rajiv Arya	Oregon Renewable Energy Center
Jon Bertolino	Sacramento Municipal Utility District
Sara Birmingham	Pacific Gas & Electric
Bill Blackburn	California Energy Commission
Bruce Bowen	Pacific Gas & Electric
Dave Cavanaugh	Bureau of Land Management
Mike D'Antonio	Public Service Co. of New Mexico
Kevin Doran	University of Colorado
Todd Foley	BP Solar
Lisa Frantzis	Navigant Consulting
Shannon Graham	Navigant Consulting
Gordon Handelsman	Shell Solar
Thomas Hansen	Tucson Electric Power
John Hargrove	Sierra Pacific Power Company /Nevada Power
Herb Hayden	Arizona Public Service Company
Mike Henderson	Sandia National Laboratory
Scott Jones	R.W. Beck, Inc.

Scott Kane	Creative Energies/Wyoming Outdoor Council
Golam Kibrya	California Energy Commission
Hal LaFlash	Pacific Gas & Electric
Bob Liden	Stirling Energy Systems, Inc.
Barbara Lockwood	Arizona Public Service Company
Ben Luce	Coalition for Clean, Affordable Energy
Ravi Malhotra	International Center for Appropriate & Sustainable Technology
Tom Mancini	Sandia National Laboratory
Kate Maracas	Red Mountain Energy Partners
Robert Margolis	National Renewable Energy Lab
Michael McDowell	Rocketdyne
Jan McFarland	Americans for Solar Power /PUMA Solar
Mark Mehos	National Renewable Energy Lab
Les Nelson	California SEIA/Western Renewables Group
Chris O'Brien	Sharp Solar
Craig O'Hare	New Mexico Energy Department
Laurie Park	Navigant Consulting
Terry Peterson	Electric Power Research Institute
Steve Ponder	Florida Power and Light Company
Rhone Resch	Solar Energy Industries Association
J.P. Ross	Vote Solar
Sol Shapiro	Consultant
Ed Smeloff	Sharp Solar
Tim Tutt	California Energy Commission
Michael Wheeler	National Renewable Energy Lab
Tex Wilkins	U.S. Department of Energy

Facilitator

Kate Kopischke	Policy Consensus
Will Singleton	The Keystone Center

Quantitative Working Group

The quantitative working group was created by the CDEAC to compare the analysis of data among task forces in order to ensure consistency in assumptions across the reports.

The following members contributed to this report:

Doug Arent	National Renewable Energy Laboratory
John Tschirhart	Department of Economics, University of Wyoming
Dick Watson	Quantitative Working Group

Table of Contents

Overview	1
Part I. Central Station Solar	
Summary	5
Introduction.....	9
Solar Resource for CSP Plants.....	10
Capacity Supply Curves and Optimal CSP sites.....	11
Expected Electricity Demand and Industry Supply Capability.....	12
Technology Description and Characteristics	13
Projected Costs and Competitive Position	15
Competitive Target Price Point for CSP	16
Benefits to Ratepayers and Society at Large	18
Risks and Barriers to Realizing CSP Potential	19
Case Studies.....	20
Policies and Incentives.....	22
Enabling Regulations and Actions.....	24
Conclusions for Central Solar Plants	25
Part II. Distributed Solar	
Summary.....	27
Distributed Solar Benefits All Ratepayers.....	30
Society Benefits from Distributed Solar Energy.....	31
There are No Physical or Technical Barriers to Market Entry.....	32
Public Policies Around Solar Economics Make the Difference	35
WGA States Have Already Taken the Lead	36
Key Policies and Programs to Enable Solar to Succeed	37
Conclusion: Distributed Solar Can Contribute 4,000 MW of Generation and 2GW _{th} of Solar Thermal Power by 2015	44
Appendices.....	45

Overview

To the Western Governors:

The continued prosperity of the West depends on strong economic growth, which in turn requires a secure and predictable energy supply. The recent volatility of wholesale natural gas prices, which have risen from under \$3.00/MBTU in 2001¹ to more than \$14/MBTU in October of 2005², are having a dramatic impact on natural gas and electricity prices facing the citizens in your states, prompting many to look for alternative sources of energy to meet their needs. The solar radiation in your states is the most abundant of all the renewable sources and a practical energy resource of great economic value. Solar energy can make a major contribution to the 2015 goal of 30,000 MW of clean energy adopted by the WGA in 2004. In fact, we project that as much as 8,000 MW of capacity could be installed with a combination of distributed solar electricity systems and central concentrating solar power (CSP) plants by 2015, and an additional 2,000 MW_{th} of solar thermal systems could be installed in the same timeframe. At that point, the cost of electricity from future CSP plants should be on a par with that from plants burning costly natural gas, and distributed systems should have declined in price to the point that they should be able to produce electricity below retail utility rates in most parts of the West. Best of all, the fuel source for these systems is free. Once the systems are installed, all price volatility is removed, yielding the secure and predictable energy supply so critical to the region's growth.

Initial system expense is currently the single biggest barrier to widespread deployment of solar. Worldwide experience has shown, however, that these costs can be driven down through accelerated growth sparked by temporary economic-development policies. The recently enacted two-year, 30 percent Federal investment tax credit is a case in point. For distributed solar technologies, this credit will provide short-term help to increase the number of systems installed throughout the WGA states. It will have little effect on central-station solar installations not already well underway, however, because the two-year duration is too short relative to the time needed to develop projects and bring them into operation. It is imperative, therefore, that you use your considerable leverage in Washington to ensure that this credit is extended for a full ten years. Without the assurance of this support, large central systems will find it difficult to attract financial backers, and manufacturers of components used in distributed solar systems will not have the confidence to make investments to expand production capacity that will ultimately drive down costs for everyone.

This report outlines additional initiatives needed at the state and Federal level to unleash private investment in solar. Many involve changes in policies or regulations with little or no budgetary impact. Where direct incentives are involved, they are designed to decline over the next ten years to the point that they are no longer needed to sustain a rapidly expanding industry.

The Solar Task Force offers the following set of recommendations to the Governors that if enacted will enable solar technologies to make a meaningful contribution to the 30,000 MW of new clean, diversified energy.

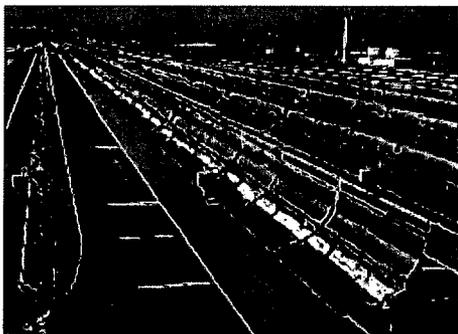
¹ http://futures.tradingcharts.com/hist_NG20013.html

² <http://www.wtrg.com/daily/gasprice.html>

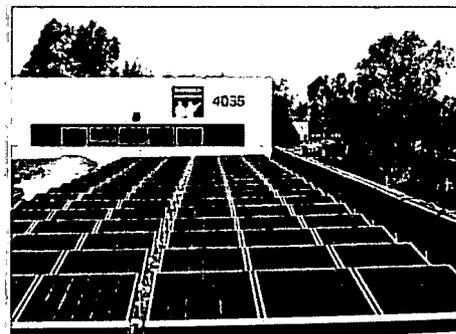
- Work aggressively with your Congressional delegations to extend the 30% Federal investment tax credit to a 10-year term and remove the \$2000 cap on residential systems.
- Expand the deployment of central solar plants by encouraging 30-year power purchase agreements and aggregation of utility plant orders and project bids to accelerate scale-up cost reductions.
- Encourage widespread adoption of distributed solar by creating incentives either in the form of declining up-front rebates that help reduce the “first cost” challenge in purchasing a solar system or by establishing ongoing performance-based incentives that pay for production of electricity, both of which have been adopted in certain WGA states. Incentives should be available to both solar thermal (space heating and cooling as well as water heating) and solar electricity systems and apply equally to residential and commercial buildings.
- Reward solar production and encourage conservation during critical peak periods by facilitating simplified interconnection standards, net metering, and rate structures that will benefit distributed solar systems.
- Exempt both CSP plants and distributed solar systems from state and local sales and property taxes. The loss to your treasury of these taxes will be more than compensated by increases in tax revenues through growth in personal and corporate income taxes, gross receipts taxes from equipment sales, compensating taxes on imported equipment and other taxes specific to electric utilities. In addition some of the money that now leaves your state’s economy for energy purchases will instead remain at home.
- Integrate solar into existing state policies such as a Renewable Portfolio Standard, which can help develop central and distributed solar markets when structured properly.
- Consider adopting target tariffs that reflect the value of solar energy for peak periods and that adjust for natural gas price changes.

With these policies implemented, an additional 32,500 jobs will be created and a new solar energy manufacturing industry will emerge in the West.

Broadly speaking, there are two technology market segments that can take advantage of the West’s abundant solar resource: central station and distributed generation. Central station solar fits the typical power-production model employed throughout the grid, generating electricity at an often remote location and wheeling that energy across the grid to recipient utilities and other customers. In contrast, distributed solar systems are installed on rooftops or on land adjacent to buildings, enabling homeowners, businesses, schools and government buildings to generate their own electricity and/or heat.



Central – Kramer Junction (CA) Solar Electric Generating Station



Distributed – Rooftop PV system at Swinerton, Inc. offices in Concord, CA

Both central station and distributed solar can be successfully deployed in the West, and both will be needed to help meet the Governors' target of 30,000 MW of new clean, diversified energy by 2015. However, the barriers to widespread adoption and consequently the policies needed to overcome them are in most cases as different as the two deployment strategies themselves. For these reasons, the balance of this report is divided into two sections, one covering central station solar and the other distributed solar. Beginning with an executive summary, each section presents the various types of solar systems that can be deployed; specific barriers they face; the policies and programs we recommend that the Governors consider to overcome those barriers; and the potential impact in energy production, jobs and other economic and environmental benefits that the WGA states will enjoy as a result.

Respectfully submitted,

The Solar Task Force

Glenn Hamer, *First Solar*, Task Force Chairman and Chair, Distributed Working Group

Fred Morse, *Morse Associates, Inc.*, Chair, Central Station Working Group

Steve Chadima, *Energy Innovations, Inc.*, Report Editor and Lead Author, Distributed Section

David Kearney, *Kearney & Associates*, Lead Author, Central Station Section

Don Aitken, *Donald Aitken Associates*

Mitch Apper, *Sunergy Systems*

Rajiv Arya, *Oregon Renewable Energy Center*

Jon Bertolino, *Sacramento Municipal Utility District*

Sara Birmingham, *Pacific Gas & Electric*

Bill Blackburn, *California Energy Commission*

Bruce Bowen, *Pacific Gas & Electric*

Dave Cavanaugh, *Bureau of Land Management*

Mike D'Antonio, *Public Service Co. of New Mexico*

Kevin Doran, *University of Colorado*

Todd Foley, *BP Solar*

Lisa Frantzis, *Navigant Consulting*

Shannon Graham, *Navigant Consulting*

Gordon Handelsman, *Shell Solar*

Thomas Hansen, *Tucson Electric Power*

John Hargrove, *Sierra Pacific Power Company / Nevada Power*

Herb Hayden, *Arizona Public Service Company*

Mike Henderson, *R.W. Beck, Inc.*

Scott Jones, *Sandia National Laboratory*

Scott Kane, *Creative Energies / Wyoming Outdoor Council*

Golam Kibrya, *California Energy Commission*

Hal LaFlash, *Pacific Gas & Electric*

Bob Liden, *Stirling Energy Systems, Inc.*

Barbara Lockwood, *Arizona Public Service Company*

Ben Luce, *Coalition for Clean, Affordable Energy*

Ravi Malhotra, *International Center for Appropriate & Sustainable Technology*

Tom Mancini, *Sandia National Laboratory*

Kate Maracas, *Red Mountain Energy Partners*

Robert Margolis, *National Renewable Energy Lab*

Michael McDowell, *Rocketdyne*
Jan McFarland, *Americans for Solar Power /PUMA Solar*
Mark Mehos, *National Renewable Energy Lab*
Les Nelson, *California SEIA / Western Renewables Group*
Chris O'Brien, *Sharp Solar*
Craig O'Hare, *New Mexico Energy Department*
Laurie Park, *Navigant Consulting*
Terry Peterson, *Electric Power Research Institute*
Steve Ponder, *FPL Energy, LLC*
Rhone Resch, *Solar Energy Industries Association*
J.P. Ross, *Vote Solar*
Sol Shapiro, *Consultant*
Ed Smeloff, *Sharp Solar*
Tim Tutt, *California Energy Commission*
Michael Wheeler, *National Renewable Energy Lab*
Tex Wilkins, *U.S. Department of Energy*

Part I. Central Station Solar

Summary

The Case for Central Station Solar Power Deployment Now in the Southwest

- **Deploying 4 GW of central station solar plants can establish a new industry in the Southwest**
- **At that scale central station solar, which works best near peak demand times, can produce power at under 10¢/kWh**
- **Such central station solar deployment would add thousands of jobs and millions of revenue dollars to the States**
- **With Federal and State policy help to deploy 4 GW, central station solar power can turn the intense southwestern sunshine into a plentiful source of low-cost electricity**
- **The policy initiatives needed to spur central station solar deployment may require no State funds**

“Western North America is blessed with an abundance of natural energy resources that have been critical to accommodating substantial population growth and fueling a dynamic economy.... Western Governors, and especially Governors from the Southwestern States, have long recognized the vast and largely untapped potential for solar powered generation in the region.”³

Increasingly volatile fossil-fuel prices since the WGA adopted this 2004 resolution have underscored the growing need for a more secure energy supply, especially during peaks in the West’s burgeoning demand.⁴ The projected 2015 Western electricity market peak load is 199 GW—a 58% increase over today’s peak.⁵

Central station solar power technologies include both solar thermal electric and photovoltaic (PV) generators. The vast majority of the central station solar projects underway or actually deployed today are concentrating solar power (CSP) technologies, which as a class include all the thermal generators as well as concentrating PV. Flat-plate PV can also be used for utility-scale systems, but the much higher energy market values of distributed generation make it the more attractive deployment mode for flat plate PV today. As PV costs decline and its market volume grows, central station flat plate PV deployment will become more commonplace. This section, therefore, focuses on CSP, while the Distributed Generation (DG) section deals exclusively with PV and solar water heating systems.

The four principal CSP technologies are parabolic troughs, dish-Stirling engine systems, power towers, and concentrating photovoltaic systems (CPV). CSP plants are utility-scale generators that produce electricity by using mirrors or lenses to efficiently concentrate the sun's energy to drive turbines, engines, or high-efficiency photovoltaic cells. CSP plants inherently generate maximum power on summer afternoons, near peak demand periods. Trough and tower configurations include large power blocks for MW-scale output, whereas dish-Stirling and CPV systems are comprised of a large number of smaller modular units. Parabolic trough systems have been deployed in major commercial installations. The other principal CSP technologies have less commercial experience, but all have seen significant pre-commercial

³ WGA Policy Resolution 04-14, “Clean and Diversified Energy for the West,” Santa Fe, NM, June 22, 2004.

⁴ NREL analysis of historical and projected fuel prices. (Doug Arent, National Renewable Energy Laboratory)

⁵ Based on The Seams Steering Group of the Western Interconnection (SSG-WI) 2015 load projection for transmission reference case expansion studies and U.S. DOE Energy Information Administration 2005 load projection.

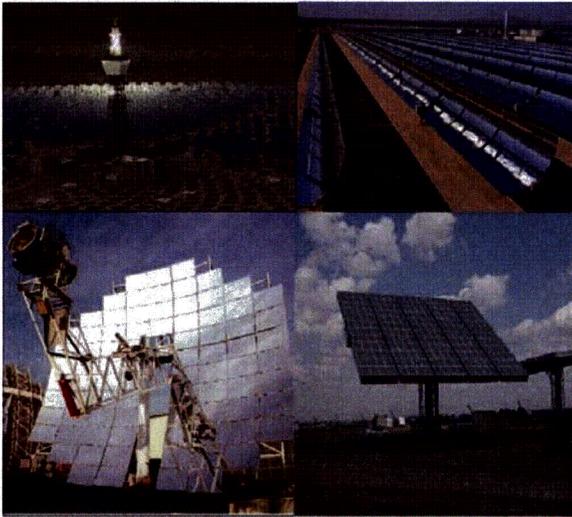


Figure I-1. CSP Technologies (from upper left, tower, trough, dish-Stirling, and CPV)

development in the past two decades. Therefore, the Task Force anticipates that they all have ample potential for large-scale commercialization.

The CSP industry core is small, but draws extensively upon production capacity of major corporations. There are 12 Solar Energy Industry Association CSP members. The four largest of these, Solargenix, Solel, Solar Millennium and Stirling Energy Systems, today employ a total of 220 people. CSP suppliers and contractors today include Flabeg, Schott, Siemens, 3M, Schuff Steel, Hoffman Construction and Sundt Construction, collectively with over \$8.8 billion annual net income. This infrastructure can support a very rapid CSP build-up in the next 10 years.

The southwestern United States possesses a world-class, well-distributed, and nearly untapped solar energy resource. It is most abundant in California, Nevada, Arizona, and New Mexico and can ultimately support CSP plants totaling several thousand GW.

The Task Force assessed the overall near-term potential for CSP capacity in the Southwest, using a sophisticated geographical information system (GIS) technique that identified areas having all the necessary conditions for development. The eligibility requirements included high insolation, near-level land, non-sensitivity to CSP use, and proximity to transmission. Figure I-2 shows the resulting numerous prime plant sites, totaling 200 GW of potential power production.

The southwestern United States possesses a world-

Large-scale central station solar deployment can help meet some of the West's most pressing needs:

- « **Peak energy supply** – central station solar plants naturally have superior load matching because high sunlight periods create both peak demand and peak production. Further, some CSP technologies can be *dispatchable*, delivering firm power during peak demand. Trough and tower plants using thermal storage or supplemental fossil-fired components are particularly suited to this purpose.
- « **Fuel price volatility** – Central station solar power provides a hedge against natural gas price fluctuations. The variable O&M costs for central station solar plants are low and predictable because the fuel (sunlight) is free after the plant capital costs are amortized. Central station solar plants, much

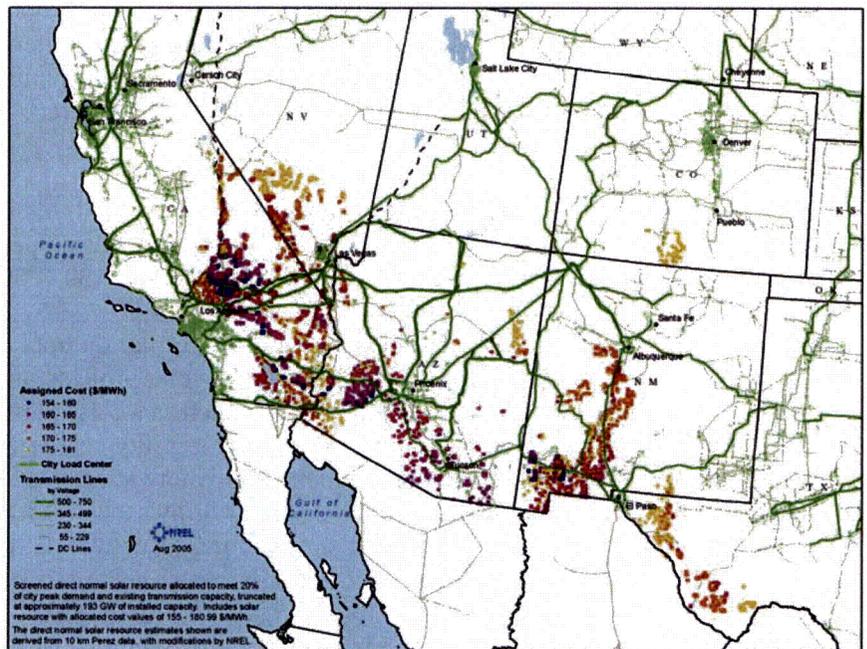


Figure I-2. Optimal CSP Sites in the SW using GIS Mapping

like hydropower plants, can operate well for longer than 30 years, generating extremely low-cost power for many years past their amortization periods.

- « **Water conservation** – Dish and PV systems require no water for cooling and only minimal amounts for mirror washing. Trough and tower plants can be built to use dry cooling technologies and then also consume very little water. Thus, central station solar power can be an attractive power option in the dry Southwestern States.
- « **Economic development** – Central station solar deployment can stimulate significant job creation and growth of manufacturing infrastructure, ancillary commerce, and tax revenues, as well as growth and diversity in Gross State Product. Recently, for example, Black & Veatch projected that 4 GW of CSP deployment in California would produce a net \$22 billion increase in gross State output, including 13,000 construction jobs, 1,100 permanent operations jobs, and \$2 billion in State tax revenues.⁶

CSP can become price competitive in the near term. The Solar Task Force projects that, with a deployment of 4 GW, total nominal cost of CSP electricity would fall below 10¢/kWh. Analysis shows that CSP at 10¢/kWh is equivalent to a blended base load-peak value of natural gas generation at a fuel cost of \$7/MMBtu.⁷ Achieving 4 GW of CSP deployment by 2015 from the current 354-MW base requires growth similar to that of the PV and wind industries in the past decade. A Solar Task Force poll of the CSP industry indicated capability to produce over 13 GW by 2015 if the market could absorb that much.

Central station solar power will produce societal and environmental benefits. Large central station solar deployments will cause reductions in natural gas, oil, and coal use, consequently reducing greenhouse gas production. Black & Veatch conservatively projected the annual CO₂ reduction from 4 GW of CSP to be 7.6 million tons, or 7% of present California electric utility output.^{6,8} They also project substantial avoided emissions of NO_x, CO, and volatile hydrocarbons.

Policy can effectively stimulate central station solar development. The following examples highlight central station solar developments encouraged by local policy measures.

California (1984): Incentives including a 25% Federal Investment Tax Credit (ITC), a 25% State ITC, property tax exemptions, and “standard offer” contracts that guaranteed a long-term market for their output, fostered development of 9 Solar Electric Generating Station (SEGS) plants between 1984 and 1990 near Barstow, CA. When the policies expired in 1990, project development activity on the SEGS abruptly stopped. With combined output of 354 MW and a design life of 30 years, all the plants are still in operation today.

Arizona and Nevada (2001): Utility renewable energy portfolio requirements in Arizona and Nevada have been key drivers in launching 1-MW and 64-MW CSP plants with anticipated start-up in 2006 and 2007, respectively. Arizona Public Service will own and operate the 1-MW plant and Nevada Power will purchase the 64-MW plant’s output. Another key factor for the Nevada plant was legislation enabling Nevada Power to enter into a long term Power Purchase Agreement (PPA) with the developer. Both States mandate that part of the required renewable energy be solar and this stimulated Tucson Electric Power’s 4.6-MW central station PV prototype installation in eastern Arizona, one of the largest PV systems in the world. It uses conventional PV technologies to power some auxiliary loads at an existing fossil-fired generating station.

Spain (2004): The first European country to introduce a solar “feed-in tariff”, Spain offered an extra 12 € cents/kWh for CSP in 2002. Little development occurred until the feed-in tariff was

⁶ “Economic Benefits of Concentrating Solar Power in California”, Draft Final Report, Black & Veatch for NREL, August 2005

⁷ This analysis is further detailed later in this section of the report.

⁸ Current emissions estimates from: California Energy Commission, June 2005, “Inventory of California Greenhouse Gas Emissions and Sinks: 1990 to 2002 Update,” Sacramento, CA, CEC-600-2005-025

increased to 18 ¢/kWh in 2004 and guaranteed for 25 years with annual adjustments for average price increases. This launched a race of major Spanish power-market players and, by mid 2005, a total of 795 MW of CSP capacity additions were planned.

California (2005): Phoenix-based Stirling Energy Systems signed PPAs for two large CSP plants in Southern California. The PPA with Southern California Edison is for a 500 MW facility with an optional 350 MW addition. The one with San Diego Gas & Electric is for a 300 MW plant with another 600 MW optional. These two contracts, totaling up to 1,750 MW, were motivated by California's 20% Renewable Portfolio Standard (RPS), now to be enforced by 2010, and they depend upon the 30% Federal ITC. Both projects are slated to start construction in 2008 or early 2009.

Central station solar deployments can help the Western States Governors to meet their clean energy goals and economic growth needs if key policies are in place. The Solar Task Force identified key policies for enabling successful scale-up of central station solar deployments. These measures do not require State expenditures. They encourage private investments that will provide significant State economic gain.

The policies are:

- **Extend the 30% Federal ITC and expand its use to utilities** – The present 2-year 30% federal ITC needs a 10-year term to allow time to design, permit, finance, and build central station solar plants. This is extremely important because it gives about a 3¢/kWh price reduction for CSP plants. Allowing utilities to use the ITC would further reduce the price by 1-2¢/kWh.
- **Exempt sales and property taxes on solar power plants** – These exemptions will result in a 1-2¢/kWh price reduction. The apparent loss to the State treasury will be offset by new tax revenues from activities caused by the new plants. For example, the increase to the New Mexico treasury as a result of CSP deployment was estimated to be about ten times larger than the forgone taxes.⁹
- **Allow longer-term Power Purchase Agreements and set equitable central station solar power price references** – Encourage State PUCs to extend the allowed PPA term to 30 years. This provides the market stability needed for capital-intensive solar power development. The State PUC and utilities also should consider adopting target tariffs that reflect the value of central station solar power for peak periods and adjust for natural gas price changes.
- **Encourage State PUCs, utilities, and project developers to seek means for aggregating plant orders and project bids to accelerate CSP scale-up cost reductions.** – Some California utilities can issue bids for large CSP plants in the 500 MW range, but others may need to coordinate¹⁰ to aggregate CSP demand. Without sufficient orders for CSP capacity, or in the absence of any of the above recommended policies, States may have to cover cost gaps with additional incentives, perhaps including a capital buy-down or a performance-based incentive such as a declining State production tax credit.

Central station solar power scale up faces risks and barriers, including delays for siting permits, limited access to existing transmission lines, and technology innovation slowdown.

⁹ "The Economic Impact of CSP in New Mexico," University of New Mexico Bureau of Business and Economic Research, December 2004, comprising Chapter 7 in "New Mexico Concentrating Solar Plant Feasibility Study," Draft Final Report, Black & Veatch, for New Mexico Energy, Minerals and Natural Resources Department, February 2005.

¹⁰ For example, Renewable Energy Credit (REC) trading between States may provide an aggregation avenue. REC trading: (1) allows CSP plant siting at the most advantageous regional resources; (2) encourages joint development and ownership of larger, more economic projects; (3) reduces transmission constraints in delivering renewable energy; and (4) promotes scale efficiencies by allowing multiple owners of the attributes without having multiple owners of the physical plant.

Each central station solar MW requires about 5 acres. Therefore, time is needed for siting and permitting these plants. On Federal land, the Bureau of Land Management's streamlined and standardized permitting program can accelerate the process. Designated solar development zones could also help to shorten this step. Many prime solar power sites are close to growing load centers, but installing 4 GW of central station solar power will place some new demands on existing transmission systems and may require some new or upgraded lines. The WGA CDEAC Transmission Task Force is addressing this issue. The technology risks, existing with any evolving technology, will be born primarily by the industry investors and project developers, aided by the U.S. Department of Energy's ongoing solar R&D.

When combined with central station solar power's presently uncompetitive prices, these risks are sufficient to inhibit nearly all potential investors. However, as the cited case studies illustrate, central station solar power's risks may be overcome with modestly supportive policies.

