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Renewable Energy 2000: Issues and Trends

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Preface

Renewable Energy 2000: Issues and Trends

Renewable Energy 2000: Issues and Trends, the second in a series of biannual reports, presents four articles that cover various aspects of renewable energy. The first article covers financial incentives, regulatory mandates, and Federal research and development (R&D) programs for renewable energy in general, including renewable transportation fuels. The remaining articles analyze issues specific to a particular resource or technology.

In a time of electricity deregulation, States and the Federal Government are debating the pros and cons of government programs to support renewable energy. "Incentives, Mandates, and Government Programs for Promoting Renewable Energy" examines the role that these programs have played in the past in these markets, and analyzes their characteristics in terms of meeting their objectives.

Due to domestic programs like the Federal Million Solar Roofs Initiative and increasing electrification worldwide, niche markets are expanding for solar photovoltaic (PV) applications. "Technology, Manufacturing, and Market Trends in the U.S. and International Photovoltaics Industry" presents a comprehensive analysis of the current status and the near-term prospects for global PV market growth in terms of both supply and demand. Growth in the municipal waste combustion (MWC) industry leveled-off in the 1990's after rapid growth in the 1980's. This trend is partly attributed to unfavorable economics at MWC facilities relative to less expensive

waste disposal alternatives such as landfilling. "The Impact of Environmental Regulation on Capital Costs of Municipal Waste Combustion Facilities: 1960-1998" examines the impact of increasingly stringent environmental regulations on the capital cost of constructing and retrofitting MWC facilities.

There is much interest in the economics of wind energy, because it is the non-hydroelectric renewable resource whose cost of producing electricity is the closest to that of conventional baseload power. A new vintage of wind turbine technology is becoming operational, and the question is how much more efficient are these turbines. Today's turbines are larger and more efficient than their predecessors, promising increased production and lower costs. "Forces Behind Wind Power" examines the factors that affect turbine performance, including siting factors and their physical and operational characteristics. In addition, the article discusses the effects of the restructuring of the electric power industry, and Federal and State incentives on the wind industry. The status of State-level wind energy activities is provided in an appendix.

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Incentives, Mandates, and Government Programs for Promoting Renewable Energy

by Mark Glelecki, Fred Mayes, and Lawrence Prete

Introduction

Over the years, incentives and mandates for renewable energy have been used to advance different energy policies, such as ensuring energy security or promoting environmentally benign energy sources. Renewable energy has beneficial attributes, such as low emissions and replenishable energy supply, that are not fully reflected in the market price. Accordingly, governments have used a variety of programs to promote renewable energy resources, technologies, and renewable-based transportation fuels.¹ This paper discusses: (1) financial incentives and regulatory mandates used by Federal and State governments and Federal research and development (R&D),^{2,3} and (2) their effectiveness in promoting renewables.

A financial incentive is defined in this report as providing one or more of the following benefits:

- A transfer of economic resources by the Government to the buyer or seller of a good or service that has the effect of reducing the price paid, or, increasing the price received, respectively;
- Reducing the cost of production of the good or service; or,
- Creating or expanding a market for producers.

The intended effect of a financial incentive is to increase the production or consumption of the good or service over what it otherwise would have been without the incentive. Examples of financial incentives are: tax credits, production payments, trust funds, and low-cost loans. Research and development is included as a support program because its effect is to decrease cost, thus enhancing the commercial viability of the good(s) provided.⁴

Regulatory mandates include both actions required by legislation and regulatory agencies (Federal or State). Examples of regulatory mandates are: requiring utilities to purchase power from nonutilities and requiring the incorporation of environmental impacts and other social costs in energy planning (full cost pricing). Another example is a requirement for a minimum percentage of generation from renewable energy sources (viz., a "renewable portfolio standard," or, RPS). Regulatory mandates and financial incentives can produce similar results, but regulatory mandates generally require no expenditures or loss of revenue by the Government.

It is very difficult to quantify total resource expenditures resulting from even just direct financial incentives, due to the large number of energy incentives that have been enacted over the past quarter of a century.⁵ In addition, the resulting interactive effect of these incentives makes

¹ A renewable energy source is one that is regenerative or virtually inexhaustible. It includes biomass, geothermal, hydro (water), municipal solid waste, solar photovoltaic, solar thermal, and wind use in the electric utility, or transportation sector.

² The term "incentive" is used instead of "subsidy." Incentives include subsidies in addition to other Government actions where the Government's financial assistance is indirect. A subsidy is, generally, financial assistance granted by the Government to firms and individuals.

³ The incentives examined in this article refer only to resource-based incentives. Also, this report excludes discussion of local government incentives.

⁴ "Determining the extent to which Government energy R&D is a subsidy is ... problematic: often it takes the form of a direct payment to producers or consumers, but the payment is not tied to the production or consumption of energy in the present. If successful, Federal-applied R&D will affect future energy prices and costs, and so could be considered an indirect subsidy." Energy Information Administration, *Federal Energy Subsidies: Direct and Indirect Interventions in Energy Markets*, SR/EMEU/92-02 (Washington, DC, November 1992), p. 3. In addition, Government R&D substitutes for private R&D expenditures.

⁵ An effort to quantify expenditures in non-energy areas is shown in an Office of Management and Budget (OMB) study, *Report to Congress on the Costs and Benefits of Federal Regulations* (Washington, DC, September 30, 1997). The report estimates the net benefits from Federal health, safety, and environmental regulations at between \$30 billion and \$3.3 trillion annually, with costs to implement them falling somewhere between \$170 billion and \$230 billion.

it extremely difficult to correlate the effect of any one incentive on a specific energy program or on the economy. A 1992 Energy Information Administration (EIA) report⁶ estimated the annual cost for Federal energy subsidies in 1990 of between \$5 billion and \$10 billion. EIA recently updated certain portions of this study in order to update cost estimates for continuing subsidies and to provide cost estimates for new subsidies for primary energy sources only (i.e., excluding electricity).⁷ This report estimated the value of Federal financial "interventions and subsidies" for renewable energy at \$1.3 billion. Of this amount, \$725 million represents the reduction in excise tax for alcohol motor fuels.⁸

Whereas these EIA subsidy reports discussed the scope of Federal energy subsidies and attempted to measure the cost of all energy subsidies, this article differs from those studies in three ways. First, this article focuses on regulatory and legislative mandates, as well as, financial incentives and Federal R&D for renewable energy, including renewable transportation fuels. Federal R&D is included because its cost to the government is well measured by the Federal budget process, and R&D is integral to lowering costs and/or reducing the time it takes for renewable technologies to become commercially viable. Second, this article does not measure the total cost of incentives, though it does provide some measures related to incentive costs. Finally, this article provides an assessment of the aggregate impact of the various programs for promoting renewable energy.

Generally speaking, Government policies have goals, while incentives, mandates, and Government programs in support of those policies have more specifically stated objectives. One gauge of the effectiveness of these measures can be the progress made toward meeting objectives. The following criteria are used to evaluate the incentives, mandates, and programs discussed in this article:

- Growth in electric generating capacity using renewable resources
- Growth in electricity generation by renewable resources
- Growth in the production of ethanol fuels

- Reduction in cost of the renewable technology/or cost competitiveness in the market
- Cost to consumers
- Market sustainability of the renewable technologies.

Sustainability of the renewable technology in a competitive market is an ultimate long-term goal.

Federal Incentives, Mandates, and Programs for Renewable Energy

In response to energy security concerns of the mid-1970s, President Carter signed into law the National Energy Act of 1978 (NEA), a compendium of five bills that sought to decrease the Nation's dependence on foreign oil and increase domestic energy conservation and efficiency. A major regulatory mandate that has encouraged renewable energy, the Public Utility Regulatory Policies Act of 1978 (PURPA), was established as a result of the NEA. Most of the remaining Federal renewable energy legislation enacted since the late 1970s are financial.

Regulatory Mandates

Public Utility Regulatory Policies Act of 1978

PURPA was the most significant section of the National Energy Act in fostering the development of facilities to generate electricity from renewable energy sources.⁹ However, with the electric power industry challenging its legality and implementation issues, the broad application of PURPA did not occur until after the legality of PURPA was upheld in 1981. PURPA opened the door to competition in the U.S. electricity supply market by requiring utilities to buy electricity from qualifying facilities (QFs). QFs are defined as nonutility facilities that produce electric power using cogeneration technology, or power plants no greater than 80 megawatts

⁶ Energy Information Administration, *Federal Energy Subsidies: Direct and Indirect Interventions in Energy Markets*, SR/EME/92-02 (Washington, DC, November 1992).

⁷ Energy Information Administration, *Federal Financial Intervention and Subsidies in Energy Markets 1999: Primary Energy*, SR/OIAF/99-03 (Washington, DC, September 1999).

⁸ *Ibid.*, Table 5, p. 15. Includes: Renewable Energy Production Incentive, Alternative Fuel Production Credit, Alcohol Fuel Credit, Research and Development for renewable energy, and the Federal Energy Management Program.

⁹ For an extensive discussion of PURPA, see Energy Information Administration, *Changing Structure of the Electric Power Industry: An Update*, DOE/EIA-0562 (96) (Washington, DC, December 1996).

of capacity¹⁰ that use renewable energy sources. There is no size restriction for cogeneration plants; however, at least 5 percent of the energy output from a qualifying cogeneration facility must be dedicated to "useful" thermal applications.

Under PURPA, utilities are required to purchase electricity from QFs at the utilities' "avoided cost."¹¹ The Federal government, in formulating regulations, often delegates implementation to the States. This occurred with PURPA, as the Federal Energy Regulatory Commission (FERC) delegated the authority for the determination of avoided cost to the States. In several States including California, avoided cost purchase contracts were very favorable to non-utility generators. For example, between 1982 and 1988, Standard Offer 4 (SO4) contracts written in California allowed QFs to sell renewable energy under 15-to-30 year terms. The contract guarantees fixed payment rates (based on forecasted short-run avoided costs) for up to 10 years if the QF has signed a contract for at least 20 years. After the 10th year, energy prices moved to the short-run avoided cost of the purchasing utility. The 10-year provisions were tied to forecasts of increases in oil and gas prices, and were the basis for the fixed payments for the first ten years of the contracts. The forecasts were much higher than prices actually turned out to be. Therefore, a price and revenue drop occurred in the eleventh year when the fixed contract energy prices converted to variable prices (based on short-term avoided cost), greatly lessening the economic viability of affected projects.

Financial Incentives

The major Federal legislation on financial incentives for renewable energy and renewable transportation fuels has been structured as tax credits and production

incentive payments. (See Tables 1 and 2 for a summary of major Federal provisions that affect renewable energy and renewable-based transportation fuels, respectively.) For renewable energy, tax credits for purchases of renewable energy equipment were aimed at both the residential and business sectors. Accelerated depreciation of renewable energy equipment and production incentives were aimed at investors. From 1978 through 1998, similar types of tax credits have been in existence. Over time, the various laws have usually expanded the technologies covered, increased the credit amount, or extended the time period.

Two new types of financial incentives were introduced as part of the Energy Policy Act of 1992 (EPACT)—a production tax credit (PTC) and a renewable energy production incentive (REPI). The PTC is a 1.5 cents-per-kilowatt-hour (kWh) payment, payable for 10 years, to private investors as well as to investor-owned electric utilities for electricity from wind and closed-loop biomass facilities. The REPI provides a 1.5 cents-per-kWh incentive, subject to annual congressional appropriations, for generation from biomass (except municipal solid waste), geothermal (except dry steam), wind and solar from tax-exempt publicly owned utilities, local and county governments, and rural cooperatives.

For renewable transportation fuels, tax credits and tax exemptions are used to promote the use of renewable fuels, with the goal of displacing petroleum use in the transportation sector. There are four¹² Federal tax subsidies for the production and use of alcohol transportation fuels: (1) a 5.4-cents-per-gallon excise tax exemption,¹³ (2) a 54-cents-per-gallon blender's tax credit,¹⁴ (3) a 10-cents-per-gallon small ethanol production tax credit,¹⁵ and (4) the alternative fuels production tax.

¹⁰ In 1990, the Solar, Wind, Waste, and Geothermal Incentives Act was passed (Public Law 101-575), giving a window of opportunity for generating plants using these sources to file by Dec. 31, 1994 for QF status with an exemption on the PURPA size limit, lowering the threshold to 50 MW. Construction of the project had to be completed by 1999. The Act was not extended after its effective end date (December 31, 1994), so subsequent to 1994 the 80 megawatt size limit for these energy sources was restored.

¹¹ Avoided cost is the cost to the utility to generate or otherwise purchase electricity from another source.

¹² A fifth incentive which is an income tax deduction for alcohol produced from coal and lignite is available. However, currently no alcohol is produced from these sources. Alcohol fuel producers do not qualify for this credit if the source is biomass. Also, there is an income tax deduction for alcohol-fueled vehicles. This article discusses only incentives for renewable resources, so discussion of this deduction is not included.

¹³ Established by the Omnibus Budget Reconciliation Act of 1990 (P.L. 101-508), which lowered the 6-cents-per-gallon credit for gasohol established in the Tax Reform Act of 1984 (P.L. 99-198).

¹⁴ Originally, the excise tax exemption was part of the National Energy Act of 1978. The excise tax credits and the blenders credit are authorized in the Intermodal Surface Transportation Act's Federal Motor Fuels Excise Tax Credit Provisions. The excise tax credits apply both to "pure" fuel ethanol (e.g., E-85, E-95) and to low-ethanol blends of gasoline (gasoline having as little as 5.7 percent ethanol). The Tax Reform Act of 1984 (P.L. 98-369) subsequently increased the blenders income tax credit to 60 cents per gallon for ethanol, before the Omnibus Budget Reconciliation Act of 1990 lowered it to 54 cents. The blenders credit is offset by any excise tax exemptions claimed on the same fuel.

¹⁵ The credit is for a maximum of 15 million gallons annually. Eligible producers are those whose annual production is less than 30 million gallons. As with the blender's credit, the small ethanol producer credit is reduced to take into account any excise tax exemption claimed on ethanol output and sales.

Table 1. Timeline – Major Tax Provisions Affecting Renewable Energy

1978	<p>Energy Tax Act of 1978 (ETA) (P.L.95-618) Residential energy (income) tax credits for solar and wind energy equipment expenditures: 30 percent of the first \$2,000 and 20 percent of the next \$8,000.</p> <p>Business energy tax credit: 10 percent for investments in solar, wind, geothermal, and ocean thermal technologies; (in addition to standard 10 percent investment tax credit available on all types of equipment, except for property which also served as structural components, such as some types of solar collectors, e.g., roof panels). In sum, investors were eligible to receive income tax credits of up to 25 percent of the cost of the technology.</p> <p>Percentage depletion for geothermal deposits: depletion allowance rate of 22 percent for 1978-1980 and 15 percent after 1983.</p>
1980	<p>Crude Oil Windfall Profits Tax Act of 1980 (WPT) (P.L.96-223) Increased the ETA residential energy tax credits for solar, wind, and geothermal technologies from 30 percent to 40 percent of the first \$10,000 in expenditures.</p> <p>Increased the ETA business energy tax credit for solar, wind, geothermal, and ocean thermal technologies from 10 percent to 15 percent, and extended the credits from December 1982 to December 1985.</p> <p>Expanded and liberalized the tax credit for equipment that either converted biomass into a synthetic fuel, burned the synthetic fuel, or used the biomass as a fuel.</p> <p>Allowed tax-exempt interest on industrial development bonds for the development of solid waste to energy (WTE) producing facilities, for hydroelectric facilities, and for facilities for producing renewable energy.</p>
1981	<p>Economic Recovery Tax Act of 1981 (ERTA) (P.L.97-34) Allowed accelerated depreciation of capital (five years for most renewable energy-related equipment), known as the Accelerated Cost Recovery System (ACRS); public utility property was not eligible.</p> <p>Provided for a 25 percent tax credit against the income tax for incremental expenditures on research and development (R&D).</p>
1982	<p>Tax Equity and Fiscal Responsibility Act of 1982 (TEFRA) (P.L.97-248) Canceled further accelerations in ACRS mandated by ERTA, and provided for a basis adjustment provision which reduced the cost basis for purposes of ACRS by the full amount of any regular tax credits, energy tax credit, rehabilitation tax credit.</p>
1982-1985	<p>Termination of Energy Tax Credits In December 1982, the 1978 ETA energy tax credits terminated for the following categories of non-renewable energy property: alternative energy property such as synfuels equipment and recycling equipment; equipment for producing gas from geopressurized brine; shale oil equipment; and cogeneration equipment. The remaining energy tax credits, extended by the WPT, terminated on December 31, 1985.</p>
1986	<p>Tax Reform Act of 1986 (P.L.99-514) Repealed the standard 10 percent investment tax credit.</p> <p>Eliminated the tax-free status of municipal solid waste (MSW) powerplants (WTE) financed with industrial development bonds, reduced accelerated depreciation, and eliminated the 10 percent tax credit (P.L.96-223).</p> <p>Extended the WPT business energy tax credit for solar property through 1988 at the rates of 15 percent for 1986, 12 percent for 1987, and 10 percent for 1988; for geothermal property through 1988 at the rates of 15 percent for 1986, and 10 percent for 1987 and 1988; for ocean thermal property through 1988 at the rate of 15 percent; and for biomass property through 1987 at the rates of 15 percent for 1986, and 10 percent for 1987. (The business energy tax credit for wind systems was not extended and, consequently, expired on December 31, 1985.)</p> <p>Public utility property became eligible for accelerated depreciation.</p>

See notes at end of table.

Table 1. Timeline - Major Tax Provisions Affecting Renewable Energy (Continued)

1992	<p>Energy Policy Act of 1992 (EPACT) (P.L.102-486) Established a permanent 10 percent business energy tax credit for investments in solar and geothermal equipment.</p> <p>Established a 10-year, 1.5 cents per kilowatthour (kWh) production tax credit (PTC) for privately owned as well as investor-owned wind projects and biomass plants using dedicated crops (closed-loop) brought on-line between 1994 and 1993, respectively, and June 30, 1999.</p> <p>Instituted the Renewable Energy Production Incentive (REPI), which provides 1.5 cents per kWh incentive, subject to annual congressional appropriations (section 1212), for generation from biomass (except municipal solid waste), geothermal (except dry steam), wind and solar from tax exempt publicly owned utilities and rural cooperatives.</p> <p>Indefinitely extended the 10 percent business energy tax credit for solar and geothermal projects.</p>
1999	<p>Tax Relief Extension Act of 1999 (P.L. 106-170) Extends and modifies the production tax credit (PTC in EPACT) for electricity produced by wind and closed-loop biomass facilities. The tax credit is expanded to include poultry waste facilities, including those that are government-owned. All three types of facilities are qualified if placed in service before January 1, 2002. Poultry waste facilities must have been in service after 1999.</p> <p>A nonrefundable tax credit of 20 percent is available for incremental research expenses paid or incurred in a trade or business.</p>

Notes: The residential energy credit provided a credit (offset) against tax due for a portion of taxpayer expenditures for energy conservation and renewable energy sources. The general business credit is a limited nonrefundable credit (offset) against income tax that is claimed after all other nonrefundable credits.