In summary:

- Continued economic growth requires energy, much in the form of electricity, and especially during peak demand periods.
- Using in-State renewable energy resources creates economic gains for the State and helps meet environmental targets, especially carbon emission reductions.
- In Arizona, California, New Mexico, and Nevada, the most abundant renewable energy resource is solar energy.
- CSP is able to provide firm dispatchable on-peak power and is a large-scale central station technology.
- Building in-State central station solar plants, rather than natural gas plants, creates more jobs, adds more money to the State's economy, adds more revenue to the tax base, and provides a hedge against volatile natural gas prices.
- The policies needed to facilitate central station solar plant deployment include (1) extending the Federal 30% ITC and allowing utilities to use it, (2) exemptions from State property and sales taxes, (3) encouraging 30 year PPAs, and (4) fostering large-block purchases.
- These policies cost State treasuries nothing and, in fact, increase tax revenues.
- Lack of any of the above four policies imposes a need for additional State incentives, such as a declining production tax credit.
- The CSP industry is ready, the technology is ready and central station solar power has the potential to add a new engine to the Western States' economies.

Introduction

Solar energy resources in the Southwest¹¹ offer a vast potential for generating electricity. Technology cost reduction is the key to utilizing CSP to harvest those resources. Public policy can also play a role in effecting that cost reduction. The important findings of the Solar Task Force have been summarized in the Summary. The following discussion provides a basis for those findings and gives more detail on the analysis leading to conclusions in several areas, particularly, the:

- Overall potential for CSP capacity in the Southwestern States
- Potential for CSP cost reduction to an economically competitive level

¹¹ The Southwest States considered in this report for the implementation of concentrating solar power facilities (which require the utilization of the direct, or beam, component of solar radiation) include portions of Arizona, California, Colorado, Nevada, New Mexico, and Utah.

- Most effective policy actions that the Western Governors can undertake to facilitate commercial development of the CSP technologies and aid their transformation into cost-effective generation options

Solar Resource for CSP Plants

Solar energy is the largest renewable energy resource worldwide. The solar energy resource in the southwestern United States is enormous and largely untapped. It is among the best in the world and has a very high potential for electricity generation. In combination with ample land availability and excellent proximity to growing population centers, the solar energy resource in the southwestern States has the potential to support central solar electric plants totaling several thousand GW of electrical capacity.

Concentrating solar power systems require direct normal insolation (DNI), or beam radiation¹² for cost-effective operation. The solar resource, since it drives the cost of the array of solar collectors (or “solar field”), is a significant factor in the economics of a solar plant. Thus, not only do sites with excellent solar radiation offer more attractive levelized electricity prices, but this single factor normally has the most significant physical impact on the cost of solar-generated electricity using a given technology.

Satellite measurements are an important source of the DNI data. This evaluation used a new, high-resolution solar resource data set developed using satellite data and correlated to good ground station data. The map shown in Figure I-3 gives the distribution of DNI over the southwest States. The radiation increases in intensity from the yellow areas through to the dark brown regions, but all are attractively high. The six southwest States with suitably high solar radiation for CSP plants are Arizona, California, Colorado, Nevada, New Mexico, and Utah. In this region, the amount of solar energy falling on an area the size of a basketball court is, in thermal energy terms, equivalent to about 650 barrels of oil a year.

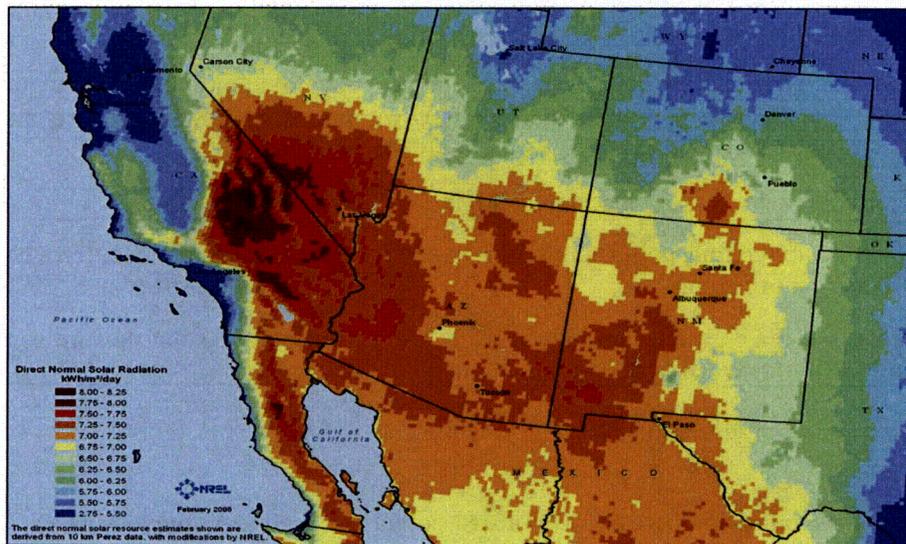


Figure I-3. Direct Normal Solar Radiation in the Southwest

¹² To further clarify this point, beam radiation is capable of casting a shadow on a sunny day, in contrast to diffuse, or scattered, radiation.

Capacity Supply Curves and Optimal CSP sites

Capacity Supply Curves

Capacity supply curves are provided in the Appendix as requested by the WGA Quantitative Working Group (QWG). Examination of the supply curves shows the proximity of the Southwest's immense solar resource to existing transmission. The curves provide a means for describing the relative cost of generation for a particular technology (renewable or conventional) and the generating capacity coincident with the cost. For renewable technologies, costs are driven primarily by two factors: resource availability and proximity to available transmission. For this analysis "busbar costs" (technology costs exclusive of transmission, that is, those costs accumulated within the perimeter of the plant site, up to and including the point of delivery to a transmission system, or "busbar") were based on a fixed charge rate (FCR) methodology supplied by the QWG. While the FCR methodology provides a simple determination of the relative cost of generation for a given resource, it overestimates the real and nominal levelized cost of energy when compared to the more detailed cash flow model used for the CSP cost analyses cited later.

Optimal CSP Sites

CSP plant siting depends on factors additional to solar resource and busbar cost. To estimate the potential for deploying CSP systems in the region, NREL performed a Geographic Information Systems (GIS) analysis of the Southwest to identify candidate areas. Not all of the land with high DNI shown in Figure I-3 is suitable for large-scale CSP plants. To be feasible and cost-effective, such plants require relatively large tracts of nearly level open land with other appropriate siting characteristics. GIS data filters were applied with the following criteria: land type (e.g., urban or agriculture), ownership (private, State, Federal), environmental sensitivity, contiguous area, and topography. The terrain available for CSP development was conservatively estimated using these filters, so that the results represent land with slope $\leq 1\%$ and exclude sensitive lands, defined to be national parks, national preserves, wilderness areas, wildlife refuges, water and urban areas. To narrow consideration to areas with a high economic potential, only lands with an average daily solar resource of about 7 kWh/m^2 were deemed acceptable for this analysis. Capacity estimates assume a need for 5 acres/MW; for example, a 100 MW plant would require 500 acres of contiguous land (less than 1 mile per side). Further, the proximity to transmission lines was taken into account using the methodology described in the Appendix.

The result of the evaluation is illustrated in Figure I-2. In essence, that figure combines the solar resource map (Figure I-3), the supply curve methodology (Appendix I-1), and the application of the other filters using the GIS mapping methodology. **The remaining identified areas have a very large total potential for CSP with a cumulative generation capacity of approximately 200 GW.** This capacity could produce about 473,000 GWh per year, equivalent to approximately 17% of the total U.S. current consumption. Additional practical development factors may well limit this very high potential, but the analysis emphasizes that **the readily accessible solar resource in the Southwest is large enough to play a major role in meeting the region's future energy needs.** This is clearly a very significant and valuable renewable energy resource for the region.

To fully identify favorable solar power plant siting opportunities, additional factors such as land ownership, road access, and local transmission infrastructure capabilities and loadings must be examined in greater detail. This will involve discussion with local experts and utility specialists, and will likely include visits to prospective locations. In addition, the impact of solar resources on the transmission system must be fully analyzed by constructing security-constrained load flow model scenarios. Finally, State-level policies and regulatory frameworks must be assessed to determine the favorability of renewable resource development in a particular State. The availability and relative cost of other renewable power technologies must be considered in this context.

Expected Electricity Demand and Industry Supply Capability

Target Electricity Demand for CSP Plants

The growth in peak demand projected by the SSG-WI team¹¹ until 2015 is about 34 GW. The California goal for renewable deployment in the time frame under consideration is about 20% of its total load. Assuming the same 20% market penetration for the six Southwestern States analyzed here, **the total peak period target for renewables (which is the suitable time period for CSP generation) is projected to be about 7 GW.**

Estimated CSP Deployment by State

Consideration of the solar resources in each state, the optimal sites for CSP plants and the expected incremental growth in peak demand leads to a tentative deployment of CSP electricity generation by State. Such a deployment, while reasonable, is somewhat arbitrary at this point in time, and will be strongly influenced by State policies and business decisions of the industry stakeholders. The objective here was to allocate 4 GW of CSP generation capacity proposed to be in place within the WECC region by 2015. The growth in peak demand¹³ in the Southwestern states is the governing criteria, given that siting constraints are minimal at these levels of deployment. Using this approach, the Solar Task Force projects the approximate deployment by State through 2015 to be:

Table I-1 Estimated CSP Deployment by State¹⁴

State	Peak Demand Growth (GW)	CSP Allocation (GW)
California	11,600	2.0
Arizona	6,100	1.0
Nevada	5,100	0.5
New Mexico	4,300	0.3
Colorado	5,300	0.1
Utah	1,700	0.1
Total	34,100	4.0

¹³ Based on The Seams Steering Group of the Western Interconnection (SSG-WI) 2015 load projection for transmission reference case expansion studies and U.S. DOE Energy Information Administration 2005 load projection.

¹⁴ Allocation of CSP resources was based on an analysis of peak demand growth and proximity to transmission in the western interconnect region. Significant solar resources also exist in Texas, most of which lies within the ERCOT system which is not part of the WECC and therefore has not been included in this analysis. Given these resources and the aggressive Texas RPS, the Solar Task Force believes that significant central station potential exists in the state.

CSP Industry Capacity

The accelerated industry growth needed for the expansion of CSP deployments will increase competition while allowing individual companies to achieve economies through large-scale production and materials procurement, all of which tend to lower product costs. Accelerated deployment is facilitated by the wide use of common materials in CSP plants. While the material requirements for CSP plants differ by technology, they mainly consist of low-cost, recyclable materials that are available worldwide: steel, glass and concrete. (Exceptions include minor use of plastics and of high-efficiency solar cells in CPV systems.) Local companies generally will construct the plants, and the modular structure of CSP systems facilitates entry into mass production with substantial potential for increased efficiency. The Luz development of the SEGS plants in California demonstrated a swift expansion to build larger and multiple plants at once, and the typical plant construction period was less than 12 months.

Independent of projected peak demand growth estimates, the companies in the CSP industry estimated their worldwide production capability under favorable financial conditions during the period from now until 2015. The totals of these estimates are shown in Table I-2. **The industry projections resulted in a cumulative 13.4 GW of additional peak period capacity**, exceeding the estimated 9.5 GW demand, but lower than the expected maximum target market for renewables of 47 GW. The parabolic trough industry estimate is based on experience with the 354 MW of solar electric plants operating in California; the other estimates are based on estimates of industry production capacity growth under favorable plant development conditions. The strong message here is that the CSP industry is in position to meet the potential market identified above.

**Table I-2. CSP Industry Estimates for Capacity Production to 2015
under Favorable Financial Conditions**

Year	Parabolic Trough MW		Power Tower MW		Dish-engine MW		Conc. PV MW		Total GW
	annual	cumul.	annual	cumul.	annual	cumul.	annual	cumul.	
2006	0	0	0	0	0	0	10	10	0.01
2007	150	150	0	0	0	0	25	35	0.2
2008	150	300	50	50	50	50	80	115	0.5
2009	300	600	50	100	150	200	100	215	1.1
2010	600	1200	150	250	300	500	150	365	2.3
2011	600	1800	150	400	600	1100	250	615	3.9
2012	900	2700	200	600	600	1700	350	965	6.0
2013	900	3600	200	800	600	2300	450	1415	8.1
2014	1200	4800	300	1100	600	2900	485	1900	10.7
2015	1200	6000	300	1400	600	3500	600	2500	13.4

Technology Description and Characteristics

Concentrating solar power plants produce electric power by using lenses or mirrors to efficiently convert the sun's energy either into high-temperature heat to drive turbines or engines or directly into electricity via high-efficiency photovoltaic (PV) cells. Two major subsystems come into play: first to collect and concentrate solar radiation, and then to convert the concentrated energy to electricity. CSP systems can be sized for distributed generation (10-35 kilowatts) or central grid-connected applications (up to several hundred megawatts).

Four concentrating solar technologies are shown in Figure I-1. Parabolic trough plants 30-80 MW in size are in commercial operation, with a total of 354 MW in the California Mojave Desert demonstrating reliable operation and excellent performance since 1985. An aerial view of five 30-MW trough plants is shown later in Figure I-5. Currently a 1-MW trough system is under construction in Arizona (for Arizona Public Service) and a 65-MW trough plant is under development in Nevada (for Nevada Power). At least two 50-MW trough plants with storage are being developed in Spain. Dish-Stirling systems are currently in an aggressive commercialization program by industry centered on a 25 kWe dish system unit for modular production of over-100 MW plants. Recently, Southern California Edison announced signing of a power purchase agreement for a 500-MW dish-Stirling project in the Mojave Desert with optional expansion to 850 MW. Separately, San Diego Gas & Electric also announced signing of a power purchase agreement for a 300-MW dish-Stirling project in the Imperial Valley with options to expand to a total of 900 MW by 2014.

A prototype 10 MW power tower that was successfully operated in California demonstrated efficient thermal energy storage and 24-hour per day electric production. Concentrating PV systems are in early commercial development at the 25 kW - 5 MW level. Flat plate photovoltaics can also be a source of utility-scale solar systems. Several systems under development in Germany are multi-megawatt power parks, and a system in excess of 60 MW has just been announced in Portugal. In Arizona, a 4.6 MW flat plate PV system has also been deployed at a utility power plant. While distributed markets may be most attractive today for PV, as the costs of this technology decline, additional opportunities will exist for central station deployments.

Dispatchability is a very important characteristic of several CSP technologies, allowing delivery of firm power during selected demand periods. Trough and tower plants can provide dispatchability by using thermal storage to store solar-produced thermal energy to generate power at a later time, by being integrated with supplemental fossil-fired components, or by being configured to share with a fossil plant the generation portion of a facility.

For example, high temperature thermal energy stored during the off-peak periods can be utilized during peak hours in the evening to generate electricity. These attributes, along with very high solar-to-electric conversion efficiencies, make CSP an attractive and viable renewable energy option in the Southwest and other sunbelt regions worldwide.

CSP systems can also be configured with auxiliary gas-fired equipment to supply thermal energy to achieve full power and remove intermittency from operation with insufficient sunlight. This is demonstrated by parabolic trough system performance at the Kramer Junction sites in California, which typifies the reliability of these systems. These plants are “hybrids” in which a gas-fired boiler can provide steam to augment solar-generated steam. In a proposed alternate hybrid configuration, heat gathered by a CSP system is fed to a larger fossil power plant to be converted to electricity. The solar heat energy can be used to increase the electric production or reduce the fuel consumption of the fossil plant.

Figure I-4 shows 16-year history of on-peak performance¹⁵ at Kramer Junction broken down into solar production (yellow) and auxiliary boiler production (red). By design, the Kramer Junction plants have averaged about 80% of rated on-peak capacity from solar energy, with natural gas used to fill in to 100%. Note in the figure that solar output was low in 1991 and 1992 as a result of the eruption of the Mount Pinatubo volcano in the Philippines. Adding thermal storage would enable nearly 100% on-peak capacity without fossil hybridization. **The ability to dispatch power during peak demand periods makes CSP an ideal renewable energy technology for the Southwest.**

¹⁵ On-peak for these plants occurs from 12pm to 6pm on weekday afternoons during June through September; capacity factor is the actual output divided by that possible with full-load nameplate turbine output during the on-peak period. Values over 100% are possible because the turbine can be driven (safely) higher than its nameplate rating.

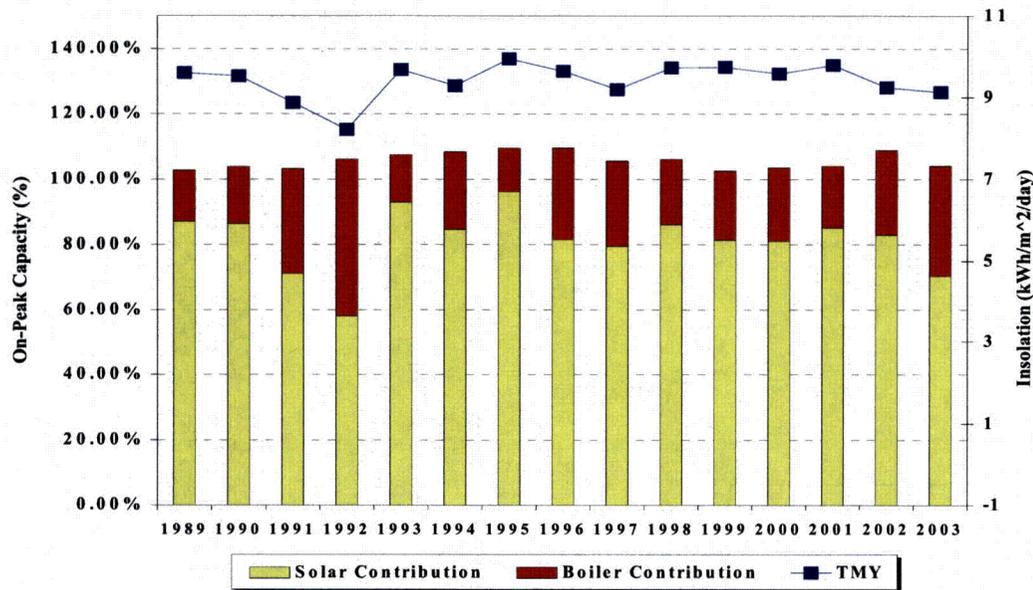


Figure I-4. Performance History of Parabolic Trough Plants at the Kramer Junction Site

Low Water Use Potential

Solar thermal electric systems can be designed for very low water requirements. Dish Stirling engines and PV systems are air-cooled by design, and the steam power plants driven by trough and tower systems can utilize dry cooling technology at a modest increase in electricity cost. The primary water uses at a Rankine steam solar power plant are for steam cycle condensate makeup, cooling for the condenser, and washing mirrors. Historically, parabolic trough plants have used wet cooling towers for cooling. With wet cooling, the cooling tower make-up represents approximately 90% of the raw water consumption. Steam cycle make-up represents approximately 8% of raw water consumption, and mirror washing represents the remaining 2%. Soiling-resistant glass is being explored to further reduce the mirror washing requirement. Still, availability of water is a significant issue in the desert SW regions.

Projected Costs and Competitive Position

Cost Reductions

Cost reductions in CSP systems will be driven by three factors – further technology development, volume production and scale-up in plant or project size. Technology development includes evolution in the performance and reliability of specific technology components, improvements in construction techniques and Operations and Maintenance (O&M) due to learning experience as more projects are installed. Volume production brings significant cost reductions with increased deployment due to decreases in manufacturing cost, material procurement costs, standardized engineering and project development costs. Large power plant sizes or multiple plants in a single project invoke economies of scale in equipment and systems.

The expected cost reduction is illustrated in Figure I-5. Estimates are given for 2015 deployment levels up to 4 GW. This represents a development and deployment plan for the relatively mature parabolic trough technology, which the Solar Task Force believes to also represent a reasonable scenario for the other CSP technologies (tower, dish and CPV). The starting costs are based on the SEGS plants, current costs for the conventional power unit technology, and current solar field estimates. The assumed levels of deployment are supported by expectations in demand growth and industry capacity. Both nominal and real levelized

costs of energy are indicated in the figure. At a deployment of 4 GW, projected CSP costs are lowered to about 8 ¢/kWh (nominal) or 5 ¢/kWh (real) from today's plant status.

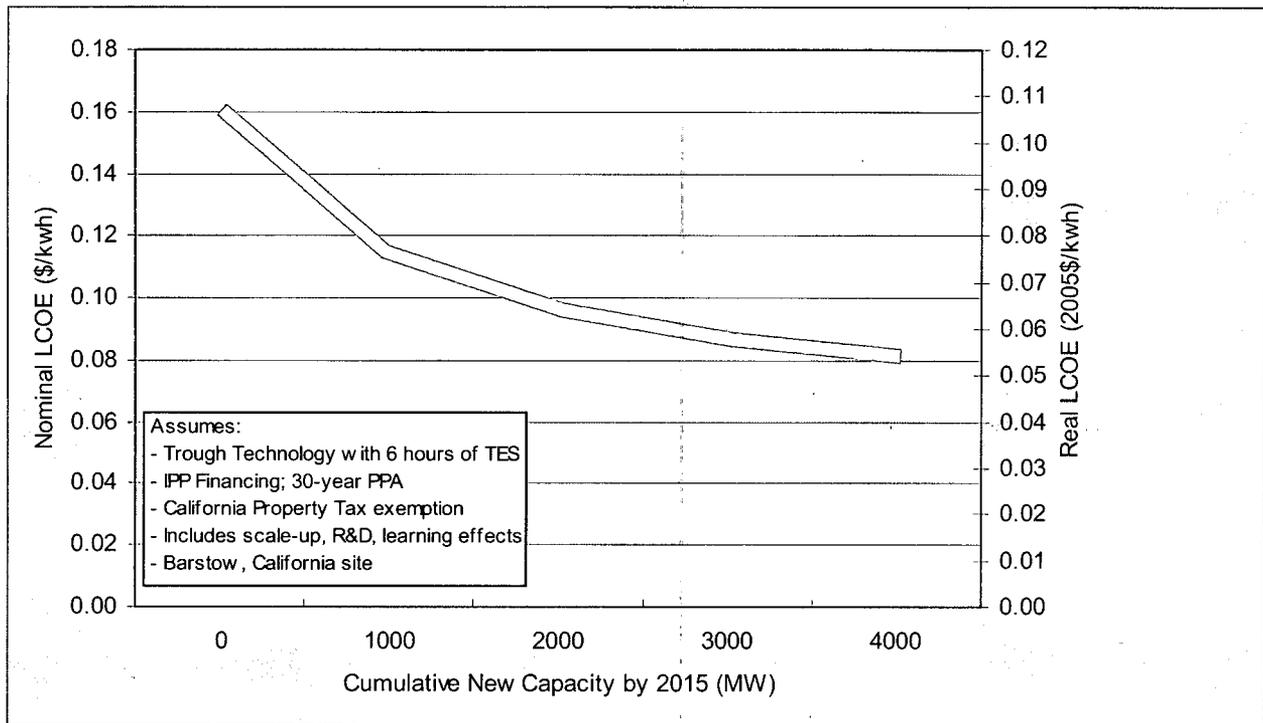


Figure I-5. Projected Cost Reduction Scenario for CSP (based on trough technology)

For reference, the assumptions used in the financial model that generated costs in Figure I-5 were provided by the Analytical Group and are:

- Independent Power Producer (IPP) project structure
- 30 year financial life, Internal Rate of Return (IRR) =15%, 3% fee
- 20-year debt, 6% interest rate, 1.4 Debt Service Coverage Ratio (DSCR), 2% fee
- California solar property tax exemption, but includes 7.75% sales tax (on equipment)
- 10% ITC and 5 year Modified Accelerated Cost Recovery System (MACRS) (see comments on 30% ITC later in this report)
- Optimized Levelized Cost of Electricity (LCOE), including debt/equity ratio, initial O&M cost and escalation, in 2005\$
- Engineering, Procurement & Construction (EPC) cost includes 10% contingency, 7% contractor fee and 3% warranty fee

Scenarios to facilitate cost reductions from increased deployment are under discussion. Using troughs as an example, there could be a process by which a utility or consortium of utilities requests that industry submit large deployment bids in incremental phases, e.g., 500 MW each. The first 500-MW phase could be guaranteed at a negotiated rate; the second 500-MW phase might be built only if agreed-upon cost goals were met. If the first GW increment met the cost goals, the process could be repeated.

Competitive Target Price Point for CSP

The target price for CSP is that which utilities would find competitive with their alternatives. This target price should reflect the value of CSP during peak periods and adjust for natural gas prices. The California Public Utility Commission has used a Market Price Referent (MPR) methodology to provide an estimate of

the long-term market price of electricity from baseload and peaking power plants. For a reference 100 MW CSP plant with 6-hours of thermal storage, the MPR methodology provides a “blended” electricity value based on the fraction of CSP generation falling into peak and non-peak periods.

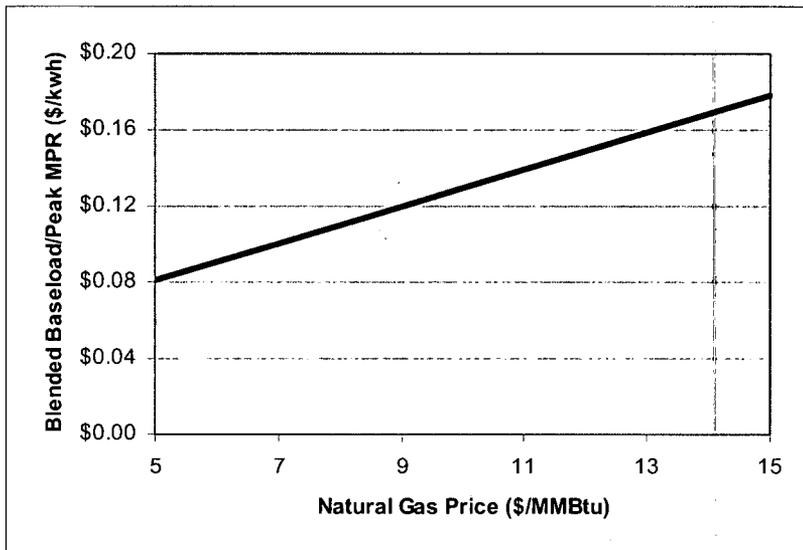


Figure I-6. Sensitivity of the blended value of peaking/baseload electricity to the price of natural gas.

Figure I-6 depicts a blended value of peaking and baseload electricity as a function of natural gas price based on the PG&E time-of-use cost structure. This analysis considered 2005 natural gas prices between \$5 and \$15/MMBtu and is assumed to escalate at 2% per year beyond 2005. For a natural gas cost of \$7/MMBtu, the analysis yields a blended baseload-peak value of 10¢/kWh. The utility participants on the Solar Task Force agreed that 10¢/kWh would represent a current competitive market price for a firm solar plant meeting the summer peak base on the proposed new resource adequacy rules. A natural gas cost of \$15/MMBtu would drive the competitive price up to about 17.5¢/kWh¹⁶.

Based on the current reference price, however, the predicted CSP technology cost projection as a function of deployment in Figure I-5 show that the cost of CSP electricity could reach the 10¢/kWh target at a deployment of about 2 GW. Because of a normal spread in extrapolated estimates and other factors, the Solar Task Force suggests using a more conservative deployment goal of 4 GW.

To summarize this argument, the following logic leads to a proposed deployment of 4 GW by 2015:

- Excellent site areas in the Southwest for CSP plants identified using GIS mapping techniques total to a least 200 GW of electrical generation (Fig. ES-2)
- The CSP industry estimates a manufacturing capacity to deploy 13.4 GW by 2015 (Table I-2)
- Growth in peak demand is estimated for six selected states to be 34 GW by 2015. Goal of 20% renewables gives market target of 7 GW. (Table I-1 and text)
- Cost estimates for the CSP technologies project cost competitiveness at a deployment of 2 GW for any single technology or, more conservatively, 4 GW for multiple technologies. (Fig. I-3)

¹⁶ Natural gas prices are difficult to predict and various well-versed experts project differing scenarios, some with high prices and others with lower ones in the long term. The Solar Task Force observes, however, that \$15/MMBtu has already been reached in August, 2005 on the spot market for natural gas.

Benefits to Ratepayers and Society at Large

Economic Impact

The social benefits accruing to all taxpayers are broad in scope. Construction and operation of CSP plants would bring significant economic impacts to the southwest States. Recent work¹⁷ by Black & Veatch on the direct and indirect economic impact of CSP plants in California is the source of the data reported here. Direct economic impacts are the dollars directly spent by the project in the region for materials, equipment, and wages. Indirect economic impacts are also referred to as the “multiplier” impacts of each dollar spent in the region. When a dollar is spent in the region, a portion of that dollar goes to pay employees’ salaries (earnings). Those dollars are then re-spent in the region to purchase goods and services. The following economic metrics can be used to measure the direct and indirect economic impact of dollars spent in a given region:

- Gross State Output--The total value of goods and services produced within the State.
- Earnings--The value of wages and benefits earned by workers in the region.
- Employment--Full and part-time jobs.

The economic impacts of a power generation project can be divided into the construction and operation periods. The fiscal impact of building CSP plants includes increased tax revenues to State and local governments. These would arrive as increased personal and corporate income taxes, increased gross receipts taxes, increased compensating taxes on imported equipment, increased property taxes, and other taxes specific to electric utilities.

Based on the result of a study focused on California, the net¹⁸ economic benefits would be:

Table I-3. Economic Benefits of CSP in California

Deployment level	2 GW	4 GW
Increase in Gross State Output	\$11.7 billion	\$22.2 billion
Creation of construction jobs	6,800	12,800
Creation of permanent operations jobs	500	1,100
Increase in State Tax Revenues	\$1 billion	\$2 billion

The direct impact to other SW States would be comparable.

Avoided Emissions

With solar energy as the primary fuel, the use of natural gas, oil and coal will be reduced, with a coincident reduction in the production of greenhouse gases. The avoided emissions at several levels of deployment are shown in Table I-4. This is a conservative estimate of the emissions offset by the deployment of CSP because it is assumed here that CSP would displace emissions from new high-efficiency plants. CSP plants could offset generation from older less-efficient natural gas plants with an average heat rate of about 10,000 Btu per kWh, which would increase the emissions offset by about 30 percent. Furthermore, these plants are likely to have greater emissions per Btu of gas consumed, such that the emissions increase is likely to considerably exceed 30 percent. CSP plants may also offset some generation by coal plants, which generally have much higher emissions than natural gas plants.

The proxy Fossil Plant for Table I-4 is assumed to be a natural gas combined cycle with a heat rate of 7,000 Btu/kWh. The CSP plants are assumed to operate at 40 percent capacity factor.

¹⁷ “Economic Benefits of Concentrating Solar Power in California”, Draft Final Report, Black & Veatch for NREL, August 2005.

¹⁸ Compared to an alternative gas-fired power plant

Central solar energy plants also provide a hedge against electricity price fluctuations due to increases in fossil fuel costs or drought. Grid security will be enhanced by this lessened dependence on fossil fuels. A study of the power flows in the southern CA distribution system showed that adding about 1 GW of CSP in select areas would strengthen the grid reliability¹⁹.

Pollutant	Proxy Fossil Plant Emissions Rate (lb/MBtu)	CSP Plant Capacity		
		100 MW (tons/year)	2,100 MW (tons/year)	4,000 MW (tons/year)
NO _x	0.0060	7.4	156	297
CO	0.0036	4.5	95	181
VOC	0.0021	2.6	54	103
CO ₂	154	191,000	4,000,000	7,600,000

Risks and Barriers to Realizing CSP Potential

The key barriers to widespread implementation of concentrating solar power plants continue to be economic in nature. First costs are high compared to traditional fossil-fired plants, and this issue is judged by the Solar Task Force to be the major barrier at present. Deployment is a critically important factor in cost reduction, as shown earlier. New policy and regulatory measures will be essential in facilitating early CSP deployment in the WGA region. A related issue – the need for full cost recovery by utilities that purchase CSP power – was ranked by the Task Force to be the second major barrier. Rising natural gas and coal prices are narrowing the cost gap from below, and that trend is likely to continue.

There are no known major technical or materials barriers to widespread implementation of concentrating solar power plants. CSP plants predominately utilize common materials such as steel and glass, with minimal specialty materials required. To a large extent, accelerated deployment can occur rapidly with the requisite addition in manufacturing capability to meet the demand. There are particular components, however, where the necessary infrastructure must be established to match a growing deployment, such as high-performance PV cells, Stirling engines, and thermal receivers.

While no technology *barriers* are evident, further technology *advances* are still essential to achieving reductions in electricity costs from CSP plants. Inadequately funded R&D is therefore a significant potential barrier. R&D on advanced, more cost-effective systems to improve performance and lower costs will continue to be a very important cost reduction driver. Other barriers include the cost of capital required for financing, the need for access to transmission, and the risk of using a relatively new technology. For trough and tower technologies, the availability of cooling water for the power block is a potential barrier to flexibility in siting. Water is an issue only with trough and power tower plants, but they could be built to use dry cooling technologies and then also consume very little water.

Permitting and siting large power plants is a costly and time-consuming process. If possible, standardized, streamlined, fast-track permitting procedures should be implemented for CSP plants to implement clean, safe renewable energy systems while retaining the need to provide for public oversight and protection.

¹⁹ "Strategic Value Analysis of Renewable Power Technologies for Concentrated Solar Generation," Davis Power Consulting, December 2004.

BLM has taken steps²⁰ in this regard to facilitate the application and permitting process, such as funding programmatic environmental impact statements to reduce the time and costs to prepare site specific environmental documents. A related concept is the creation of "solar development zones" as a policy mechanism. For example, states (or the Federal Government if on BLM land) could set aside tracts of land dedicated for solar projects. Broad EIRs, plant/animal surveys, geological, and/or weather studies could be done on the entire zone to expedite permitting and/or reduce project development time and cost (and risk).

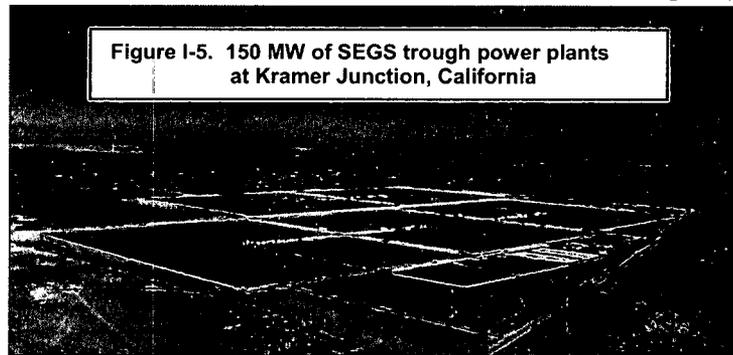
Desert land is relatively abundant, but it is also environmentally sensitive. Siting power plants is never easy and can be a barrier to solar systems that have a high land use and are more cost effective if near a water supply and adequate transmission lines.

Case Studies

Central station technology and performance have been successfully demonstrated for over 15 years. Of the four CSP technologies demonstrated to date, parabolic trough technology has been the most broadly deployed, while others such as dish-engine systems are slated to increase. The trough technologies are well vetted, and have successful track records. MW-scale flat plate PV has been installed in prototype facilities. The following case studies are illustrative of some of the world's largest central station installations.

California SEGS plants demonstrate successful operation since 1985: Solar facilities comprised of 9 Solar Electric Generating Station (SEGS) plants in the California Mojave Desert, with a combined capacity

of 354 MW have been successfully producing clean energy since 1985. The plants, utilizing parabolic trough solar fields to collect the sun's radiation to drive conventional steam turbines, have a design life of 30 years, and all are still in operation today. Still the world's largest single solar installation, the plants are owned today by independent power producers (IPPs), and their output is delivered through PPAs (Power Purchase



Agreements). The plants were deemed Qualifying Facilities under PURPA. The successful launch of these plants was driven largely by some key policy incentives in place during the mid 1980s, including a 25% federal Investment Tax Credit (ITC), a 25% state ITC, property tax exemptions, and California PUC standard offer PPAs. The standard offers fixed rates, guaranteeing energy payments for 10 years at projected prices, energy payments for 20 years at utility avoided cost, and capacity payments for the full 30 years. Another key driver was the plants' ability to meet peak demand by utilizing fossil backup fuel to provide up to 25% of the heat for the steam turbines.

Large CSP projects are underway in Arizona and Nevada: Renewable Portfolio Standards (RPS) in both Arizona and Nevada have been key drivers in the launch of a 1 MW solar plant by Arizona Public Service, and a 64 MW IPP plant in Nevada. Both plants will utilize parabolic trough technology, and are planned for start-up in years 2006 and 2007, respectively. APS will be the owner and operator of the Arizona plant, while

Nevada Power will be the purchaser of the Nevada plant's output. In Nevada, another key driver to facilitate financing for the 64 MW plant was the passing of legislation that secured

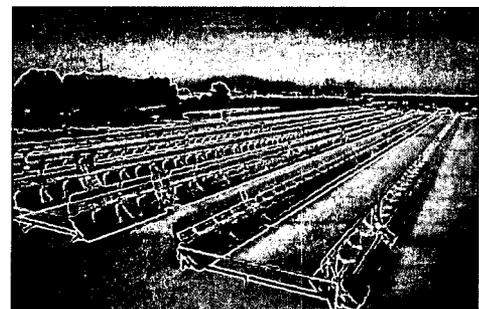


Fig. I-6. Final stages of installation of trough solar field at the 1MW APS

²⁰ See: [http://www.blm.gov/nhp/what/lands/realty/solar energy.htm](http://www.blm.gov/nhp/what/lands/realty/solar%20energy.htm) for valuable information

payment of the PPA terms independent of the utility financial condition.

Spain will launch large CSP deployments in 2007: In September 2002, Spain was the first European country to introduce a “feed-in tariff” funding system for solar thermal power. The feed-in law created a premium for solar kWh production, which was increased to 18 € cents/kWh in 2004 under Spanish Royal Decree, and guaranteed for 25 years, with annual adaptation to the average electricity price increase. This removed the concerns of investors, banks and industrial suppliers and launched a race of the major Spanish power market players to be among the first 200 MW. Currently, a total of 795 MW of solar capacity additions are planned for southern Spain, consisting of both parabolic trough and power tower technologies. The first production is expected in 2007, with additions of approximately 100 MW per year thereafter. The plants are being developed by IPPs, and will be dispatchable via thermal storage.

California utilities have just signed PPAs for energy from the world’s largest solar installation: Just this year, a Phoenix-based provider of dish-Stirling engine systems signed Power Purchase Agreements (PPAs) for two large solar power plants in Southern California. The first of these contracts is with Southern California Edison and purchases all the electricity generated from a 500 MW facility, with an option to purchase power from a 350 MW addition. The second is with San Diego Gas & Electric, for all the power from a 300 MW plant, with options for up to another 600 MW. The primary impetus behind these two contracts, which total up to 1,750 MW of solar power, is the 20% Renewable Portfolio Standard enacted in California. The requirement for such a large amount of renewable energy allowed the manufacturer to put together a large enough deployment program to achieve substantial economies of scale and automotive-scale mass-production efficiencies. The resulting bids for largely-peak power were deemed by the two utilities to provide the “Best Fit/Least Cost” renewable alternative offered under their RFP programs. Both projects are slated to start construction in 2008 or early 2009 and will start producing power soon thereafter.

The case studies above illustrate that CSP deployments can indeed allow the Western States Governors to meet their clean energy goals, while serving their economic growth needs and constraints, provided some key policies are in place. The key policies required to enable successful continuation of CSP deployments are recommended below. These measures are expected to have minimal impact on states’ treasuries, requiring few to no state incentives. In fact, they will support investments that will provide the states with positive and significant economic gain. The recommended policies will enable CSP plants to be built and those plants will increase your state’s tax revenues, create new jobs and increase your state’s GSP.

Renewable energy portfolio requirements also stimulated the 4.6-MW utility-owned central station photovoltaic prototype installation at the Springerville Tucson Electric Power station in eastern Arizona:

One of the largest PV systems in the world, it is still in the “distributed generator” size range in utility terms. Using conventional PV technologies, it powers the auxiliary loads at an existing fossil-fired generating station. The system consists of multiple independent arrays of about 2500 flat plate PV modules each. Their modularity allows PV generation plants to be purchased and built in phases, eliminating finance charges to significantly reduce their levelized cost of electricity. Tucson Electric plans to nearly double this system to 8 MW by 2010 and cites its pay-as-you-build aspect as a significant advantage. The Solar Task Force-recommended incentives for CSP technologies can also apply to such cash-financed PV systems.



Fig I-6. Springerville 4.6 MW flat plate PV plant

Policies and Incentives

Principles and Framework

As shown above, the cost of CSP electricity generation is expected to decline rapidly with increased deployment and a more favorable financial climate. In the near-term, however, Federal and State incentives are required to bridge the cost gap between CSP and competing technologies. In general there are a variety of incentives and policies that could be proposed to achieve closure. In order to identify the best incentives package, the Solar Task Force followed the following principles:

- The price point goal should be acceptable to the utilities, assuring the utilities of cost recovery and ensuring that CSP projects will be an attractive investment.
- Implementation of the proposed policies should be accomplished in a reasonable amount of time.
- The proposed policies should be structured to maximize their benefit to projects, ensuring their use and effectiveness.
- To the extent possible, and with insufficient time to implement new Federal policies, the proposals will build on existing Federal incentives and/or policies.
- Renewable Portfolio Standards and solar set-asides have strongly benefited CSP entry into the marketplace. This report, however, focuses on incentives, not mandates, to bring CSP to a fully commercial status.

Recommended Policies and Incentives

The full set of recommended policies and incentives includes:

Recommended Set of Policies/Incentives
<ul style="list-style-type: none">• Extend the 30% Federal ITC and expand its use to utilities• Exempt sales and property taxes on central solar plants• Allow longer-term Power Purchase Agreements and set equitable central solar price references• Encourage State PUC, utilities, and IPPs to seek means for aggregating plant orders and project bids to accelerate CSP scale-up cost reductions

- **Extend the 30% Federal ITC and expand its use to utilities** – The present 2-year 30% federal ITC needs a 10-year term to allow time to design, permit, finance, and build central solar plants. This is extremely important because it gives about a 3¢/kWh price reduction for CSP plants. Allowing utilities to use the ITC would further reduce the price by 1-2¢/kWh.
- **Exempt sales and property taxes on central solar plants** – This apparent loss to the State treasury will be off set by new tax revenues from activities caused by the central solar plants. For

example, the increase to the New Mexico treasury as a result of CSP deployment was estimated to be about ten times larger than the forgone taxes.²¹

- **Allow longer-term Power Purchase Agreements and set equitable central solar price references** – Encourage State PUC to extend the allowed PPA term to 30 years because a central solar plant can be viewed as a power plant with a guaranteed 30-year fuel supply at a fixed price. The price of this 30-year guarantee is the advance purchase of fuel in the form of a solar field. Given the significant private capital investment required for a central solar plant, it is essential that the appropriate framework be in place to both value and protect the investment. This provides the market stability needed for capital-intensive central solar development. The State PUC and utilities also should consider adopting target tariffs that reflect the value of central solar for peak periods and adjust for natural gas price changes.
- **Encourage State PUCs, utilities, and project developers to seek means for aggregating plant orders and project bids to accelerate CSP scale-up cost reductions.** – Some California utilities can issue bids for large CSP plants in the 500 MW range, but others may need to form consortia, or coordinate otherwise²², to aggregate CSP demand. Large orders are crucial to early-stage cost reductions. Without sufficient orders for CSP capacity, States may have to cover cost gaps with additional incentives, perhaps including a capital buy-down or a performance-based incentive such as a declining State production tax credit.

Loan guarantees have the potential of reducing both the interest rate and the equity return on investment, and therefore warrant further study. Definitions of these and related policies and incentives can be found in Appendix I-2.

Impact of the Recommendations on the Cost of Electricity from CSP

The incremental effect of each policy is shown in Table I-5. The Nominal LCOE is the metric that should be compared to the Target Price from above. The Real LCOE is shown for information only, as it is typically used to compare technology options by Federal agencies such as DOE. The estimates presented here are for a high solar resource site. The starting point is the current baseline Federal incentives and a 20-year Power Purchase Agreement with a utility. The specific policy measures are in bold print.

Parabolic trough technology was used to evaluate the current market competitiveness of CSP. The cost and performance assumptions are based on the U.S. DOE 2007 parabolic trough technology baseline system²³. The financial analysis was conducted by NREL and the results presented should be viewed as first order estimates of the cost of power and the relative effect of each policy presented. The analysis is based on NREL's current understanding of how each policy would be implemented into the financial proforma of a large commercial IPP or utility power project. The analysis begins with an IPP project and is later extended to utility financing.

²¹ "The Economic Impact of Concentrating Solar Power in New Mexico," University of New Mexico Bureau of Business and Economic Research, December 2004, comprising Chapter 7 in "New Mexico Concentrating Solar Plant Feasibility Study," Draft Final Report, Black & Veatch, for New Mexico Energy, Minerals and Natural Resources Department, February 2005. 2004 and (B&V NM report goes here when FHM finds it)

²² For example, Renewable Energy Credit (REC) trading between States may provide an aggregation avenue. REC trading: (1) allows CSP plant siting at the most advantageous regional resources; (2) encourages joint development and ownership of larger, more economic projects; (3) reduces transmission constraints in delivering renewable energy; and (4) promotes scale efficiencies by allowing multiple owners of the attributes without having multiple owners of the physical plant.

²³ The DOE 2007 parabolic trough technology baseline system is a stand-alone 100-MW Rankine steam cycle power plant with 6-hours of thermal energy storage, located near Barstow, CA (7.65 kWh/m²-day).

Table I-5. Financial Impact of Recommended Policies and Incentives

Nominal LCOE ¢/kWh	Analysis for Basic Set of Policy Incentives	Real LCOE 2005 ¢/kWh
18.3	(Baseline Federal Incentives, 20 yr PPA) ²⁴	13.3
17.5	Extend PPA to 30 Years	11.8
14.8	10-year Federal 30% ITC	10.0
13.3	Enact State Property Tax Exemption	8.9
12.8	Enact State Sales Tax Exemption	8.6
10.3	Extend Federal ITC to Utilities	7.0

It can be seen that after implementing the initial policy recommendations (30% ITC extension to 10 years, solar sales and property tax exclusions), the total cost (12.8¢/kWh) is still approximately 3¢/kWh above the desired price target (about 10¢/kWh). However, if utilities are able to take the 30% ITC and purchase and finance the plant directly, the cost of electricity is reduced to about 10.3¢/kWh. Utility purchase of power in large blocks, e.g., 500 MW, from project developers could bring similar reductions.

It remains, then, to evaluate the magnitude of the final two State incentives. This was carried out by assessing the level of solar firm capacity buy-down or the solar production tax credit that would be necessary to achieve the 10 ¢/kWh cost goal. The impact of the two tax credits is strongly influenced by plant ownership (project developer or utility) and deployment (early projects or after large deployment increments, e.g., 500 MW).

If any of the recommended set of Federal and State policies are not implemented, or the plants are developed in relatively small incremental builds, then the State will need to provide appropriate incentives such as a production tax credit or a buy-down. Either such incentive will decrease as CSP capacity grows, and disappear when up to 4 GW of additional CSP capacity have been installed.

Enabling Regulations and Actions

The following actions for the WGA region and States on regulatory and administrative steps are recommended to enable central solar plants after the incentives are in place.

- **Regional**
 - 1) Explore regional trading of renewable energy credits through the WREGIS system.
 - 2) Evaluate developing a standardized contract approach for central solar system procurement by utilities (perhaps through the WECC).
 - 3) Work with BLM more closely to standardize permitting on public lands.
 - 4) Evaluate standardization of other permitting requirements among States.
 - 5) Form via the WGA a CSP Task Force of utilities and State energy offices to address issues and approaches
 - 6) Create new education and awareness campaigns
- **States**
 - 1) Form Task Forces to evaluate in-state issues, benefits, and impacts of deploying CSP systems, including electric transmission
 - 2) Identify in-state incentive packages (such as mechanisms to allow above-market central solar plant PPAs) and work with regulators to identify implementation
 - 3) Develop policies and/or legislation to support the defined approach
 - 4) Create new education and awareness campaigns

²⁴ Baseline IPP Project with 20-year PPA, 10% Federal ITC, 5-year MACRS accelerated depreciation.

- **Federal**
Significant opportunity appears to exist for cost reduction through continued research and development both nationally and in the western states. R&D conducted in the U.S. is more likely to address the needs of U.S. power markets and is more likely to develop U.S. industry. Experience has shown that European R&D has helped improve CSP technologies over the last 15 years, but tended to build European industrial capacity.
- **Development of Large Solar Power Projects (~500 MW)**
As previously indicated, the cost of power from CSP technologies is expected to decline over time as more plants are built due to learning and project scale-up. One of the most effective ways to facilitate learning and benefit from scale-up is to encourage the development of large, multi-unit power plants. As an example, significant cost savings are believed to be possible by building, for example, five 100 MW plants over a period of five years at a single site instead of a single standalone 100 MW plant. The cost reduction occurs in all phases of the project from project development, common facilities and infrastructure, improved competitive procurements, labor learning, and O&M. The larger build will also have a more sustained positive economic impact on the local community. For example, for parabolic trough technology, a 5-year project of this size would potentially justify the building of a local factory for manufacture of receivers and mirrors, components currently imported from outside the US. For purpose of assessing the value of a solar power park development, it is estimated that a 10% reduction in the capital and O&M cost can be achieved over a single standalone power project.
- **Hybridization and Solar Co-firing**
Hybridization of solar typically means that the plant can operate either from solar energy or from a backup fossil fuel source. Current Public Utility Regulatory Policy Act (PURPA) rules allow solar plants to use up to 25% fossil input to the plant. Hybridization provides the ability to dispatch power as needed, even with low solar radiation. The ability to hybridize a solar plant is seen as important to utilities participating on the Solar Task Force, although the current PURPA rules, which do not distinguish between the solar and fossil-fueled plant outputs, are problematic in times of relatively low-priced gas. Given the 9.6¢/kWh price target and the likely higher future cost of natural gas, it is unlikely that a hybrid solar plant would burn natural gas unless it was necessary to firm up on-peak generation.

There are also existing fossil (or other) power plants that could be co-fired with solar energy. The solar contribution may range from a small to relatively large percent of the total electric generation. Often these solar co-firing opportunities represent some of the least expensive opportunities for increasing solar electric generation and offsetting conventional fossil generation. It is desirable that all incentives presented above are also made available to the solar co-fired portion of such plants and their output.

Conclusions for Central Solar Plants

- The solar resource in the Southwest is very large. Of particular note, the prime solar energy resource potential in the seven States is 200 GW, and there is ample highly suitable land to support large-scale CSP development.
- CSP technology is proven, and it can provide firm dispatchable power to meet peak power demands. The CSP industry estimates that a total plant capacity of 13.4 GW could be deployed for service by 2015, which equals about 30% of the growth in peak regional demand.
- The cost target for CSP, based on gas-fired plants, is slightly under 10¢/kWh in 2015. When up to 4 GW have been installed, the cost of electricity from future CSP plants is expected to be on a par with plants burning natural gas.
- The economic benefits that would accrue to the States from development of their CSP resources are large enough to add a significant new engine in those States' economies. Using California as an example, building 4 GW of CSP plants in that state will inject, relative to installation of gas-fired

plants, over \$22 billion into the gross state output, approximately 13,000 construction jobs and 1,100 permanent operation jobs, and an additional \$2 billion to tax revenues.

- The major barrier is current higher capital cost. Policy and regulatory measures create opportunities to reduce and/or remove barriers.
- The most important Federal policies for central solar are extension of the recently passed 30% Federal Investment Tax Credit to 10 years and allowing it to be used by the utilities.
- The most important State policies are property and sales tax exemptions for central solar plants and 30-year PPAs with a capacity payment. These actions are expected to have minimal net cost impact on the State treasuries. The apparent loss to the States will be offset by new tax revenues from activities caused by the CSP plants.
- If the above policies are enacted, and if CSP plants can be constructed in 500 MW increments, additional State incentives may not be required.

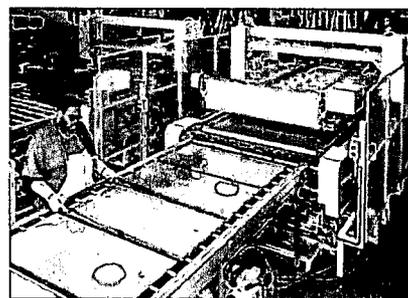
Part II. Distributed Solar

Summary

Distributed solar technologies present an opportunity to enroll businesses, schools, governments and millions of homeowners to contribute individually and collectively to the region's energy security and supply, taking actions that have the potential to benefit the entire West while helping to diversify and hedge the sources of supply needed to meet the West's energy needs.

If the region moves ahead aggressively implementing programs to promote solar, we estimate²⁵ that by 2015:

- An additional 4,000 MW of distributed solar PV could be installed²⁶
- At least 500,000 solar thermal water heating systems could be installed, providing the equivalent of 2,000 MW_{th} of generating capacity and saving almost 15 billion cubic feet of natural gas per year
- Approximately 5 to 6 million megawatt-hours of electricity annually will be contributed to the region's energy needs, shaving approximately 5 percent off of the West's growth in peak energy demand over the next ten years
- Between 4 and 4.8 million metric tons of CO₂ emissions can be avoided annually, the equivalent of taking over a million cars off the road
- Between 2.2 and 5.0 million gallons of water per day would be saved depending on the type of power displaced, enough to supply between 7,000 and 14,000 homes
- 15,000 high-quality jobs will be added in the region
- And hundreds of thousands of homeowners and businesses will be provided with an important energy option.



Increased demand for solar systems can drive expanded manufacturing in the region, bringing with it thousands of high-paying jobs

No major physical or technical barriers stand in the way of widespread adoption of solar; the major impediments are in the realm of economic and public policies. One hurdle for consumers is that costs are heavily front-loaded – much like paying cash for a car all of the fuel needed to run it for 25 years included in the sticker price. A number of inconsistent public policies around interconnection and metering exist as well. As a result, while the number of installations has been rapidly growing in recent years, the industry is still very much in its infancy. Experience in the West and around the world has demonstrated that economic stimuli and policies that encourage easy adoption of solar can be effective in accelerating demand and driving down costs. Adoption of the right policy framework could create the environment where the investment in solar technologies will be one that is cost positive for consumers.

²⁵ See Appendix II-1 for detailed description of the methodology behind these estimated benefits.

²⁶ The 4000 MW target was set based on growth in the WGA states averaging 32% annually over the next decade on the assumption that the WGA states take strong policy actions to encourage the growth of distributed solar technologies. However, it is a reasonable estimate of the capacity of the PV industry to grow in the WGA states over the next decade under solar-friendly policies and is in line with both historical growth rates of the PV industry during the past decade (see Strategies Unlimited, *Photovoltaic Manufacturer Shipments 2004/2005*. Report PM-57. 2005, and Maycock, Paul. 2005. *PV News*. Vol. 24, No. 3 and 4. PV Energy Systems, Warrenton, VA), and projected growth rates by the U.S. PV industry over the next decade (see Solar Energy Industries Association, *Our Solar Power Future: The U.S. Photovoltaic Industry Roadmap Through 2030 and Beyond*, 2004).