Table 2. Timeline - Major Tax Provisions Affecting Renewable Transportation Fuels

1978	<p>Energy Tax Act of 1978 (ETA) (P.L.95-618) Excise tax exemption through 1984 for alcohol fuels (methanol and ethanol): exemption of 4 cents per gallon (the full value of the excise tax at that time) of the Federal excise tax on "gasohol" (gasoline or other motor fuels that were at least 10 percent alcohol (methanol and ethanol))</p>
1980	<p>Crude Oil Windfall Profits Tax Act of 1980 (WPT) (P.L.96-223) Extended the gasohol excise tax exemption from October 1, 1984, to December 31, 1992.</p> <p>Introduced the alternative fuels production tax credit. The credit of \$3 per barrel equivalent is indexed to inflation using 1979 as the base year, and is applicable only if the real price of oil is below \$27.50 per barrel. The credit is available for fuel produced and sold from facilities placed in service between 1979 and 1990. The fuel must be sold before 2001.</p> <p>Introduced the alcohol fuel blenders' tax credit; available to the blender in the case of blended fuels and to the user or retail seller in the case of straight alcohol fuels. This credit of 40 cents per gallon for alcohol of at least 190 proof and 45 cents per gallon for alcohol of at least 150 proof but less than 190 proof was available through December 31, 1992.</p> <p>Extended the ETA gasohol excise tax exemption through 1992.</p> <p>Tax-exempt interest on industrial development bonds for the development of alcohol fuels produced from biomass, solid waste to energy producing facilities, for hydroelectric facilities, and for facilities for producing renewable energy.</p>
1982	<p>Surface Transportation Assistance Act (STA) (P.L. 97-424) Raised the gasoline excise tax from 4 cents per gallon to 9 cents per gallon, and increased the ETA gasohol excise tax exemption from 4 cents per gallon to 5 cents per gallon. Provided a full excise tax exemption of 9 cents per gallon for "neat" alcohol fuels (fuels having an 85 percent or higher alcohol content).</p>

Table 2. Timeline – Major Tax Provisions Affecting Renewable Transportation Fuels (Continued)

1984	<p>Deficit Reduction Act of 1984 (P.L.98-369) The STA excise tax exemption for gasohol was raised from 5 cents per gallon to 6 cents per gallon.</p> <p>Provided a new exemption of 4.5 cents per gallon for alcohol fuels derived from natural gas.</p> <p>The alcohol fuels “blenders” credit was increased from 40 cents to 60 cents per gallon of blend for 190 proof alcohol.</p> <p>The duty on alcohol imported for use as a fuel was increased from 50 cents to 60 cents per gallon</p>
1986	<p>Tax Reform Act of 1986 (P.L.99-514) Reduced the tax exemption for “neat” alcohol fuels (at least 85 percent alcohol) from 9 cents to 6 cents per gallon.</p> <p>Permitted alcohol imported from certain Caribbean countries to enter free of the 60 cents per gallon duty.</p> <p>Repealed the tax-exempt financing provision for alcohol-producing facilities.</p>
1990	<p>Omnibus Budget Reconciliation Act of 1990 (P.L. 101-508) Allows ethanol producers a 10 cent per gallon tax credit for up to 15 million gallons of ethanol produced annually.</p> <p>Reduced the STA gasohol excise tax exemption to 5.4 cents per gallon.</p>
1992	<p>Energy Policy Act of 1992 (EPACT) (P.L. 102-486) Provides: (1) a tax credit (variable by gross vehicle weight) for dedicated alcohol-fueled vehicles; (2) a limited tax credit for alcohol dual-fueled vehicles; and (3) a tax deduction for alcohol fuel dispensing equipment.</p>
1998	<p>Energy Conservation Reauthorization Act of 1998 (ECRA) (P.L. 105-388) Amended EPACT to include a credit program for biodiesel use by establishing Biodiesel Fuel Use Credits. An EPACT-covered fleet can receive one credit for each 450 gallons of neat (100 percent) biodiesel purchased for use in vehicles weighing in excess of 8500 lbs (gross vehicle weight (GVW)). One credit is equivalent to one alternative fueled vehicle (AFV) acquisition. To qualify for the credit, the biodiesel must be used in biodiesel blends containing at least 20 percent biodiesel (B20) by volume. If B20 is used, 2,250 gallons must be purchased to receive one credit.</p> <p>Transportation Equity Act for the 21st Century (TEA-21) (P.L. 105-178) Maintains, through 2000, the 5.4 cent per gallon (of gasoline) excise tax exemption for fuel ethanol set by the Omnibus Budget Reconciliation Act of 1990 (P.L. 101-508). Extends the benefits through September 30, 2007, and December 31, 2007, but cuts the ethanol excise tax exemption to 5.3, 5.2, and 5.1 cents for 2001-2002, 2003-2004, and 2005-2007, respectively, and the income tax credits by equivalent amounts. The exemption is eliminated entirely in 2008.</p>

However, only the partial exemption from motor fuels excise tax is used to any extent. It is important to note that there are important financial incentive issues in the form of tax equity regarding all of the “alternate transportation fuels.” However, only the alcohol fuels are renewable, so this paper is confined to those. The primary incentive is the ethanol excise tax exemption.

Research and Development

Government research and development (R&D), especially applied research, is considered a support program

because, when successful, it reduces the capital and/or operating costs of new products or processes. Research and development comprises three components: basic research (original investigation in some area but with no specific commercial objective), applied research (investigation with a specific commercial objective in mind), and development (translating scientific discovery into commercial products or processes).¹⁶

The Department of Energy (DOE) applied research program for renewable energy is accomplished through the use of partnership programs. These programs, in which

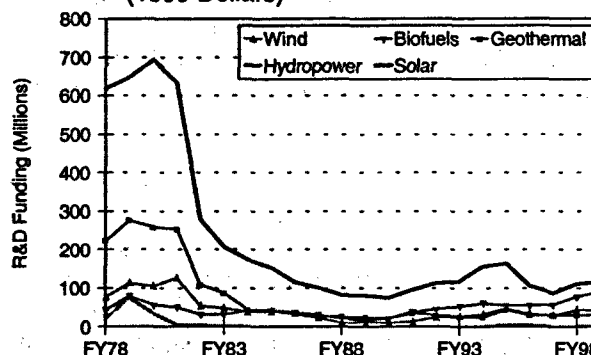
¹⁶ An alternative formulation is provided in Solar Energy Research Institute, *The Potential of Renewable Energy: An Interlaboratory White Paper* (SERI/TP-260-3674, March 1990), p. 29.

the Department acts primarily as a facilitator, have been a prominent part of renewables R&D funding since the mid-1980s. There are two funding components to this type of program: cost-sharing and in-kind contributions. Cost sharing refers to project funding contributions by all parties involved in the project. In-kind contributions refer primarily to, on the company side, the payment of salaries and the use of equipment and resources during the course of work on the project, and on the government side, the use of capital equipment, such as scientific and engineering equipment and facilities at DOE's national laboratories. (In the past, such programs have included a payback feature where the contractor repaid the government its original investment once the project became commercial and profitable.) In partnering programs, the Department also works with the ultimate product consumer to determine desired product characteristics and feeds this information back to its partner(s). For R&D projects, the private sector cost share is 20 percent. By comparison, demonstration projects require at least a 50 percent cost share by private firms. Figure 1 shows renewable energy R&D funding over time in 1999 dollars.

The DOE has consistently supported solar (including solar thermal, passive solar, and photovoltaic) R&D efforts at a higher level than other renewables. However, major new Presidential biofuels energy initiatives during the past 2 years have increased 1999 DOE R&D spending for biomass energy systems (including both electric and transportation applications) by 64 percent over its 1997 level. In 1999, more than 35 percent of biomass energy system R&D was directed toward ethanol.¹⁷ Major areas being investigated are: advanced fermentation organisms, advanced cellulase (enzyme) development, integrating the various stages of cellulose to ethanol production, and support for cellulose to ethanol demonstration production facilities.¹⁸ The principal method for achieving production increases is via leveraged partnerships with private ethanol producers.

Other Federal agencies have also contributed to renewable energy R&D efforts. The National Aeronautics and Space Administration (NASA) works on fuel cell research (in conjunction with DOE), solar energy applications in underdeveloped countries, and conducts

Figure 1. R&D Funding for Selected Renewable Energy Technologies (1999 Dollars)



Source: Data obtained from U.S. Department of Energy, Office of Budget, April 1998. Current ("Then-Year") Dollars normalized to 1999 dollars. See website at http://www.eia.doe.gov/cneat/solar.renewables/rea_issues/rea_issues_sum.html.

Note: Figure excludes the following items: Renewable Energy Production Incentive Program, Ocean Energy Systems, National Renewable Energy Laboratory Program Support and Resource Assessment, Alcohol Fuels, Hydrogen Research, Electric Energy Systems, Energy Storage Systems, Policy and Management, and Renewable Indian Energy Resources.

modest studies on microwave energy from solar panels which would orbit the earth. The Department of Agriculture (USDA) has the Alternative Agricultural Research and Commercialization Corporation, a venture capital firm for alternate energy sources. USDA also joins effort with the Environmental Protection Agency to capture methane from lagoons to supply heat and power.

State Incentives, Mandates, and Programs for Renewable Energy

Electric industry restructuring is the major issue affecting renewable energy at the State levels. In a few States, electric industry restructuring legislation supports renewable energy with financial incentives through funds from surcharges on electricity sales or renewable portfolio standards.¹⁹ Most States provide for net metering.²⁰ Even prior to electric restructuring

¹⁷ Information on ethanol R&D expenditures is from unpublished budget documents of the U.S. Department of Energy's Office of Energy Efficiency and Renewable Energy, Office of Transportation Technologies, Office of Fuels Development.

¹⁸ Cellulosic feedstocks include agricultural residues from harvesting operations (corn, wheat, rice, etc.), forest wastes/residues (excess growth, dead trees, etc.), and energy crops, i.e., trees and grasses grown specifically for use as energy feedstocks.

¹⁹ A renewable portfolio standard (RPS) is a mandate requiring that renewable energy provide a certain percentage of total energy generation or consumption.

²⁰ Net metering refers to an arrangement that permits a facility (using a meter that reads inflows and outflows of electricity) to sell any excess power it generates over its load requirement back to the electrical grid to offset consumption.

legislation, many States had financial incentives for renewable energy. (A DOE-sponsored North Carolina State University website provides summary information, updated periodically, on State-level financial incentives, and regulatory programs and policies for renewable energy.)²¹

State financial incentives include personal income tax credits and deductions for the purchase of various renewable-based technologies or alternative fuel vehicles; corporate income tax credits, exemptions, and deductions for investments in renewable technologies; sales tax exemptions on renewable equipment purchases; variable property tax exemptions on the value added by the renewable energy system; renewable technology and demonstration project grants; and special loan programs for renewable energy investments.

Some State incentives for renewable energy technologies overlap the Energy Policy Act of 1992 (EPACT) Production Tax Credit (PTC). When State and Federal incentives overlap, the PTC may or may not be reduced, depending on Internal Revenue Service rulings. In California, for example, wind projects can get renewable resource funds without jeopardizing eligibility for the PTC. In other cases, the PTC is reduced by the amount of the State incentive.²²

While some ethanol-producing States do not subsidize ethanol, others offer tax incentives for gasoline blended with ethanol and for ethanol production, which vary from \$0.10 to \$0.40 per gallon.

California

Because of its long history of promoting renewable energy and the dominant position which the State holds in renewable energy production,²³ this report examines renewable energy incentives promulgated by California. From about 1980 through 1983, California had a 25-percent tax credit for wind energy systems. Combined with Federal tax credits, the effective tax credit for wind plants during that time was nearly 50 percent. It is therefore hardly surprising that wind energy capacity in

California grew from 176 MW in 1982 to 1,015 MW in 1985. California also strongly supported renewables beginning in 1982 via pricing terms of the Standard Offer 4 contract mentioned earlier, which utilities were required to sign with qualifying facilities.

With the move toward deregulation and restructuring of the electric power industry, the California General Assembly passed a law in 1996, which on March 31, 1998, opened electricity markets to retail competition. Although California had previously been aggressive in promoting renewable energy, Assembly Bill (AB) 1890 enacted an entirely different approach. It established a new statewide renewables policy by providing \$540 million collected from the State's three largest investor-owned utilities over 4 years starting in 1998 to support existing, new, and emerging renewable technologies to make the transition to a competitive market. The bill also allocates an additional \$62.5 million for energy projects deemed to be in the "public interest."

After the California Energy Commission submitted its recommendations to the Legislature for allocating and distributing these funds (\$540 million) in March 1997, the General Assembly enacted Senate Bill 90, which created a Renewable Resource Trust Fund containing four accounts: Existing Renewable Resources Account (\$243 million), New Renewable Resources Account (\$162 million), Emerging Renewable Resources Account (\$54 million), and Customer-side Renewable Resources Account (\$81 million).

The program has a competitive bidding mechanism to reward the most cost-effective projects with a production incentive for existing and new technologies.²⁴ The funds are distributed by program type as follows:

- **Existing technologies:** funds are distributed differentially among three technology tiers (groupings) through a cents per kilowatt-hour production incentive, with a cap of 1.5 cents per kWh. Funds for existing technologies may decrease annually from January 1, 1998, to January 1, 2002, to increase funds for the development of new renewable technologies.

²¹ See <http://www-solar.mck.ncsu.edu/dslre.htm>, June 27, 2000, and Interstate Renewable Energy Council, North Carolina Solar Center *National Summary Report on State Programs and Regulatory Policies for Renewable Energy* (Raleigh, NC, January 1998).

²² See, for instance, Lawrence Berkeley National Laboratory, "Evaluating the Impacts of State Renewables Policies on Federal Tax Credit Programs" (Berkeley, California, December 1996).

²³ California has more non-hydroelectric renewable generating capability than any other State; see Energy Information Administration, *Renewable Energy Annual 1999*, DOE/EIA-0603(99) (Washington, DC, March 2000), Table C54.

²⁴ Production incentives do not apply to "emerging technologies."

- **New technologies:** funds are distributed through a production incentive based on a competitive solicitation process, with a cap of 1.5 cents per kWh, to be paid over a 5-year period after a project begins generating electricity. The funds may increase annually from January 1, 1998, to January 1, 2002.
- **Emerging technologies:** funds are provided through rebates, buy-downs, or equivalent incentives to purchasers, lessees, lessors, or sellers of eligible electricity generation systems.
- **Customer-side account:** funds determined by dividing available funds by eligible renewable generation with a 1.5-cents-per-kWh cap, and for industrial customers a limit of \$1,000 in rebates. The size of this account is fixed, so that as customer demand increases, the payment decreases; it is presently 1.0 cent per kWh.

By early July 1998, the new technologies auction received 56 bids representing nearly 600 megawatts of new renewable energy resources. All of the bids received amounted to a total of \$182 million in incentive payments, \$20 million more than the \$162 million allocated in the renewable energy program for new generation. Bids were used to ensure a competitive, market-based, environment using a performance-based criterion. They were submitted on a cents per kWh basis for electricity production, not to exceed 1.5 cents. The renewable resource technologies determined eligible to receive funding at an average incentive of 1.2 cents per kWh include: wind, approximately 300 megawatts (also eligible for the PTC); geothermal, 157 megawatts; land-fill gas, 70 megawatts; biomass, 12 megawatts; digester gas, 1 megawatt; and small hydro, 1 megawatt. The combined impact of all incentives (State and Federal) has assisted in bringing 290 MW of new or repowered wind capacity online in 1999.²⁵ Thus, the incentives used in California have been successful in meeting the objective of increasing the number of renewable projects in the State.

A major characteristic responsible for this success is the incentive program's competitive bidding mechanism to reward the most cost-effective projects, using a production incentive rather than an investment tax credit.

Public Interest Energy Research Program (PIER) – Assembly Bill 1890 also requires that a minimum of \$62.5 million in funds, collected annually from investor-

owned utility ratepayers, be used for "public interest" energy research development and demonstration (RD&D) efforts that would not be provided adequately by either a competitive or regulated market. Senate Bill 90 required that the PIER portfolio include the following areas: renewable energy technologies; environmentally preferred advanced generation; energy-related environmental enhancements; end-use energy efficiency; and strategic energy research.

Effectiveness of Incentives, Mandates, and Government Programs

How effective have renewable energy incentives, mandates, and Federal and State programs been? It is virtually impossible to quantify the effect of any single action, because of the interdependence of many of the renewable energy programs in effect at any one time. Even the effects of straightforward incentives such as the Renewable Energy Production Incentives (REPI) are difficult to determine, because it is not known how much renewable generation would have been produced in the absence of REPI. Further, REPI itself may not have been sufficient to induce the renewable generation eligible for REPI payments, but rather a combination of REPI and other Federal and State incentives. Following is a discussion of the effectiveness of four Federal renewable energy support programs—PURPA, REPI, the Federal ethanol incentive program, and R&D funding. The characteristics of these programs and an assessment of whether they have proven effective in achieving the desired results are discussed.

PURPA

This assessment of the effectiveness of PURPA is actually an assessment of PURPA in combination with various tax incentives in place between 1978 and 1998. PURPA established a new class of generator, qualifying facilities (QF), that afforded cogenerators and certain renewable generators the opportunity to sell electricity to electric utilities at the utility's avoided cost rates. These facilities were also granted tax benefits described in Table 1, which lowered their overall costs.

PURPA's QF status applied to existing as well as new projects. Together, by year-end 1998, existing and new projects totaled 12,658 megawatts of QF renewable

²⁵ American Wind Energy Association, <http://www.awea.org/projects/california.html>, September 15, 2000.

capacity (Table 3). Of this, two-thirds (8,219 megawatts) of QF capacity was biomass. Some of these biomass QFs, however, were not "new" facilities, but rather had gone into commercial operation prior to PURPA.²⁶ PURPA enabled these facilities to connect to the grid, if they chose to become QFs, and sell any generation beyond their own use at avoided cost rates.

As stated in the Introduction, two of the criteria for evaluating the effectiveness of incentives and mandates such as PURPA are renewable capacity and generation growth. The EIA began collecting data from nonutility companies in 1989 (Table 4), 11 years after the passage of PURPA. However, between 1989 and 1998, renewable

capacity increased by 11.9 percent. At the national level, non-hydroelectric renewable generating capacity rose by 4,426 MW; the increase in hydroelectric capacity was 5,703 MW. Renewable generation rose by 22 percent (Table 5). Most of the increase in electricity generation from renewable energy is in the utility hydropower sector, including net imports. Nearly all of the increase in biomass, geothermal, solar, and wind generation occurred between 1989 and 1993. Non-hydro renewable generation, excluding imports, actually declined by more than 5 percent between 1993 and 1998, due primarily to California replacing Standard Offer 4 contract "avoided cost" provisions with competitive bidding mechanisms, and declining production at The Geysers

Table 3. Nonutility Qualifying Facilities Using Renewable Resources as of December 31, 1998

Fuel Source	Nameplate Capacity (megawatts)	Gross Generation (thousand megawatthours)
Biomass	8,219	45,032
Geothermal	1,449	9,882
Hydroelectric ^a	1,263	5,756
Wind	1,373	2,568
Solar Thermal	340	876
Photovoltaic	14	11
Total Renewable QF	12,658	64,126
Total QF, All Sources	60,384	327,977
Total Nonutility, All Sources	98,085	421,364

^aConventional; excludes pumped storage.

Notes: Totals may not equal sum of components due to independent rounding.

Source: Form EIA-860B, "Annual Electric Generator Report - Nonutility."

Table 4. U.S. Electric Power Sector Net Summer Capability, 1989-1998
(Megawatts)

Source	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998
Hydroelectric ^a	74,587	73,964	76,179	74,773	77,405	78,042	78,563	76,437	79,788	79,573
Geothermal	2,603	2,669	2,632	2,910	2,978	3,006	2,968	2,893	2,853	2,917
Biomass	7,840	8,796	9,627	9,701	10,045	10,465	10,280	10,557	10,535	10,266
Solar/PV	264	339	323	339	340	333	333	333	334	365
Wind	1,697	1,911	1,975	1,823	1,813	1,745	1,731	1,678	1,579	1,698
Total Renewables ..	86,990	87,679	90,736	89,547	92,582	93,591	93,874	91,897	95,090	94,819
Non Renewables	637,275	647,241	649,741	657,016	662,373	670,423	675,643	683,975	683,412	681,065
Total	724,265	734,920	740,477	746,563	754,955	764,014	769,517	775,872	778,502	775,884

^aConventional; excludes pumped storage.

Notes: Biomass capability does not include capability of plants where the Btu of the biomass consumed represents less than 50 percent of the Btu consumed from all energy sources. Totals may not equal sum of components due to independent rounding.

Sources: Energy Information Administration, Form EIA-860A, "Annual Electric Generator Report -- Utility" and predecessor forms, and estimated data using Form EIA-860B, "Annual Electric Generator Report -- Nonutility," and predecessor form.

²⁶ Sources: See Table 6 of this report, as well as the Renewable Electric Plant Information System (REPiS Database), developed by the National Renewable Energy Laboratory. See <http://www.eren.doe.gov/repiS>, February 15, 2000. These data include facilities which have retired since 1996.