Central to our recommendations that the Governors should pursue is the extension of the 30 percent Federal tax credit for a total of ten years. Congress should also be encouraged to lift the \$2000 credit cap on residential systems, providing homeowners with the same incentive as businesses to size systems appropriate to their energy needs. These modifications provide an unprecedented opportunity for the Governors to leverage state solar incentive funds. Though the Federal tax credit is not sufficient to drive solar on its own, it can greatly reduce the allocation of state or ratepayer funds necessary to ensure a rapidly expanding solar market. In addition, while individual homeowners and businesses can take advantage of this credit in 2006 and 2007, the lack of a long-term program is a major disincentive for suppliers to invest in expanded manufacturing capacity. These investments are necessary to ensure continued cost reductions that will eventually eliminate the need for subsidies while providing a source of high-paying jobs in the region. Finally, Federal and state recognition of the value of renewable technologies through the establishment of programs and incentives has proven to be a powerful stimulus for prospective purchasers of solar systems.

Beyond the Federal tax credit, this report covers a wide range of policy and program options from which the Governors can select the ones most appropriate for their states' circumstances. All are based on programs already in operation in one or more WGA states. To date, the most effective programs to stimulate solar installations have been to:

- Use **economic incentives** to mitigate the capital-intensive nature of solar, encouraging homeowners and businesses to invest their capital in systems, driving demand that ultimately results in increased production and lower costs. The most popular programs are:
 - ▶ Declining up-front rebates to underwrite the cost of installing systems
 - ▶ Ongoing performance-based incentives, paying system owners only for the electricity they actually generate
 - ▶ Access to low-cost capital, enabling building owners to repay loans out of the savings on their electricity bills
 - ▶ Exemption from state and local sales and property taxes, further reducing the upfront capital costs and ongoing expenses associated with these systems.
- Adopt policies to **remove barriers** to the easy installation of solar. These simple initiatives can pave the way for individual action by homeowners and businesses:
 - ▶ Simplified interconnection standards that enable easy access to the grid.
 - ▶ Solar access laws that ensure that local governments and homeowners associations can't enact rules that restrict the installation of solar systems.
- Enact programs that encourage solar system owner-generators to **optimize their solar energy production**:
 - ▶ Encourage utilities and/or regulatory bodies to offer optional time-of-use electricity rates that reward generators for maximizing the output of their solar systems during high-value peak periods.
 - ▶ Provide net metering, a simple way to account for the net amount of electricity generated and used by building owners with solar electricity systems.
 - ▶ Facilitate ownership of Renewable Energy Credits (RECs) as well as the ability of owner-generators to exchange these RECs in open markets to help states meet renewable or environmental portfolio standards.



Solar systems can be installed on homes in aesthetically pleasing ways, particularly in new home construction

- Demonstrate leadership through **state purchases** of solar energy and **public education**:
 - ▶ States can send a clear signal to their citizens about the long-term economic and environmental benefits of distributed solar by purchasing systems for state buildings.
 - ▶ Use public education and awareness program to inform homeowners and businesses about the costs, benefits and technology options available to them.



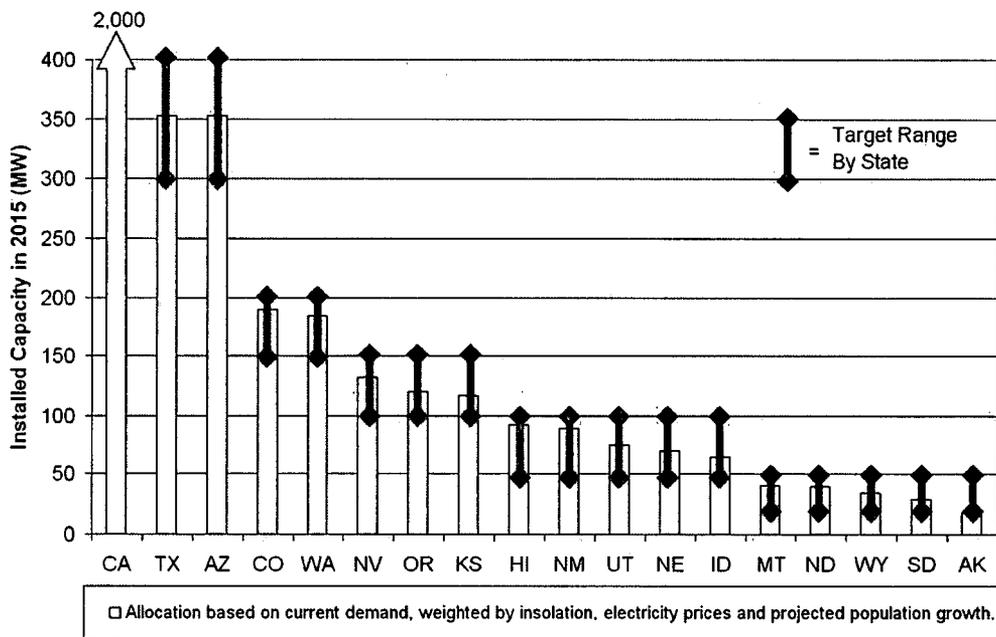
Solar parking lot canopies, such as this one at Cal State Northridge, are highly visible signals to consumers about the benefits of solar

Solar Works in Every WGA State

One of the greatest attributes of distributed solar is that every state can take advantage of its benefits. While the Southwestern states and Hawaii clearly enjoy greater solar resources than states farther north, solar electricity, solar water heating systems and solar space heating and cooling systems will deliver valuable renewable energy throughout the West. While the solar resource in Portland and Seattle is 60% of the solar resource in Phoenix, two-thirds of the Northwest receives as much or more direct sunlight as Florida. Even the rainforests of the Olympic peninsula receive as much sunlight as many areas in Germany and Japan – the two countries with the vast majority of the world’s solar photovoltaic installations and among the world’s leaders in solar thermal (water and space heating) installations. Over 20,000 solar water heating systems have been installed in Oregon since 1978, for example, showing that solar can thrive in any climate when barriers are removed and the right level of incentives is used to drive demand. That demand, in turn, can fuel a cycle of declining prices and expanding markets.

Based on current demand, weighted by the amount of sunshine, electricity prices and projected population growth, we believe that each state will be able to make a meaningful contribution to the region’s energy needs through the installation of distributed solar systems.

Figure II-1. Weighted Allocation of Installed Capacity in WGA States (Total = 4GW in 2015)



Source: NREL

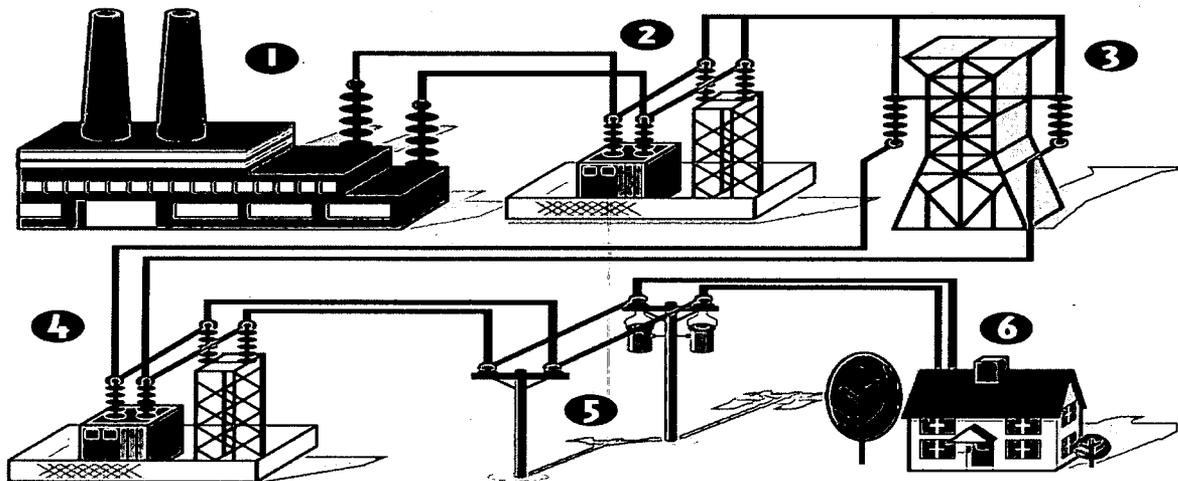
Distributed Solar Benefits All Ratepayers

- Power is most often produced during critical peak hours
- Power is produced on-site, avoiding line losses, reducing the strain on the transmission and distribution systems, and potentially deferring the need for new distribution and transmission investments

Distributed solar offers many unique and valuable contributions to the economic health of the region and to the stability of the electricity and natural gas distribution systems. However, two broad categories stand out. First and foremost, while each state may have different peak load and system performance characteristics, solar PV systems are often most productive during peak hours – including the time when demands on the electrical grid can be the greatest.²⁷ This reduces peak electricity demands, resulting in lower peak energy costs and lower price volatility for all consumers. Furthermore, reducing demand for peaking power lowers demand for natural gas, keeping gas procurement costs down. Second, because generation is located at or close to the point of use, a number of benefits can accrue to the entire grid. Reduced line losses help the grid to operate more efficiently, security concerns are lessened, and over time upgrades to the transmission and distribution systems may be mitigated, potentially deferring investment capital.

Figure II-2 demonstrates the steps involved in transmitting power generated at a traditional power plant to the end user. When PV systems are operating, typically during peak electricity demand periods, they provide electricity on site for the PV owner and bypass stages 1 to 5. Although these stages cannot be eliminated since most residents and businesses require electricity 24 hours a day, the strain on these systems during peak periods could be reduced substantially with widespread PV application.

Figure II-2. Schematic of the Electric Power Grid



When electricity leaves a power plant (1), its voltage is increased at a "step-up" substation (2). Next, the energy travels along a transmission line to the area where the power is needed (3). Once there, the voltage is decreased or "stepped-down," at another substation (4), and a distribution power line (5) carries the electricity until it reaches a home or business (6).

Source: Edison Electric Institute, *Key Facts: A Look at the Electric Power Industry*

²⁷ See Appendix II-1 for a more detailed description by NREL of the region's effective load-carrying capacity (ELCC) – the relationship between the load shape and the resource availability (insolation) in a particular area.

Distributed solar thermal systems also reduce electricity or natural gas consumption at the point of use. Reduced electricity consumption through the use of solar thermal systems is functionally identical to the production of electricity during those same periods, and this potential is further available through the newer solar space heating and solar cooling technologies coming to market. Reduced natural gas consumption translates into more natural gas available for electricity generation and industrial use.

There is a wide range of economic and environmental benefits from distributed solar photovoltaics. The most significant of these are in avoided costs for natural gas for electricity generation and for capital costs to build new plants. Recent studies of the California market indicate a potential for a variety of other benefits, including the value of avoided T&D losses, avoided CO₂ and NO_x emissions, avoided water usage, and many others.²⁸ The California Public Utilities Commission is currently considering which of these are appropriate to include in a formal cost-benefit analysis of its existing subsidy program and how best to calculate the impact of those that are included. Regardless of which are ultimately deemed appropriate to include and at what level, enacting programs that have the effect of reducing costs will ultimately improve net benefits.

Similarly, small-scale solar thermal technologies have both environmental and economic benefits, particularly when systems are used to offset the consumption of electricity or natural gas²⁹, which along with propane are the primary water heating energy sources used in the WGA states. In many areas in the West, natural gas is used almost exclusively for water heating applications in new construction.

Society Benefits from Distributed Solar Energy

- **Jobs**
- **Healthier environment**
- **Keeps money in region**
- **No water is consumed**

In addition to ratepayer benefits, there are a series of advantages that accrue to society at large. First, developing a distributed solar industry can help to build local and regional economies by creating high-paying local manufacturing and installation jobs, thereby increasing state and local tax revenues. A healthy, growing solar industry, installing solar products that convert indigenous solar resources into usable energy, can have the added advantage of converting into local contracting and manufacturing jobs those dollars that would otherwise be sent out of state or out of the country for the importation of fossil fuels. According to a recent study by researchers at the University of California, Berkeley, the solar industry currently supports 33.25 installation and manufacturing jobs for every megawatt installed³⁰ – more local jobs per MW than any other energy technology³¹ – so the employment leverage offered by an expanded solar market can be substantial. In addition, there is a wide range of environmental benefits, such as reduced use of scarce water resources and avoided emissions of greenhouse gases and other pollutants that further contribute toward the WGA's objectives in its energy program.³²

²⁸ Severin Borenstein, *Valuing the Time-Varying Electricity Production of Solar Photovoltaic Cells*, Center for the Study of Energy Markets, University of California Energy Institute, March 2005; and Ed Smeloff, *Quantifying the Benefits of Solar Power for California*, The Vote Solar Initiative, December 2004

²⁹ US Department of Energy, Energy Efficiency and Renewable Energy Solar Energy Technologies Program, *Solar and Efficient Water Heating*, 2005.

³⁰ Virinder Singh, *The Work That Goes Into Renewable Energy*, Renewable Energy Policy Project, 2001.

³¹ Daniel M. Kammen, *Putting Renewables to Work: How Many Jobs Can the Clean Energy Industry Generate?*, Goldman School of Public Policy, UC Berkeley, 2005

³² See Appendix II-1 for NREL's detailed analysis on reduced water use and greenhouse gas emissions.

What Will It Take to Enable Solar Technologies to Make a Meaningful Contribution to the Region's Energy Needs?

There is a common misconception that solar is too immature to make a meaningful contribution to the region's energy needs. In fact, both the solar photovoltaics and the solar thermal (space and water heating) markets are already substantial. In 2004, over \$7 billion of PV systems were sold worldwide, and solar thermal sales are approaching \$5 billion per year. PV industry leaders include multinational corporations from traditional energy (BP Solar, Shell) and electronics (Sharp, Kyocera) industries, many of whom have manufacturing facilities in the U.S. Growth in the industry has also been enviable by most industries' standards. Over the past eight years, sales of PV systems have grown an average of 31% annually and solar thermal systems 20% annually, and most analysts expect these rates to continue for the foreseeable future. Solar heating and cooling, although new to the U.S. market, is prevalent in the European Union and is projected to continue to grow. The European Renewable Energy Council is predicting that, for the European Union, renewable thermal cooling and heating can achieve 25% of the total cooling and heating demand by 2020.

Despite this phenomenal growth, the industry still represents less than one-tenth of 1% of the electricity generated in the West, and the US share of those robust global markets is declining markedly. Many thoughtful observers have noted that solar is an industry ready to explode. So what can the current programs in the West and around the world tell us about what we need to do to make that happen? What are the roadblocks we need to clear and the catalysts we can employ to encourage energy consumers to make the levels of private investments in distributed solar needed to help meet the Governors' goal of 30,000 MW of clean energy?

There are No Physical or Technical Barriers to Market Entry

- **Plenty of sunshine**
- **Plenty of roof space**
- **New technologies are providing competition that will ensure continuing decline of average system prices**

Much of what we need to make this happen is largely in place. First, there are no physical barriers to achieving our goals. We have an abundant natural resource in sunlight – indeed some of the best in the world. The maps below³³ indicate the amount of solar radiation in the US annually (left) and during August (right). The annual map indicates the potential for significant year-round contributions from at least ten WGA states. However, in the height of summer, when the grid is straining to meet regional

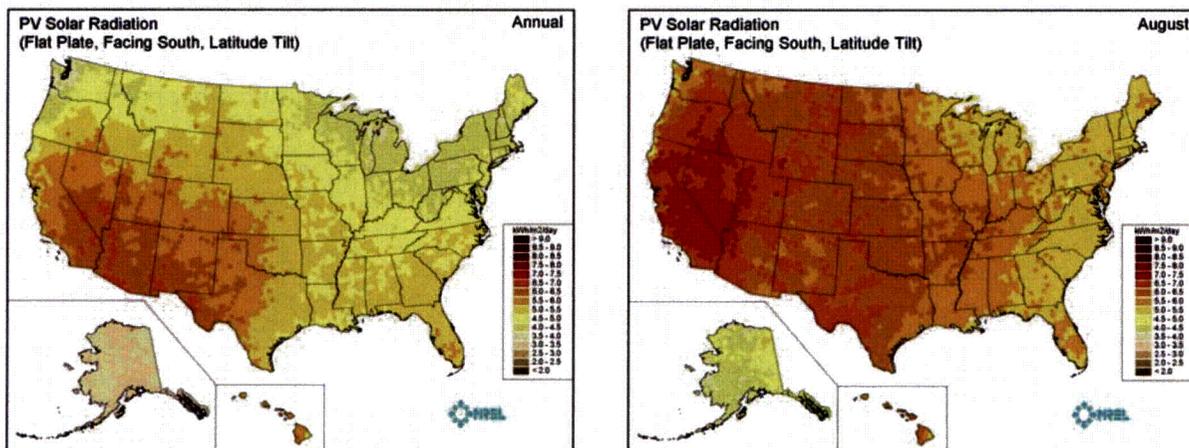


Figure II-3. Solar radiation in the US annually (left) and during August (right).

³³ See http://www.nrel.gov/gis/solar_maps.html for detailed maps and an explanation of how they were derived.

electricity needs, every WGA state is in a great position to contribute to the total requirements through distributed solar. By comparison, if one were to plot on this same scale the solar resource in Germany and Japan (which together are home to the vast majority of the world's solar PV installations), their maps would look like the northwest corner of Washington State in most areas of their respective countries.

There is also ample roof space available for distributed solar installations. In September, 2004, the Energy Foundation and Navigant Consulting released a detailed study estimating by state and building sector (residential, commercial, etc.) the amount of roof area appropriate for installing solar.³⁴ Even after eliminating 78% of residential roofs for such factors as steep angles or improper orientation and 35% of commercial roofs for structural inadequacy, shading and the like, approximately 22 billion square feet of roof space in the WGA states appear appropriate for use by solar systems. Although neither recommended nor even realistic, it is interesting to note that the entire 30,000 MW of clean generating capacity sought by the Governors could be generated by less than 18 percent of the available and appropriate roof space. Clearly lack of spots to site solar systems will not be a constraining factor.

In addition, in most areas of the West there appear to be no major technical barriers to success. While additional R&D, largely through federal and private investment, will be needed to uncover the technical advancements that will further drive the industry, existing technologies are ready for market now. Current PV systems already work exceptionally well. Panel failures are extremely low (nearly all manufacturers guarantee their products for 25 years), and the inverters that convert DC power from the panel to usable AC power usually last five to ten years before needing replacement. Given that most of these systems have not been in the field for anything close to their expected lifetimes, many utilities and industry groups are watching the performance of panels and inverters carefully and may have further recommendations for improvements in the coming years.

Solar water heating systems are also typically reliable. The Solar Rating & Certification Corporation and the Florida Solar Energy Center have equipment certification protocols that address collector and system design and performance. Several electric utilities are involved in highly successful solar water heating programs, demonstrating that properly designed programs lead to highly reliable solar energy systems. The Utility Solar Water Heating Initiative (USH₂O) is an electric utility/solar industry collaborative which now counts nearly 30 utility members from across the US, as well as 45 other solar industry, state government and utility commission members, all of whom are working towards developing additional effective and reliable utility-based solar water heating programs.³⁵ As an example, Hawaiian Electric Company's Energy Solutions Solar Water Heating Program has grown to over 3,000 systems per year since its inception in 1996.³⁶

In recent months, there has been a worldwide shortage of PV panels due to the dramatic increase in demand from Germany, leading to a modest reversal of the decades-long trend of declining prices of modules. Exacerbating the problem has been revived growth in the semiconductor industry, which relies on the same highly pure silicon feedstock as its base semiconducting material. There is consensus among manufacturers, however, that these shortages are temporary, and every major manufacturer is bringing on new production lines and/or expanding capacity at existing facilities over the next year. Despite these increases in module costs, overall system costs have continued to decline, according to rebate applications filed with the California Energy Commission's Emerging Renewables Program³⁷.

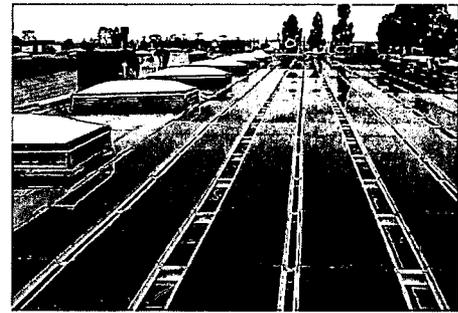
³⁴ Maya Chaudhari, Lisa Frantzis, and Tom Hoff, *PV Grid Connected Market Potential Under a Cost Breakthrough Scenario*, The Energy Foundation and Navigant Consulting, September 2004. Report can be downloaded at <http://www.ef.org/documents/EF-Final-Final2.pdf>. Also, see Appendix II-1 for NREL's detailed analysis on rooftop PV potential in the WGA region.

³⁵ See: <http://www.eere.energy.gov/solar/ush2o/>

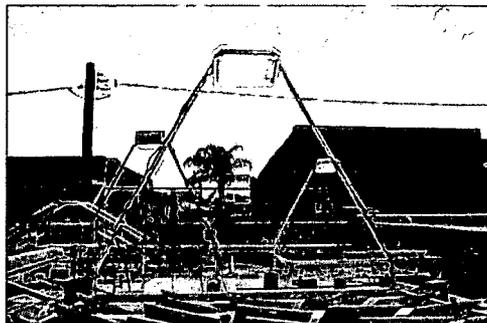
³⁶ <http://www.heco.com/CDA/frontDoor/>

³⁷ See http://www.energy.ca.gov/renewables/emerging_renewables/2005-11-02_post_1_1_2005_update.xls

Further, there are a number of new PV technologies recently on or soon to be introduced to the market that are designed to provide competition for the traditional, silicon-based PV cells and modules. This competition has come from two basic directions. The first group of companies is developing new semiconducting materials to replace or expand on the silicon in PV cells. In addition to the considerable expense of the silicon feedstock itself, the manufacturing process that turns it into a PV cell is difficult and expensive. There are two paths being pursued. One involves somewhat less efficient but substantially less expensive PV material not based in silicon wafers, such as thin-film PV (so called because ultra-thin photovoltaic material is deposited on an inexpensive material such as glass or plastic) and other new materials.³⁸ The other involves somewhat more expensive but substantially more efficient semiconductors, such as multi-junction cells (named as such because they involve layering of different materials, each of which responds to a different wavelength of light, into a single cell). Products based on these materials are already on the market, and new designs are emerging on a regular basis.



New thin-film PV material is incorporated into panels and installed atop the City of San Diego Miramar Operation Center



Rooftop solar concentrator eliminates 95% of the silicon-based PV material required to produce a given amount of energy

The second group is focused on more mechanical solutions. Here again, there are two distinct areas of effort. One involves process improvements in manufacturing PV cells that would result in less semiconductor stock (often silicon) being used. The other is to find clever approaches to concentrating light that would enable a lot less of the expensive PV material, silicon or otherwise, to be used for a given amount of electrical output.

All of these new efforts have the ultimate goal of dramatically reducing the cost of power generated by PV systems. There are trade-offs, to be sure. For example, many of the new-materials technologies such as thin film PV are currently less “area efficient” than silicon PV (meaning they take up more roof space to produce the same amount of output). For many building owners, however, trading additional roof space for a lower price and quicker payback is a worthwhile compromise. For others, the traditional systems are more suited to their needs.

This growing number of options, which are emerging precisely because of the various market-stimulating incentives being offered around the world, can be expected to produce at least two major market effects. At minimum, these new technologies can reduce the pressure on silicon-based photovoltaics to meet the entire growth in demand for distributed solar electricity systems. That in turn will lessen demand for the underlying silicon feedstock and reduce upward pressure on silicon prices. The advent of new module technologies will also ensure that there are sufficient modules available for programs like the ones proposed here, no matter how substantially the PV market grows as a result of its widespread adoption. Even more importantly, new options will provide intense competitive pressure to ensure that prices for all systems will continue to decline and reach ambitious competitive cost levels as the market matures.

This emerging market in new, clean energy technologies has also caught the attention of the mainstream venture capital community. In the first nine months of 2005 alone, over \$100 million in investment capital³⁹ has poured into early-stage companies pursuing thin-film, nanomaterial, solar concentrator and

³⁸ For an analysis of the costs, efficiencies and potential for thin-film PV to meet energy needs, see Ken Zweibel, *The Terawatt Challenge for Thin-film PV*, NREL Technical Report NREL/TP-520-38350, August 2005, <http://www.nrel.gov/docs/fy05osti/38350.pdf>

³⁹ CleanEdge, Venture Power, Dow Jones' *Venture Wire* and other industry reports.

manufacturing technologies, among many others. Several solar companies have also gone or are in the process of going public in 2005. Major financial analysts, including CLSA Asia-Pacific Markets and Piper Jaffray, regularly issue extensive reports covering the solar industry and its key players. Clearly the industry – and the financial community’s interest in it – is expanding rapidly.

Additionally, given high rates of growth in many areas in the West, home developers who are building zero-energy homes and/or integrating solar systems into new home construction can make a meaningful contribution to reducing overall growth in demand for new generation capacity. Builders can take advantage of cost efficiencies inherent in designing solar electric and solar water heating systems into new developments, and home buyers can finance these improvements through minimal increases in their home mortgages offset by lower utility bills, yielding a net reduction in their living expenses from the moment they move in. Indeed, many top builders and developers, including KB Home, Pardee Homes, and Ladera Ranch, among others, are integrating solar systems into their offerings in response to consumer demand.

Public Policies Around Solar Economics Make the Difference

The remaining challenges are all in the realm of economics and public policy, representing major opportunities for the Governors to take a lead in recommending and adopting the programs that will clear the way for solar to make a powerful contribution to the region’s energy supply. In this regard, much can be learned from successful programs in other countries as well as throughout the Western states. Most of these were designed to get over the one significant hurdle standing in the way of widespread adoption of solar – its current economics. In various ways these countries or states provided sufficient financial incentives to homeowners or businesses to enable their investments in solar to be cost-effective. In the process, they created vibrant economies around manufacturing and installing systems and drove down the cost of systems as a result of increased manufacturing and installation efficiencies and the impact of competition.

The first major set of policies designed to stimulate the development of a solar PV industry was initiated in Japan. Starting in 1994, consumers were provided up-front subsidies to purchase systems for their homes. Incentives were specified over a ten-year period and on a declining scale, providing manufacturers with the market certainty they needed to make investments in plants and equipment. The program was by all accounts successful in meeting its objective. Today, Japanese manufacturers dominate the industry with a 48% worldwide market share in modules, and the Japanese market was until 2004 the largest in the world. The result is a self-sustaining solar energy industry that continues to add clean energy to the grid through the private investment of home and business owners. It is noteworthy that while the federal government is ending the residential subsidy program this year, it is considering embarking on a new program to encourage broader commercial adoption of solar.

Germany took a different but no less successful approach. Motivated by both environmental and economic-development considerations, the government established a “feed-in tariff,” guaranteeing the purchase of whatever energy was produced from a PV system over a twenty-year period at a substantial premium. With that level of certainty and incentive, the market has exploded. In 2004 alone, over 350 MW of solar were installed, edging out Japan for the first time.

California, the third-largest solar PV market in the world, adopted a program similar to Japan’s. Combining net-metering laws and interconnection standards with up-front incentives and waivers from a number of costs have encouraged homeowners and businesses to respond in ever-growing numbers. Indeed, during 2005 the various incentive programs offered by the California Energy Commission and the California Public Utilities Commission have been fully subscribed and in some cases vastly over-subscribed. Realizing the latent demand for and potential benefits of solar, Gov. Schwarzenegger has

proposed a series of initiatives designed to stimulate 3,000 MW of distributed solar over the next 13 years (through 2018) and has supported legislative and regulatory initiatives to reach this goal.