Table 5. Electricity Generation From Renewable Energy by Energy Source, 1989-1998
(Thousand Kilowatthours)

Source	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998
Nonutility Sector (Gross Generation)										
Biomass	36,350,275	42,499,581	48,259,818	53,606,891	55,745,781	57,391,594	57,513,666	57,937,058	55,144,102	53,744,724
Geothermal	5,416,495	7,235,113	8,013,969	8,577,891	9,748,634	10,122,228	9,911,659	10,197,514	9,382,646	9,881,958
Hydroelectric	7,124,418	8,152,891	8,180,198	9,446,439	11,510,788	13,226,934	14,773,801	16,555,389	17,902,653	14,632,521
Solar	488,527	663,387	779,206	746,277	896,796	823,973	824,193	902,830	892,892	886,553
Wind	1,832,537	2,250,846	2,605,505	2,916,379	3,052,416	3,481,616	3,185,006	3,399,642	3,248,140	3,015,497
Total	51,212,252	60,801,818	67,838,696	75,293,877	80,954,413	85,046,345	86,208,325	88,992,433	86,569,433	82,161,253
Electric Utility Sector (Net Generation)										
Biomass	1,959,864	2,064,331	2,038,229	2,088,109	1,986,535	1,985,463	1,647,247	1,912,472	1,983,532	2,024,377
Geothermal	9,341,677	8,581,228	8,087,055	8,103,809	7,570,999	6,940,637	4,744,804	5,233,927	5,469,110	5,176,280
Hydroelectric	265,063,067	283,433,659	280,060,621	243,736,029	269,098,329	247,070,938	296,377,840	331,058,055	341,273,443	308,843,770
Solar	2,567	2,448	3,338	3,169	3,802	3,472	3,909	3,169	3,481	2,518
Wind	479	398	285	308	243	309	11,097	10,123	5,977	2,957
Total	276,367,654	294,082,064	290,189,528	253,931,424	278,659,908	256,000,819	302,784,897	338,217,746	348,734,543	316,050,902
Imports and Exports										
Geothermal (Imports)	533,261	538,313	736,980	889,864	877,058	1,172,117	884,950	649,514	16,493	45,145
Conventional Hydroelectric (Imports) .	19,148,542	16,302,116	22,318,562	26,948,408	28,558,134	30,478,863	28,823,244	33,359,983	27,990,905	26,031,784
Conventional Hydroelectric (Exports) .	5,464,824	7,543,487	3,138,562	3,254,289	3,938,973	2,806,712	3,059,261	2,336,340	6,790,778	6,158,582
Total Net Imports	14,216,980	9,296,942	19,916,921	24,583,983	25,496,219	28,844,268	26,648,933	31,673,157	21,216,620	19,918,347
Total Renewable Electricity Generation	341,796,886	364,180,824	377,945,145	353,809,284	385,110,540	369,891,432	415,642,155	458,883,336	456,520,167	418,129,367

Note: Totals may not equal sum of components due to independent rounding.

Sources: Nonutility Sector - 1989-1997: Energy Information Administration, Form EIA-867, "Annual Nonutility Power Producer Report." Nonutility Sector - 1998: Energy Information Administration, Form EIA-860B, "Annual Electric Generator Report - Nonutility." Electric Utility Sector - 1989-1997: Energy Information Administration, Form EIA-860, "Annual Electric Generator Report." Electric Utility Sector - 1998: Form EIA-860A "Annual Electric Generator Report - Utility." Imports and Exports: Energy Information Administration, *Renewable Energy Annual*, DOE/EIA-0603(95-99) (Washington, DC).

geothermal plant. Also, in 1992, New York amended its Six-Cent Rule, which established a 6-cents-per-kilowatt-hour floor on avoided costs for projects less than 80 MW in size, such that it was not applicable to any future power purchase agreements.²⁷

Data on renewable capacity in California were available for years prior to 1989. These data, for 1980 through 1996 (Table 6), more clearly show the growth in renewable capacity owned by nonutilities since the passage of PURPA. Renewable-based nonutility capacity (excluding cogeneration) rose from 187 megawatts in 1980 to 3,777 megawatts (excluding small hydropower and cogeneration plants) in 1996.

Most of the growth had occurred by 1990. Between 1990 and 1993, California nonutility renewable capacity (excluding small hydropower and cogeneration plants)

increased just 3 percent to 3,878 megawatts, and between 1993 and 1995, capacity actually dropped to 3,553 megawatts; generation followed a similar pattern. The principal reasons for this decline were the lower PURPA "avoided costs" when the long-term energy payment provisions of the contracts (usually 10-years), mostly signed in the early 1980s, expired. Natural gas prices in nominal dollars paid by electric utilities in California declines from a high of \$6.77 per million Btu in 1982 to between \$2.50 to \$3.00 in 1986 through 1993. By 1995, the price declined further to \$2.22.²⁸ This, along with the repeal of the standard investment tax credits in 1986, caused some wind, biomass, and solar facilities to reduce output or cease operation.²⁹ Also, there was a substantial slowdown in the construction of new capacity. This slowdown transpired despite substantial decreases in short-run average costs of renewables because the operation costs were not reduced enough to

Table 6. California Nonutility Power Plants Installed Capacity, 1980-1996
(Megawatts)

Year	Cogeneration ^a	Waste-to-Energy ^b	Geothermal	Small Hydro	Solar	Wind	Total
1980	227	14	0	0	0	173	414
1981	261	14	0	0	0	176	451
1982	412	32	0	48	1	176	669
1983	658	46	9	59	8	227	1,007
1984	893	79	96	67	27	496	1,658
1985	1,444	140	178	107	57	1,015	2,941
1986	1,788	275	188	144	122	1,235	3,752
1987	3,063	396	319	176	155	1,366	5,475
1988	3,662	513	587	229	221	1,378	6,590
1989	4,942	783	806	298	301	1,382	8,512
1990	5,315	878	870	321	381	1,647	9,412
1991	5,838	883	813	330	374	1,698	9,936
1992	5,684	804	831	371	408	1,729	9,827
1993	5,778	845	863	370	373	1,797	10,026
1994	5,857	795	863	410	373	1,629	9,927
1995	6,280	709	846	349	368	1,630	10,182
1996	6,177	823	885	362	360	1,709	10,316

^aIncludes gas-fired facilities and biomass co-firing and cogeneration.

^bWaste-to-Energy includes wood and wood waste, municipal solid waste, landfill gas, and other biomass. However, biomass co-firing and cogeneration capacity is included under Cogeneration.

Source: California Energy Commission, Draft Final Report, *California Historical Energy Statistics*, January 1998, Publication Number: P300-98-001.

Notes: Data exclude facilities rated less than 5 megawatts. Some data in this table are inconsistent with national data in Table 4 due to different sources, categories, and coverage. Also, these data represent installed capacity, while the data in Table 4 represent net summer capability.

²⁷ In 1981, New York State enacted legislation which established a minimum price of 6 cents per kilowatthour for utility purchases from QFs. As a result, nearly one-third of New York's generation comes from QFs. (See Edison Electric Institute, *1996 Capacity and Generation of Non-Utility Sources of Energy*, 30 (1997).)

²⁸ Energy Information Administration, *State Energy Price and Expenditures Report 1995*, DOE/EIA-0376(95) (Washington, DC, August 1998), p. 50.

²⁹ Science Applications International Corporation, "Assessment of Incentives for Renewable and Alternative Fuels," prepared for the Energy Information Administration (McLean, VA, September 1998).

be competitive in the market conditions of the mid-to-late 1990s.³⁰

Another criterion in evaluating the effectiveness of PURPA, in addition to expansion of renewable energy capacity and generation, is the cost competitiveness of the renewable facilities in the market. Utility wholesale power purchases from other utilities, which are more often made on a mutually agreeable economic basis between utilities and may be regarded as reflecting "wholesale" prices, averaged 3.53 cents per kWh nationwide in 1995.³¹ Although EIA has not attempted to estimate the cost of PURPA directly,³² it has examined the prices that utilities paid in 1995 to purchase power from nonutilities and, in particular, PURPA QF nonutilities using renewable resources.³³ The average price utilities paid all nonutilities was 6.31 cents per kWh nationwide, considerably higher than the average wholesale price. Higher still was the price utilities paid nonutilities for renewable-based electricity. Utilities paid an average of 8.78 cents per kWh for power generated from renewable sources, compared with 5.49 cents per kWh for power from non-renewable sources.³⁴ Utilities paid an average of 9.05 cents per kWh for nearly 42,800 million kWh of power from renewable QFs in 1995, compared with just 5.17 cents per kWh for 3,300 million kWh of power from non-QF renewables. This difference was even more extreme in California, where the renewable QF/non-QF purchased power costs were 12.79 and 3.33 cents per kWh, respectively.³⁵ All non-QF purchases of renewable energy, however, were from hydropower facilities,³⁶ the lowest cost renewable resource—and the

lowest cost of all electricity resources.³⁷ In analyzing these data, the reader should bear in mind that by 1995, many of the original PURPA power purchase contracts between utilities and nonutilities had expired. Therefore, the data reflect a mixture of the original avoided cost contracts and newer contracts.³⁸

Renewable-based generation costs would obviously have compared much more favorably with other generation costs during 2000, when California experienced severe electricity and natural gas shortages. Natural gas prices—the primary basis for determining alternative generation cost—rose sharply during 2000. Through September, the average cost of gas delivered to electric utilities in California increased to \$4.32 per million Btu as compared to \$2.68 for deliveries through September 1999.³⁹

Renewable Energy Production Incentive (REPI)

Initial payments under the Energy Policy Act of 1992 (EPACT) Renewable Energy Production Incentive (REPI, summarized in Table 1), for Fiscal Year (FY) 1994 totaled \$693,120 and were distributed among four State-owned and three city-owned facilities which generated 42 million kWh of electricity from seven facilities (Table 7). One used wind, two used solar photovoltaics (PV), and four used methane from landfills.⁴⁰ By FY 1998, net generation eligible for REPI payment had reached 529 million kWh from 19 facilities. Interesting points to note about the REPI program are: (1) The number of facilities has remained relatively stable since FY 1996; (2) The number

³⁰ In fact, the result of PURPA and California/Federal financial energy incentive programs of the late 1970s and early 1980s was that the proportion of natural gas-fired nonutility capacity (cogeneration) actually increased between 1980 and 1993, from 55 to 57 percent.

³¹ Energy Information Administration, "Renewable Electricity Purchases: History and Recent Developments," from *Renewable Energy 1998: Issues and Trends*, DOE/EIA-0628(98) (Washington, DC, March 1999), Figure 1, p. 2.

³² For a private analysis of PURPA costs, see, Utility Data Institute, *Measuring the Competition: Operating Cost Profiles for U.S. Investor-Owned Utilities 1995, 1* (1996).

³³ Energy Information Administration, *Electric Power Monthly*, DOE/EIA-0226 (2001/01) (Washington, DC, January 2001), Table 42.

³⁴ *Ibid.*, Figure 2.

³⁵ Refer to Federal Energy Regulatory Commission, FERC Form 1, "Annual Report of Major Electric Utilities, Licensees and Others," Energy Information Administration, Form EIA-412, "Annual Report of Public Electric Utilities," and Rural Utilities Service, RUS Form 7, "Financial and Statistical Report," RUS Form 12a through 12i, "Electric Power Supply Borrowers," and RUS Form 12c through 12g, "Electric Distribution Borrowers with Generating Facilities."

³⁶ The reverse is not true, however. Fifty-five percent (4,474 MWh) of total hydropower purchases in 1995 were from QFs. However, these purchases represented only 10 percent of total 1995 utility power purchases from QFs, so a QF/non-QF comparison is still largely a non-hydro/hydro comparison.

³⁷ California, which accounted for almost 40 percent of U.S. renewable power purchases in 1995, did not use market transaction costs for the first round of PURPA contracts. However, since avoided costs are defined by the States, some States may have done so.

³⁸ The California Energy Commission and the California Public Utilities Commission estimated in 1988 above-market costs of electricity due to Standard Offer 4 (SO4) contracts. While their approach only looked at nonutility facilities with SO4 contracts having prices based on 1983 forecasts of natural gas prices, the study unfortunately does not break out costs associated with renewables. See California Energy Commission/California Public Utilities Commission, "Final Report to the Legislature on: Joint CEC/CPUC Hearings on Excess Electrical Generating Capacity," P150-87-002 (Sacramento, CA, June 1988).

³⁹ Energy Information Administration, *Electric Power Monthly*, DOE/EIA-0226 (2001/01) (Washington, DC, January 2001), Table 42.

⁴⁰ For a complete discussion of REPI payments, see website <http://www.eren.doe.gov/power/repi.html>, December 17, 1999.

Table 7. Renewable Energy Production Incentive (REPI) Disbursements

Fiscal Year	Facilities	Energy Source	Net Generation (million kWh)	Nominal Payments (thousand dollars)
1994	2	Solar PV		8
	1	Wind		93
	4	Landfill Methane		592
Total	7		42	693
1995	4	Solar PV		15
	2	Wind		205
	5	Landfill Methane		2,178
Total	11		153	2,398
1996	9	Solar PV		28
	3	Wind		205
	5	Landfill Methane		1,879
	1	Biomass Digester Gas		417
Total	18		177	2,529
1997	2	Solar PV		31
	3	Wind		123
	8	Landfill Methane		1,212
	1	Biomass Digester Gas		265
	1	Wood Waste		1,222
Total	15		458	2,853
1998	3	Solar PV		91
	5	Wind		31
	9	Landfill Methane		1,716
	1	Biomass Digester Gas		359
	1	Wood Waste		1,803
Total	19		529	4,000

Source: <http://www.eren.doe.gov/power/repi.html> (October 22, 1999).

of solar/PV facilities has been quite modest, except for a one-time increase in FY 1996 which did not result in a sizable increase in REPI-eligible generation; and (3) The greatest increase in both eligible facilities and generation occurred in two areas, landfill methane and wood waste, which are often excluded (along with municipal solid waste) from actual and proposed renewable energy incentives; and (4) only tax-exempt facilities are eligible.

It is important to note that while the generation eligible for REPI payments increased more than twelvefold, the number of facilities receiving REPI support increased only threefold, and that increase occurred during the first 3 years of the program. This could have occurred because the 1.5 cents per kWh has not been sufficient to encourage much additional construction, though it may

be a factor in maintaining production from economically marginal wind farms, or, more likely, because of the uncertainty associated with year-to-year congressional appropriations, or both. For existing biomass generators, whose variable costs per kWh are generally higher than those for wind generators, the 1.5-cents-per-kWh credit is much less likely to support continued operation of marginal plants.

Federal Ethanol Incentive Program

Prior to the Federal ethanol subsidy program, begun in 1979,⁴¹ the United States produced virtually no fuel ethanol. In the first year of the subsidy program, the United States produced 10 million gallons. Production increased rapidly, to 175 million gallons in 1981, 870

⁴¹ The ethanol subsidy program began with a provision of the Energy Tax Act of 1978. This provision suspended the Federal excise tax on gasoline blended with alcohol derived from biomass (e.g., corn).

million gallons in 1990, 1.4 billion gallons in 1998, and 1.5 billion gallons in 1999.⁴² Virtually all production is in the Midwest, and fuel ethanol stocks are sizable only in the Midwest and Gulf Coast regions.

To determine what production of ethanol would be without the subsidies, it is necessary to analyze ethanol's three distinct purposes as an additive to gasoline. Originally, it was used to extend gasoline supplies as "gasohol," a mixture of 10 percent ethanol and 90 percent gasoline. As such, it was necessary for ethanol to compete economically with gasoline, necessitating the 54-cent-per gallon subsidy of corn-based ethanol. Ethanol also is used to raise the octane level of gasoline—its octane rating is 133. Beginning in the late 1970s, the use of lead, the only major octane enhancer used until then, was phased down. Both MTBE⁴³ and ethanol were used.

For octane-enhancing purposes, MTBE has a clear economic advantage over ethanol. More recently, ethanol and MTBE have been added to gasoline as an oxygenate to reduce harmful emissions. The incremental cost per gallon of MTBE-based gasoline (which receives no subsidy) is 2 to 3 cents per gallon. Using a 7.7 percent blend of ethanol, the value of the ethanol subsidy alone in a gallon of gasoline would be 4.1 cents. The total incremental cost per gallon of ethanol-based gasoline is 4.4 cents.⁴⁴ While MTBE has an economic advantage per gallon of additive, ethanol has a higher oxygen content than MTBE. Thus, only about half the volume of ethanol is required to produce the same oxygen level in gasoline as if MTBE is used. This allows ethanol, typically more expensive than MTBE per unit of product, to compete favorably with MTBE for the wintertime oxygenate market.⁴⁵ However, recent EPA "Tier 2" requirements for summer time reformulated gasoline made it necessary to increase the ethanol content to 13 percent in

1999. Clearly, increasing the ethanol content of gasoline in the near term increases its cost vis-a-vis MTBE-based gasoline.

It is also important to note that ethanol's one-third share of the oxygenate market is concentrated in the Midwest where most of the corn is grown. Many States in the Midwest have sizable ethanol support programs.⁴⁶

The use of MTBE in some parts of the country may have less to do with economics than with the cost of transporting ethanol far from where it is produced. Ethanol is "splash blended" at gasoline distribution tank farms because it cannot be transported via pipeline.

Assessments of repealing the Federal ethanol subsidies differ widely, from no industry⁴⁷ to the continuance of the market (about one-third of the current market for ethanol) for the use of ethanol as an oxygenate. Clearly, the continuance of State support for ethanol is a critical issue if the Federal subsidies were to be repealed.

Returns to Research and Development

Returns to renewable energy R&D are difficult to calculate, especially, given the diffuse nature of R&D activity. Research and development is conducted in a number of countries world wide, and the learning effects cross borders and cannot always be attributed to a specific R&D activity.

If the goal of R&D is to lower costs, then one measure of effectiveness is to examine the cost of renewable technologies over time. For the Sacramento Municipal Utility District (SMUD), which has the largest distributed utility PV system in the world, the PV system average cost (1996 dollars) per watt has fallen from \$79 in 1975 to

⁴² Source: 1980-1992, Renewable Fuels Association (see website <http://www.ethanolrfa.org/outlook99/99industryoutlook.html>); 1993-1999, Energy Information Administration, *EIA-819M Monthly Oxygenate Telephone Report* (January 2000 and prior issues).

⁴³ Methyl Tertiary Butyl Ether is a fuel oxygenate produced by reacting methanol with isobutylene.

⁴⁴ This calculation is based on the average prices of gasoline and ethanol between July 1998 and June 1999 and the ethanol subsidy in effect then of 54 cents per gallon of ethanol. See http://www.cnle.org/nle/eng-59.html#_1_13, Table 5.

⁴⁵ The continued need for octane levels in gasoline initially left the refiner with few choices: increase the aromatic and olefin contents of the fuel, or seek alternative products with favorable blending and performance properties. The increased use of aromatics and olefins meant more severe refinery processes needed to be used, having lower yields per barrel and higher costs for the final gasoline product. Additionally, potential health concerns about these components—from both the direct exposure due to evaporation from the gasoline and the reaction of combustion products contributing to ozone formation—limited the levels at which it was desirable to blend them into fuel. Methanol's use ceased when the Environmental Protection Agency approved MTBE in 1979.

⁴⁶ Many corn-producing States mandate the use of methanol. In Minnesota, for example, the Omnibus Environment, Natural Resources and Agriculture Appropriations bill (SF 3353) mandated that ethanol plants in the State attain a total annual production level of 240 million gallons per year, enough ethanol to completely satisfy in-State demand. Minnesota will now allocate up to \$36.4 million per year for payments to the State's ethanol producers.

⁴⁷ See GAO Congressional testimony, <http://frwebgate.access.gpo.gov/cgi-bin/useftp.cgi?IPaddress=162.140.64.21&filename=gg97041.txt&directory=/diskb/wals/data/gao>, August 4, 2000.

\$11.88 in 1990, to \$4.90 in 1998 and to \$3.65 in 2000.^{48, 49} Also, the cost of wind power has declined markedly. The average cost of electricity from wind energy has dropped from 50 cents per kilowatthour in 1980 to a projected 6 cents per kilowatthour in 2000 in favorable wind regimes.⁵⁰ Despite these successes in reducing costs, these technologies are still not generally commercially viable.

Another performance measure of applied R&D "success" is inventions patented. In order to protect the rights to an invention, a patent is usually applied for.⁵¹ A patent has to be obtained within 1 year of publishing the results of the relevant research in order to gain protection in the United States, and immediately upon publication to obtain protection abroad. This is generally insufficient time for market studies, so that more patents are applied for than are commercially successful. In general, fewer than 10 percent of patents are licensed and, therefore, commercialized. The number of patents resulting from renewable energy R&D is therefore considered as a proxy for returns to R&D (Table 8). For the reasons stated above, however, it is a very crude measure of success of R&D expenditures. In addition, the market success of any one product (resulting from one patent) can dwarf the successes of numerous other products, yet be sufficient to spawn a new industry. This thereby results in large returns to R&D. Finally, there is a widely varying, unknown time lag between R&D efforts and "successes." Given these conditions, annual patent counts are, at best, only a very general indicator of R&D success. It should be noted that the counts include only patents issued to DOE and the National Renewable Energy Laboratory (NREL) on inventions reported during each listed fiscal year for contracts with NREL and its predecessor, the Midwest Research Institute. It does not include patents retained by DOE contractors.

Table 8 Patents Issued to DOE and NREL

Fiscal Year	Number of Patents
1981	1
1982	0
1983	1
1984	3
1985	14
1986	7
1987	13
1988	2
1989	4
1990	6
1991	8
1992	7
1993	18
1994	17
1995	41
1996	17
1997	16
1998	25

Source: National Renewable Energy Laboratory.

Summary

The effectiveness of tax credits and production incentives has varied considerably, depending on the amounts and certainty of the incentive. The long-term nature and financial support levels of the PURPA Standard Offer 4 contracts in California, in addition to the Federal and State tax credits, provided reasonable assurance that investors in power plants using renewable resources would make a profit.⁵² In contrast, the Renewable Energy Production Incentive of EPACT relies upon year-to-year congressional funding, raising the level of uncertainty investors face. It has resulted in only a small amount of additional renewable generating

⁴⁸ Sources: Sacramento Municipal Utility District, Sacramento, CA, 1975-1990: *Photovoltaic Validation Study*; 1998 and 2000: American Solar Energy Society, *Advances in Solar Energy XIV, 2000*, "Sustained Orderly Development and Commercialization of Grid-Connected Photovoltaics: SMUD as a Case Example," Donald E. Osborn, Sacramento Municipal Utility District, February 24, 2000.

⁴⁹ Because of SMUD's long experience with PV technology and the high volume of their PV purchases and installations, it is likely that their costs are lower than for others.

⁵⁰ Energy Information Administration, *Annual Energy Outlook 2000*, DOE/EIA-0383(2000) National Energy Modeling System run AEO2k.d100199A.

⁵¹ A patent is a grant by the United States Patent and Trademark Office to the inventor, of the right to exclude others for a period of 17 years from making, using, or selling the invention throughout the country. Thus, the primary reason to apply for a patent is to provide exclusive commercial rights for viable inventions.

⁵² Energy Information Administration, *Renewable Energy 1998: Issues and Trends*, DOE/EIA-0628(98) (Washington, DC, March 1999), p. 65. See also, Lawrence Berkeley Laboratory, R. Wiser and E. Kahn, "Alternative Windpower Ownership Structures: Financing Terms and Project Costs," May 1996, LBNL-38921. According to this study, the most important variable in comparing wind and natural gas project costs is the relatively low return on equity (12 percent) that is required by investors in gas projects compared to 18 percent for wind projects.

facilities. Other tax credits (e.g., the residential solar/wind tax credit) have generally had much less impact, simply because the gap between competitive energy prices and energy production costs is greater than the benefit investors perceive such tax credits are worth.

In the case of alcohol fuels, the impact of the Federal 54 cents per gallon incentive was substantial and immediate. Production of fuel ethanol would no doubt drop sharply if the Federal 54 cents per gallon (of ethanol) incentive were removed and States provided no supports for, or, mandates to use, ethanol.

The cost of photovoltaic and wind electricity generation has declined consistently over the past 20 to 25 years. Federal renewable energy R&D, though inconsistently funded, has been undertaken continuously during this time. Although available data are insufficient to establish a quantifiable relationship between R&D funding and

renewable energy cost reduction, the data suggest that such benefits have occurred.

Together, the Federal and State incentives, mandates, and support programs, including R&D, have been effective when measured by growth in electric generating capacity and electricity generation, or, in the transportation sector with growth in ethanol production. However, they failed to ensure the future self-sustainability of renewable facilities that would substantially contribute to the overall energy security policy of the era in which the incentives were created. One reason for this is that although there have been some reductions in the cost of renewable electric generating technologies, these cost reductions have not kept pace with the general declines in cost seen in natural gas-fired generation. These cost reductions, however, have put renewables in a better competitive position, especially given the sharp increases in natural gas prices in 2000.

Technology, Manufacturing, and Market Trends in the U.S. and International Photovoltaics Industry

by Peter Holihan

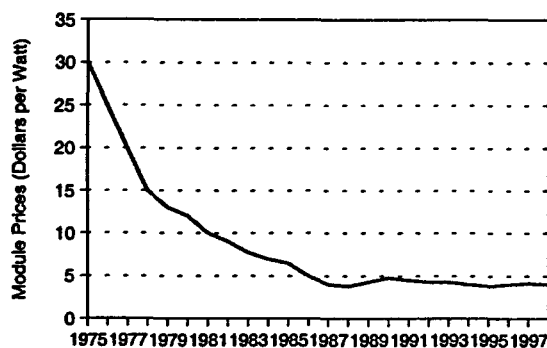
Introduction

In 1954, Bell Laboratories researchers announced the development of a silicon solar cell with a 4.5-percent energy efficiency,¹ sparking photovoltaic (PV) cell development that has progressed from space applications in the late 1950s to terrestrial applications today. Over this period, research and development have resulted in lower prices for solar cells and modules (Figure 1) and higher efficiency. U.S.-based photovoltaic manufacturers' development efforts have benefitted from a partnership with the Federal government. Similar partnerships at the State level have also been beneficial. Additionally, rising electricity prices and an increase in the cost of building new generation, transmission, and distribution capacity have had a positive impact on photovoltaic system economics and sales. Also during this period, photovoltaic system sales have expanded as a solution to remote distributed generation requirements. In such markets, photovoltaic systems often

prove to be cost effective when compared to the common distributed generation alternative, diesel generators, which may be high priced because of the cost of transporting fuel to remote regions.

More recently, photovoltaic cell and module shipments have grown on an international scale. Data for 1999 show 201 peak megawatts (MWp) of worldwide shipments (Figure 2). Shipments from manufacturing capacity in the United States and Japan dominate the market, with about 30 percent of shipments from the United States and about 40 percent of shipments from Japan (Figure 3). This represents a marked change from 1995, when U.S.-based manufacturing capacity accounted for 45 percent of world shipments, with Japan at 26 percent. The increase in Japanese market share is

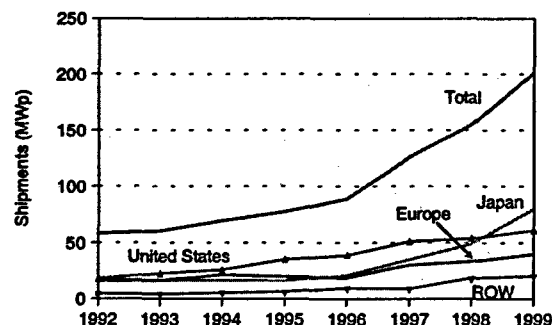
Figure 1. Decline in Photovoltaic Module Prices, 1975-1998



Source: P. Maycock, *The World Photovoltaic Market 1975-1998* (Warrenton, VA: PV Energy Systems, Inc., August 1999), p. A-3.

¹ M. Fitzgerald, *The History of PV* (Highlands Ranch, Colorado: Science Communications, Inc.). See website <http://www.pvpower.com/pvhistory.html> (December 1999).

Figure 2. World Photovoltaic Shipments, 1992-1999



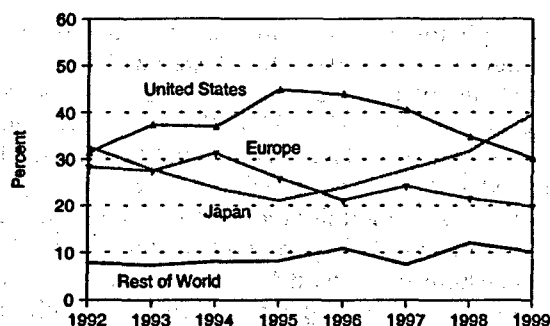
ROW = Rest of World.

MWp = Peak megawatts.

Note: The number of U.S. total PV shipments is a third quarter estimate given by the companies, while in Figure 4 the number of U.S. total PV shipments is an end-of-year actual accounting.

Sources: 1993 through 1999 revised data from: Paul Maycock, *PV News*, Vol. 19, No. 3 (Warrenton, VA: PV Energy Systems, Inc., March 2000). 1992 data from: P. Maycock, *PV News*, Vol. 18, No. 2 (Warrenton, VA: PV Energy Systems, Inc., February 1999).

Figure 3. Photovoltaic Shipments Market Share, 1992-1999



Sources: 1993 through 1999 revised data from: P. Maycock, *PV News*, Vol. 19, No. 3 (Warrenton, VA: PV Energy Systems, Inc., March 2000). 1992 data from: P. Maycock, *PV News*, Vol. 18, No. 2 (Warrenton, VA: PV Energy Systems, Inc., February 1999).

due to growth of the building-integrated photovoltaic (BIPV) applications market in Japan, which benefits from Ministry of International Trade and Industry (MITI) programs, subsidies, and net metering regulations.

The following analysis discusses the dynamics of the international photovoltaic (PV) market, addressing the activities of PV manufacturers and consumers that have shaped the international market and their impact on the U.S. domestic PV industry. It will explain three major features of recent PV manufacturing and shipment history.

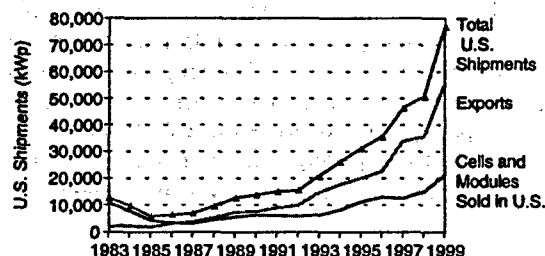
Three Major Features

- (1) **Industry Consolidation:** In the early 1990s, ownership of PV manufacturing capacity consolidated as Siemens purchased Arco Solar in March 1990 and ASE purchased Mobil Solar in July 1994. By 1997, about 80 percent of PV shipments from the United States were attributable to manufacturing capacity owned by Siemens Solar and ASE Americas, both German firms, and BP Solarex, a British firm.² At the heart of these corporate entities are firms that were originally founded as U.S. corporations: Arco Solar, Mobil Solar, and Solarex, respectively. About 11 percent of PV shipments from the United States in 1997 were attributable to manufacturing capacity at

Solec International and United Solar Systems Corporation (USSC), which are joint ventures between U.S. and Japanese corporations.³

- (2) **U.S. Shipments Dominated by Exports:** Most PV cell/module shipments from U.S. manufacturing facilities are exported (Figure 4). In 1998, U.S. manufacturing facilities exported 35 megawatts (MW) of PV cells and modules, or 70 percent of total U.S. shipments,⁴ continuing a trend. Exports of PV cells/modules manufactured in the United States have exceeded 55 percent of total U.S. cell/module shipments every year since 1987.

Figure 4. U.S. Photovoltaic Cell and Module Shipments, 1983-1999



kWp = Peak kilowatts.

Note: The number of U.S. total PV shipments is an end-of-year actual accounting while in Figure 2, the number of U.S. total PV shipments is a third quarter estimate given by the companies.

Source: Energy Information Administration, Form EIA-63B, "Annual Photovoltaic Module/Cell Manufacturers Survey."

- (3) **Market Growth in Either Subsidized or High Value Markets:** Countries experiencing growth in photovoltaic shipments either have programs that heavily subsidize photovoltaic system purchases or market characteristics that lend value to photovoltaic electricity. Several subsidy programs exist to promote installation of distributed photovoltaic systems, including building-integrated photovoltaic systems. Value characteristics that enable photovoltaic systems to compete include high electricity prices (e.g., high cost of generating fuel), or no electricity at all, and environmental concerns that entice consumers to pay a premium for electricity from photovoltaic or other renewable sources (i.e., through green pricing/marketing programs).

² P. Maycock, *Photovoltaic Technology, Performance, Cost and Market*, V. 7 (Warrenton, VA: PV Energy Systems, August 1998), pp. 15-18.

³ *Ibid.*

⁴ Energy Information Administration, Form EIA-63B, "Annual Photovoltaic Module/Cell Manufacturers Survey."

History

The market for photovoltaic systems has developed in three stages, distinguished by the type of application and by the focus of State, Federal, and international market development initiatives.

Space Program

During the first stage (1950s through 1960s), PV development was motivated primarily by a need for electricity generation technology that would be suited for the space program. In 1958, Vanguard I became the first PV-powered satellite. The 0.1 watt (W), approximately 100 cm² (square centimeters), silicon cell system powered a 5 milliwatt backup transmitter for 8 years.⁵ It offered a relatively lightweight solution to power supply for satellites and spacecraft. The single-crystal silicon photovoltaic cells deployed in space in the late 1950s had cell efficiencies that ranged from 8 to 10 percent.⁶ By 1998, efficiencies of modules made from such cells had increased to between 14 percent and 16 percent.⁷

Oil Price Pressures

The second stage (1970s through mid-1980s) commenced with the Arab OPEC oil embargo of 1973, which resulted in a significant increase in oil prices. One response in the United States and other countries was to fund development of renewable and energy-efficient technologies that would relieve dependence on fossil fuels. Federal and State tax credits for both residential and commercial customers subsidized expansion of terrestrial applications markets during this period. In addition, in 1978, the Public Utilities Regulatory Policy Act (PURPA) provided another market development support by guaranteeing "qualifying facilities" access to the electricity utility grid and requiring utilities to purchase the electricity. In California, the Standard Offer Number 4 electricity purchase contract offered renewable electric "qualifying facilities" a very attractive purchase price, which was guaranteed for a period of 10 years. Qualifying facilities included renewable electric generators, such as photovoltaic systems. By the late 1980s, Federal tax credits had expired and other market mechanisms for new applicants were terminated. The result was a significant drop in the addition of new photovoltaic electric generation capacity.

⁵ M. Fitzgerald, *The History of PV* (Highlands Ranch, Colorado: Science Communications, Inc.). See website <http://www.pvpower.com/pvhistory.html> (December 1999).

⁶ U.S. Department of Energy, *History: PV Timeline, About Photovoltaics*. See website <http://www.eren.doe.gov/pv/history.html> (May 2000).

⁷ P. Maycock, *Photovoltaic Technology, Performance, and Cost 1995-2010* (Warrenton, VA: PV Energy Systems, Inc., January 2000), p. x.

Globalization of the Market

The U.S. photovoltaic industry is now in the third market development stage, which began with increased sales to the international terrestrial electric power market in the late 1980s. U.S. Energy Information Administration (EIA) data show that in 1985, the year in which Federal tax credits expired, U.S. exports of photovoltaic cells/modules represented approximately 29 percent of total U.S. photovoltaic shipments. This percentage jumped to about 49 percent in 1986 and has remained at or above 55 percent since 1987, as photovoltaic cells and modules manufactured in the United States have been shipped internationally to serve terrestrial markets for PV in areas remote from a central station power grid (Table 1). Such areas face the high cost of diesel power generation, which make PV cost-effective. The 1990s have witnessed continued growth of these markets aided, for example, by initiatives of donor agencies (e.g., World Bank, United Nations Development Programme, U.S. Agency for International

Table 1. U.S. Photovoltaic Cell and Module Shipments, 1983-1998

Year	Total Shipments (kWp)	Exports (kWp)	Exports (percent)
1983	12,620	1,903	15.1
1984	9,912	2,153	21.7
1985	5,769	1,670	28.9
1986	6,333	3,109	49.1
1987	6,850	3,821	55.8
1988	9,676	5,358	55.4
1989	12,825	7,363	57.4
1990	13,837	7,544	54.5
1991	14,939	8,905	59.6
1992	15,583	9,823	63.0
1993	20,951	14,814	70.7
1994	26,077	17,714	67.9
1995	31,059	19,871	64.0
1996	35,464	22,448	63.3
1997	46,354	33,793	72.9
1998	50,562	35,493	70.2

kWp = Peak kilowatts.

Source: 1983-1997 data from Energy Information Administration, *Annual Energy Review 1998*, DOE/EIA-0384(98) (Washington, DC, July 1999), Table 10.6; 1998 data from Energy Information Administration, Form EIA-63B, "Annual Photovoltaic Module/Cell Manufacturers Survey."

Development) and regional development banks. Additionally, the 1990s have witnessed a growing interest in renewables as a means to address environmental problems such as global warming. This interest is driving programs such as the Million Solar Roofs Initiative and State initiatives to promote renewables in a deregulated electricity generation market. In addition, the governments of Japan and Germany strongly support PV programs.

Japan has a subsidy program goal of increasing PV demand by 400 MW per year through 2010 and Germany has a goal of 100 MW per year through 2005. This increased demand is being met by domestic cell and module production and imports from the United States.

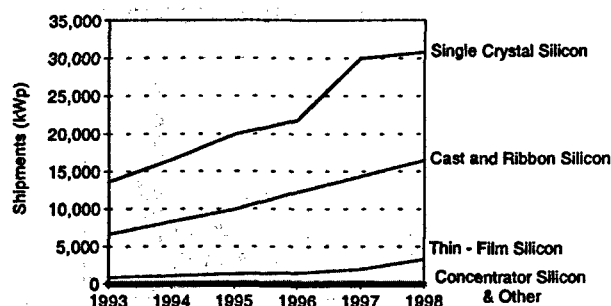
Domestic and International Supply

U.S.-based manufacturers had an early market lead based on inventing and patenting PV technology. This lead is being challenged by competition from countries such as Japan and Germany. This international competition, along with years of manufacturing experience and government research and development funding, has produced gains in photovoltaic module energy efficiency and cost reductions. New photovoltaic technologies that show promise for further energy efficiency gains and cost reductions are starting to emerge. However, single crystal silicon technology continues to dominate both U.S. and some international cell and module shipments (Figures 5 and 6). U.S. photovoltaic cell and module shipments are shown in Figure 7. The following section reviews manufacturing and research trends. It also discusses the impact that factors such as an educated labor force, Federal and State support of research and development (R&D), and availability of venture capital have on growth of manufacturing capacity in a country.

U.S. and International Shipment and Capacity Trends

From 1994 to 1999, annual worldwide shipments of photovoltaic cells and modules almost tripled, growing from about 69 MW in 1994 to about 201 MW in 1999. During this period, the combined market share of 10 companies grew from about 70 percent to 85 percent (Table 2). These companies have a global presence for manufacturing cells and modules (Table 3). During the 1990s, photovoltaic manufacturing capacity expanded beyond the United States, Japan, and Germany. In 1997, worldwide cell and module shipments came from

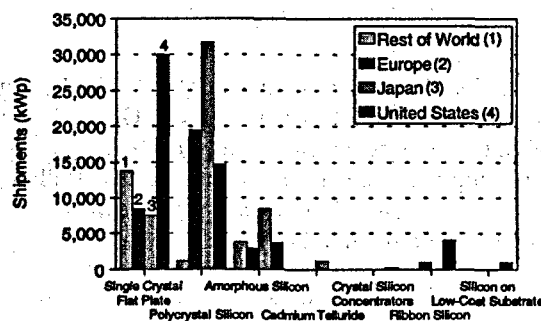
Figure 5. U.S. Shipments by Cell/Module Type, 1993-1998



kWp = Peak kilowatts.

Source: Energy Information Administration, Form EIA-63B, "Annual Photovoltaic Module/Cell Manufacturers Survey."

Figure 6. World Shipments by Module Type, 1998



kWp = Peak kilowatts.

Source: P. Maycock, *The World Photovoltaic Market 1975-1998* (Warrenton, VA: PV Energy Systems, Inc., August 1999), p. 13.