European countries have also instituted a series of very successful incentive programs for solar water and space heating systems, enabling them to make significant progress and poising them for continued growth. Incentive programs are quite modest in countries with the most active solar water heating programs with rebates ranging from \$300 to \$1400 per system depending on size. Many of these countries have substantially less solar resource than that available in the Western US, yet they have more aggressive solar thermal programs. A subset of seven European Union countries⁴⁰ together installed approximately 250,000 solar thermal systems in 2003, or 875 MW_{th} equivalent.⁴¹ Austria alone (population of 8.1 million) has an existing installed solar thermal generating capacity of 1,469 MW_{th}, equal to all of the installed solar thermal capacity in the entire US (population 294 million). Israel, with the population roughly equivalent to Arizona, is home to 5 percent of the world's solar water heating deployments. By contrast, the US solar thermal market for water heating has been stagnant for a number of years at around 8,000 systems.

WGA States Have Already Taken the Lead

California's efforts have already resulted in over 93⁴² megawatts of grid-connected solar PV installations throughout the state, but it's not alone. Other Western states have also taken the lead in identifying and eliminating barriers to solar utilization and have adopted programs to provide financial support for solar technologies. Arizona, New Mexico and Nevada have provided system owners with up-front help in the purchase of solar systems similar to successful programs in Japan and California, and the State of Washington recently passed a feed-in tariff akin to the one that worked so well in Germany. Hawaii and Oregon have in place tax incentives that are similar in nature to the Federal incentive.

About half of the Western states – representing far more than half of the population in the West – have adopted Renewable Portfolio Standards (RPSs) in which targets are set for the amount of electricity generated by a given date that must come from renewable sources. A number of Western states have enacted specific policies to use RPSs to advance solar. While most often associated with encouraging utilities to contract for the output of large-scale central-station solar facilities, several states have also used their RPSs to promote distributed generation as well. Nevada has a set-aside requiring that a minimum subset of the total RPS come from solar and a 2.4 multiplier for distributed applications. Arizona is revising its Environmental Portfolio Standard to include a 30 percent distributed resources set-aside. In Colorado, the voters recently passed a ballot initiative enacting an RPS. It requires that a certain percentage come from distributed solar and includes a minimum rebate (\$2 per watt) to help accomplish this. New Mexico's RPS includes triple credits to advance solar technologies. One utility in California (SDG&E) has a separate solicitation to advance distributed PV. And the California Public Utilities Commission has indicated that solar renewable energy credits (RECs) belong to the owner operator, which provides another avenue for distributed solar system owners to participate in RPS programs. Several of these individual states have adopted mechanisms for the inclusion of solar thermal technologies in their RPS programs as well.

The following table, prepared by NREL, catalogs the many efforts underway throughout the WGA states. The full document detailing each of these programs is included in Appendix II-1.

⁴⁰ Austria, France, Germany, Greece, Italy the Netherlands and Spain

⁴¹ Solar Heating Worldwide; Markets and Contribution to the Energy Supply 2003 IEA Solar Heating and Cooling Programme, May 2005; Appendix 6, pg. 25 “Annual Installed Capacity”

⁴² 46 MW installed under the CEC's program and 26 MW under the CPUC's SGIP program. Remainder installed by Sacramento Municipal Utility District, Los Angeles Department of Water and Power, and other small municipal utilities. Internal CEC document provided by Bill Blackburn.

Table II-1. Overview of PV Related Policies in the WGA States.

State	Net Metering	RPS	Rebate/Buy-down Program	Production Incentive	Low-interest Loans	Tax Incentives	System Benefit Charge	Total
CA						Pe, Pr, C		8
OR						Pe, Pr, C		8
MT						Pe, Pr, C		7
NV		+++				Pr, S		6
AZ		+++				Pe, S		5
TX						Pr, C		5
WA						S		5
CO		+++						4
HI						Pe, C		4
ID						Pe, S		4
UT						Pe, C, S		4
ND						Pe, Pr, C		4
NM								3
WY						S		3
AK								1
NE								1
KS						Pr		1
SD						Pr		1
Total	12	7	5	5	5	29	3	

Notes:

Tax Incentive Abbreviations: Pe=Personal Pr=Property C=Corporate S=Sales.

Policy and Incentive data is based on DSIRE as of August 2005 (<http://www.dsireusa.org/>). Income tax credit in California expires at the end of 2005.

Production Incentives do not include the Federal Conservation Security Program which applies to all states.

 Not implemented state-wide.

 Solar set-aside included within RPS.

Key Policies and Programs to Enable Solar to Succeed

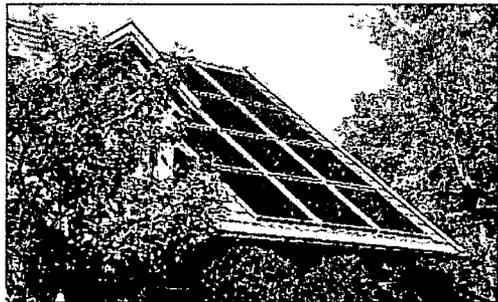
- **Provide financial incentives to encourage private investment in solar systems**
- **Remove barriers to the easy installation of solar**
- **Implement programs that encourage solar system owner-generators to optimize their solar energy production**
- **Demonstrate leadership through state purchasing and public education programs**

From among the successful programs throughout the West, we have identified a number of policies, programs and operating principles that have proven invaluable in cultivating a viable and growing market. In many cases, these can be accomplished through executive or administrative actions and have little or no impact on state revenues. Each state is unique in its needs and interests, and each Governor will undoubtedly find some more appropriate than others for his or her state. Further, by leveraging the new federal solar tax credit of 30 percent of system costs, many of these programs are now highly affordable. The most critical programs to consider are covered below. A more detailed table of options can be found in Appendix II-1.

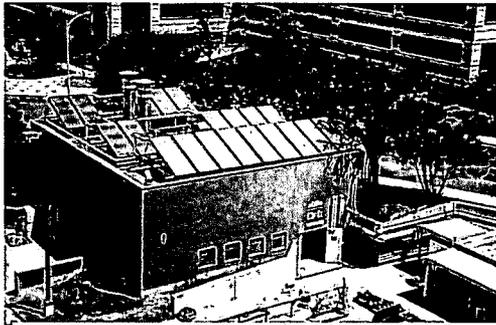
Provide Financial Incentives to Stimulate the Market

Once the path has been cleared for easy installation of solar technologies, consumers often face a substantial economic hurdle to purchasing these systems. While the price of solar PV has come down substantially in recent years, the payback period is still long in most areas, making it difficult for most homeowners and businesses to justify the investment. The Federal government has done its part to reduce the cost of solar technologies by enacting a 30 percent tax credit for commercial and residential applications starting in 2006. For those states that wish to leverage the federal tax credit and stimulate local markets – to develop local manufacturing and installation industries and to accelerate experience that further drives down prices – incentive programs may be appropriate. General state revenues can be used to underwrite these programs, or they can be funded through public benefits charges on utility bills or small increases in tariffs to cover the expense of these incentives.

The single most significant collective action that the Governors should pursue is the extension of the 30 percent Federal tax credit for a total of ten years. Congress should also be encouraged to lift the \$2000 credit cap on residential systems, providing homeowners with the same incentive as businesses. While individual homeowners and businesses can take advantage of this credit in 2006 and 2007, the lack of a long-term program is a major disincentive for suppliers to invest in expanded manufacturing capacity. These investments are not only necessary to ensure continued cost reductions that will eventually eliminate the need for subsidies, they are also the source of high-paying jobs in the region. While Federal support is vital to the overall success of the solar effort in the West, state leadership is equally important, if not more so. The following programs should be considered as part of that effort.

- **Provide modest incentives for residential solar thermal technologies** that reduce the consumption of electricity or natural gas. Natural gas price and availability will continue to be volatile, and electricity prices in the West are closely tied to natural gas fundamentals. The reduction of electricity or natural gas consumption via the use of solar thermal technologies is indistinguishable from energy efficiency and on-site electricity generation. Solar water heating can be both cost-effective and attractive to consumers with minimal incentives. Public indifference can be turned into strong demand with modest financial incentives in the range of \$750 to \$1000 per system that strongly communicates the importance of investing in this energy-saving technology. Further, where homeowners with existing electric water heaters want to take advantage of incentives for PV, they should be encouraged to install solar water heaters first or alongside a PV system to increase the effectiveness of whatever incentives are provided.
- 
- Newest-generation residential solar hot-water systems can be tightly integrated into building design.*
- **Incorporate solar thermal cooling, heating, domestic hot water and process heat in commercial and industrial applications into the incentive system for renewable energy** in order to allow this technology to quickly achieve cost reduction and market penetration in the U.S. These systems, which incorporate flat-plate, trough and vacuum tube collectors, can provide buildings with space heating, space cooling, domestic hot water and process heat, depending on need. Because buildings in many of the WGA states experience high cooling loads, the use of solar thermal technologies to replace electrically driven air conditioners is very attractive. In addition, this is a firm technology, allowing for permanent displacement of load from the grid.

Programs that incorporate either a buy-down or a performance-based incentive would be an effective approach to stimulating commercial and industrial (C&I) solar thermal projects. The industry is currently working with utilities and regulators to establish the basis for appropriate incentive levels and



Commercial buildings can incorporate solar thermal heating, cooling and hot water systems to reduce both electricity and natural gas usage.

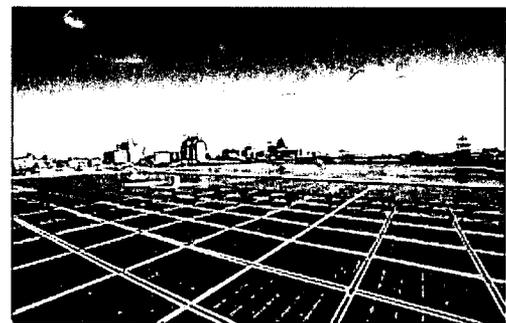
contract lengths (typically 10-15 years) required for this technology in the U.S. as well as to enable the formation of Renewable Energy Service Companies (RESCos) to install, own and operate systems on customer sites.

Incentive programs must be designed in a way that recognizes that the economics of C&I solar thermal applications will vary from state to state, depending on such variables as type of fuel used, primary application (e.g. cooling, cooling/heating, domestic hot water, etc.), and solar radiation. The first step for each State is to include C&I solar thermal technologies in its RPS or other equivalent program and work with industry, regulators, and

utilities to establish appropriate incentive levels. States will benefit from these actions by making a proven, cost-effective solar technology available to address the needs of commercial and industrial customers. Given that the use of C&I solar thermal is in its infancy in the U.S., a significant decline in system price by 2015 is not unreasonable if proper incentive programs are put in place now.

- **Build smart incentive programs that leverage private investment to drive the PV market.** Incentive programs will necessarily vary from one state to the next, driven largely by available solar resources and the cost of electricity – the two most critical variables to a cost-effective installation beyond the price of the system itself. In order to be effective, incentives should be structured so that distributed PV is economically attractive for electricity consumers, enabling private investment by homeowners and businesses to drive the market. Current industry experience is that the tipping point for demand is reached when the payback on an investment in a solar system falls below ten years for homeowners and five years for businesses. (Businesses enjoy greater federal incentives than homeowners such that these critical payback points may be reached with equal programmatic support for these two groups at the state level.) Additionally, states should consider special incentives to ensure that low-income families can participate in these programs. As noted previously, this collective demand will in turn allow PV system providers to gain additional levels of experience that have proven effective in driving down the cost of systems, eventually eliminating the need for incentives altogether.

Direct incentives form the heart of all of the world's successful PV programs. Each state should consider adopting at least one of the following types of incentives – if not providing homeowners and businesses the option of choosing whichever of the two best suits their particular situation. Regardless of which is adopted, it is critical to commit to the program over a substantial period of time, typically ten years. This commitment provides suppliers with the market assurance they need to invest their capital in local infrastructure and plant expansion, R&D and other programs that will ultimately drive down costs for consumers.



Wide swaths of unobstructed commercial roof space are prime targets for solar PV systems.

- ▶ **Up-front incentives to purchase** – These incentives are typified by the successful programs in California and elsewhere that underwrite the initial purchase of a system, reducing up-front capital costs. Often called “buy-down programs,” these incentives should be structured so that they decline over time, eventually zeroing out.

- ▶ **Performance-based incentives** – More philosophically appealing, particularly for large commercial installations, are programs in which system owners are paid only for the electricity they produce, not the capacity they install. These typically involve a modest per-kWh payment spread over a fairly long period of time, ensuring the continued production of energy and continued benefit to the grid. The key to the success of such an effort lies in selecting the appropriate per-kWh payment and time period such that business owners can achieve an adequate return on their investment in the system. Performance-based incentives can be easily incorporated into RPS requirements for distributed solar.

The costs of incentive programs have been the subject of much debate, particularly with regard to capping total program costs to limit the impact on ratepayers. For example, recent discussions in California on the costs of implementing the (3GW) Million Solar Roofs Initiative focused on limiting the cost of direct incentives over ten years to \$2.5-\$3 billion. To put that figure in context, if spread over all ratepayers in that state over ten years, an additional charge of approximately \$0.001 (one-tenth of one cent) per kWh would be required to fund the direct incentive portion of the program.

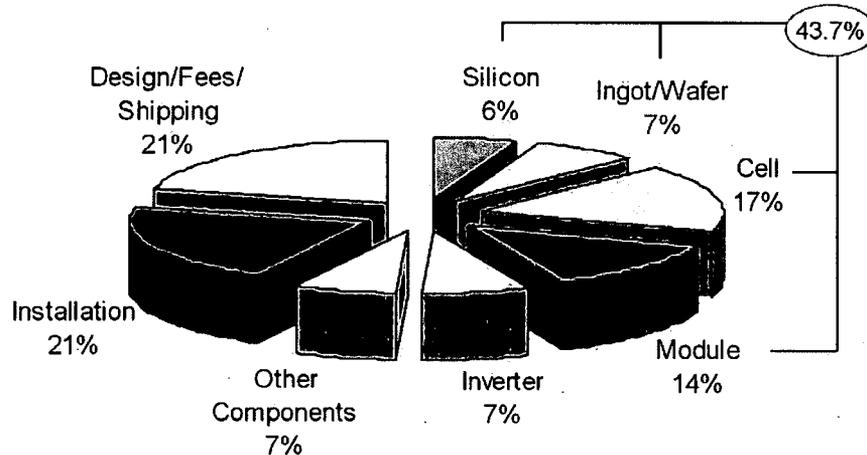
The benefits to consumers of a sustained set of incentives have been demonstrated around the world. Every industry has its experience curve in which additional volumes of production yield reductions in costs, and solar is no exception. It has been widely observed that for every doubling of cumulative global production in megawatts, the cost of PV modules drops by roughly 20%⁴³. Where markets have been robust, such as in Japan and Germany, similar reductions have been seen in installation costs, and balance-of-system costs (inverters, mounting hardware, etc.) have begun similar declines⁴⁴. It is important to note that while increasing worldwide production of PV modules helps drive down costs for everyone, modules are only half of the equation. As shown in Figure II-4, the non-module portion of the total installed system cost for systems installed in California during 2004 were over 56 percent. Unless the WGA states grow their local markets, the anticipated cost reductions related to increased experience and installation efficiency are not likely to occur. However, assuming that WGA states adopt the recommendations in this report and are successful in growing their local markets, we anticipate that through a combination of global learning and local progress average installed system costs will drop from around \$8 per watt today – equivalent to 15 to 30 cents per kWh over 25 years depending on how sunny the location is – to roughly half that amount by 2015 in the WGA region.⁴⁵

⁴³ Nemet, Gregory F., *Technical Change in Photovoltaics and the Applicability of the Learning Curve Model*. International Institute of Applied Systems Analysis, Laxenburg, Austria. Report IR-05029, 2005.

⁴⁴ Ikki, Osamu, *PV Activities in Japan*. RTS Corporation, Tokyo, Japan (May), Jager-Waldau. 2004. *PV Status Report 2004*. Joint Research Centre, European Commission, Ispra, Italy. Report EUR 21390 EN, 2005.

⁴⁵ This assumes a combination of global learning and local progress in which states are successful in growing their local markets. The range of expected price reduction is based on different levels of insolation occurring between states. All LCOE calculations anticipate a system lifetime of 25 years.

Figure II-4. Breakdown of average PV system costs⁴⁶



A recent unexpected surge in demand from Germany has temporarily halted and in some cases reversed this downward price trend, but the consensus among manufacturers is that investments in expanded capacity already underway will enable the PV industry to continue down the traditional cost-volume curve within the next year or two. Indeed, this reduction in costs, which is aimed at creating an industry able to continue on its own without incentives, is precisely the point of a declining incentive schedule recommended above.

Any incentive program needs to be designed like any investment program – the goals should be attainable, the incentive designed so that the goal can be reached, the costs and impacts should be transparent and fully accounted for, and progress toward the goal should be monitored. Further, a large percentage of customers in some states receive power from publicly owned utilities or other energy service providers, and these entities should be encouraged to participate in incentive programs so that they are available to all customers.

Removing Barriers to Easy Installation of Solar

In many areas of the West, when homeowners or businesses want to invest in a solar system for their buildings, they often face obstacles that have nothing to do with the challenges of financing a capital-intensive system. Simple improvements can pave the way for broader adoption of this important technology. Among the most critical are:

- **Adopt common and simplified small generator interconnection standards.** Make it easy and inexpensive for consumers and businesses to connect solar systems to the grid with standardized policies, streamlined procedures and simplified standard form contracts. Fast and easy interconnection is absolutely necessary for developing a robust distributed solar market, and stakeholder working groups have demonstrated success in streamlining this process. Residential and commercial solar customers in most cases must be able to easily plug their solar system into the grid, consistent with applicable system protection, reliability and safety standards, without undue cost or hardship imposed by utilities or state regulations. The most effective interconnection standards:

⁴⁶ Source: Energy Innovations, Inc. calculated based on worldwide gross spending by component industries, global revenue pool of component industries, prices in key world markets, and wholesale component costs in the US.

- ▶ Allow for the interconnection of pre-certified systems
- ▶ Establish reasonable timelines for utility responses to interconnection applications
- ▶ Eliminate undue fees or insurance requirements on interconnecting customers
- ▶ Have a pre-determined dispute-resolution process
- ▶ Provide for transparency and consistency among different utilities and states, consistent with safety requirements

FERC has recently released the Standard Interconnection Agreements & Procedures for Small Generators, Order No. 2006⁴⁷, which will apply to utilities across the country and is substantially similar to rules adopted in California, New Jersey and other leading solar states. In addition, the recently enacted 2005 federal energy bill requires all states to consider adopting uniform interconnection rules based on IEEE Standard 1547.

- **Ensure access to the sun.** Throughout the Western states, there are numerous examples of home and business owners who have had to resort to battling restrictive zoning ordinances and homeowner association rules in the courts to enable them to install solar panels on their rooftops. Invariably the building owners win the right to install, but the process is daunting even for the most ardent solar advocate. California⁴⁸ and other states have taken a lead in this area with solar rights laws, but much work remains to be done. The Governors need to develop policies that ensure that homes and businesses are presumed to have the right of access to the sun unless there are extraordinary mitigating circumstances.

Implement programs that encourage system owners to optimize their energy production.

The third category of policy that can make the difference between an investment in a solar system being appealing or not is the ongoing benefits that accrue to the system owner. In one way or another, it is important for the homeowner or business contributing to the region's energy needs to be encouraged to optimize the amount of electricity generated. Several approaches have been taken that acknowledge the strong correlation that in many areas occurs between solar production and peak energy needs, attempting to align the payment or reimbursement schemes to actual avoided costs. As with other incentive programs, publicly owned utilities and other energy service providers should be encouraged to participate in these types of programs for them to be optimally effective.

- **Provide net metering.** Net metering is the simplest way to value the electricity generated on site by a home or business. The term is derived from the way in which electricity production and usage is measured at the meter. When a building uses energy from the grid, the meter records consumption in the usual fashion. When on-site energy production exceeds usage, it is exported to the grid, and the meter spins backwards. Because the customer's meter "nets" the differences between two over the billing period, the term "net metering" is used. The effect of net metering is to compensate system owners at retail rates in effect when they generate electricity – often during critical peak hours. The recently enacted 2005 Federal energy bill requires all states that have not already done so to consider enacting net metering programs within the next two years.

Retail electricity rates are established with a variety of components including generation, transmission and distribution, and various mandated surcharges. It is generally agreed that PV-generated energy from an individual home or business and delivered to the grid eliminates the utility-delivered generation of those same kilowatt-hours. There is some debate, however, on how to appropriately value the other benefits to the transmission and distribution system portion of the costs. Regardless, net

⁴⁷ FERC Order No. 2006: <http://www.ferc.gov/industries/electric/indus-act/gi/small-gen.asp>

⁴⁸ See California Civil Code Section 714; California Government Code Sec. 65850.5; and California Health & Safety Code Sec. 17959.1 at www.leginfo.ca.gov

metering policies, when structured appropriately, can incentivize the solar generator to continue to operate its solar systems effectively.

- **Encourage solar-friendly rate structures.** Another critical factor in valuing any distributed resource or energy efficiency improvement is the current rate structure used by the electric or gas utility. It is important to keep in mind that utilities are entitled under the law to earn a fair return on their investments to provide electricity. However, there is great flexibility in designing rate structures that both ensure that rates adequately compensate utilities yet at the same time provide significant encouragement for greater conservation and use of distributed resources. Cost-based fixed charges (often called customer charges) that are kept to a minimum would provide such encouragement. Declining block rates, which charge a lower per unit cost based on greater consumption, can undermine efforts to encourage efficiency. Commercial customers in particular could be offered the option of converting to a tariff that eliminates demand charges but includes very high per-unit charges, providing strong incentives to keep distributed solar systems working at their maximum. One Western utility, Pacific Gas & Electric Company, provides an optional tariff to small businesses that encourages conservation and distributed solar installations. PG&E's A-6 tariff rolls all transmission and distribution costs into a single energy charge that is dependant on the time and season of consumption, providing a strong incentive for solar owners to keep systems operating at peak efficiencies. This tariff is one factor that has contributed to the large number of PV installations in PG&E's service territory. Similar tariffs would encourage distributed solar installations throughout the WGA states.
- **Facilitate REC ownership and exchanges.** The Western Renewable Energy Generation Information System, established by the WGA, is being designed to accurately measure and track renewable energy credits (RECs) so that a market for the specific financial benefits associated with renewable energy can be sustained. Governors should encourage policies that allow REC owners to fully realize the benefits of these markets.

Demonstrate Leadership Through State Purchases and Public Education

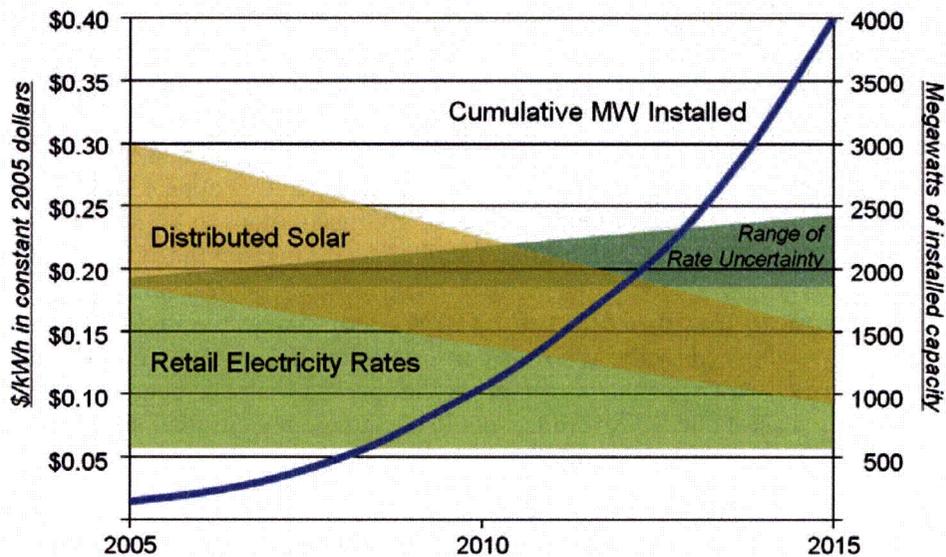
Finally, each Governor has an opportunity to take a strong leadership position through actions that demonstrate a firm commitment to deploying his or her state's solar resources toward meeting the region's growing energy needs. The public at large – homeowners, businesses, nonprofit organizations, schools and other public institutions – take their cues from state initiatives.

- **Purchase solar electricity for state buildings.** One high-profile initiative that can have a strong ripple effect throughout the region is to purchase solar electricity systems for key state buildings. These installations can also serve to demonstrate the economic viability of solar electricity and can provide Governors with an opportunity to show real savings to taxpayers on electricity costs over time. Governor Napolitano's Executive Order is an excellent model. It requires that 10 percent of the energy usage in new state-funded buildings in Arizona to come from renewable resources. The new Federal renewable purchase requirement contained in the Federal Energy Policy Act of 2005 is another useful model. The Act also requires that a certain percentage of a government building's energy use be derived from renewables, and double credits are provided for on-site generation.
- **Encourage adoption through public education and awareness programs.** In many instances solar systems are already cost-effective, and yet few home or business owners know it. This is particularly true of solar thermal systems for heating water and air. By using the pulpit of the Governor's office and through state publications and outreach programs, building owners can learn how to adopt these technologies to save money on their energy bills and contribute to the region's economic and environmental health.

Conclusion: Distributed Solar Can Contribute 4,000 MW of Generation and 2GW_{th} of Solar Thermal Power by 2015

With these programs implemented throughout the region over the next few years, we estimate that distributed PV solar can contribute 4,000 MW of the Governor’s objective of 30,000 MW of clean, diversified energy. In addition, 500,000 solar thermal systems could be installed, providing the equivalent of 2GW_{th} of energy and saving 15 billion cubic feet of natural gas per year.

Projected Cost Reductions for Distributed Solar PV
Assuming Deployment Targets are Met



Source: NREL and industry data

This will add over 15,000 high-quality jobs in the West and contribute up to 6 million megawatt-hours of electricity annually to the region by 2015 – the equivalent of the electricity consumed during peak hours by Portland, Seattle and Denver each year *combined*. Ten years of growth could also drive down the cost of solar systems by approximately 50%, resulting in an industry that should be able to thrive without financial subsidies. These estimates are based on continuing the existing industry growth rate in the Western US of approximately 32% per year. After 2015, assuming growth in the distributed PV industry slows to an average of 20% annually, by 2025 another 30GW of systems could be installed without subsidies at prices below retail electricity rates in most states. Much of this growth is driven currently by incentive programs in California, and the overall goal cannot be reached without those programs continuing in one form or another, whether through Governor Schwarzenegger’s Million Solar Roofs Initiative (targeting 3,000 MW of solar by 2018) or equivalent programs adopted by the California Public Utilities Commission. In addition, however, the efforts of every state in the WGA will be needed to reach the 2015 goal of 4,000 MW of distributed PV and 2GW_{th} of solar thermal systems, and we encourage the Governors to adopt programs from among the myriad options that best suit their individual states’ circumstances.