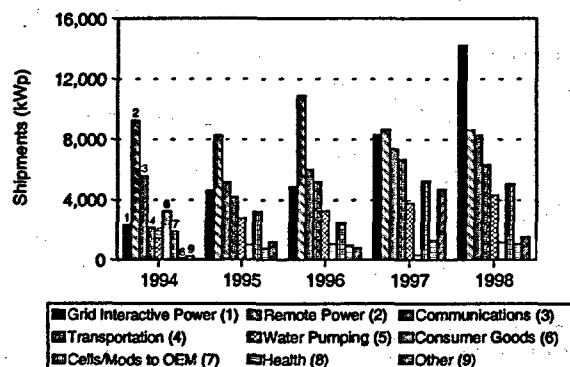
(manufacturing capacity in the United Kingdom (10 percent); France (5 percent); India (4 percent); Italy (3 percent); and other countries (8 percent), including Spain, Taiwan, The Netherlands, and the Peoples Republic of China.⁸ By 1999, Japanese manufacturers (Kyocera, Sharp, and Sanyo) grew to lead world shipments, supported by government programs in Japan to use PV in building applications (Table 3). In 1999, the combined market share of Kyocera, Sharp, and Sanyo rose to 37 percent, up from about 19 percent in 1994.

To meet growing demand, an estimated 250 MW of new manufacturing capacity for producing PV systems are currently planned for post-1998 installation (Table 4).⁹ Most of the new capacity will be constructed in the United States, Japan, and Germany. This new capacity will include new thin film materials, such as copper

⁸ P. Maycock, *Photovoltaic Technology, Performance, Cost and Market*, V. 7 (Warrenton, VA: PV Energy Systems, August 1998), pp. 15-18.

⁹ P. Maycock, *Photovoltaic Technology, Performance, and Cost 1995-2010* (Warrenton, VA: PV Energy Systems, Inc., January 2000), p. vii.

Figure 7. U.S. Photovoltaic Cell and Module Shipments by End Use, 1994-1998



kWp: Peak kilowatts.

Note: Numbers above bars correspond to end use category.

Source: Energy Information Administration, Form EIA-63B, "Annual Photovoltaic Module/Cell Manufacturers Survey."

indium diselenide, which Siemens Solar is producing currently at a market introduction level. Generally, it takes about 1 year to construct a 5 to 10 megawatt manufacturing plant to produce single, polycrystalline, and amorphous photovoltaic cells using existing manufacturing technology. It takes up to an additional 6 months to bring the new manufacturing facility up to normal operation. Longer periods are expected initially for the new thin film photovoltaic technologies.

Manufacturing Strategies

Photovoltaic manufacturers have developed the following diverse strategies for competing in global markets:

Table 2. Global Corporate Market Share, 1994-1999 (Percent)

Supply Company	1994	1995	1996	1997	1998	1999
Siemens	19.4	22.2	19.2	17.5	12.9	12.0
Solarex	10.8	12.2	12.2	11.8	10.3	8.9
BP Solar	8.8	9.3	9.5	9.0	8.7	7.2
Kyocera	7.9	7.9	10.3	12.2	15.8	15.1
Sanyo	7.9	6.6	5.2	3.7	4.1	6.5
ASE	4.3	4.8	3.4	4.8	4.5	5.5
Sharp	2.9	5.2	5.6	8.4	9.0	14.9
Photowatt	2.6	2.6	2.8	4.5	7.7	5.0
Astropower	2.4	3.2	3.2	3.4	4.5	6.0
Isophoton	2.2	1.9	1.7	2.1	2.7	4.0
Other Companies	30.7	24.2	26.8	22.5	19.8	15.0

Source: Based on data in P. Maycock, *PV News*, Vol. 19, No. 3 (March 2000) and Paul Maycock, *PV News*, Vol. 19, No. 2 (February 2000).

¹⁰ Personal communication between Kent Whitfield (Spire Solar, Chicago) and William R. King (SAIC), March 8, 2000.

Locating Near End-Use Markets. Manufacturers benefit from the end-user and system installer feedback they gain on product design and performance when selling photovoltaic systems locally. This can be integrated into improved system design, including balance of system improvements, which may result in cost reductions. Manufacturers hope this will support increased sales by providing end-users with desired features. Increased sales help reduce the cost per kW price of a PV module by spreading development and overhead costs over a higher kW sales volume.

The Spire Corporation/BP Solarex venture in Chicago is an example of the trend toward locating manufacturing capacity close to end-users. PV modules will be manufactured in Chicago and the modules, incorporated into solar systems, will be marketed to residential and commercial customers in the Midwest. The Spire agreement with the City of Chicago and Commonwealth Edison (ComEd), the local utility, will provide \$8 million of PV systems. Funding from ComEd shareholders accounts for \$6 million.¹⁰ The remaining \$2 million will be funded from the City of Chicago's budget. Installing PV systems on schools is a priority. ComEd has first right of refusal on an additional \$6 million of PV systems. Manufacturing plants built to service such markets are generally small, modular plants.

If proximity to the end-use market is beneficial, then U.S.-based manufacturers, who export most of their product, may be at a disadvantage when it comes to (1) designing and manufacturing photovoltaic products to meet most of their end-users' needs and (2) benefitting from the lower system costs per kW that may result from advances in product design and from increased

Table 3. Module and Cell Shipments by Company, 1994-1999
(Megawatts)

Company (Manufacturing Location)	1994	1995	1996	1997	1998	1999
ASE (Germany)	2.4	1.7	—	2.0	3.0	7.0
ASE (US)	0.6	2.0	3.0	4.0	4.0	4.0
Astropower (US)	1.7	2.5	2.85	4.3	7.0	12.0
BP Solar (Australia)	—	—	—	—	5.1	5.5
BP Solar (India)	—	—	—	—	3.8	4.0
BP Solar (UK)	6.1	7.2	8.45	11.3	4.5	5.0
Isophoton (Spain)	1.5	1.5	1.5	2.7	4.2	8.1
Kyocera (Japan)	5.5	6.1	9.1	15.4	24.5	30.3
Photowatt (France)	1.8	2.05	2.5	5.7	12.0	10.0
Sanyo (Japan)	5.5	5.1	4.6	4.7	6.3	13.0
Sharp (Japan)	2.0	4.0	5.0	10.6	14.0	30.0
Siemens (Germany)	0.5	0.2	0.05	0	0	2.0
Siemens (US)	13.0	17.0	17.0	22.0	20.0	22.2
Solarex (US)	7.5	9.5	10.8	14.8	15.9	18.0
Other Companies	21.3	18.8	23.8	28.3	30.6	30.2
World Total	69.4	77.6	88.6	125.8	154.9	201.3

Sources: P. Maycock, *PV News*, Vol. 19, No. 3. (March 2000) for companies with Manufacturing Location listed as France, Germany, Spain, United Kingdom, United States or World Total. P. Maycock, *PV News*, Vol. 19, No. 2 (February 2000) for companies with Manufacturing Location listed as Australia, India, or Japan.

Table 4. Examples of Post-1998 New Manufacturing Capacity Systems for PV

Country	Company	Technology	Manufacturing Capacity (megawatts)	On-Line Date
United States	Siemens Solar	Single crystal silicon	30 to 32	2000
United States	Solarex	Amorphous silicon	10	2000
United States	ASE Americas	Octagon EFG ribbon	20	2000
United States	United Solar Systems	Triple stack amorphous silicon	5	2000
United States	Solar Cells Inc.	Cadmium telluride	50	NA
United States (California, Sacramento Municipal Utility District)	Energy Photovoltaics	Amorphous silicon	5	2000
Germany (Saxony)	Energy Photovoltaics	Copper indium diselenide	5	2000
Germany (Gelsenkirchen)	Shell Renewables	Cast ingot polycrystalline silicon	25	2000
Japan	Sanyo	Amorphous Silicon on crystal silicon	10	2000
Japan	Kyocera	Cast ingot polycrystalline silicon	25	2000
Japan	Sharp	Crystalline silicon	30	NA
Australia	Solarex	Cast ingot polycrystalline silicon	20	1999
Hungary	Energy Photovoltaics	Amorphous silicon	2.5	1998-99
Other (various countries, companies, and technologies)			12	
Total			250	

NA = Not available.

Source: P. Maycock, *Photovoltaic Technology, Performance, and Cost 1995-2010* (Warrenton, VA: PV Energy Systems, Inc., January 2000), pp. viii-x.

sales of systems that meet end-user design requirements. U.S.-based manufacturers compensate for their distance from many end-use markets with a willingness to place technically trained marketing representatives on site around the world. They also engineer cells and modules for long-term trouble-free operation, covering them with warranties of 20 to 25 years.

Production in Japan and Germany is growing, despite high labor costs in both countries compared with the United States. High labor costs are offset, however, by strong domestic markets, which enable emerging photovoltaic technology product development and cost reduction efforts to benefit from end-user feedback. Strong domestic markets also enable Japan and Germany to export lower cost systems.

Changing Plant Capacity. As mentioned above, there is a trend toward building smaller PV cell and module plants closer to end-user markets. These plants can be expanded as demand increases. This strategy is motivated by several factors.

First, current PV manufacturing facilities have capacities of 5 MW to 20 MW per year output, designed to support local or regional demand, including utility-sponsored PV programs. Second, transportation costs are reduced for manufacturing plants situated locally relative to the end-user market. Third, the proximity of the plant to end users enables feedback from end users that is valuable in refining product design to meet end-user requirements and in addressing any performance problems.

For example, Energy Photovoltaics, Inc. (EPV) in Princeton, New Jersey, has a 5-year, 10 MW purchase contract with the Sacramento Municipal Utility District (SMUD) under which EPV will locate a 5 MW amorphous silicon

module manufacturing facility in the Sacramento area. Volume purchase contracts provide a near-term way to attain lower photovoltaic module wholesale prices (Table 5).

Other manufacturers are taking the opposite approach, increasing plant size substantially. Large plants (e.g., over 20 MW) would be built to achieve economies of scale that will reduce the production cost of photovoltaic modules. For instance, as SMUD's residential grid-connected demand grows enough to support large capacity factories (40 MW and up), the wholesale price for a thin film module is expected to fall to \$1/W from current costs of \$4.50/W.

Price decreases are expected to occur in steps. When a higher capacity factory starts to produce modules, module prices will remain high until demand increases enough to take advantage of the economies of scale of the larger manufacturing plant. Breaking the \$2/W manufacturing cost barrier for photovoltaic modules within the next 5 to 10 years will depend on high efficiency thin films (e.g., copper indium diselenide (CIS), cadmium telluride (CdTe)) and "next generation" production volume manufacturing facilities.¹¹ In Germany, Shell Renewables is following a strategy to build large facilities. They opened a 25-MW facility to manufacture cells in Gelsenkirchen, Germany in January 2000.¹²

Separation of Cell Manufacturing and Module Fabrication Operations. Photovoltaic cell manufacturing processes require technically qualified labor to produce quality cells. Thus, cell manufacturing operations are located in countries where such labor is available (e.g., United States, Japan, Germany). Assembly of cells into modules does not require the same level of technical

Table 5. Photovoltaic Module Costs (Wholesale)

Type of Sales Transaction	Capacity of Module Manufacturing Facility (megawatts)	Resulting Wholesale Module Price (dollars per watt)	Year in Which Price Will Be Attainable
High-volume purchase: 5-year contract to purchase 10 megawatts of amorphous thin film modules	5-20	1.50-2.50	Current (2000)
Low-volume purchase: block purchases of PV modules where the total purchase is in the hundreds of kilowatts range.	5-20	3-4	Current (2000)
Thin film module	40-100	1	2005

Source: Personal communication between Don Osborn (SMUD) and William R. King (SAIC), March 3, 2000.

¹¹ Personal communication between Tom Surek (NREL) and William R. King (SAIC), July 3, 2000.

¹² R. Curry, *Photovoltaic Insider's Report*, Vol. XIX, No. 2 (February 2000), p. 6.

expertise; therefore, manufacturers often ship cells to countries with end-use markets for assembly into modules. The practice helps keep photovoltaic module costs as low as possible because many countries where photovoltaic modules are deployed also have large pools of low-cost labor qualified for module assembly and because cells are less expensive to ship than modules. For example, in South Africa the strategy is to provide low-cost module assembly to meet demand generated by the South African program to promote photovoltaics for rural electric applications. South Africa has two module assembly plants, several wholesalers, and about 40 distributor/systems integration companies.¹³

In-Country Corporate Presence. Photovoltaic manufacturers may establish a cell or module manufacturing presence in a country to obtain preferential treatment. For instance, a country may exempt the manufacturer with domestic operations from certain tariffs. Additionally, countries such as Germany provide investment incentives for manufacturers to build plants. The companies have employed these strategies in various ways. In the United States, photovoltaic manufacturing firms have formed alliances with utilities, as well as located the manufacturing plant near the end users. Examples include Tucson Electric/Global Solar (Arizona) and GPU, Incorporated (New Jersey, Pennsylvania), a subsidiary of GPU International, Incorporated, a worldwide developer of independent powerplants, which operates GPU Solar as a joint venture with AstroPower, Inc., a photovoltaic module manufacturer.

Export Strategies

U.S. companies have also used different export strategies. Photovoltaic cells and modules are shipped worldwide from manufacturing facilities in the United States. From 1993 to 1998, Japan and Germany were among the top three recipients of these shipments (Table 6). Often, cells are shipped to module assembly plants. U.S. manufacturers prefer to produce cells in the United States because of the availability of technically qualified labor needed to produce quality photovoltaic cells. Additionally, they benefit from the availability of quality materials from U.S. vendors, such as polymers, for manufacturing cells. Cells are less expensive to ship than

modules, and assembly of modules close to the installation site benefits from low labor rates at many international sites.

In contrast to the United States, which in recent years exported up to 70 percent of domestically manufactured cells and modules, Japan is more focused on proximity to the end-use customers. Japan exported only 35 percent of domestic production in 1996 and 31 percent in 1997 (Table 7). Japan tends to export multicrystalline and amorphous silicon cells produced domestically and to import single crystal silicon cells.

In India, the strategy is to use a technically adept and low-cost workforce to manufacture cells. BP Solar manufactures cells in India to take advantage of such labor rates and exports the cells to end-use markets. Indian manufacturers are also developing capacity. In Pune, India, Eco Solar Systems India is using a USAID conditional grant (3.5 million Rupees (Rs) or about \$80,000) and a commercial loan (Rs 12.2 million, or about \$280,000) to upgrade and modify a prototype photovoltaic cell manufacturing line.^{14, 15} This funding comes from USAID/India project reflows¹⁶ of Rs 261 million (about \$6 million), \$4 million (from USAID's technology development program of the mid-1980s), and Rs 660 million (about \$15 million) from Public Law 480 Title III funds for private sector projects.

Photovoltaic Technology Development Programs

Both government and corporate photovoltaic technology development programs are directing funding toward photovoltaic technology that can be produced more cost-effectively. There are four or five independent technology paths to low-cost PV, ranging from continuation of crystalline silicon technology to thin film alternatives.

Lower Cost of Single Crystal Silicon

One approach is to continue trying to push the cost of single crystal silicon lower. However, cost reductions are hindered because feedstock for single crystal silicon cells is the waste silicon from the electronics industry. Increasing demand for waste silicon is leading to shortages.

¹³ R. Karotki and D. Banks, "PV Power and Profit? Electrifying Rural South Africa," *Renewable Energy World*, Vol. 3/No. 1 (January 2000), p. 51.

¹⁴ U.S. Agency for International Development, *USAID Activities in India's Western States: Maharastra, Gujarat, and Madhya Pradesh*. See website <http://www.info.usaid.gov/india/> (March 2000), p. 8.

¹⁵ Indian rupees (Rs) are converted to equivalent U.S. dollars at a 1999 annual U.S. Federal Reserve rate of 43.13 Rs/US dollar, per Federal Reserve Statistical Release G.5A, January 3, 2000.

¹⁶ Reflows are revenues from projects that are paid back to the group that originally provided project funding. Then, the group can use the funds for other projects.

Table 6. U.S. Exports by Country of Destination, 1993-1998

Country	Cell and Module Shipments											
	1993		1994		1995		1996		1997		1998	
	Peak Kilo-watts	Percent of Total Exports	Peak Kilo-watts	Percent of Total Exports	Peak Kilo-watts	Percent of Total Exports	Peak Kilo-watts	Percent of Total Exports	Peak Kilo-watts	Percent of Total Exports	Peak Kilo-watts	Percent of Total Exports
Africa												
South Africa	399	2.7	791	4.5	1,294	6.5	541	2.4	939	2.8	2,608	7.3
Asia and the Middle East												
Japan	1,440	9.7	2,857	16.1	3,616	18.2	2,889	12.9	8,056	23.8	9,586	27.0
Hong Kong	1,567	10.6	1,175	6.6	1,125	5.7	701	3.1	1,423	4.2	1,323	3.7
India	94	0.6	806	4.6	2,398	12.1	755	3.4	285	0.8	435	1.2
Singapore	639	4.3	1,072	6.1	1,352	6.8	1,168	5.2	1,106	3.3	611	1.7
Australia	92	0.6	7	—	16	0.1	387	1.7	61	0.2	119	0.3
Europe												
Germany	4,972	33.6	4,641	26.2	3,755	18.9	8,150	36.3	11,162	33.0	9,727	27.4
Spain	—	—	80	0.5	664	3.3	481	2.1	651	1.9	1,442	4.1
Switzerland	4	0.0	138	0.8	799	4.0	177	0.8	31	0.1	1,220	3.4
North America												
Canada	819	5.5	1,043	5.9	503	2.5	793	3.5	775	2.3	633	1.8
Mexico	761	5.1	2,058	11.6	493	2.5	780	3.5	1,319	3.9	1,405	4.0
South America												
Brazil	401	2.7	61	0.3	260	1.3	269	1.2	1,259	3.7	1,012	2.9
Total U.S. Exports	14,814	75.5	17,714	83.1	19,871	81.9	22,448	76.1	33,793	80.1	35,493	84.9

Notes: Total U.S. exports do not equal 100 percent because only those countries with the largest import markets are shown. U.S. totals include exports to other countries with non-sustainable export shipments.

Sources: Energy Information Administration, *Renewable Energy Annual 1999*, DOE/EIA-0603(99) (Washington, DC, March 2000), for years 1994 through 1998, and *Solar Collector Manufacturing Activity 1993*, DOE/EIA-0174(93) (Washington, DC, August 1994), for 1993.

Table 7. Japanese Photovoltaic Cell Exports and Imports, 1996 and 1997
(Kilowatts)

Cell Type	Fiscal Year 1996			Fiscal Year 1997		
	Domestic Production	Imports	Exports	Domestic Production	Imports	Exports
Single Crystal Silicon	5,379.0	2,118.0	850.0	9,813.1	3,351.6	601.5
Multicrystalline Silicon	9,535.0	680.0	4,005.0	17,525.0	1,964.0	5,111.0
Amorphous Silicon	5,574.0	14.0	1,725.0	5,936.3	7.6	3,817.0
Other	1,018.0	0.0	920.0	989.4	0.0	948.0
Total	21,506.0	2,812.0	7,500.0	34,263.8	5,323.2	10,477.5

Source: O. Ikki, et al., *The Current Status of Photovoltaic Dissemination Programme In Japan* (Tokyo, Japan, September 1998), Table 8. Japan Photovoltaic Energy Association data.

In addition, the single crystal silicon cell is thick compared to thin film alternatives. Use of more material increases product cost. On the positive side, single crystal silicon modules still command an energy conversion efficiency premium per square meter over alternative PV products. In addition, crystal silicon is a known material with years of proven performance in the

field. Thus, single crystal silicon modules have an advantage over other PV flat-plate module technologies in applications where space is at a premium.

Another approach is amorphous silicon, which may be viewed as a transitional technology, since it has a lower energy efficiency than alternatives and since amorphous

silicon modules must be aged prior to sale to ensure that their energy efficiency remains stable. Copper indium diselenide (CIS) is the leading material for amorphous silicon technology. The current problem with CIS is availability; Siemens Solar is manufacturing only pre-commercial market conditioning volumes.¹⁷ For the CIS market to develop, purchases in the 100 kW range are needed. To support such purchases, production in the one megawatt per year range is needed.

United States National Photovoltaics Program

The National Photovoltaics Program, funded by the U.S. Department of Energy, involves national laboratories, universities, and industry stakeholders in cooperative research and development of photovoltaic systems to attain higher module energy efficiencies, lower system costs, and longer system life. The long-term goal of the program is to make photovoltaic electricity available at an operating cost of \$0.06/kWh. Current program goals were established by U.S.-based photovoltaic industry members to establish a "roadmap" for future industry development (Table 8).¹⁸ The roadmap's goal for shipments is 25 percent annual growth in shipments from manufacturing facilities based in the United States. This growth rate would result in at least 6 gigawatts-peak (GWp) installed worldwide by 2020 from manufacturing capacity based in the United States, including 3.2 GWp of domestic installations.¹⁹ The 3.2 GWp target assumes (1) a constant U.S. share of worldwide annual shipments of 40 percent and (2) installation of 30 percent of U.S. shipments in the United States in the year 2000, increasing to 50 percent by 2020. The expected application mix for the 3.2 GWp is the following:

- 50 percent alternating current (AC) distributed generation (remote, off-grid power for applications including cabins, village power, and communications)
- 33 percent direct current (DC) and AC value applications (consumer products such as cell phones, calculators, and camping equipment), and
- 17 percent AC grid (wholesale) generation (grid-connected systems including BIPV systems).²⁰

For FY2000, the Federal PV research and development program is funded at a level of \$65.9 million (Table 9). The program is divided into three areas:

Table 8. U.S. National Photovoltaics Program Goals - 2000-2005

	1995	2000	2005
Module Efficiency (percent) ..	7-17	8-18	10-20
System Cost (1999 dollars per watt)	7-15	5-12	4-8
System Life (years)	10-20	> 20	> 25
U.S. Cumulative Sales (megawatts)	175	500	1,000-1,500

Note: Table shows range of module efficiencies for commercial flat-plate and concentrator modules.

Source: U.S. Department of Energy, *Photovoltaics - Energy for the New Millennium: The National Photovoltaics Program Plan 2000-2004*, DOE/GO-10099-940 (Washington, DC, January 2000), p. 9.

- **Fundamental Research.** Support industry and university research to characterize cell materials and devices; conduct research to understand defects in conventional crystalline silicon and thin film materials; and develop techniques to reduce efficiency-limiting defects in cell material; increase the efficiency of multijunction concentrating cells and large-area, monolithically interconnected thin films.
- **Advanced Materials and Devices.** Develop next generation thin film technologies through cost-shared efforts with industry and universities. This effort includes support of first-time manufacturing and scale-up of thin film amorphous silicon, CIS, CdTe, and thin silicon. Develop high efficiency crystalline silicon devices, emphasizing manufacturing methods that reduce cost.
- **Technology Development.** Develop manufacturing methods that result in lower cost, higher efficiency modules and in lower cost PV system components (e.g., batteries and inverters). This effort has included the Photovoltaic Manufacturing Technology (PVMAI) initiative, which addresses systems engineering and reliability issues through activities such as testing, developing domestic and international standards and codes, and analyzing factors affecting stability of encapsulated materials and performance of cells in modules. Technology development also includes: (1) developing advanced PV building concepts, tools, and modeling procedures; (2) motivating introduction of PV into

¹⁷ Personal communication between Don Osborn (SMUD) and William R. King (SAIC), March 3, 2000.

¹⁸ Proceedings from the U.S. Photovoltaics Industry PV Technology Roadmap Workshop (Energetics, Inc., ed.), National Center for Photovoltaics (Chicago, IL, September 1999).

¹⁹ *Ibid.*, p. A4.

²⁰ *Ibid.*

Table 9. U.S. Federal Photovoltaic R&D Budget
(Thousand Dollars)

Program Area	FY 1999 Actual	FY 2000 Appropriation	FY 2001 Request
Fundamental Research	10,761	14,221	20,300
Advanced Materials and Devices	25,836	27,000	27,000
Technology Development	33,964	24,691	34,700
Partners for Technology	3,800	500	2,000
Introduction Million Solar Roofs Initiative	1,500	1,500	3,000
International Clean Energy Initiative	0	0	4,000
Total Budget	70,561	65,912	82,000

Source: FY 2001 Congressional Budget.

building systems through cost-shared projects (Partnerships for Technology Introduction) and support of the Million Solar Roofs Initiative; and (3) accelerating introduction of photovoltaic power as a rural electrification option for developing countries by developing prototype systems, advancing the concept of international equipment standards, and developing tools for analyzing distributed photovoltaic opportunities (International Clean Energy Initiative).

The Partnerships for Technology Introduction, Million Solar Roofs Initiative, and International Clean Energy Initiative elements of the Technology Development budget address market stimulation through funding of cost-shared projects, prototype systems, and activities to promote formation of Million Solar Roofs partnerships. None of the \$1.5 million for the Million Solar Roofs Initiative is an end-use incentive.

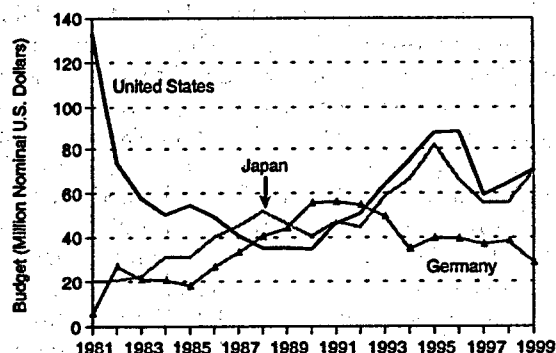
Japanese and German National Photovoltaic Development Programs

The Japanese and German development programs have provided competition for the United States over the years. For instance, during the 8-year period from 1981 to 1988, the German and Japanese Federal PV R&D budgets increased, while the U.S. Federal budget fell (Figure 8). Recent funding data show the willingness of the Japanese government to spend relatively large amounts on direct market stimulation for end uses to promote their building photovoltaic program. They are funding market stimulation at a rate over four times that spent by either the United States or German programs (Table 10). Data indicate that the Japanese PV promotional budget rose steadily from \$53 million in 1995 to \$132 million in 1998.²¹

²¹ O. Ikki, K. Tomori, and T. Ohigashi, *The Current Status of Photovoltaic Dissemination Programme in Japan* (Tokyo, Japan: Resources Total System Co. Ltd., September 1998).

²² P. Maycock, *PV News*, Vol. 19, No. 3 (March 2000).

Figure 8. Federal Photovoltaic R&D Budgets, United States, Japan, and Germany, 1981-1999



Sources: United States – FY 1999 budget from: FY 2001 Congressional Budget, Energy Supply, Solar and Renewable Resources Technologies, Photovoltaic Systems, pp. 44-57. FY 1981 through FY 1998 budgets from: Historical data from National Photovoltaics Program records. Germany (Federal Department of Education, Science, Research and Technology budget) and Japan (Sunshine PV Program budget) – Historical data from Jack L. Stone, National Renewable Energy Laboratory, National Center for Photovoltaics.

U.S. and International Demand

In 1999, worldwide shipments of PV cells and modules totaled 201 MW,²² a 30-percent increase over 1998 worldwide shipments of 155 MW. U.S. manufacturers shipped just under 51 MWp of the total 1998 worldwide photovoltaic cell and module shipments. Factors motivating photovoltaic sales included Federal government and State tax incentives, utility rebate programs, "green" pricing programs, and donor agency programs to install photovoltaic systems in developing economies.

Table 10. Research, Development, Demonstration, and Market Stimulation Budget Comparison, Fiscal Year 1998 (Million U.S. Dollars)

Program Area	United States	Japan	Germany
R&D	64.7	56.1	38.3
Demonstration	—	21.4	—
Market Stimulation	*	132.5	18.4
Total Budget	64.7	210.0	56.7

— = Not applicable.

* In FY 1998, about \$30 million of the U.S. \$64.7 million R&D budget was spent on a combination of market stimulation-related activities (market transformation, research initiatives, application-specific research, and manufacturing process research). These expenditures are included in the R&D budget for the United States because their objective is related more to R&D than to market stimulation. Market stimulation amounts shown for Japan and Germany reflect payment of subsidies to reduce the cost of photovoltaic systems.

Sources: International Energy Agency, *Trends in Photovoltaic Applications in Selected IEA Countries Between 1992 and 1998* (IEA-PVPS 1-07:1999) (Paris, France, October 1999), p. 6. R&D budgets for Japan (Sunshine PV Program budget) and Germany (Federal Department of Education, Science, Research and Technology budget) from Jack L. Stone, National Renewable Energy Laboratory, National Center for Photovoltaics.

Over 80 percent of 1998 shipments by U.S. manufacturers went to the following end uses: remote and grid interactive electricity generation (45 percent); communications (16 percent); transportation, e.g., power on boats, in cars, in recreational vehicles, and transportation support systems (13 percent); and water pumping (9 percent). Key market niches encompassed by these end uses include building integrated photovoltaics promoted by utilities and national climate change or green power initiatives; other village, rural, or distributed generation applications in both developed and emerging economies; water pumping and irrigation systems, communications, and consumer products.

The following sections characterize these markets and discuss factors that influence demand.

U.S. Demand

The U.S. market is characterized by several niches that accounted for 15 MWp of cell and module shipments from manufacturing facilities in the United States in 1998. The domestic U.S. market includes the following segments, defined by application:²³

²³ Kyocera discusses several of these applications on its website at <http://www.kyocerasolar.com/Industrial/> (March 2000).

²⁴ National Renewable Energy Laboratory, *Photovoltaics: Advancing Toward the Millennium*, DOE/GO-10095-241 (Golden, CO, May 1996), pp. 14-15.

Building Integrated Photovoltaics (BIPV). These are PV arrays mounted on building roofs or facades. For residential buildings, analyses have assumed BIPV capacities of up to 4 kWp per residence. Systems may consist of conventional PV modules or PV shingles. This market segment includes hybrid power systems, combining diesel generator set, battery, and photovoltaic generation capacity for off-grid remote cabins.

Non-BIPV Electricity Generation (grid interactive and remote). This includes distributed generation (e.g., standalone PV systems or hybrid systems including diesel generators, battery storage, and other renewable technologies), water pumping and power for irrigation systems, and power for cathodic protection. The U.S. Coast Guard has installed over 20,000 PV-powered navigational aids (e.g., warning buoys and shore markers) since 1984.²⁴

Communications. PV systems provide power for remote telecommunications repeaters, fiber-optic amplifiers, rural telephones, and highway call boxes. Photovoltaic modules provide power for remote data acquisition for both land-based and offshore operations in the oil and gas industries.

Transportation. Examples include power on boats, in cars, in recreational vehicles, and for transportation support systems such as message boards or warning signals on streets and highways.

Consumer Electronics. A few examples are calculators; watches; portable and landscaping lights; portable, lightweight PV modules for recreational use; and battery chargers.

Market growth in each segment is affected by countervailing factors. The primary factor thwarting growth is the installed cost per kilowatt of the photovoltaic system, which often causes the cost of electricity (e.g., cents per kilowatthour) from such systems to be higher than the cost of electricity produced by fossil-fired or hydropower generation alternatives. National and international research efforts focus on ways to reduce the cost of photovoltaic systems.

Cost-Effective Markets

Near-term market growth is occurring where the end-use is in a remote location or the measurable cost of

electricity from alternative generation technologies is high enough for photovoltaic systems to be cost-effective. U.S. distributors have identified markets where photovoltaic power is cost-effective now, without subsidies. Examples include the following: (1) rural telephones and highway call boxes, (2) remote data acquisition for both land-based and offshore operations in the oil and gas industries, (3) message boards or warning signals on streets and highways, and (4) off-grid remote cabins, as part of a hybrid power system including batteries.²⁵

The current installed cost of photovoltaic systems ranges from \$0.20 to \$0.50 per kilowatthour, depending on factors such as the volume purchased and the level of solar insolation. Therefore, the electric price of the next best alternative must be no lower than this range for PV to be cost-effective. High electric prices tend to be found where there is no cost-effective access to the electric grid (e.g., remote applications markets, including distributed generation, telecommunications, navigational aids, and cathodic protection). Diesel generator sets are the alternative to photovoltaic electricity in some of these markets. In remote applications, diesel generator sets may be at a disadvantage to PV because these systems bear high costs of hauling fuel to the site, storing fuel, and maintaining equipment.

In the longer term, it will take a combination of wholesale system price below \$3.00/W and large volume dealers for PV to be cost-effective in the residential grid-connected market. PV installed system costs must fall to a range where they are competitive with current retail electric rates of \$0.08 to \$0.12/kWh in the residential market and \$0.06 to \$0.07/kWh in the commercial market.²⁶

Photovoltaic "Green" Power

U.S. Federal programs such as Million Solar Roofs and programs in states such as California emphasize the advantage of photovoltaic power as a clean sustainable power source, one that promotes lower environmental emissions. Programs are a mix of those that promote growth of photovoltaic power market share (e.g., Million Solar Roofs, PV Pioneer programs, Solar Power Hosting and Ownership programs, and Emerging Renewables Buy-Down Program) and those that support PV product development, testing, and operation in

actual applications to ensure successful transition of the product to the market place (e.g., PV:Bonus, TEAM-UP (Technical Experience to Accelerate Markets in Utility Photovoltaics), and PVUSA) (Table 11). Another variant on this approach is public policy initiatives designed to support photovoltaic sales with subsidies or appeals to "green" consumers willing to pay a premium for clean photovoltaic power.

TEAM-UP Program

In the United States, the Federal TEAM-UP program, a government-industry cost-shared program managed by the Utility Photovoltaic Group (UPVG), is an example of market conditioning support. TEAM-UP is not a large program; the first three rounds of competitively awarded installations will total more than 7.5 MW in 31 states.²⁷ For grid-connected systems, the subsidies under this program are negotiated depending upon program size and have averaged about 20 percent of total system installed cost.²⁸ In the United States, utility programs to subsidize PV system deployment are motivated by individual states' electric utility restructuring and deregulation activities.

For example, in California, revenues from a public benefit charge are used to fund renewable energy projects, including photovoltaic projects. A public benefit charge is an amount embedded in the electricity rate paid by consumers to cover public goods programs that would not otherwise be funded by deregulated utilities. The state, through the California Energy Commission, manages activities in investor-owned utility service territories; municipal utilities such as the Sacramento Municipal Utility District (SMUD) and the Los Angeles Department of Water and Power (LADWP) manage their own photovoltaic programs. Other states are considering renewable energy portfolio legislation to require a certain percentage of generation from renewable resources.

Buy-Down Programs

California and Maryland are examples of states with buy-down programs for photovoltaic systems. The California Energy Commission's (CEC's) Emerging Renewables Buy-Down Program offers cash rebates for systems purchased from eligible providers listed on the program's web site. Eligible technologies are photovoltaic

²⁵ For example, Kyocera discusses such applications on its website at <http://www.kyocerasolar.com/industrial/> (March 2000).

²⁶ Personal communication between Don Osborn (Sacramento Municipal Utility District) and William R. King (SAIC) (March 3, 2000).

²⁷ Utility Photovoltaic Group, "What Is TEAM-UP?" See website http://www.ttcorp.com/upvg/team_mn.htm (March 2000).

²⁸ Ibid.

Table 11. Examples of Photovoltaic Technology Market Development Initiatives

Initiative	Sponsor(s)	Inception Date - Completion Date	Objective	Strategy	Results
PV:Bonus ^a	U.S. Department of Energy (DOE)	1993 -- ongoing	Develop prototype PV products to replace conventional windows, skylights, and walls.	Innovative product designs for building applications. Fund product development.	Developed products including flexible solar shingle and alternating current (AC) PV modules.
TEAM-UP ^b	Utility industry-DOE cost-sharing partnership managed by Utility Photovoltaic Group (UPVG)	1994 -- 2000	Demonstrate and validate PV system hardware installations for various utility/energy service provider applications. Build owner and customer confidence in systems.	Market conditioning through demonstration. Competitively procure, install, and demonstrate 50 MW of PV systems. Awards made to ventures that will build a PV system and sell to end-users.	4.5 MW installed under Round One and Two solicitations. Total 7.4 MW installed capacity (2300 PV systems) by October 2000.
Million Solar Roofs ^c	U.S. Department of Energy	June 26, 1997 -- 2010	Reduce greenhouse gases and other emissions. Create high-tech jobs. Keep U.S. PV industry competitive.	Encourage installation of one million solar energy systems on U.S. rooftops by 2010.	Motivating formation of partnerships committed to installed PV on rooftops. Examples of partnership activities include the SMUD, LADWP, and Spire Solar Chicago PV programs. ^d
PVUSA ^e	Co-sponsors include various State and Federal agencies and various electric utilities. ^f	1986 -- 2000	Enable utilities to evaluate grid-connected PV system performance, reliability, and cost and to assess system operations & maintenance (O&M) requirements.	Market conditioning through demonstration. Evaluate various PV technologies within a systems context using three grid-connected pilot test stations in different parts of the United States.	In 1998, monitoring activities covered 26 PV systems with combined 2.3 MW capacity in 10 U.S. locations.
PV Pioneer I ^g	Sacramento Municipal Utility District (SMUD)	1993 -- on-going	Reduce price of PV generated power.	Mass purchase. SMUD purchases and installs PV system on volunteering customer's roof and operates the system for 10 years with all the solar electricity sold to the customer at regular SMUD rates. Volunteers pay an additional \$4.00 a month, which is decreased if rates increase.	As of year end 1999, about 550 residential and commercial rooftop PV systems (total capacity about 2 MW). ^h About 35 church and school rooftop systems and parking lot systems (1.5 MW total capacity) under the Neighborhood PV Pioneers version of PV Pioneer I. ⁱ System costs have declined from \$7.70/W to less than \$4.25/W.
PV Pioneer II ^j	Sacramento Municipal Utility District	1999 -- on-going	Reduce price of PV generated power.	Subsidized purchase. SMUD enables customers to purchase a rooftop PV system at a substantial discount and receive credit on their electric bill for the energy the system produces under a net metering arrangement.	250 signed letters of commitment with virtually no marketing. First system installed April 1999. By year end 1999, first 50 systems installed or scheduled for installation. ^k

See notes at end of table.

Table 11. Examples of Photovoltaic Technology Market Development Initiatives (Continued)

Initiative	Sponsor(s)	Inception Date - Completion Date	Objective	Strategy	Results
Solar Power Hosting ^l	Los Angeles Department of Water and Power (LADWP)	May 1998 -- on-going	100,000 systems on residential rooftops in LA City by the year 2010	Mass purchase. LADWP installs and owns the PV system on the customer volunteer's roof.	15 customers (40 kW total capacity) to date. Includes 14 customers with 2.5 kW systems and one 5 kW system. ^m
Solar Power Ownership ⁿ	Los Angeles Department of Water and Power	December 31, 1998 -- on-going	100,000 systems on residential rooftops in LA City by the year 2010	Subsidized purchase. Customer owns the PV system on his/her roof and is billed by LADWP for electricity on a net metering basis.	35 customers (100 kW total capacity) to date. ^o
Emerging Renewables Buy-Down Program ^{p,q}	California Energy Commission (CEC)	March 20, 1998 -- on-going	Increase use of renewable electricity. Over 30 MW of power possible under the program. Most assumed to be PV; but PV, solar thermal, fuel cell, and small wind systems (no larger than 10 kW capacity) are eligible.	Subsidized purchase. Provides cash rebates of up to \$3,000/kW, or 50 percent of the system price, whichever is less.	As of March 14, 2000, 622 reservation requests received, including 471 completed or approved projects. Completed or approved projects include 2.9 MW of power from 428 PV systems, 41 wind systems, and 2 fuel cell systems with 400 kW combined capacity. \$4.2 million paid for 282 completed projects; \$3.8 million encumbered for 189 approved projects.

^l U.S. Department of Energy, *Photovoltaic Energy Program Overview: Fiscal Year 1998*, DOE/GO-10099-737 (Washington, DC, March 1999).

^b Utility Photovoltaic Group, *4.5 Megawatts of PV and Counting... Technical and Business Experience of TEAM-UP Program Partnerships* (Washington, DC, November 1999).