Appendices

- Section I – Central Station Solar
 1. Supply Curves
 2. Definitions and Discussions of Incentives, Policies and Other Factors

- Section II – Distributed Solar
 1. “Status of Distributed PV Policies in the WGA States,” Robert Margolis and Michael Wheeler, National Renewable Energy Laboratory, November 15, 2005
 2. Background on Installing 500,000 Solar Water Heating Systems Over 10 Years
 3. Policy Options to Encourage Widespread Adoption of Distributed Solar

APPENDIX I-1 – Supply Curves

Capacity supply curves provide a means for describing the relative cost of generation for a particular technology (renewable or conventional) and the generating capacity coincident with the cost. For renewable technologies, costs are driven primarily by two factors, resource availability and proximity to available transmission. For this analysis “busbar costs” (technology costs exclusive of transmission, that is, those costs accumulated within the perimeter of the plant site, up to and including the point of delivery to a transmission system, or “busbar”) were based on a fixed charge rate (FCR) methodology supplied by the WGA Quantitative Working Group (QWG). While the FCR methodology provides a simple determination of the relative cost of generation for a given resource, it over-estimates the real and nominal levelized cost of energy when compared to the more detailed cash flow model used for cost analyses performed for the Central Solar WG.

One of the supply curve sets that were requested by the QWG is shown in Figure A1-1. This supply curve assumes, per QWG guidance, 20% transmission capacity availability to the nearest load center(s). Where the solar resource is located adjacent to a load center, 20% of city demand is assumed to be available to off-take the solar generation without the need for new transmission. The supply curve in Figure A1-2 assumes that once the 20% capacity is allocated, new transmission must be built to carry additional supply to the nearest load center. New transmission cost is assumed to be \$1000 per MW-mile. The final supply curve, to be supplied, assumes 0% transmission capacity availability to nearest load center(s). That is, the supply curve must include new transmission and associated costs.

As new capacity is deployed, it may be further from transmission lines or require new transmission because the existing line capacity is filled. The cost is constrained to rise, but at a rate determined by line capacities and plant locations. **These curves show by their relative flatness that the solar resource and transmission infrastructure impose minimal constraints on development, and that most of the SW states can build significant CSP capacity before the costs of power increase. In this case the curves go to 10 GW, but this is also the case for much higher deployment levels.**

The supply curves described in the figures are essentially a snapshot in time and do not account for cost reductions due to levels of deployment commensurate with the capacity depicted on the supply curves. As such the supply curves, while providing an important qualitative assessment of the magnitude of the resource and proximity to transmission, are impractical and incapable of depicting actual costs, and should not be used as the source of information on the current or projected future cost of the technology. Cost reductions as a function of deployment are shown later in this report.

Figure A1-1

CSP Energy Supply Curve
20% Availability of City Peak Demand and 20% Availability of Transmission Capacity

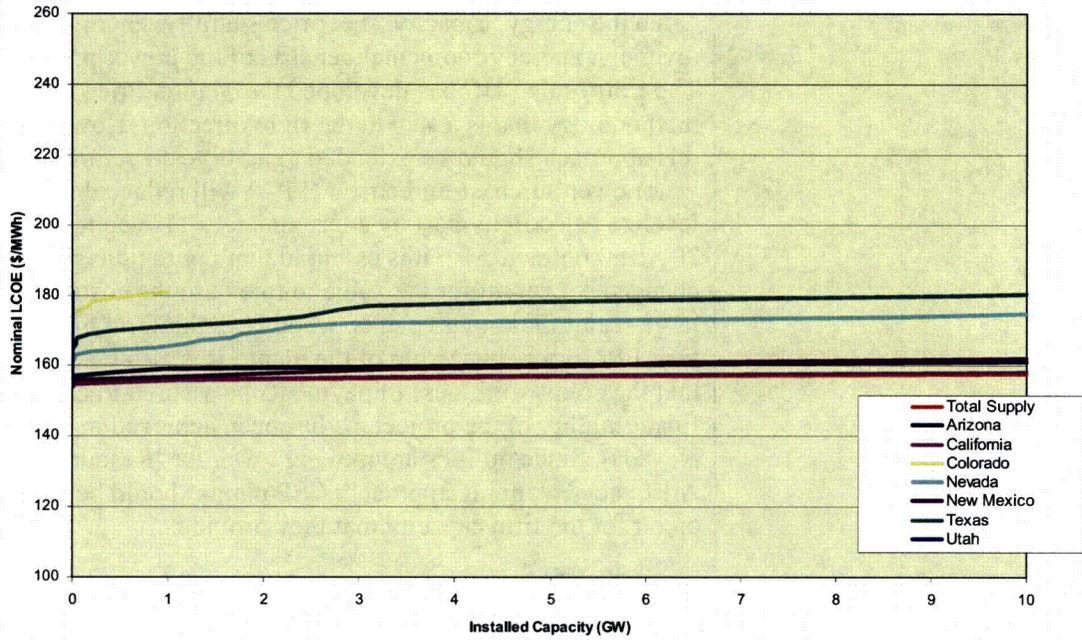
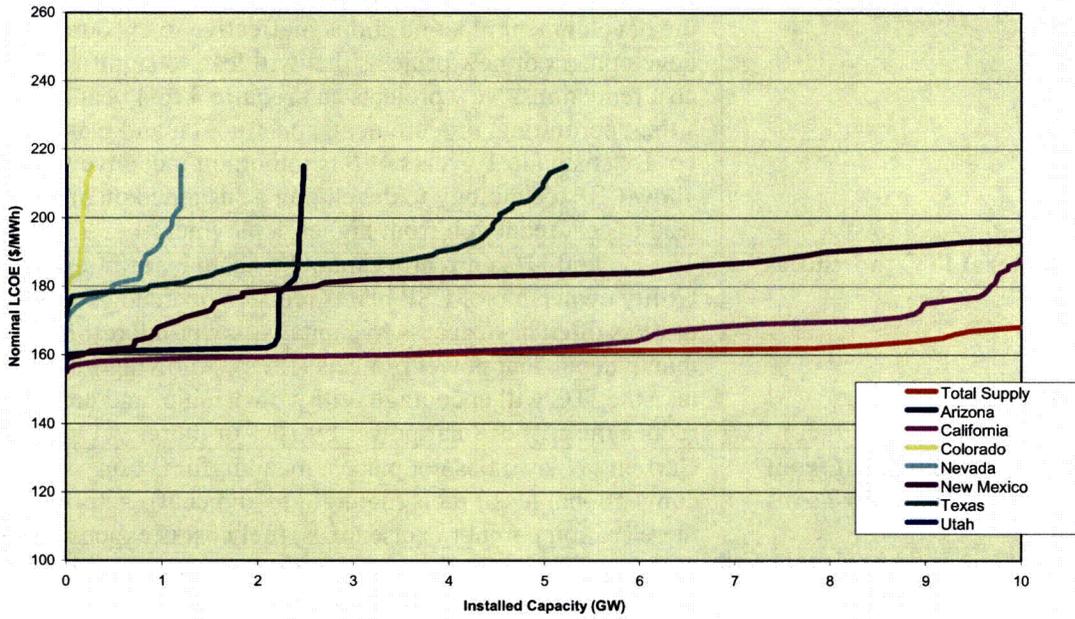


Figure A1-2

CSP Energy Supply Curve
20% Availability of City Peak Demand and 0% Availability of Transmission Capacity



APPENDIX I-2 – Definitions and Discussions of Incentives, Policies and Other Factors

<p>Extend PPA to 30 Years</p>	<p>It is important that a fair methodology be put in place to value the energy, capacity, fuel price stability, energy diversity, and environmental benefits of the power produced. The California PUC has developed the Market Price Referent methodology that is a step in the right direction. However, this approach should be extended to a 30-year lifetime. A 30-year power purchase agreement (PPA) will reduce the (real) levelized electricity cost by approximately 11% compare to a 20-year contract. Also it is essential that regulations be changed so that utilities are able to rate base the costs for large scale solar power plants, whether in the form of a 30-year PPA or by ownership of the plant. It is also essential that the creditworthiness of payments be assured to ensure financeability of the project (as has been achieved in Nevada). Since utilities are moving toward a “Resource Adequacy” planning approach, CSP plants should be given credit for the firm capacity that they provide.</p>
<p>Include \$60 Capacity Credit</p>	<p>Quantification of the capacity credit for firm power operation. Justified by the inherent characteristics of CSP solar thermal plants, and the performance experience at the SEGS facilities.</p>
<p>Extend Federal 30% ITC to 10-year window.</p>	<p>The Federal solar Investment Tax Credit (ITC) was recently increased from 10% to 30% in the federal energy bill for a period of 2 years, reducing the LCOE by about 20%. The current 2-year timeframe will only benefit plants currently in the development pipeline and is ineffective to encourage development of new projects that will lead to significant cost reductions. New projects can require 3 to 4 years for siting, permitting, procurement, construction and plant start-up. Extension to 10 years of this important incentive would allow CSP technology to develop in a sustained manner and lead to cost reduction from higher deployments.</p>
<p>Extend Federal ITC to Utilities</p>	<p>The Federal ITC currently cannot be taken by utilities. Utility ownership of CSP plants reduces financing since utilities often have access to capital at lower interest rates than independent power projects (IPPs). Allowing utilities to take the ITC will encourage utility ownership, and could reduce the cost of solar power by 10% or more.</p>
<p>Exempt Solar Equipment from State Property and Sales Taxes</p>	<p>Current tax law does not place a meaningful tax on conventional fossil fuels (natural gas and coal). Although there are some minor excise taxes, fuel cost is expensed and written off the taxes. However, because solar fuel is the solar field itself, sales taxes and property taxes are in effect paid on solar fuel. In fact, a solar plant must pay sales taxes on the equivalent of a 30-year fuel supply up front, and then must pay property taxes each year on the 30-year fuel supply. To better achieve tax equity for solar electricity, sales taxes and property taxes on solar equipment should be</p>

	<p>eliminated. California already waives property taxes on the entire solar plant. It is in the states' interest in minimizing the cost of energy to ratepayers to eliminate these taxes. This tax burden is just transferred to the electric ratepayers in the form of increase PPA costs or utility rates. Exempting property and sales taxes will reduce the cost of solar power by about 10% and 5%, respectively.</p>
<p>Solar Firm Capacity Buy Down</p>	<p>Many states already use a cost buy down incentive to encourage the implementation of solar technologies. This is typically used for photovoltaic systems in the form of dollars per peak watt installed. One of the concerns with this type of incentive is that the incentive is not tied directly to the performance of the system, thus two systems could receive the same amount of incentive but deliver significantly different levels of energy. The solar firm capacity buy down would be different in that it is an incentive for dispatchable solar technologies. The incentive would be used to buy down solar technologies with a firm capacity capability using thermal energy storage or fossil backup to assure that the solar plant will meet the plant rated capacity during the system peak on sunny summer days. The incentive is an upfront payment at the point commercial operation that would be based on the plant rated capacity as defined by the power purchase agreement with the utility.</p>
<p>Solar Production Tax Credit (PTC) CSP Performance-based Incentive (PBI)</p>	<p>The Federal production tax credit has been used to encourage the development of wind power. The production tax credit is generally favored over an investment tax credit because it is a performance-based incentive. The credit is paid based on the actual electricity delivered over some period of time, typically the first 5 or 10 years of a project's operation. The state could provide a similar electric generation based tax incentive that would be used to bridge the cost gap. For purpose of this analysis a flat state PTC is assumed for a 10-year period. However, more analysis should be conducted to determine if 10 years is the best duration, and whether the incentive should be flat, has some inflation over time, or has rate tiers that change over time. In any case, the incentive should be available to IPPs or investor owned utilities.</p> <p>If the initial policy recommendations of a 30% federal ITC extended to 10 years, solar sales and property tax exemption, provision of a 30 year PPA with a \$60/kW-yr capacity payment, there will be about a 3 ¢/kWh gap between the CSP cost and the 9.6 ¢/kWh price target. This gap could be addressed with a CSP performance-based incentive that will require the utilities to pay 11 cents for each kWh generated by the CSP plant for the term of the PPA. As the utilities can recover the target price of 9.6 ¢/kWh in their rate base, the impact of the PBI is to add another 3 ¢/kWh to their rate base. The CSP PBI could be capped at 1 GW and a lower PBI be determined for the next GW.</p>

Loan Guarantees

The recent federal energy bill put in place the structure for federal loan guarantees on clean energy technologies. This type of loan guarantee provides a lenders protection against loan defaults due to technology risk, and could enable a project to get debt financing for demonstration of new technologies that otherwise would be unable to. The primary disadvantage of the federal loan guarantee is that it must be appropriated by congress in its annual appropriations process.

One of the primary differences between IPP and utility financing is that the loan on the IPP project is entirely secured by the revenues generated by the project itself. The loan on a utility project is secured by the overall credit worthiness of the utility as a whole. As a result, utilities can obtain longer term debt financing and do not require the same debt service coverage requirements that an IPP project does. For capital intensive solar power projects, this can significantly lower the cost of debt service on the project.

In principle it is possible that a State loan performance guarantee would allow the cost of power from IPP projects to be reduced to that of a utility owned project. In this approach, the state would need to guarantee that the loan would be repaid no matter how the project actually performed. A detailed analysis of this approach needs to be verified with the financial lending industry to be assured that this approach will in fact have the desired effect on the resulting cost of electricity, and to determine what form the loan guarantee would take.

Appendix II-1: Status of Distributed PV Policies in the WGA States and Additional Technical Detail¹

November 15, 2005

In this appendix we review PV related policies, provide a baseline projection for distributed PV in the WGA states, and provide additional technical detail. First, we present two tables that provide an overview of policies, and then compare policies in place with installed PV capacity, average electricity prices, and available solar resources by state. Second, we present a set of tables that provide considerably more detail on the PV related policies in place in the WGA states. From these tables one thing is clear: the WGA states are pursuing a very diverse set of policies aimed at facilitating investments in distributed PV technology. Third, we present a table with detailed information on policies currently under consideration in the WGA states. Fourth, we present a set of baseline projections. These baseline projections take into account both existing policies and a reasonable expansion of existing policies given what is currently on the table. These projections are provided to WGA Solar Task Force as a benchmark against which to evaluate the impact of additional policies focused on distributed PV in the WGA States. Finally, we provide additional technical detail on the following topics: rooftop availability and potential installed capacity in the WGA states, projected solar jobs in the WGA states, effective load carrying capacity (ELCC) in the WGA states, projected avoided CO₂ emissions in the WGA states, projected avoided water use in the WGA states, projected levelized cost of electricity in residential and commercial systems, and a state by state allocation of the 2015 installed PV target.

1. Overview of Existing PV Policies

As shown in Table 1, there is considerable variation across the WGA states in terms of how policies and market incentives have been used to encourage deployment of PV technology. There are three basic types of policy tools that are currently being employed: regulatory levers (net metering and Renewable Portfolio Standards), direct incentives (rebates/buy-downs and production incentives) and tax incentives. While there are some policies that appear to be implemented widely, for example some form of net metering exists in 14 of the 18 WGA states, there are important differences across states in how policies have been implemented.

As shown in Table 2, the top five WGA states in terms of PV installations are CA, AZ, HI, TX and CO. CA is the clear leader accounting for at least 90% of total installed grid-connected distributed PV capacity in the WGA states through 2004.² CA's lead is not surprising given its use of aggressive PV policies such as net metering, consumer-friendly interconnection standards, various consumer rebates, and solar friendly rate structures³ combined with high electricity prices and very good solar resources. Four out of five offer significant rebates at state, local, or

¹ This appendix was prepared by Robert M. Margolis (NREL) and Michael Wheeler (NREL) for the WGA Solar Energy Task Force. Paul Denholm (NREL) provided input to the section on rooftop availability, and Bruce Ellestad (SEIA) provided assistance in gathering data on pending legislation.

² This estimate excludes central PV in AZ.

³ The impact of various rate structures on the value of output from PV systems will be examined in a separate paper currently under preparation by NREL for the WGA Solar Task Force.

utility levels. In addition, the top four all have multiple tax incentives. Through a combination of policy tools states can implement strategies that incorporate both regulatory and market-based elements and create a push and pull effect on the market for distributed PV.

Understanding how policies influence market development requires that states learn from each other about how various tools work best together. In the next section we present detailed tables for each of the policy options shown in Table 1.

Table 1. Overview of PV Related Policies in the WGA States.

State	Net Metering	RPS	Rebate/ Buy down Program	Production Incentive	Low Interest Loans	Tax Incentives	System Benefit Charge	Total
CA	X	X	X	X		Pe, Pr, C	X	8
OR	X		X	*	X	Pe, Pr, C	X	8
MT	X	X			X	Pe, Pr, C	X	7
NV	X	X*	X	X		Pr, S		6
AZ	X	X*	*			Pe, S		5
TX	X	X	*			Pr, C		5
WA	X		*	X	*	S		5
CO	X	X*	X		*			4
HI	X	X				Pe, C		4
ID	*				X	Pe, S		4
UT	X					Pe, C, S		4
ND	X					Pe, Pr, C		4
NM	X	X		X				3
WY	X		X			S		3
AK					X			1
NE					X			1
KS						Pr		1
SD						Pr		1
Total	12	7	5	5	5	29	3	

Notes:

Tax Incentive Abbreviations: Pe=Personal Pr=Property C=Corporate S=Sales.

Policy and Incentive data is based on DSIRE as of November 2005 (<http://www.dsireusa.org/>). Income tax credit in California expires at the end of 2005.

Production Incentives do not include the Federal Conservation Security Program which applies to all states.

* Not implemented state-wide.

X* Soar Set Aside included within RPS.

Table 2. PV Policies and Installed Capacity in the WGA States.

State	Total PV-Related Policies	PV Installed (kW) ^a	Average Electricity Price (¢/kWh) ^b	Solar Resource (kWh/kW)		
				Low	High	Average
NM	3	82	7	1,840	2,102	1,971
NV	6	112	8.3	1,752	2,102	1,927
AZ	5	5,000	7.3	1,752	2,015	1,883
HI	4	1,014	14.5	1,752	1,840	1,796
CO	5	775	6.8	1,577	1,927	1,752
CA	8	93,000	11.6	1,577	1,840	1,708
TX	5	980	7.5	1,577	1,752	1,664
WY	2	46	4.8	1,489	1,840	1,664
ID	4	140	5.2	1,489	1,752	1,621
UT	4	1	5.4	1,489	1,752	1,621
MT	6	157	6.2	1,402	1,664	1,533
NE	1	4	5.6	1,402	1,664	1,533
KS	1	0	6.4	1,402	1,664	1,533
SD	1	0	6.4	1,402	1,664	1,533
ND	4	0	5.5	1,314	1,577	1,445
OR	7	74	6.2	1,139	1,314	1,226
WA	5	75	5.9	1,051	1,226	1,139
AK	1	21	10.5	788	964	876

Notes:

a. PV Installation data is as of January 2005 for:

CA; 46 MW installed under the CEC's program and 26 MW under the CPUC's SGIP program. Remainder installed by Sacramento Municipal Utility District, Los Angeles Department of Water and Power, and other small municipal utilities. Data received from Bill Blackburn of the CEC.

AZ; 5.0 MW represents only distributed PV installations installed through MSR and other programs. In addition, APS has installed nearly 5 MW of utility scale arrays around the state, TEP has completed a 4.6 MW facility, and SRP has a total of 525 kW.

All other state data is through 2002 from the NREL's Renewable Electric Plant Information System. REPiS data is for both stand-alone and grid-connected systems.

Web address: <http://www.nrel.gov/analysis/repis/index>.

b. Average price data in ¢/kWh for all customer classes in 2003. EIA Electricity Publications Sales and Revenue Data Tables 2003. Web address: http://www.eia.doe.gov/cneaf/electricity/esr/esr_tabs.html

c. Solar Resource data was calculated from the capacity factors derived using NREL's PVWatts PV simulation program. For each state, a representative city was chosen, based on the availability of data near the state's largest population center. Three cities were chosen in California. This limited data set will result in some errors, particularly in larger states, or in states with greatly varied solar resources such as Washington and Oregon.

PV Watts Web address: http://rredc.nrel.gov/solar/codes_algs/PVWATTS/version1/

2. Detailed Tables on Existing Policies

Net Metering

Net Metering allows for the flow of electricity both to and from the customer through a single, bi-directional meter. With net metering, during times when the customer's generation exceeds his or her use, electricity produced by the customer offsets electricity consumed from the utility at another time. In effect, the customer is credited for this excess generation at the retail rather than wholesale rate. Under most state rules, residential, commercial, and industrial customers are eligible for net metering, but some states restrict eligibility to particular customer classes. In practice, net metering has emerged as a key policy to promote distributed PV. The rationale for instituting net metering is based on the fact that distributed PV provides energy at the point of use, thus distributed PV can help avoid the cost of T&D upgrades, the capital cost of increased peaking capacity, and the associated losses of centralized generation.⁴ As shown in Table 3, 14 out of the 18 WGA states have enacted net metering legislation. Of the top five states listed in Table 3, CA and HI have set statewide limits on net metered generation at .5% of peak demand. The other states either allow utilities to set their own rules or plan to revisit the issue once a certain threshold of participation is reached.⁵

Table 3. Net Metering Policies in the WGA States

State	State-wide/ Utility	Residential/ Commercial	System Size	Enrollment Limit	Net Excess
AZ	Salt River Project	Residential	10 kWp	None	Purchased monthly with price adjustment of .017¢
	Tucson Electric Power	Res. & Comm.	10 kWp	500 kWp	Credit to following month's bill. EOY net excess credited to TEP
CA	State-wide	Res. & Comm.	1 MWp	.5% utility peak	Credit to following month's bill. EOY net excess to utility
CO	Xcel Energy	Res. & Comm.	10 kWp	None	Credit to following month's bill
	Holy Cross Electric	Res. & Comm.	Not specified	50 kWp	Full retail credit
	Aspen Electric	Res. & Comm.	Not specified	50 kWp	Full retail credit
	Gunnison Co. Electric	Res. & Comm.	10 kWp	50 customers	Full retail credit
	Fort Collins Electric	Residential	10 kWp	25 customers	Credit to following month's bill
HI	All utilities	Res. & Comm.	50 kW	.5% utility peak	Granted to utility monthly

⁴ Smeloff, Ed. 2005. "Quantifying the Benefits of Solar Power for California" Vote Solar; E3 Consulting. 2004. "Methodology and Forecast of Long Term Avoided Costs for the Evaluation of California Energy Efficiency Programs". Energy and Environmental Economics Inc.; Schell, Laurie & Shirly Neff. 2005. "Testimony Before the Public Utilities Commission of the State of California". Docket # R.04-03-017

⁵ Solar Flare. March 2005. Issue 2005.1

Table 3 (cont.)

ID	Alvista Utilities	Res. & Comm.	25 kWp	.1% 1996 peak or 1.52 MWp	Credit to following month's bill. EOY net excess to utility
	Idaho Power	Res. & Comm.	25-100 kWp	.1% 2000 peak or 2.9 MWp	Res. and Small Com.: Full retail credit – monthly. Large Com.: 85% of Mid-Columbia rates – monthly.
	Utah Power & Light	Res. & Comm.	25-100 kWp	.1% 2002 peak or 714 kWp	Res. and Small Com.: Full retail credit – monthly. Large com.: 85% of Dow Jones index for non-firm energy rates – monthly
MT	Investor-owned utilities only	Res. & Comm.	50 kWp	None	Credit to following month's bill. EOY net excess to utility
	Montana Electric Cooperatives	Res. & Comm.	10 kWp	None	Credit to following month's bill. EOY net excess to utility
ND	IOUs only	Res. & Comm.	100 kWp	None	Purchased at avoided cost
NM	IOUs and Co-ops	Res. & Comm.	10 kWp	None	Purchased at avoided cost or credited to following month
NV	IOUs only	Res. & Comm.	30 kWp	None	Credited to utility
OR	All utilities	Res. & Comm.	25 kWp	.5% utility peak	Purchased at avoided cost or credited to following month. EOY net excess to utility.
	Ashland	Res. & Comm.	None	None	Full retail credit up to 1,000 kWh purchased monthly.
TX	State-wide	Res. & Comm.	50 kWp	None	Purchased at avoided cost
	Austin Energy	Res. & Comm.	20 kWp	Re-evaluate at 1% of load	Monthly credit to customer, calculated by multiplying the net kWh fed into grid by current fuel charge or by appropriate Green Power Charge
	San Antonio	Res. & Comm.	25 kWp	None	Credit of 1.65¢ /kWh Oct.-May and 2.02¢ /kWh June-Sept.
UT	All electric utilities and coops(munis excluded)	Res. & Comm.	25kWp	0.1% of 2001 peak	Credit to following month's bill. EOY net excess to utility
WA	All utilities	Res. & Comm.	25 kWp	0.1% of 1996 peak demand	Credit to following month's bill. EOY net excess to utility
	Grays Harbor PUD	Res. & Comm.	26 kWp		Purchased at EOY for 50% retail rate
WY	All utilities	Res. & Comm.	27 kWp	None	Credited to the following month, then purchased at avoided cost by the utility at the end of the annual period

Source: Data is based on DSIRE as of November 2005 (<http://www.dsireusa.org/>).

Interconnection Standards

The ability to sell distributed PV power to the grid through net metering requires that a physical interconnection be created. In order to insure a safe and reliable grid most utilities treat small-scale PV systems similar to the way they treat large-scale PURPA facilities. Engineers must review system designs and engineering diagrams on a one-system-at-a-time basis. As state policies promoting distributed PV increase, both utilities and their customers will save time and money by adopting uniform interconnection standards that speed the process. As shown in Table 4 the WGA states address interconnection at varying degrees from lack of awareness at the utility level to state-wide standards. At a minimum, utility-level standard agreements give the customer knowledge up front about what the utility will require and costs that can be expected. When these vary from one utility to another, customer confusion and frustration can arise. Issuing state-wide interconnection standards helps to reduce the barriers associated with distributed PV. However, a state-wide interconnection standard can still present barriers to the customer such as requiring insurance or providing the same requirements of small generators (< 50 kW) as large generators (up to 20 MW).

Table 4. Interconnection Standards

State	Authority	Applicable Sectors ¹	System Size/ Enrollment Limit	Standard Agreement	Insurance Required	External Disconnect Required
AZ	Varies by Utility	R, C, I	No	Varies by Utility	Varies by Utility	No
CA	Varies by Utility	R, C, I	10MW-max, 10 kW-simplified/ no limit	Yes	No	Yes > 1 kW
CO	Varies by Utility	R, C, I	10 kW (Varies by Utility)	Varies by Utility	Varies by Utility	Yes
HI	State-wide	R, C, I	.5% of peak	Yes	No	Yes
ID	Varies by Utility	R, C, I	Varies by Utility	Varies by Utility	No	Yes
KS	State-wide	R, C, I	25kW – Res 100 kW – Com/Ind	No	No	Yes
MT	State-wide	R, C, I	50 kW	Yes	No	Yes
NV	State-wide	R, C, I	20 MW	Yes	No	No
NM	State-wide	R, C, I	10 kW	Yes	Yes	Yes
OR	State-wide	R, C, I	25 kW	No	No	No
TX	State-wide	R, C, I	10 MW	Yes	No	Yes
UT	State-wide	R, C, I	25 kW/ .1% of 2001 peak	No	No	No
WA	State-wide	R, C, I	25 kW/ .1% of 1996 peak	Yes	Yes	No
WY	State-wide	R, C, I	25 kW	Yes ²	No	Yes

¹ Applicable Sectors: R=Residential; C=Commercial; I=Industrial.

² Only applies to PacifiCorp

Sources: DSIRE as of November 2005 (<http://www.dsireusa.org/>), Strategies Unlimited, 2004. "Global Analysis of PV Markets and Application Factors"

Renewable Portfolio Standards and Solar Set Asides

A Renewable Portfolio Standard (RPS) requires that a certain percentage of a utility's overall or new generating capacity or energy sales must be derived from renewable resources, i.e., 1% of electric sales must be from renewable energy in the year 20xx. Portfolio Standards most commonly refer to electric sales measured in megawatt-hours (MWh), as opposed to electric capacity measured in megawatts (MW). An RPS with a solar set aside adds a requirement that a certain percentage of a utility's overall energy sales or generating capacity must be derived from solar installations (may included distributed and central generation). As shown in Table 5, seven of the WGA's eighteen states currently have an RPS. Of those seven, three have a specific solar set aside.