^c U.S. Department of Energy, <http://www.eren.doe.gov/millionroofs/> (December 1999).

^d A tally of partnerships may be found at Million Solar Roofs, Current State and Community Partnerships, <http://www.eren.doe.gov/millionroofs/tally.html> (May 2000).

^e Photovoltaics for Utility System Applications, <http://www.pvusa.com/index.html> (December 1999), and SMUD, *1998 PVUSA Progress Report, 1999*, (Sacramento, CA, 1999), pp. 1, 3, and

6. ^f Co-sponsors include DOE; Electric Power Research Institute; Department of Defense; various utilities and national labs; New York State Energy Research and Development Authority; City of Austin, Texas; and the Solar Energy Industries Association. PVUSA is managed by the California Energy Commission and the Sacramento Municipal Utility District. See website <http://www.pvusa.com> (December 1999).

^g Sacramento Municipal Utility District, http://www.smud.org/home/pv_pioneer/index.html (December 1999).

^h Donald Osborn, "Sustained Orderly Development and Commercialization of Grid-Connected Photovoltaics: SMUD as a Case Example," pre-print, *Advances in Solar Energy*, Vol. 14, 2000 American Solar Energy Society (Boulder, CO, May 2000), p. 8.

ⁱ Donald Osborn, "Sustained Orderly Development and Commercialization of Grid-Connected Photovoltaics: SMUD as a Case Example," pre-print, *Advances in Solar Energy*, Vol. 14, 2000 American Solar Energy Society (Boulder, CO, May 2000), p. 11.

^j Sacramento Municipal Utility District, http://www.smud.org/home/pv_pioneer/index.html (December 1999).

^k Donald Osborn, "Sustained Orderly Development and Commercialization of Grid-Connected Photovoltaics: SMUD as a Case Example," pre-print, *Advances in Solar Energy*, Vol. 14, 2000 American Solar Energy Society (Boulder, CO, May 2000), p. 11.

^l Los Angeles Department of Water and Power, <http://www.ladwp.com/whatnew/solarroof/solarroof.htm> (December 1999).

^m Personal communication between Robert McKinney (LADWP Solar Power Program Manager) and William R. King (SAIC), May 24, 2000.

ⁿ Los Angeles Department of Water and Power, <http://www.ladwp.com/whatnew/solarroof/solarroof.htm> (December 1999).

^o Personal communication between Robert McKinney (LADWP Solar Power Program Manager) and William R. King (SAIC), May 24, 2000.

^p Information from Sandy Miller, Manager, California Energy Commission Emerging Renewables Buy-Down Program (May 22, 2000).

^q California Energy Commission, Emerging Renewables Buy-Down Program, <http://www.energy.ca.gov/greengrid/index.html> (March 8, 2000).

systems, wind turbines with maximum output of 10 kW, fuel cells, and solar thermal systems. This program is only available to customers of the following investor-owned utilities: Pacific Gas & Electric (PG&E), San Diego Gas & Electric (SDG&E), Southern California Edison (SCE), and Bear Valley Electric Company. The Maryland Solar Roofs Program provides \$2.00/W cost-sharing in the year 2000 for residential photovoltaic systems. The Maryland program estimates that this would cover 40 percent of installed system cost. The cost-share amount declines in subsequent years.²⁹

Municipal Utility Programs

SMUD and LADWP, both municipal utilities, have photovoltaic system deployment programs because they get to spend their public benefit program funds. Both programs are similar. In California, utilities embed a public benefit charge in the rate charged for electricity. This charge funds programs, such as renewable technology market development, that would not be pursued normally in a deregulated utility environment. Municipal utilities are allowed to keep the revenue generated by this charge to spend on public benefit programs, such as renewable technology deployment programs, within their service territory. In contrast, public benefit program revenue generated by shareholder-owned utilities in California is collected in a central pool. These funds are available for CEC-sponsored energy projects, such as photovoltaic system buy-downs.

PV Pioneer I and II

SMUD runs the PV Pioneer I and PV Pioneer II programs. Under PV Pioneer I, the end user allows SMUD to install a grid-connected BIPV system. The end user pays \$4 per month to SMUD. This fee is decreased if the electricity rate increases and is eliminated if the rate increases at least 15 percent. SMUD agrees to install and operate the system for 10 years, after which SMUD may (1) sell the system to the customer at an attractive rate and convert the customer to the PV Pioneer II program; (2) ask for an extension of the agreement, perhaps at reduced rates; or (3) remove the system and repair the roof.

Under the PV Pioneer II program, the end user purchases a grid-connected BIPV system at a discounted per kilowatt rate. The end user uses electricity from the BIPV system under a net metering arrangement with SMUD. SMUD and LADWP bill customers who own their BIPV systems on a net metering basis, so the value of electricity equals the price the customer would pay for electricity purchased from the utility.

Solar Power Hosting and Ownership Programs

LADWP's PV programs, the Solar Power Hosting Program and the Solar Power Ownership Program, are similar to SMUD's.³⁰ Under the Hosting Program, LADWP installs and maintains the BIPV system; the end user pays nothing. Under the Ownership Program, the end user installs and owns a BIPV system and uses electricity from the system under a net metering arrangement with LADWP. The end user does not purchase the BIPV system through LADWP; LADWP just subsidizes the purchase and facilitates system interconnection with the grid.

International Demand

Shipments of photovoltaic cells and modules from manufacturing facilities in the United States and other countries supply growing international demand. Growing markets include those where factors such as high electricity prices and subsidies or other incentives improve the cost-effectiveness of PV systems. In several countries, average residential electricity prices are high compared to the United States (Table 12). These prices represent those for grid-connected customers. The following sections provide examples of these and other factors that are motivating demand.

Japan

The Ministry of International Trade and Industry (MITI) promotes photovoltaic sales primarily through programs that promote growth of the residential BIPV market. The ministry's targets for installed PV capacity across all applications are 400 MW by the year 2000, and 5,000 MW by the year 2010.³¹ Much of this capacity will

²⁹ C. Cook, "The Maryland Solar Roofs Program: State and Industry Partnership for PV Residential Commercial Viability Using the State Procurement Process," Second World Conference on Photovoltaic Solar Energy Conversion, Vienna, Austria. See website <http://www.energy.state.md.us/paper.htm> (July 1998).

³⁰ Los Angeles Department of Water and Power, Solar Electricity Rooftop Program. See website <http://www.ladwp.com/whatnew/solarroof/solarroof.htm>, March 2000. Personal contact between Robert McKinney (LADWP Program Manager) and William R. King (SAIC), March 2000.

³¹ O. Ikki, K. Tomori, and T. Ohgashi, *The Current Status of Photovoltaic Programme in Japan* (Tokyo, Japan: Resources Total System Co., Ltd., September 1998), Table 3.

Table 12. Examples of Countries with High Residential Electricity Prices Relative to the United States, 1997

Country	Electricity Price (dollar per kilowatthour)
United States	0.085
Other OECD Countries	
Japan	0.207
Denmark	0.195
Austria	0.169
Belgium	0.168
Spain	0.163
Germany	0.161
Italy	0.159
Portugal	0.156
Switzerland	0.136
France	0.134
Ireland	0.131
Netherlands	0.130
United Kingdom	0.125
Luxembourg	0.124
Non-OECD Countries	
Grenada	0.193
Suriname	0.171
Barbados	0.167
Uruguay	0.157
Argentina	0.139
Peru	0.138
Jamaica	0.135
Chile	0.121
Panama	0.121

Source: Energy Information Administration, "International Electricity Prices for Households," <http://www.eia.doe.gov/emeu/iea/elecprth.html> (October 20, 2000).

be in BIPV systems. Assuming 400 MW installed by 2000, the annual demand from 2001 through 2010 would be 460 MW per year. This amount helps explain the current PV manufacturing capacity additions being

implemented by Japanese companies, including capacity additions that result when these companies purchase companies previously incorporated in other countries.

The MITI BIPV program, through its New Energy Foundation, plans to equip 70,000 homes with 3 kW systems by 2000 (210 MW at 3 kW/system) and install BIPV on half of new homes by 2010.³² As of March 31, 1999, BIPV systems were installed on 28,000 homes (84 MW at 3 kW/system). MITI motivates demand for the BIPV systems through an incentive program that pays half the cost difference between installed system cost per kW and \$3,100/kW for BIPV systems up to 10 kW capacity. The program requires that electric utilities purchase excess electricity from residences at the going residential rate through net metering.

Germany

By year-end 1997, Germany had close to 10,000 grid-connected PV systems (34 MW total capacity).³³ Catalysts for PV system market growth included financial incentives (Federal and State), rate-base incentives, and green pricing. Incentives contributed to 45 percent of 1997 PV systems.

As of 1998, 3,500 residences had BIPV systems. The economics of these installations benefitted from government subsidies and a high price paid by the utility for excess electricity produced by each system.³⁴

In 1999, the German government initiated a "100,000 Roofs Program" with the goal of installing 300 to 500 MW of BIPV systems over the period 1999 through 2005.³⁵ Program cost is expected to be about \$600 million.³⁶ In 1999, installation of 6,000 3-5 kW arrays was expected;³⁷ actual home installations were about 35 percent less—3,834 grid-connected arrays (10.1 MW) from program initiation through February 2000.³⁸ Planned annual installations will increase to more than 32,000 in the program's final year.³⁹ The program offers

³² M. Dunn, U.S. Department of Energy, Office of Intelligence, *International Solar Cells Outlook '99*, NIS-8(U) 99-102 (Washington, DC, April 1999), p. 11.

³³ Dr. H. Gabler and V.U. Hoffman (Fraunhofer-Institute for Solar Energy Systems ISE), Dr. Klaus Heldler (The Solar Consultancy), "Financing Germany's PV expansion," *The Sustainable Energy Industry Journal*, Issue 8 (Vol. 3, No. 2) (1998), p. 16.

³⁴ M. Dunn, U.S. Department of Energy, Office of Intelligence, *International Solar Cells Outlook '99*, NIS-8(U) 99-102 (Washington, DC, April 1999), p. 10.

³⁵ *Ibid.*

³⁶ International Energy Agency, *Trends in Photovoltaic Applications in Selected IEA Countries Between 1992 and 1998*, IEA-PVPS 1-07:1999, (Paris, France, October 1999), p. 12.

³⁷ M. Dunn, U.S. Department of Energy, Office of Intelligence, *International Solar Cells Outlook '99*, NIS-8(U) 99-102 (Washington, DC, April 1999), p. 10.

³⁸ P. Maycock, "100,000 Roofs Serves 3834 Roofs," *PV News*, Vol. 19, No. 4 (April 2000), p. 3.

³⁹ M. Dunn, U.S. Department of Energy, Office of Intelligence, *International Solar Cells Outlook '99*, NIS-8(U) 99-102 (Washington, DC, April 1999), p. 10.

a 10-year low interest loan with repayment starting in the third year.⁴⁰

The new Renewable Energy Law,⁴¹ passed February 25, 2000, is already prompting interest on the part of companies involved in the photovoltaics industry. It guarantees fixed tariffs for green electricity to the grid and provides a national incentive of 0.99 deutsche marks (DM) per kWh (\$0.51 per kWh) over 20 years for electricity from renewable sources, including photovoltaics. This incentive may be combined with zero interest loans available under the "100,000 Roofs" program.

RWE Energie.⁴² RWE Energie, the largest energy service company in Germany, has built two PV power plants, each 350 kW, one on the Moselle River and one at Lake Neurath in the Rhenish lignite-mining area. The company operates a 1 MW plant jointly with Spanish partners, near Toledo, Spain.⁴³ The plant is one of the largest in Europe.

In mid 1996, RWE Energy initiated two consumer incentive programs, KesS SOLAR and Ecotariff, to promote renewable energy, including photovoltaics.⁴⁴

KesS SOLAR. The consumer receives DM 2,000 (about \$1,030) for purchasing a residential solar system (solar collectors, PV, or electric heat pumps). RWE Energy has paid DM 20 million (about \$10.3 million) under this program.

Ecotariff (green pricing). The consumer purchases at least 100 kWh per year at a premium of 20 pfennigs/kWh (about \$0.10/kWh) over the normal retail price. RWE Energie matches the contribution. Amounts are used to build new plants equivalent to the "green" kilowatthours. RWE Energy made DM 20 million (about \$10.3 million) available under this scheme. Fifteen thousand customers have used this plan, purchasing 2.6 million kWh of renewable electricity. Twenty-four

ecotariff plants have been built, including 22 photovoltaic plants. RWE Energy takes credit for the CO₂ reduction.

Other European Activity

Switzerland. Up to 25 percent of the installed cost of a PV system is subsidized. More than 170 public schools have rooftop PV systems.⁴⁵ Other activities include over 1,000 grid-connected 3 kW residential systems, 500 kW on Mont Soliel, and 600 kW on highway sound barriers.⁴⁶ The Swiss government has promoted photovoltaic systems under its "Energy 2000" project.

The Netherlands. In 1997, the government initiated a program to increase use of renewable energy. Goals for photovoltaic systems are 10 MW by 2000 and 250 MW by 2010.⁴⁷

In a 500-household PV complex, 50 percent of the electricity (1.3 MW/year) will be provided by 12,000 square meters (m²) of PV panels (20 m² per house). The complex is being developed by REMU, a Dutch electric power company, and is sponsored by the European Union and Dutch government. It includes both residential and commercial installations. Residents pay 50 percent of the panel cost. Generated electricity belongs to the homeowner, who is compensated using net metering. The project is motivated by global warming worries; the elevation of much of the country's land is below sea level.⁴⁸

India

Through Winrock International's Renewable Project Support Office (REPSO) in India, USAID supports PV projects including the following:⁴⁹

SELCO Photovoltaic Electrification Private Limited (SELCO), Bangalore. Under a conditional grant of Rs. 5

⁴⁰ International Energy Agency, *Trends in Photovoltaic Applications in Selected IEA Countries Between 1992 and 1998*, IEA-PVPS 1-07:1999, (Paris, France, October 1999), p. 12.

⁴¹ P. Maycock, "New Renewable Energy Law to Trigger Solar Boom in Germany," *PV News*, Vol. 19, No. 4 (April 2000), p. 3.

⁴² In this section, German deutsche marks (DM) are converted to equivalent U.S. dollars at a rate of 1.94 DM/US dollar.

⁴³ Dr. Munch, "A Partnership with Our Customers to Promote Renewable Energy," *The Sustainable Energy Industry Journal*, Issue 8 (Vol. 3, No. 2) (1998), p. 27.

⁴⁴ *Ibid.*

⁴⁵ M. Dunn, U.S. Department of Energy, Office of Intelligence, *International Solar Cells Outlook '99*, NIS-8(U) 99-102 (Washington, DC, April 1999), pp. 13-14.

⁴⁶ P. Maycock, *The World Photovoltaic Market: 1975-1998* (Warrenton, VA: PV Energy Systems, Inc., August 1999), p. 40.

⁴⁷ M. Dunn, U.S. Department of Energy, Office of Intelligence, *International Solar Cells Outlook '99*, NIS-8(U) 99-102 (Washington, DC, April 1999), p. 13.

⁴⁸ R. Curry, *Photovoltaic Insider's Report*, Vol. XIX, No. 2 (February 2000), p. 2.

⁴⁹ U.S. Agency for International Development, *USAID Activities in India's Southern States: Tamil Nadu, Karnataka, Kerala, and Andhra Pradesh*. See website <http://www.info.usaid.gov/india/states/south.htm> (March 2000), pp. 5-6.

million (\$140,000), SELCO will promote commercialization of residential PV lighting systems in Andhra Pradesh and Karnataka. Over 2,500 systems have been sold. SELCO has started making repayments to Winrock as reflows,⁵⁰ which can be used for other renewable energy activities.

Polyene Film Industries (PFI), Chennai. Under a conditional grant of Rs. 4.3 million (\$100,000), PFI will install 100 PV water pumping systems for irrigation. The systems will be used by poor farmers and tribal people in District Nellore, Andhra Pradesh and Tamil Nadu. The grant will be repaid by PFI up to 1.4 times in semi-annual installments starting 2 years from the date of the conditional grant. The systems use 800 Wp DC motors powered by multicrystalline thin-film Solarex PV modules.

Center for Technology Development NGO Resource Center (CTD-RC), Bangalore. Under a conditional grant of Rs. 5.6 million (approximately \$130,000), CTD-RC, in collaboration with SELCO, will commercialize residential PV lighting systems in rural areas of Karnataka. Cooperative banks will act as financial intermediaries. The end-user will pay 20 percent of the total installed system cost up front. The remaining 80 percent of system cost will be financed by a loan to the end-user guaranteed by CTD-RC, and repaid in convenient installments.

Examples of other PV projects in India include the following:

- A 50 kW PV power plant commissioned on Kadmat Island in the Arabian Sea, in Lakshwadeep, India. The power plant serves the Water Sports Institute and surrounding cottages and is the first PV facility to serve sporting activity. On the Bitra and Bangaran Islands in Lakshwadeep, 25 kW and 10 kW PV power plants, respectively, meet residential lighting loads.⁵¹ Examples of other PV projects in India include the following:
- Two grid-connected PV plants approved for the State of Punjab by the Punjab Energy Development

agency. The total cost of Rs 32.14 million (\$750,000) is financed by the Ministry of Non-Conventional Energy Sources (MNES) and Indian Renewable Energy Development Agency Limited (IREDA) and includes World Bank funding.⁵²

- Fifteen PV streetlights installed in Sanjay Gandhi Biological Park. The park's medical clinic also has a PV system that ensures uninterruptible electricity.⁵³

People's Republic of China

The World Bank has signed a renewable energy development agreement for the People's Republic of China. Included in the agreement is a \$15 million Global Environment Facility (GEF) grant to install 10 to 12 MW of photovoltaics in 400,000 households.⁵⁴ The total \$444 million renewable energy project also supports installation of 190 MW wind turbines (Table 13).⁵⁵

The GEF grant will fund a \$1.50/Wp installed system payment to Chinese PV system companies for systems 10 Wp or greater in capacity. The \$15 million grant would, therefore, cover 10 MW of installed PV capacity meeting the 10 Wp minimum system capacity. This grant is given to these companies to (1) improve product quality, (2) improve warranties and service, (3) strengthen business capabilities and marketing efforts.⁵⁶

Additionally, \$7 million as a GEF grant and \$4 million from other sources, for \$11 million total, are allocated for a PV market development program (awareness programs, demos, market development assistance) and for institutional strengthening (PV quality assurance and project management capabilities).⁵⁷

The following photovoltaic system market development barriers have been identified for the People's Republic of China.⁵⁸

High cost of PV systems. A 20 Wp system costs about \$200, including value-added tax (VAT), making these

⁵⁰ Reflows are revenues from projects that are paid back to the group that originally provided project funding. Then, the group can use the funds for other projects.

⁵¹ P. D. Maycock, "Unique Solar Plant Commissioned in Lakshwadeep," *PV News*, Vol. 19, No. 3 (March 2000), p. 6.

⁵² P. D. Maycock, "Ministry Approves 2 Grid Interactive PV Units," *PV News*, Vol. 19, No. 3 (March 2000), p. 6.

⁵³ P. D. Maycock, "Biological Park Gets Solar PV for New Years Day," *PV News*, Vol. 19, No. 3 (March 2000), pp. 6-7.

⁵⁴ Personal communication between Susan Bogach (The World Bank) and Peter Holihan (DOE/EIA) (March 2000).

⁵⁵ The World Bank, *Project Appraisal Document on a Proposed Loan in the Amount of US\$100 million and a Proposed GEF Grant of US\$35 million equivalent to the People's Republic of China for a Renewable Energy Development Project*, Report No. 18479-CHA (Washington, DC, May 5, 1999), p. 6.

⁵⁶ *Ibid.*, p. 7.

⁵⁷ *Ibid.*, pp. 7-8.

⁵⁸ *Ibid.*, p. 5.