Table 5. Renewable Portfolio Standards in WGA States

State	Title	Standard	Solar Technology Set Aside	Credit Trading
With Solar Set Aside				
AZ	Environmental Portfolio Standard	0.2% in 2001, 1.1% in 2007-2012	50% (of 0.2%) in 2001-2003 60% (of 1.1%) in 2004-2012	
CO	Renewable Energy Requirement	3% by 2007; 6% by 2011; 10% by 2015	4% of total renewable kWh 1/2 of this 4% must be from distributed PV	Yes
NV	Renewable Energy Portfolio Standard	5% in 2003, 15% by 2013	5% of total renewable kWh (includes both PV or CSP) PV kWhs get 2.4 multiplier	Yes
TX	Renewable Generation Requirement	5,880 MW in 2015	Solar and biomass must account for 500 MW	Yes
Without Solar Set Aside				
CA	Renewable Portfolio Standard	Increase 1% per year beginning in 2003 to reach at least 20% by end of 2017		
HI	Renewable Portfolio Standard	7% by 2004; 8% by 2006, 10% by 2011, 15% by 2016, 20% by 2021 (includes existing renewables)		No
MT	Renewable Portfolio Standard	5% in 2008, 10% in 2010, 15% in 2015		Yes
NM	Renewable Portfolio Standard	5% in 2006, 10% in 2011	Some sources have higher "value" credit	Yes

Source: Data is based on DSIRE as of November 2005 (<http://www.dsireusa.org/>).

Rebate Programs

A wide range of rebate programs are offered at the state, local, and utility levels to promote the installation of renewable energy equipment. The majority of rebate programs are available from state agencies and municipally owned utilities and support solar water heating and/or photovoltaic systems. Eligible sectors usually include residents and businesses, although some programs are available to industry, institutions, and government agencies as well. In some cases, rebate programs are combined with low or no-interest loans. As shown in Table 6, seven WGA states currently have PV specific rebates in place. In comparison the typical installed cost of a residential PV system in CA during 2004 was \$8-9/Wac. High initial rebates may be required to spur the development of local PV market infrastructure.

Table 6. PV Related Rebates in WGA States

State	Title	Amount	Maximum Incentive	Eligible System Size	Installation Requirements	REC Ownership
AZ	APS Utility	\$4/Wdc	No Limit	No limit	Grid-connected	Customer
	SRP Utility	\$3/Wp	\$9,000	No limit	Grid-connected	SRP(util)
	TEP Utility	\$2/Wp	\$20,000	>= 10 kWp	Grid-connected	Customer
	UES Utility	\$3/Wdc	\$15,000	>= 5 kWdc	Grid-connected	Customer
CA	Self-Generation Incentive Program (SGIP)	\$3.50/W	1 MW	30 kW – 5 MW based on customer demand	Grid connected	Customer/producer
	Emerging Renewables Program	\$2.80/W	\$400,000 ¹	<30 kW	Grid connected	Customer/producer
CO	Utility PV Rebate	\$2/W (min)	TBA	TBA	TBA	TBA
NV	SolarGenerations PV Rebate Program	Year 1: \$5/Wp Year 2: \$4/Wp Year 3: \$3/Wp	Residential/Schools Year 1: \$25,000 Year 2: \$20,000 Year 3: \$15,000 Comm./Public Year 1: \$150,000 Year 2: \$120,000 Year 3: \$90,000	5 kWp (Res/Schools) 30 kWp (Comm)	Grid-connected & net-metered	Nevada Power Company, Sierra Pacific Power Company
OR	Solar Electric Buy-down Program	\$3/Wdc	Res: \$6,000	Maximum of 10 kW	Grid-connected & net-metered	Customer/producer
TX	Austin Energy Utility	\$5-6.25/W	80% or \$15,000	No limit	Grid-connected & net-metered	Austin Energy (Utility)
WA	Clallam PUD	\$.45/W	Not Determined	No limit	Grid connected	Customer
	Klikitat PUD	\$.40/W		3 kW	Grid connected	Customer
	Orcas Power	\$1.5/Wp	\$4,500	>100 kW	Grid connected	Utility
	Puget Sound Energy	\$.525-\$.6/W	No limit	No limit	Grid connected	Customer

¹ This figure represents the maximum available in the Emerging Renewables Performance Based Incentive program. See Table 7 for more details.

Source: Data is based on DSIRE as of November 2005 (<http://www.dsireusa.org/>).

Production Incentives

Production incentives (or feed-in tariffs) provide project owners with cash payments based on electricity production on a \$/kWh basis for a fixed number of years. By paying for performance rather than capital investments production incentives provide an effective mechanism for ensuring quality projects. A number of European countries (most notably Germany and Spain) have implemented very aggressive production incentives. As shown in Table 7, five WGA states have some form of production incentive for PV, the most aggressive being the recently implemented feed-in tariff in WA.

Table 7. PV Related Production Incentives in WGA States

State	Title	Amount	Max. Limit	Terms
CA	Supplemental Energy Payments (SEPs)	For above market costs as compared to a market price referent		3 - 10 year contracts
CA	Emerging Renewables (Rebate) Program	\$0.50/kWh for 3 years.	\$400,000	Must be grid-connected
NV	Renewable Energy Credits	1 kWh of PV = 2.4 kWh REC sold to utilities at market price	None	Must be grid-connected
WA	Feed-in Tarrif	15-54 cents per kWh	10 years	Must be grid-connected
NM	Renewable Energy Production Tax Credit	\$0.01/kWh	Minimum of 10 MW capacity. Total annual generation > 2 million MWh/year	10 years
CO	Aspen Solar Pioneer Program	\$.25/kWh	\$1,000	4 years

Source: Data is based on DSIRE as of November 2005 (<http://www.dsireusa.org/>).

Low-Interest Loan Programs

Loan programs offer financing for the purchase of renewable energy equipment. Low-interest or no-interest loans for energy efficiency are a very common strategy for demand-side management by utilities. State governments also offer loans to assist in the purchase of renewable energy equipment. As shown in Table 8, seven WGA states currently have low interest loan programs that apply to distributed PV technology. In many states, loans are available to residential, commercial, industrial, transportation, public, and nonprofit sectors. Repayment schedules vary; while most are determined on an individual project basis, some offer a 5-10 year loan term.

Table 8. PV Related Low Interest Loans in WGA States

State	Program Name	Amount	Terms
AK	Power Project Loan Fund	>\$1 million	Repayment to match term of municipal bonds
CO	Aspen Solar Pioneer Program Gunnison County Electric	NA \$25k	0% interest 5 year term Fixed for 10 years
ID	Low-Interest Loans for Renewable Energy Resource Program	Res: \$1k - \$10k Com: \$1k - \$100k	4% interest, 5-year term
MT	Alternative Energy Revolving Loan Program	\$10k	5 years; 5% for 2004
NE	Dollar and Energy Savings Loans	5% or less	
OR	Small Scale Energy Loan Program (SELP)	\$20k - \$20 million	Repayment to match term of municipal bonds
WA	Franklin PUD Energy Loans	\$400 - \$10k	0% interest

Source: Data is based on DSIRE as of November 2005 (<http://www.dsireusa.org/>).

Personal Tax Incentives

Many states offer personal income tax credits or deductions to cover a portion of the expense of purchasing and installing renewable energy equipment. The allowable credit may be limited to a certain number of years following the purchase or installation of renewable energy equipment. As shown in Table 9, seven WGA states currently offer personal tax incentives for PV systems.

Table 9. PV Related Personal Tax Incentives in WGA States

State	Title	Amount	Maximum Incentive	Carryover Provisions	Eligible System Size
AZ	Solar and Wind Energy Systems Credit	25%	\$1,000	5 year carryover	Not specified
CA	Solar or Wind Energy System Credit – Personal	7.5%	Not specified	7 year carryover	200 kW
HI	Residential Solar and Wind Energy Credit	35%	Varies by technology and property owner	Indefinite carryover.	Not specified
ID	Solar, Wind, and Geothermal Deduction	40% 1st year 20% next 3 years	\$5,000 per year; up to \$20,000	Not specified	
MT	Residential Alternative Energy Tax Credit	100%	\$500	4 year carryover	Not specified
ND	Geothermal, Solar and Wind Personal Credit	15% (3%/ yr for 5 years)	Not specified	Credit is taken in installments of 3% per year, over five years.	Not specified
OR	Residential Energy Tax Credit	\$3.00/W	\$6,000	10 year carryover	Not specified
UT	Renewable Energy Systems Tax Credit – Personal	25%	\$2,000	4 year carryover	Not specified

Source: Data is based on DSIRE as of November 2005 (<http://www.dsireusa.org/>).

Property Tax Incentives

Property tax incentives typically follow one of three basic structures: exemptions, exclusions, and credits. The majority of the property tax provisions for renewable energy follow a simple model that provides the added value of the renewable device is not included in the valuation of the property for taxation purposes. As shown in Table 10, eight WGA states currently have property tax incentives that apply to PV systems.

Table 10. PV Related Property Tax Incentives in WGA States

State	Title	Amount	Limit	Terms
CA	California Property Tax Exemption for Solar Systems	100% of project value	No limit	
KS	Renewable Energy Property Tax Exemption	100%		
MT	Renewable Energy Systems Exemption		\$20,000 for single family, \$100,000 multi-family & commercial	10 years
NV	Renewable Energy Systems Exemption	100%	None	
NV	Renewable Energy Producers Property Tax Exemption	50%		10 years
ND	Geothermal, Solar, and Wind Property Exemption	100%	None	5 years
OR	Renewable Energy Systems Exemption	100%		
SD	Renewable Energy Systems Exemption	50% commercial; 100% residential		For 3 years
TX	Solar and Wind-Powered Energy Systems Exemption	100%	None	

Source: Data is based on DSIRE as of November 2005 (<http://www.dsireusa.org/>).

Corporate Tax Incentives

Corporate tax incentives allow corporations to receive credits or deductions ranging from 10% to 35% against the cost of equipment or installation to promote renewable energy equipment. In some cases, the incentive decreases over time. Some states allow the tax credit only if a corporation has invested a certain dollar amount into a given renewable energy project. In most cases, there is no maximum limit imposed on the amount of the deductible or credit. As shown in Table 11, seven WGA states currently offer corporate tax incentives that can be applied to PV systems.

Table 11. PV Related Corporate Tax Incentives in WGA States

State	Title	Amount:	Maximum Incentive	Carryover Provisions	Eligible Size
CA	Solar or Wind Energy System Credit - Corporate	7.5%	Not specified	7 year carryover	> = 200 kW
HI	Corporate Solar and Wind Energy Credit	Solar Thermal and PV 35%	Varies	Unlimited carryover	Not specified
MT	Alternative Energy Investment Corporate Tax Credit	35% customer investment >= \$5000	Not specified	7 year carryover	Not specified
ND	Geothermal, Solar, and Wind Corporate Credit	15% (3% per year, for five years)	Not specified	5 year carryover	Not specified
OR	Business Energy Tax Credit	35%, distributed over five years	\$10 million	8 year carryover; 10% in 1 st -2 nd years, 5% in each year thereafter;	Not specified
TX	Solar Energy Device Franchise Tax Deduction	100% capital or 10% profit	None	1 year	Not specified
UT	Renewable Energy Systems Tax Credit - Corporate	10%	\$50,000	4 year carryover	Not specified

Source: Data is based on DSIRE as of November 2005 (<http://www.dsireusa.org/>).

Sales Tax Incentives

Sales tax incentives typically provide an exemption from the state sales tax for the cost of renewable energy equipment. As shown in Table 12, six WGA states currently provide sales tax incentives for PV systems.

Table 12. PV Related Sales Tax Incentives in WGA States

State	Title	Amount	Limit	Terms
AZ	Solar and Wind Equipment Sales Tax Exemption	100%	\$5,000 /system for retailers \$5,000 /contract for contractors	Retailer or contractor must register with the AZ Dept. of Revenue
ID	Renewable Energy Equipment Sales Tax Refund	100%	Not specified	> 25 kW
NV	Renewable Energy/Solar Sales Tax Exemption	100% local sales taxes. State sales tax reduced to 2%	Not specified	Not specified
UT	Renewable Energy Sales Tax Exemption	100%	Not specified	Systems >20 kW
WA	Sales and Use Tax Exemption	100%	200W minimum	Not specified
WY	Renewable Energy Sales Tax Exemption	100%	Not specified	Not specified

Source: Data is based on DSIRE as of November 2005 (<http://www.dsireusa.org/>).

System Benefit Charge

System Benefit Charges (SBC) are typically state-level programs created as part of the electric utility restructuring process as a measure to assure continued support for renewable energy resources, energy efficiency initiatives, and low-income support programs. Such a charge is usually unavoidable and applied to all customers based on electricity consumption, e.g., 0.2 cents/kWh. In a number of states funds raised through a SBC have been used to support rebates on renewable energy systems; funding for renewable energy R&D; and development of renewable energy education programs. As shown in Table 13, three WGA states currently have SBCs in place.

Table 13. System Benefits Charges in WGA States

State	Title	Uses	Fund Size	Customer Charge
CA	Renewable Resources Trust Fund	Renewables	\$135 million/year	2-3 mills/kWh (\$0.002/kWh - \$0.003/kWh)
MT	Universal System Benefits Program	Efficiency, renewable energy, low-income assistance	\$14.9 million annually	Electricity suppliers will annually contribute 2.4%
OR	Public Benefits Funds	Renewables, efficiency, low income, schools	\$10 million for renewables/year	3% from high demand customers

Source: Data is based on DSIRE as of November 2005 (<http://www.dsireusa.org/>).

3. Review of PV Policies Currently Under Consideration

Proposed legislation and rule changes under consideration that may affect the incentives and rates of installation of new PV are listed in Table 13. The incentives applicable to individual consumers may include tax credits, buy-downs and rebates. Mandatory regulations for utilities, such as Renewable Portfolio Standards, may create opportunities for individual and corporate installations of PV. The actions listed below were under consideration of November 2005.

Table 13. Proposed Renewable Energy Legislation and Rule Changes by State

State	Policy	Proposed Action
AZ ¹	EPS (RPS) Rule Changes	The Arizona Corporation Commission recommended (on 1/21/05) that the RPS be increased from 1% to 5% by 2015 and 15% by 2025, and the distributed generation requirement would be set at 25% of the RPS.
CA ²	California Solar Initiative	Following the demise of SB 1 (Murray/Campbell), the Governor is pursuing a California Solar Initiative that would nearly replicate SB1 through the state PUC. It is likely that the CSI would aim for 3,000 MW of solar PV, by 2018.
	RPS	AB 1585 (Blakeslee) - Would increase the RPS target to achieve 20% by 2010, 33% by 2020.
	RPS	AB 1009 (Richman) - Would utilize time-of-use pricing. Includes a provision for time of use valuation of PV.
HI ³	Net Metering	HB 1018 – Would increase individual generation capacity limit to 500 kW.
OR ⁴	Net Metering	SB 84 – Would enable the PUC to increase the system size of net metered systems.
	Solar on Public Buildings	HB 3001- Would set aside 1% of appropriations for public buildings to be used for solar.
SD ⁵	RPS	HB 1217 (Dennert) – Would require all utilities to add renewable energy equal to 50% of new electricity sold.

Sources:

1. <http://www.cc.state.az.us/utility/electric/EPS-StaffRpt-01-21-05.pdf>
2. <http://www.calseia.org/currentstate0819.htm>
3. <http://www.forsolar.org/?q=taxonomy/term/11>
4. <http://www.oregonseia.org/legislation.htm>
5. <http://legis.state.sd.us/sessions/2005/bills/HB1217p.htm>

4. A Baseline Projection for Distributed PV in the WGA States

In this section we present - a high baseline projection and a low baseline projection for distributed PV in the WGA states. These projections are based on (1) the implementation of existing solar set asides (SSA) in CO, NV, and AZ, and (2) continued growth in CA (with and without the implementation of the California Solar Initiative).

Our high and low baseline assumptions related to SSA implementation are shown in Table 14.⁶ In CO and NV the only difference between the low and high cases is the assumed share of the SSA from PV. In AZ all three factors are assumed to change between the low and high cases: that multiplier declines, the share of the SSA from PV increases, and the RPS compliance rate increases. The result, as shown in Figures 1 and 2, is that in our baseline projection we expect between 100 and 280 MW of PV to be installed in CO, NV, and AZ by 2015 due to existing SSA legislation.

Table 14. Solar Set Aside High and Low Baseline Assumptions

State	Low			High		
	PV Credit Multiplier	PV Share of SSA	RPS Compliance	PV Credit Multiplier	PV Share of SSA	RPS Compliance
CO	1.25	60%	100%	1.25	100%	100%
NV	2.4	30%	100%	2.4	80%	100%
AZ	2.5	75%	40%	1.75	100%	100%

Because of its leadership role to date, and pending legislation, CA holds a unique position within the WGA states with respect PV. Thus we will treat it separately in projecting PV capacity additions. As of the end of 2004, a total of 93 MW of PV were installed in CA primarily under the CEC and CPUC programs.⁷ A majority of the systems in CA were installed during the past 2 years (36 MW in 2003 and roughly 40 MW in 2004). In our low baseline projection we assume that the CA market continues at its current level without any growth (i.e. at 40 MW per year). Even under this very conservative assumption CA continues to be the dominant force in the WGA states with respect to PV. As shown in Figure 1, in the low baseline scenario, CA is projected to have a total installed PV capacity of 500MW in 2015 and 700MW in 2020.

⁶ Here we have followed the methodology in used in Wisner, R. and M. Bolinger. 2005. "Projecting the Impact of State Portfolio Standards on Solar Installations" Presentation prepared for the California Energy Commission (January 20).

⁷ Internal CEC record of annual installations by utility and program provided by Bill Blackburn.

Figure 1. Projected PV Installations in the WGA States – Low Baseline Scenario

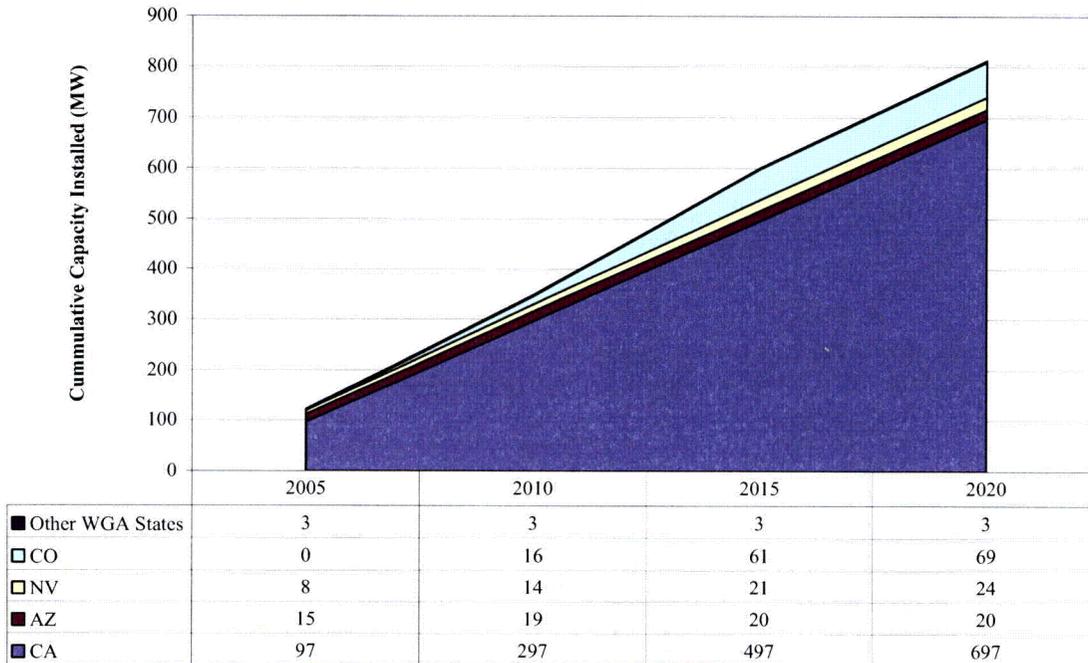
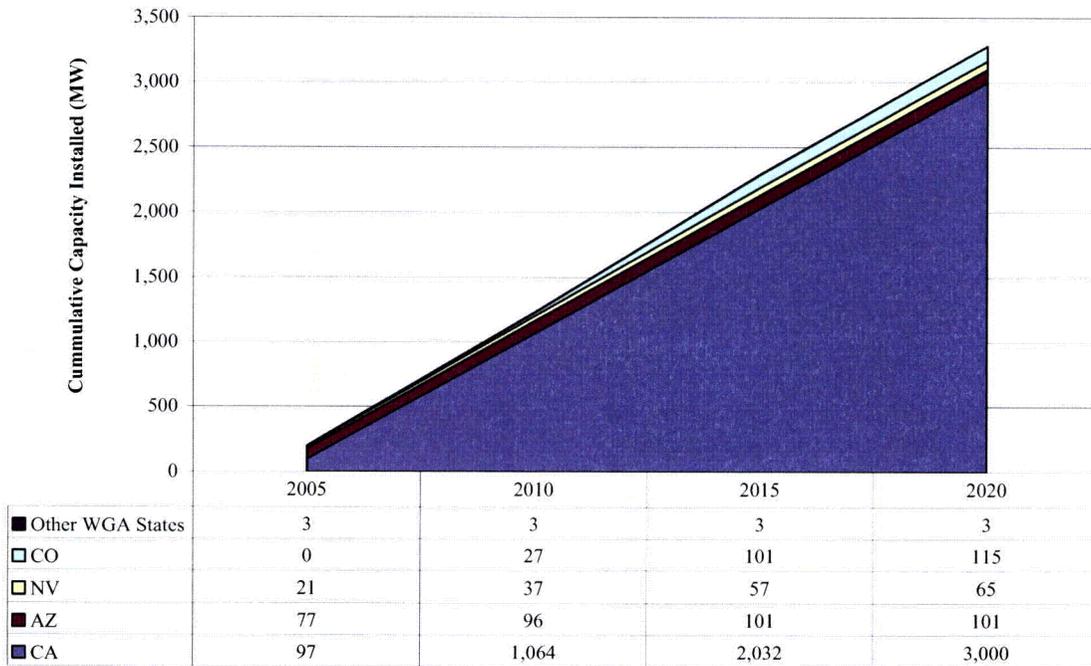


Figure 2. Projected PV Installations in the WGA States – High Baseline Scenario



In contrast, if the CSI moves forward the CA market is expected to expand dramatically and will likely dwarf all other markets in the US over the next decade. Thus, in our high baseline projection, as shown in Figure 2, we have assumed that the CSI is implemented and that the CSI goal of installing 3,000 MW by 2018 will be fully achieved by 2020. Here the total installed PV capacity in WGA states reaches 2,300 MW in 2015 and 3,300 MW in 2020.

As shown in Figures 1 and 2, CA dominates PV installation in the WGA states in both the low and high baseline scenarios, accounting for 86% and 91% respectively of total cumulative installations in 2020. In terms of the WGA goal of installing 30,000 MW of clean energy in the West by 2015, we expect PV to deliver 2-8% (600-2,300 MW) of this goal under existing SSA and CA policies, i.e., in our baseline projections. This baseline is a reasonable benchmark against which to evaluate the impact of additional distributed PV related policies in the WGA states.

5. Rooftop Availability and Resulting Capacity in the WGA States

Lack of potential rooftop area is not a barrier for distributed PV in the WGA states. In fact, distributed PV is unique among renewable technologies because of its modular ability to make use of rooftop space. Several PV studies have attempted to assess the availability of this rooftop space,⁸ the most recent being the Navigant Consulting study written for The Energy Foundation.⁹ The Navigant study assesses the market potential for grid connected rooftop PV and identifies current market barriers. It also provides an analysis of resource adequacy and energy policy for all 50 states and selects 10 top performers. This analysis presented here builds on the Navigant estimates of rooftop availability for the WGA area and evaluates the potential of rooftop PV to provide a significant fraction of the region's electricity demand. The following tables indicate that there is an extremely large resource for solar PV on rooftops.

Rooftop Availability

To estimate suitable US rooftop space, the Navigant study calculated total rooftop area from building survey data using type of building, floor-space, and number of floors as key inputs. Multiple screens were applied to this estimate to consider shading and orientation issues.¹⁰ Structural adequacy and material compatibility were also taken into consideration but were not found to pose any significant issue. Table 1 provides estimates based on Navigant of total rooftop availability on residential and commercial buildings in the WGA states. The data from the Navigant document was adjusted to estimate the building stock totals in year 2005. Industrial and non-occupied buildings such as parking structures are not included here.

Overall, the Navigant study estimated the area available for PV on Residential and Commercial buildings to be 22% and 65% respectively of their sector's total roof area. It should be noted that these fractions are based on estimates for the national average. This value might be higher or lower for western states due to lower shading impacts or larger than average HVAC requirements. This issue will be a concern only if extremely large PV deployment is projected.

⁸ Arthur D. Little. 1995 "Building-Integrated Photovoltaics (BI-PV) Analysis and US Market Potential", Prepared by Arthur D. Little, Inc. for the US Department of Energy Office of Building Technologies, NREL/TP-472-7850, DE95004055

⁹ Chaudhari, Maya, Lisa Frantzis, Tom Hoff.. 2005. "PV Grid Connected Market Potential in 2010 under a Cost Breakthrough Scenario." Prepared by Navigant Consulting for The Energy Foundation.

¹⁰ The Navigant study uses floor space data from the U.S. EIA's 2001 Residential Energy Consumption Survey and the 1999 Commercial Buildings Energy Consumption Survey. The floor space is adjusted to roof space considering number of floors, and PV available rooftop is estimated using estimates of rooftop structural compatibility, shading, and orientation. Description of screens is found on p.78-79 of the Navigant study.

Table 1: Estimated Rooftop Area Available for PV in 2005 (million feet²)

State	Residential Total	Commercial Total	State Total
AK	80	83	163
AZ	657	504	1,161
CA	4,055	3,387	7,442
CO	590	569	1,160
HA	128	119	248
ID	176	220	396
KS	343	359	703
MT	133	179	312
NE	219	231	450
NV	268	268	536
NM	237	254	491
ND	87	90	177
OR	498	457	956
SD	99	98	197
TX	3,174	2,490	5,663
UT	249	202	452
WA	845	617	1,462
WY	73	116	188
	11,911	10,244	22,156

Data is provided only for U.S. states due to data availability limitations for Pacific Islands.

Potential Rooftop Capacity

Table 2 provides an estimate for the total capacity of PV systems installed on all available rooftops in the WGA area. The capacity of commercial buildings is presented in two ways. Flat Orientation assumes that all suitable commercial rooftops are completely covered with PV. Tilted Orientation increases PV performance by optimizing energy production, but reduces the area available due to shading effects. Tilted Orientation therefore assumes a 25% decrease in available rooftop area.

Table 2: Estimated 2005 Available PV Capacity (Peak MWAC)

State	Residential Total	Commercial Total		State Total	
		Flat Orientation	Tilted Orientation	Flat Orientation	Tilted Orientation
AK	696	724	543	1,419	1,238
AZ	5,718	4,382	3,286	10,100	9,004
CA	35,279	29,467	22,100	64,746	57,379
CO	5,136	4,953	3,715	10,088	8,850
HA	1,116	1,037	778	2,153	1,894
ID	1,529	1,914	1,435	3,442	2,964
KS	2,984	3,128	2,346	6,112	5,330
MT	1,157	1,560	1,170	2,716	2,326
NE	1,909	2,010	1,508	3,919	3,416
NV	2,329	2,332	1,749	4,661	4,078
NM	2,062	2,211	1,658	4,273	3,721
ND	760	780	585	1,540	1,345
OR	4,335	3,980	2,985	8,315	7,320
SD	857	852	639	1,710	1,497
TX	27,612	21,660	16,245	49,272	43,857
UT	2,168	1,761	1,321	3,928	3,488
WA	7,352	5,371	4,028	12,723	11,380
WY	631	1,005	754	1,636	1,385
State Total	103,629	89,125	66,844	192,754	170,473

Data is provided only for U.S. states due to data availability limitations for Pacific Islands.

Potential Energy Production

The potential PV energy production can be calculated with the Table 2 estimate of rooftop capacity by applying typical solar PV capacity factors.¹¹ Capacity factors for each state were selected based on a representative city with preference for the state's population center. The use of a single capacity factor for each state may result in some errors.¹² This estimate does not include the potential application of PV to parking lot awnings or other non-occupied structures.

Table 3: Estimated Technical Potential for Rooftop PV Energy Production in 2005

State	City	Capacity Factor	Annual Potential (TWh)	Estimated Electricity Demand - 2005 (TWh)	Potential Fraction of Total Electricity from PV in 2005(%)
AK	Anchorage	9-11%	1.1-1.3	5.7	19-22
AZ	Phoenix	20-23%	16.9-19.4	65.4	26-30
CA	Long Beach, Sacramento, San Francisco	18-21%	95.3-109.8	243.5	39-45
CO	Colorado Springs	18-22%	15.1-17.6	47.4	32-37
HA	Honolulu	20-21%	3.4-3.9	10.6	32-36
ID	Boise	17-20%	4.7-5.4	21.6	22-25
KS	Topeka	16-19%	8.1-9.3	37.5	22-25
MT	Billings	16-19%	3.5-4.1	12.9	27-31
NE	Omaha	16-19%	5.1-6.0	26.4	20-23
NV	Las Vegas	20-24%	7.8-9.0	30.7	25-29
NM	Albuquerque	21-24%	7.2-8.4	19.7	37-43
ND	Fargo	15-18%	1.9-2.2	10.7	18-21
OR	Portland	13-15%	8.8-10.1	46.1	19-22
SD	Sioux Falls	16-19%	2.2-2.6	9.3	24-28
TX	Fort Worth	18-20%	72.3-83.0	329.1	22-25
UT	Salt Lake City	17-20%	5.66.5	24.3	23-27
WA	Seattle	12-14%	12.9-14.8	79.7	16-19
WY	Cheyenne	17-21%	2.32.7	13.5	17-19
Total			274.3-316.0	1034.2	27-31

These estimates indicate that existing rooftop space is not a significant limitation to large-scale distributed PV deployment in the Western States and could provide nearly one-third of electricity demand. Assuming building stock grows at the same rate as electricity demand, this fraction could be expected to remain nearly constant. However, if PV efficiency increases at a rate faster than building energy intensity, this fraction could significantly increase. Use of rooftop resources such as parking lot awnings and bus stops could extend PV's contribution to the western state's electricity demand well beyond one-third.

¹¹ The capacity factors were derived by using NREL's PVWatts PV simulation program:
http://rredc.nrel.gov/solar/codes_algs/PVWATTS/version1/

¹² The highest probability of error will exist in states that are large; (CA, TX) or with varied insolation (WA, OR).

6. Projecting PV Related Jobs in the WGA States

In projecting the growth of PV related jobs in the WGA states we started with the most recent estimate of jobs involved in manufacturing and installing PV systems (based on production and installation in a given year), and O&M for PV systems (based on total installed capacity in a given year). These two factors were drawn from a report published by the Renewable Energy Policy Project (REPP) in 2001. This report estimated that for PV systems there are 33 jobs per MW involved in production and installation, and 0.25 jobs per MW involved in O&M (actual estimate was 2.5 jobs/MW over 10 years, we divided this number by 10 to create an annual O&M number). We then used the cost reductions projected for PV systems over the next 10 years to create a jobs index. This index reflects the fact that as costs decline jobs will also decline. In other words, labor productivity is assumed to increase in proportion to overall systems cost reductions, resulting in a one-to-one correspondence between declining cost and job intensity. We then used this jobs index to scale down the projected production and installation jobs per MW and the O&M jobs per MW. The resulting PV related employment projection is shown in Table 1.

Table 1: Projected PV Related Jobs in the WGA States

	2005	2010	2015
Ave. Installed Cost (\$/kW)	8.00	5.50	4.00
Jobs Index	1	0.69	0.50
Annual Installed Capacity (MW)	64	250	1,000
Cumulative Installed Capacity (MW)	170 ¹	1,000	4,000
Manufact/Install Jobs per MW ²	33	22.7	16.5
O&M Jobs per MW	.25	.2	.1
Total Industry Jobs (thousands)	2.1	5.7	17.5

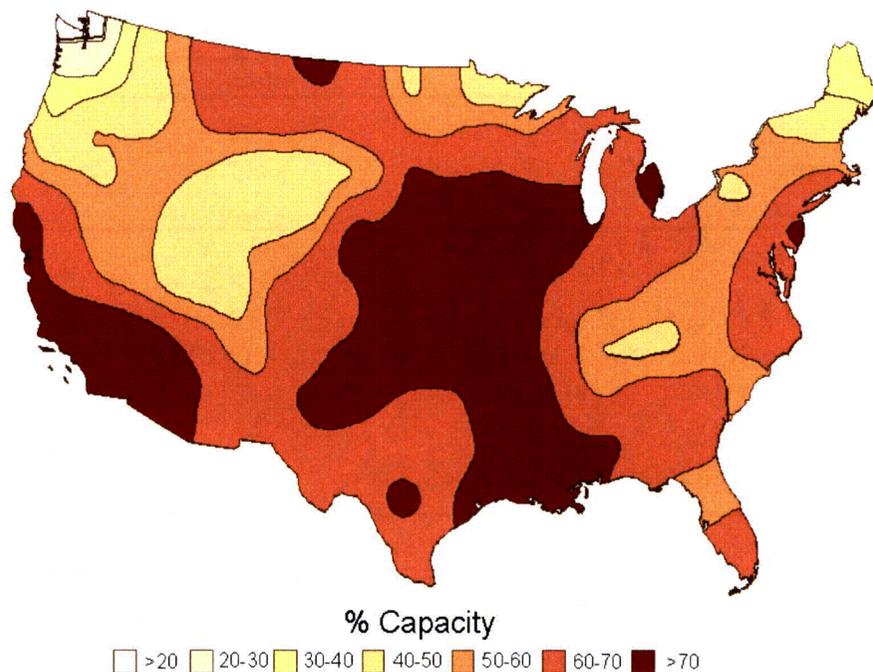
¹Estimated cumulative capacity includes sum of end year 2004 WGA installations in Appendix 1, Table 2 plus estimated 2005 additions.

²A typical full time job includes 1,960 hours of work per year assuming a 40-hour work week and two weeks vacation. This remains constant throughout the timeframe of the analysis.

7. Effective Load Carrying Capacity (ELCC) in the WGA States

Effective Load Carrying Capacity (ELCC) represents the relationship between load shape and resource availability (insolation) in a particular area. Specifically, it describes the fraction of nameplate capacity that can be expected to be available during peak demand. ELCC is greatest in areas with intense summer heat waves (where heavy cooling loads drive peak demand), high daytime commercial demand, and/or small electric-heating demand. Such areas with high daytime loads allow PV to provide maximum support to the grid when it is most constrained. Areas with high ELCC include not only the Southwest, but also areas in the Mid-West and Deep South as shown in Figure 1¹³.

Figure 1: Effective Load Carrying Capacity (ELCC) Map.



As evident in Figure 1, the majority of WGA states have an ELCC greater than 60% on average. In the mountainous areas of Washington, Oregon, Idaho, Utah, and Colorado, ELCC averages around 50%. Assuming an average ELCC of 60% would imply that achieving the task force's 4,000 MW goal for distributed PV, could offset roughly 5% of the WGA region's projected growth in peak demand.¹⁴

¹³ Herig, Christy, et al. 1996. "Photovoltaics Can Add Capacity to the Utility Grid". National Renewable Energy Laboratory, Golden, CO. Report DOE/GO-10096-262.

¹⁴ Specifically, EIA forecasts growth in peak demand for the WECC and ERCOT subregions of about 2.4% between 2004-2008. We extended EIA's forecast for the WECC and ERCOT subregions to 2015, which results in additional demand of about 50 GW by 2015 (from a starting point of 189 GW in 2005). These two subregions represent over 85% of the WGA's total demand. Source: <http://www.eia.doe.gov/cneaf/electricity/epa/epat3p1.html>

8. Avoided CO2 Emissions

Grid-connected photovoltaics offset fossil fuel generators and avoid the emission of CO2 during daytime hours. Within the WGA region, 4,000 MW of PV can be expected to avoid the emission of 4 - 4.8 million metric tons of CO2 annually. This estimate is based on the assumption that PV offsets fossil fuel generators comprised of 75% natural gas and 25% coal.¹⁵ In addition, it is conservatively estimated that the annual generation from PV would be within a range of 5 to 6 billion kilowatt hours.

Fossil fuel generators burning coal emit CO2 at a higher rate than those burning natural gas. In the US in 2002, the rate of CO2 emission was nearly twice as great for coal as natural gas as illustrated in Table 1.

Table 1: US Emissions of CO2 by Fuel

	Natural Gas	Coal
2002 CO2 Emissions (Million Metric Tons of CO2)	299.1	1,874.7
2002 Electricity Generation (Billion kWh)	607.7	1910.6
CO2 Emission Rate (kg CO2/kWh)	0.492	0.981

EIA Annual Energy Review 2003, Tables 8.2b and 12.3

A 75% natural gas and 25% coal fuel mix would result in a CO2 emission rate of 0.614 kg/kWh. Based on this emission rate, between 4 and 4.8 million metric tons of CO2 emissions would be avoided. This range is illustrated in Table 2.

Table 2: Avoided CO2 Emissions in WGA Region

	Low (5 billion kWh)	High (6 billion kWh)
Avoided Emission Rate kg/kWh	0.614	0.614
Million metric tons CO2	4.0	4.8
Million metric tons carbon	1.1	1.3

The factors governing the CO2 emissions avoided by PV are primarily 1) the type of fossil fuel displaced in regional power plants, and 2) how closely the time, amount and duration of electrical demand coincides with electricity generation by PV.

¹⁵ Locally, measuring the quantity of avoided CO2 emissions requires knowledge of the emission rates of the displaced fossil fuels as well as the average capacity factor of the PV. Each state in the WGA territory has a different average capacity factor for PV and a different mixture of power plants each with a unique profile of CO2 emissions based upon its fuel, efficiency, and time of operation.

9. Avoided Water Use

PV offsets the use of conventional energy generation sources and avoids the use of water for cooling and other processes. 4,000 MW of PV installed within the WGA territory will reduce the quantity of water lost to evaporation by between 2.5 and 5 million gallons per day. This is illustrated in Table 1.

Table 1: Daily Avoided use of Water from 4,000MW of PV

	Low	High	Units
PV Installed	4000	4000	MW
PV Generation	5	6	Billion kWh
Conventional Water Use Rate	0.18*	0.3**	Gallons/kWh
Annual Avoided Water Use by PV	2.5	4.9	Million Gallons/Day

*Equals the average consumption of water by a natural gas combined cycle plant with recirculating cooling system

**Equal to a 75-25 ratio of the technology representing the low end of the range and a steam cycle coal fired plant with recirculating cooling.¹⁶

According to the American Water Works Association (AWWA),¹⁷ the average household use of water in the US is 350 gallons per day. The water savings from 4,000MW of PV would supply enough water to supply between 7,000 and 14,000 households.

Large water demands in arid regions have begun to be sighted as reasons for not issuing construction permits to power plant developers. The ability for PV to offset the need for water as cooling of conventional power plants is coincident with peak water demand in most of the WGA region. Water storage, distribution, and consumption is nearly analogous to the modern energy system. Prices fluctuate as each resource and its transport become constrained. Peak demand for water by power plants (for cooling purposes during hot summer months) is coincident with peak demand for power to pump water to customers. The avoided use of water is as only as valuable as the market for water determines. However, water is a finite resource and scarcity only increases its value.

¹⁶ Clean Air Task Force. 2003. "The Last Straw: Water Use by Power Plants in the Arid West" Hewlett Foundation

¹⁷ <http://www.awwa.org/Advocacy/learn/conserve/resources/ConservationInfo.cfm>

10. Calculating/Projecting the Levelized Cost of Energy for PV Systems

In calculating the levelized cost of energy (LCOE) for PV systems it is important to state one's assumptions and methodology. For example, factors such as system costs, system performance, financing and policies can have a significant impact on the calculated LCOE. In estimating the current and projected range of LCOE for distributed PV we included estimates for both commercial and residential systems. In Table 1 we show a simplified set of assumptions for projecting LCOE in the residential and commercial sectors. The assumptions shown in Table 1 represent systems that are installed well in a good location at aggressive but well documented prices. These estimates are in line with the recently published PV industry roadmap¹⁸ and draft DOE Solar Energy Technologies Program Multi-Year Program Plan¹⁹. They include the permanent federal 10% ITC and accelerated depreciation for commercial systems, but do not include any incentives (state or federal) for residential systems.

Table 1. Current and Projected Levelized Cost of Energy for PV Systems

	Residential Systems (no incentives)			Commercial Systems (w/ ITC and MACRS)		
	2005	2010	2015	2005	2010	2015
Year	2005	2010	2015	2005	2010	2015
Interest Rate (real) (i) *	4.0%	4.0%	4.0%	5.0%	5.0%	5.0%
System Lifetime (n)	25	30	30	25	30	30
Capital Recovery Factor (CRF)	0.064	0.058	0.058	0.071	0.065	0.065
System Selling Price (\$/Wdc)	7.30	5.17	3.89	6.00	4.41	3.60
AC-DC Conversion Efficiency (%)	91%	94%	97%	93%	95%	97%
AC Equiv. System Price (\$/Wac)	8.02	5.50	4.01	6.45	4.64	3.71
Fed ITC Rate (at permanent 10% level)	-	-	-	10%	10%	10%
Value of Fed ITC	-	-	-	0.65	0.46	0.37
Sys Cost after Fed ITC	-	-	-	5.81	4.18	3.34
Fed Accelerated Depreciation (Net Present Value)**	-	-	-	34%	34%	34%
Value of Fed Acc Dep. (basis = .95*system cost)	-	-	-	2.08	1.50	1.20
Final Cost (\$/Wac) (ICC)	8.02	5.50	4.01	3.72	2.68	2.14
Capacity Factor (CF)	21%	21%	21%	18.5%	18.5%	18.5%
O&M	0.02	0.01	0.005	0.02	0.01	0.005
Levelized Cost of Energy (LCOE) (cents/kWh)***	29.9	18.3	13.1	18.3	11.8	9.1

* These are real interest rates (i.e., adjusted for inflation and tax benefits) not nominal interest rates.

** Based on MACRS rates from IRS Publication 946, Table A-2 (assuming investment is made in 1st quarter of the year).

*** The LCOE values were calculated using the standard formula for amortization of cost over time, assuming the system is financed through a loan matched to the lifetime of the system.

$LEC = (ICC \times 1000 \times CRF) / (CF \times 8760) + O\&M$, where

ICC = Installed Capacity Cost (\$/Wp),

CRF = Capital Recovery Factor = $(i \cdot (i+1)^n) / ((i+1)^n - 1)$,

CF = Capacity Factor,

O&M = Operation and Maintenance (\$/kWh),

i = interest rate,

n = system lifetime (i.e, how many years to amortize cost of system over).

¹⁸ Solar Energy Industries Association. 2004. *Our Solar Power Future: The U.S. Photovoltaic Industry Roadmap Through 2030 and Beyond*. Solar Energy Industries Association, Washington, DC.

¹⁹ U.S. Department of Energy. 2005 (Draft). *Solar Energy Technologies Program Multi-Year Program Plan 2007-2011*. Office of Energy Efficiency and Renewable Energy, U.S. Department of Energy, Washington, DC.

11. State-by-State Allocation of the Distributed PV Target

There are a number of ways one could define a state-by-state allocation of the solar task force's 4,000 MW target for distributed PV in 2015. We chose to use electricity demand weighted by average insolation, average electricity prices, and projected population growth. Table 1 shows the data used in this weighting process and the resulting targets for each state. Note that the targets for CA and TX were set separately – CA was set at 2,000 MW in 2015 to reflect the goals of the California Solar Initiative (likely to be implemented through the California Public Utilities Commission) and TX was set at 350 MW based on input from task force members (this was viewed a reasonable target given current discussions in TX on expanding its RPS).

We also experimented with other initial allocation and weighting schemes, but felt that the approach adopted in Table 1 was the most intuitive and easiest to understand. This approach captures the notion that each state should contribute towards the task force's 2015 target in proportion to its size (reflected in demand), but that resource availability, cost of electricity (which is related to the value of the PV output), and projected population growth (which is a reasonable proxy for demand growth) are also important. The values shown in the last column of Table 1 were used to rank the states and to set target ranges for groups of states as follows:

- 1) 300-400 MW - AZ and TX,
- 2) 100-200 MW - CO, WA, NV, OR, and KS,
- 3) 50-100 MW - HI, NM, UT, NE, and ID,
- 4) 25-50 MW - MT, ND, WY, SD, and AK.

With these ranges a majority of the WGA states, but not all of the WGA states, would need take action to meet the task force's 4,000 MW target for distributed PV in 2015.

Table 1. State-by-State Targets for Distributed PV in 2015

State	Electricity Demand (TWh) ¹	Initial Share	Solar Insolation (kWh/kW) ²	Insolation Multiplier	Average Electricity Price 2003 (¢/kWh) ³	Electricity Price Multiplier 2003	Population 2005 (million) ⁴	Population 2015 (million) ⁴	10 Year Population Growth Index	Population Growth Multiplier	Final Share ⁵	Final Allocation (MW)
CA	243.5	na	1,708	na	11.6	Na	36.039	40.123	1.11	na	na	2000
TX	329.1	na	1664	na	7.5	Na	22.775	24.649	1.08	na	na	353
AZ	65.4	14.2%	1,883	1.19	7.3	1.16	5.868	7.495	1.28	1.17	21%	353
CO	47.4	10.3%	1752	1.11	6.8	1.08	4.618	5.049	1.09	1.00	12%	190
WA	79.7	17.3%	1139	0.72	5.9	0.94	6.205	6.951	1.12	1.03	11%	184
NV	30.7	6.7%	1927	1.22	5.6	0.89	2.352	3.058	1.30	1.19	8%	132
OR	46.1	10.0%	1226	0.78	6.2	0.98	3.596	4.013	1.12	1.02	7%	120
KS	37.5	8.1%	1533	0.97	6.4	1.02	2.752	2.853	1.04	0.95	7%	117
HI	10.6	2.3%	1796	1.14	14.5	2.30	1.277	1.386	1.09	1.00	6%	92
NM	19.7	4.3%	1971	1.25	7.0	1.11	1.902	2.042	1.07	0.99	5%	90
UT	24.3	5.3%	1621	1.03	5.4	0.86	2.418	2.783	1.15	1.06	5%	75
NE	26.4	5.7%	1533	0.97	5.5	0.87	1.744	1.789	1.03	0.94	4%	70
ID	21.6	4.7%	1621	1.03	5.2	0.83	1.407	1.630	1.16	1.06	4%	65
MT	12.9	2.8%	1533	0.97	6.2	0.98	0.933	0.999	1.07	0.98	2%	40
ND	10.7	2.3%	1445	0.92	8.3	1.32	0.635	0.635	1.00	0.92	2%	39
WY	13.5	2.9%	1664	1.06	4.8	0.76	0.507	0.528	1.04	0.96	2%	34
SD	9.3	2.0%	1533	0.97	6.4	1.02	0.772	0.797	1.03	0.95	2%	29
AK	5.7	1.2%	876	0.56	10.5	1.67	0.661	0.733	1.11	1.02	1%	18
Median			1,577		6.3				1.09			

Notes:

1. Electricity demand: U.S. Department of Energy. 2004 (December). *Electric Power Annual 2003*, Energy Information Administration, U.S. Department of Energy, Washington, DC.
2. Solar insolation: Data was calculated from capacity factors derived using NREL's PVWatts PV simulation program. For each state, a representative city was chosen, based on the availability of data near the state's largest population center. Three cities were chosen in California. This limited data set will result in some errors, particularly in larger states, or in states with greatly varied solar resources such as Washington and Oregon. PV Watts Web address: http://rredc.nrel.gov/solar/codes_algs/PVWATTS/version1/
3. Average electricity prices: U.S. Department of Energy. 2004 (December). *Electric Power Annual 2003*, Energy Information Administration, U.S. Department of Energy, Washington, DC.
4. Population in 2005 and 2015: US Census Bureau <http://www.census.gov/population/www/projections/projectionsagesex.html>
5. The insolation, electricity price and population growth multipliers were calculated relative to the median value for each variable. After multiplying the initial shares by the three multipliers, the final shares were re-normalized to sum to 100%.

Appendix II-2. Background on Installing 500,000 Solar Water Heating Systems Over 10 Years

The 2,000 MW_{th} target is based on worldwide growth in the solar thermal industry. Many of the European Union and the other countries listed have incentive programs or standing policies similar to what is being proposed for the WGA Solar Initiative, which have led to significant growth in the market for solar thermal systems. Considering the subset of European Union countries listed below where solar thermal activity is occurring, their population of 380 million citizens are installing over half a million solar water heating systems per year, whereas with a population of over 297 million in the United States, just over 10,000 systems per year are being installed.

With the advent of the federal tax credit set to take effect in 2006, with the prospect of incentives stemming from this WGA incentive phasing in over the next several years, with the cost of natural gas and electricity poised to rise, and with numerous foreign solar thermal equipment manufacturers beginning to enter the US market, a significant ramp-up in solar thermal system sales appears inevitable. The western US should be easily able to accomplish in ten years what the European Union countries alone are achieving in less than two.

	<u>MWth 1999¹</u>	<u>MWth 2003²</u>	<u>% Increase (Decrease)</u>	<u># Systems Installed</u>
<u>European Union³</u>				
• Austria (EUR)	98.81	116.8	18	33,288
• Belgium (EUR)	1.05	6.3	600	1,796
• Denmark	10.78	5.6	(49)	1,596
• Finland (EUR)	1.12	1.1	(1)	314
• France (EUR)	16.80	58.7	249	16,730
• Germany (EUR)	294.00	504.0	71	143,640
• Greece (EUR)	112.78	88.2	(22)	25,137
• Ireland (EUR)		0.7		200
• Italy (EUR)	33.6	39.9	18	11,371
• Netherlands (EUR)	19.6	19.4	(1)	5,529
• Portugal (EUR)	5.95	6.4	8	1,824
• Spain (EUR)	15.11	48.5	221	13,823
• Sweden	6.65	13.5	103	3,848
• United Kingdom of Great Britain and Northern Ireland	6.3	15.4	144	4,389
	Total MW_{th} 2003	924.5	Total Systems 2003	263,575
<u>Other</u>				
• Japan	214.73	196.3	(9)	55,946
• Australia		93.8		26,733
• China		7,980.00		2,274,300
• India		70.0		19,950
• Israel		280.0		79,800
• Turkey		560.0		159,600
• United States	27.31	36.4	33	10,374

¹ Solar Heating Worldwide; Markets and Contribution to the Energy Supply 2003 IEA Solar Heating and Cooling Programme, May 2005; Appendix 6, pg. 25 "Annual Installed Capacity"

² Ibid., pg. 29

³ Population of European Union countries below (not all listed) – 380,270,826 (2005 Estimated)

Expressing Solar Thermal Energy Production in terms of Electrical Energy Production Equivalent

In September 2004, stakeholders from Austria, Canada, Germany, the Netherlands, Sweden and the USA, as well as the European Solar Thermal Industry Federation (ESTIF) and the International Energy Agency's Solar Heating and Cooling Programme, agreed to use a factor of $0.7 \text{ kW}_{\text{th}}/\text{m}^2$ to derive the nominal equivalent electrical generation capacity from the area of installed solar thermal collectors. Until then, installed solar thermal capacity had traditionally been counted by numerous countries and other entities in terms of square meters of collector area, a unit not comparable with other renewable energy technology statistics, which are usually based on peak generation capacity under an accepted set of ambient conditions. Prior to the European decision, in 2003 the US-based Solar Rating & Certification Corporation reached a similar conclusion, reporting on its website:

<http://www.solar-rating.org/solarfacts/energyproduction20011017.pdf>

that a square meter of solar thermal collector had an equivalency factor of $0.71 \text{ kW}_{\text{th}}/\text{m}^2$ or approximately 4 kW per 64 square foot solar water heating system.

Since solar water heating systems will vary in size in the WGA states based on climatic conditions, an average system size of 52.5 square feet (5 m^2) net aperture is used here to reflect a single residential system with a $3.5 \text{ kW}_{\text{th}}$ capacity. Thus, 500,000 systems totalling $2,500,000 \text{ m}^2$ at $0.7 \text{ kW}_{\text{th}}/\text{m}^2$ is equivalent to $1,750 \text{ MW}_{\text{th}}$ equivalent generating capacity.

Reference the attached document: Technical Note on the Conversion Factor provided by ESTIF:

<http://www.estif.org/143.0.html>

APPENDIX II-3. POLICY OPTIONS TO ENCOURAGE WIDESPREAD ADOPTION OF DISTRIBUTED SOLAR

Objectives	Strategies	Tactics	Policy & Program Options
Provide financial incentives to stimulate market	Provide tax incentives	▪ Federal incentives	▪ Extend 30% ITC (including IOUs) for 10 years ▪ Continued support for accelerated treatment of depreciation
		▪ State incentives	▪ Sales and property tax exemption ▪ Tax credit for distributed generation investments ▪ Manufacturing tax credits
	Provide direct incentives	▪ Capital cost subsidies	▪ Up-front, declining buy-downs for PV and thermal that attain targeted payback periods for system owners
		▪ Production-based subsidies	▪ Performance-based incentives such as per-kWh payments over guaranteed period of time
Facilitate easy access to solar	Maximize availability of solar resource	▪ Solar access	▪ Solar enterprise zones ▪ Statewide solar access rules/solar “rights” policies
	Expedite development	▪ Permits & approvals	▪ Streamline siting, permitting, zoning
▪ Common interconnection standards		▪ Allow for the connection of pre-certified systems ▪ Establish reasonable timelines for utility responses to applications ▪ Eliminate undue fees and insurance requirements ▪ Establish dispute-resolution process ▪ Transparency & consistency among utilities and states	
Provide ongoing support	Demonstrate leadership	▪ Advocacy	▪ Encourage “Zero Energy Buildings” ▪ Public education programs to promote efficiency, alt. energy
		▪ Public purchasing	▪ Purchase distributed solar for public buildings ▪ Purchase solar under long term power purchase agreements
		▪ Regulatory & market stability	▪ Establish stable, long-term programs (minimum 10 years) ▪ Structure incentive programs to attract investment (e.g, 10-year payback for residential, 5 years for businesses) ▪ Design programs to support self-sustaining markets ▪ Encourage participation by publicly owned utilities
		▪ Low-cost capital	▪ Tax-free solar bonds for public projects ▪ Long-term debt financing ▪ Government guarantees (loan or performance) ▪ Public-private partnerships
	Encourage optimized production	▪ Net metering	▪ Credit customer for excess energy generated and supplied to the grid
		▪ Alternative rates	▪ Encourage optional rate structures that incentivize PV including time-of-use tariffs
		▪ Create revenue stream	▪ REC trading and ownership