Table 13. Funding for Photovoltaics/Wind World Bank China Project

Technology	Funding Source	Amount
Photovoltaics	Global Environment Facility (GEF) Grant Funding from other sources (power and PV companies; banks; consumers)	\$15 million \$129.9 million
Wind	IBRD loan to the PRC government GEF Grant Funding from other sources (power and wind companies; banks; consumers)	\$100 million \$20 million \$179.1 million
Total Funding		\$444 million

Source: The World Bank, project appraisal document on a proposed loan in the amount of US \$100 million and a proposed project GEF grant of US \$35 million equivalent to the People's Republic of China for a Renewable Energy Development Project, Report No. 18479-CHA (May 5, 1999), pp. 7-8.

systems very expensive for Chinese consumers. Such consumers, including those in urban areas, do not have easy access to credit and usually cannot afford cash purchases.⁵⁹

Poor quality of products and services. Locally made modules sold by Chinese PV system companies are not certified, and their performance is often overrated. To reduce system cost, smaller systems are sold without controllers, a practice that can shorten battery life. Poor service support after installation can lead to low system availability, since suppliers of replacement parts are often distant from the installation.

South Africa

The South African government has initiated a rural electrification program with goals for installation of BIPV systems. The foundation for the initiative is the government's White Paper on Energy Policy, which establishes universal access to electricity as primary South African energy policy goal. About one-third of South African households have no access to grid electricity, and one to two million of these are too far from the grid⁶⁰ for grid extension to be a consideration.

Initiated in early 1999, the goal of the BIPV program is installation of 350,000 systems.⁶¹ The program will be implemented by seven private utility consortia, each awarded an exclusive service territory in which it will install and operate approximately 50,000 BIPV systems. Service territories are awarded using a competitive bidding process. Awards already made include:⁶²

(1) Shell Renewables-ESKOM joint venture (in the Eastern Cape); (2) BP-ESKOM (northern KwaZulu-Natal); (3) Electricite de France; and (4) NUON (The Netherlands) in partnership with RAPS (South Africa).

To ensure that the consortia charge an affordable price for BIPV electricity, the government pays at least 50 percent of the investment cost (\$450 to \$500). The remainder of the investment is covered by each consortium using equity or debt financing. The Shell Renewables-ESKOM joint venture is an example of how the program will work.⁶³ Each customer will pay \$30 for installation of a 50 Wp system, large enough to run a small black and white TV, radio, and three to four lights. Community-owned and operated companies will operate and maintain each system. Customers prepay the local company an \$8 monthly fee for service. Upon payment, the company issues a card used to operate a prepayment meter integrated into the system's charge controller. The system and access to electricity are protected against theft by (1) integrating an intelligent switching device into the module and battery that deactivates them if the system is disconnected, and (2) controlling access to electricity with a prepayment meter that deactivates the system if payments are not made.

Other end-uses for photovoltaics in South Africa include:⁶⁴

- School PV electrification program operated by ESKOM. ESKOM installed 1,200 systems (400 and 900 Wp arrays) to provide light and power. About 16,000 schools are without electricity.

⁵⁹ Despite cash shortages, cash sales have grown steadily over the period 1996 to 1999, with continued growth expected.

⁶⁰ R. Karottki and D. Banks, "PV Power and Profit? Electrifying Rural South Africa," *Renewable Energy World*, Vol. 3/No. 1 (January 2000), p. 51.

⁶¹ *Ibid.*

⁶² *Ibid.*, p. 54.

⁶³ *Ibid.*, p. 54.

⁶⁴ *Ibid.*, p. 52.

- Independent Development Trust (IDT). The IDT has provided PV-based electricity for about 210 rural clinics (light, vaccine refrigeration, nurse's homes).
- Rural telephone systems operated by Telkom (national company). Over 2.5 years, Telkom has purchased 84,000 PV modules rated 32 and 55 Wp for solar-powered wireless systems.

Multi-Country Activities Promoted by International Assistance Organizations

U.S. Agency for International Development. During Fiscal Years 1998 and 1999, USAID's renewable energy program installed over 4,000 photovoltaic systems in Brazil, India, Indonesia, the Philippines, Guatemala, and South Africa.⁶⁵

United Nations Development Program. The United Nations Development Program supports photovoltaic projects under the Bureau for Development and Policy (BDP)/Sustainable Energy and Environment Division (SEED)/Energy and Atmosphere Programme (EAP)/Energy Account. The Energy Account was established in 1980. Since September 1, 1994, it has been under UNDP/BDP/SEED/EAP. Primary sources of financial support for the Energy Account are The Netherlands Directorate for International Co-operation (DGIS), the Government of Japan, and the OPEC Fund for International Development.

Under the Energy Account, the FINESSE (Financing Energy Services for Small Scale End-users) program assists countries in identifying and promoting technically feasible and economically viable renewable energy technologies. Initiated in 1989 jointly by The World Bank, DOE, DGIS, and UNDP, the program's objective is to provide small loans to small-scale end-users without incurring the high overhead costs for administering small loans. Large multilateral financing organizations sell loans wholesale to commercial banks, utilities, or NGOs, which make loans at market rates to small users.⁶⁶ FINESSE was instrumental in the formation of Asia Alternative Energy Program (ASTAE) in 1991. The amount of current PV activity is unknown; however, there is current renewables and energy

efficiency development activity in Africa (Lesotho, South Africa, Zimbabwe, Angola, Malawi, and Namibia).

Examples of other Energy Account projects are:

- Syria (Project No. SYR/97/E01). Decentralized rural electrification with PV (Rural Electrification Programme) cottage industries established to use excess electricity in summer months since PV systems sized to meet winter electrical loads when solar insolation is lowest⁶⁷ (3-year project, January 8, 1997 to January 8, 2000), \$553,700.
- Sudan (Project No. SUD/90/E01 and SUD/90/010). Rural electrification of at least 50 communities with PV; encourage commercialization of solar energy (5-year project, January 12, 1992 to January 12, 1997), \$1,800,000.

Near-Term Industry Prospects

In the near-term, the worldwide photovoltaic market could well grow at an annual rate of 15 to 25 percent. Capital cost subsidies, and tax and financial incentives, driven by the Japanese and German solar building programs, are driving global photovoltaic power market growth. In the long-term, larger manufacturing facilities being constructed in the United States and abroad are expected to achieve economies of scale that reduce the cost of manufacturing photovoltaic cells, enabling photovoltaic power to be cost-effective in more markets without subsidies. These facilities would have capacities over 20 MW.

Manufacturing capacity to meet this demand is being constructed in Japan, Germany, and the United States. Photovoltaic cells from U.S.-based manufacturing capacity are shipped worldwide, including Japan and Germany. Such shipments should continue because (1) global capacity, including U.S.-based capacity, is needed to meet the world market growth rate; (2) shipment costs currently do not affect competitiveness; (3) the United States has the technically qualified labor required for cell production; (4) U.S. vendors provide high-quality materials needed for manufacturing cells; and (5) U.S.-based research programs are on the cutting edge of

⁶⁵ U.S. Agency for International Development, Remarks by Ambassador Harriet C. Babbitt (Deputy Administrator), *International Conference on Accelerating Grid-Based Renewable Energy Power Generation for a Clean Environment*. See website http://www.info.usaid.gov/press/spe_test/speeches/2000/world_bank.html (March 7, 2000), p. 2.

⁶⁶ United Nations Development Programme, FINESSE Concept. See website <http://www.undp.org/seed/eap/activities/finesse.html> (February 2000), p. 1.

⁶⁷ United Nations Development Programme, FINESSE Concept. See website <http://www.undp.org/seed/eap/activities/finesse.html> (February 2000), p. 2.

new photovoltaic cell technology and manufacturing techniques. Evidence of the cutting edge is the copper indium diselenide production capacity being developed by Siemens Solar in California.

Conclusions

The world PV market for cells and modules has grown rapidly since 1994, due principally to heavily subsidized programs for PV use in Japan and Germany. Continued near-term growth is heavily dependent on retention of these subsidies.

U.S. manufacturers have shared in the rapidly expanding world markets, with U.S. cell and module shipments rising from 26 MW in 1994 to 61 MW in 1999. Much of the increase in U.S. shipments has gone to export markets, principally Japan and Germany. However, the U.S. share of world PV cell and module

shipments has decreased from 45 percent in 1995 to 30 percent in 1999. This has been caused by Japanese-based PV manufacturing firms, who have increased local manufacturing capacity in response to heavy government support for the integration of PVs into buildings.

Future U.S. success in manufacturing cells and modules for export lies in the availability of a highly skilled manufacturing work force, high-quality materials, and a willingness to send highly trained technicians to work with end users. Near-term growth in U.S. cell and module production for export is highly dependent on foreign governments retaining their PV end-user support programs. U.S. Federal support for PV use is relatively modest, and most near-term domestic growth is expected to occur in unsubsidized niche markets or in response to State and local programs. Even in these areas, continued cost reductions will be necessary to sustain 15-25 percent annual growth in U.S. PV cell and module production for the next several years.

The Impact of Environmental Regulation on Capital Costs of Municipal Waste Combustion Facilities: 1960-1998

Introduction

Growth in the municipal waste combustion industry slowed dramatically during the 1990s after very rapid growth during the 1980s.¹ This leveling of growth is attributed to three primary factors: (1) the Tax Reform Act of 1986, which made capital-intensive projects such as municipal waste combustion facilities more expensive relative to less capital-intensive waste disposal alternative such as landfills; (2) the landmark 1994 Supreme Court decision (*C&A Carbone, Inc. v. Town of Clarkstown*²), which struck down local flow control ordinances that required waste to be delivered to specific municipal waste combustion facilities rather than landfills that may have had lower tipping fees; and (3) increasingly stringent environmental regulations that increased the capital cost necessary to construct and maintain municipal waste combustion facilities. The Energy Information Administration (EIA) has already published articles pertaining to the first two factors.³ This paper focuses on the third factor and attempts to quantify and isolate the variables affecting the cost of constructing and retrofitting municipal waste combustion facilities.

Background

Between 1960 and 1998, Federal regulations governing plant operations changed considerably. This paper divides the 38-year time frame into three different regulatory periods. The first period, 1960 to 1981, was a time when relatively low-level regulatory attention was paid to waste incineration facilities. Yet during this

period the groundwork for future regulatory approaches was established. In 1963 the Clean Air Act was passed, and during the 1960s, particulate standards for all incinerators were promulgated under the law. In 1970, the U.S. Environmental Protection Agency (EPA) was formed. Despite EPA's growing attention to airborne pollutants, it and other governmental bodies perceived municipal waste combustion favorably. As many sub-standard local landfills were closing, municipal waste combustion was considered a technologically advanced method of reducing the volume of waste. In addition, after the Arab oil embargoes in the 1970s, the concept of generating energy from waste was given impetus by favorable tax and utility regulations. Thus, in sum, this period saw the birth of the environmental movement in the United States and the attendant focus on air and water pollution control. EPA's regulatory approach and framework was established during this period. However, given the facts that the municipal waste combustion industry was in its infancy and that it was seen as an improved waste disposal alternative to landfilling, few regulatory barriers stood in its path. Actually, tax and utility regulatory policy provided incentives to build such facilities.

The second period, 1982-1990, marked the growth phase of the municipal waste combustion industry, due primarily to the existence of various tax and investment subsidies, as well as acceptance of the technology by Federal and local governments. EPA continued to focus its regulatory attention on the air emissions of these plants. Of particular concern were the carcinogenic effects of dioxins and furans⁴ produced by the

¹ This article comes from an unpublished report: Eileen B. Berenyi, "The Impact of Federal Regulation on Capital Costs of Municipal Waste Combustion Facilities: 1980-1998," Governmental Advisory Associates, Inc., prepared for the Energy Information Administration, U.S. Department of Energy.

² *C&A Carbone, Inc. v. Town of Clarkstown, New York*, No. 114, S. Ct. 1677 (1994).

³ Two of the factors are discussed in the following documents and the third is the focus of this paper: J. Carlin, "The Impact of Flow Control and Tax Reform on Ownership and Growth in the U.S. Waste-to-Energy Industry," in Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0535(94/09) (Washington, DC, September 1994), and "Public Policy Affecting the Waste-to-Energy Industry" and "Flow Control and the Interstate Movement of Waste: Post-Carbone," in Energy Information Administration, *Renewable Energy Annual 1996*, DOE/EIA-0603(96) (Washington, DC, March 1997).

⁴ Furans and dioxins are trace emissions from the combustion of commonly used materials such as paper and plastics.

combustion process, the toxicity of incinerator ash, and ash disposal methodology and testing. By 1987, EPA proposed new source performance standards (NSPS) for waste incinerators. Best available control technology (BACT) was upgraded through the use of acid gas scrubber/baghouse combinations as well as the installation of controls on nitrous oxide production. As air pollution control technology improved, EPA implemented more stringent standards, forcing municipal waste combustion facilities to upgrade or install new air pollution control systems.

As a concurrent development during this period, in 1986 Congress passed the Tax Reform Act. Prior to 1986, Federal financial incentives for the municipal waste combustion industry included grants for feasibility studies and pilot projects, investment tax credits, favorable tax treatment for equipment depreciation, and the ability to qualify for public financing. The Tax Reform Act of 1986 removed or curtailed most of these incentives for prospective facilities, creating a negative impact on the industry by constraining the availability of low-cost capital and limiting the favorable tax treatment afforded to the industry. In essence, with the removal of tax protection, municipal waste combustion facilities had to rely more heavily on tip fees and revenues generated from energy sales. With both of these revenue sources facing downward pressure in the 1990s, the financial viability of many projects has been under stress.⁵ Coupled with the increased regulatory costs associated with meeting BACT, these changes in the tax law affected the financial viability of many plants.

The last period, from 1991 to 1998, represents a time of intense regulatory activity by EPA, focusing on air emissions of municipal waste combustion projects and the toxicity of ash produced as a residue of incineration. In addition, with the decline in revenues from energy sales and tipping fees, the adoption of waste recycling, and the growth of modern code compliant large landfills, municipal waste combustion no longer fulfilled its earlier function as a viable disposal technology and a source of alternative energy. By 1989, EPA began the process of upgrading its NSPS for municipal waste combustors (MWCs), as municipal waste combustion facilities came to be called. In its final rule of 1991, EPA proposed standards for air emissions control. Later rulings also incorporated requirements for a ban on the combustion of lead acid batteries and for materials

separation and recovery of municipal waste streams prior to combustion.

Furthermore, in November 1990, Congress enacted the Clean Air Act Amendments of 1990 to the Clean Air Act of 1977. These amendments directed EPA to develop new emission guidelines for existing MWCs and NSPS for new MWC facilities. Five years later, after much discussion, the EPA published air emission guidelines for existing MWCs. The new guidelines covered not only large facilities (plants with capacities greater than 248 tons per day), but also contained requirements for smaller facilities. While the requirements applying to smaller facilities were under challenge, they have been modified and were implemented in 1999.

The new regulations require an aggressive approach to the reduction of toxic emissions through a combination of air pollution control systems, improved monitoring of emissions, application of tested combustion methods, personnel training, and front-end materials separation programs. These regulations set numerical limits for sulfur dioxide, hydrogen chloride, cadmium, lead, and mercury emissions. Additionally, more stringent limits were set for dioxins and furans as well as for nitrogen oxides, fugitive fly, and bottom ash. Facilities were required to adopt maximum achievable control technology (MACT) to reach acceptable levels of air emissions and install continuous emission monitoring (CEM) systems to track and report emissions on a periodic basis. MACT includes scrubber/baghouses, as well as mercury and nitrous oxide control systems. The implementation deadline for large facilities to meet these criteria was December 2000.

The result of this renewed emphasis on air emissions control has been twofold. First, a number of small, aging projects have shut down, possibly as a result of calculating that it was no longer economically feasible to operate, given the large capital investment necessary to comply with new Federal regulations. Second, existing projects are undergoing or are planning significant upgrades to their air pollution control and combustion systems.

Prior to a discussion of the methodology and findings, several points relevant to this analysis must be noted. First, no standard annual reporting mechanism exists by which municipal waste combustion projects report

⁵ Data from the Energy Information Administration survey Form EIA-860B, "Annual Electric Generator Report - Nonutility," and nonpublished analysis from the Office of Coal, Nuclear, Electric and Alternate Fuels indicate the weighted average capacity factor of the municipal waste combustion facilities in three of the four regions (South, West, and North Central) has dropped below the 85-percent norm (to almost as low as 70 percent in the North Central Region) for the industry during 1998.

capital or operating costs and additional capital investments made over time. Second, no sufficient measure of intensity or change in the Federal regulatory environment exists. Indeed, even attempting to categorize regulatory periods is fraught with difficulty. No fool-proof method exists to distinguish where one regulatory regime begins and another ends, as final rules by the EPA may be challenged in court, modified, or overturned. Even when dates are published, the determination of when a given regulatory policy will take effect is judgmental. Plant owners respond in different ways. Some will act in advance of implementation, making changes to their facilities prior to the date; others will seek exemptions or attempt to obtain time extensions. Underlying most of the analysis presented in this paper is the notion that time will be a substitute (albeit an imprecise one) for regulatory period.

Methodology

To assess the regulatory impact on capital costs of municipal waste combustion facilities, a viable database was constructed from data on municipal waste combustion facilities. These data were abstracted from the Governmental Advisory Associates' Resource Recovery Yearbook series. While information pertaining to 1982 through 1998 was available from all Yearbooks, the data were reformatted to be compatible over the 16-year observation period. There have been seven survey periods between 1982 and 1998. For a plant coming on line in 1982 and still operating as of 1998, there are seven possible observations for any given variable. While certain data remain constant, such as original capital cost or year operations commenced, other characteristics are dynamic, changing periodically. These variables include actual tons processed, gross and net electricity output, additional capital investment, operation and maintenance costs, owner, and operator.

Any project in operation as of 1980 is included in the data set. Appendix A lists the projects in the study, and includes basic information about each facility. Once a project closes down, it "falls out" of the database. Thus, at any period of time, the database consists of projects of mixed vintages—some recent and others near the end of their operational life. A capital profile for each project was then constructed; profiles contain both initial and additional capital costs. Appendix B outlines the definition and construction of the capital cost profile in detail. Capital costs were divided by design tons per day

for the given year to control for size of facility. To create this profile, the Engineering News Record (ENR) industrial building index was used to inflate both initial capital costs and additional capital costs to 1999 dollars, thereby removing the effects of inflationary price increases over time.⁶ A depreciation factor was added to more accurately represent the value of capital stock at any given point in time. For the purposes of this study, a straight-line 25-year depreciation was used, which is an industry standard. The depreciation factor was applied both to the original capital costs as well as to the additional capital expenditures made during the relevant time periods.

Upon the creation of this profile, the behavior of capital costs of municipal waste combustion projects can be viewed over time, both in aggregate and separated by technology type or other variables. As technology type was shown to have an impact on capital costs, the first breakdown was done by technology.

Technology Used for Waste Combustion

All municipal waste combustors incinerate the waste and use the resultant heat to generate steam, hot water, or electricity. Projects rely on three basic types of technologies: mass burn, modular, and refuse-derived fuel (RDF). Pyrolysis and anaerobic digestion represent waste disposal processes that have yet to be commercially developed in the United States. Although a number of such facilities have been built (Table 1), none of them remain operational or commercially viable.

Mass burning technologies are most commonly used in the United States. This group of technologies process raw municipal solid waste (MSW) "as is," with little or no sizing, shredding, or separation prior to combustion. At most plants, large bulky items such as "white goods," e.g., large appliances, batteries and/or hazardous materials are either prohibited or removed from waste receiving areas by crane operators and other personnel. Waste materials are typically deposited in a pit or on a "tipping floor" and the refuse is fed into individual furnaces by overhead cranes (or front-end loaders in the case of smaller facilities). The wastes are burned in one or more furnaces of differing designs, and heat produced by the combustion process is used to create steam for use as an energy product. The steam can be sold directly to industrial or institutional customers and/or used to power a turbine for the generation of electricity, which is typically sold to an investor-owned or municipal utility.

⁶ "Building Cost Index History (1916-1999)," *Engineering News Record*, Vol. 242, No. 12 (March 22/March 29, 1999), p. 99.

Table 1. Years Projects Began And Ceased Operation

Began Operation					
Year	Mass Burn	Modular	RDF	Pyrolysis	Total
≤1980	12	15	9	1	37
81-84	5	19	7	1	32
85-88	26	23	12	--	61
89-92	27	1	9	--	37
93+	7	1	1	--	9
Total	77	59	38	2	176

Ceased Operation					
Year	Mass Burn	Modular	RDF	Pyrolysis	Total
≤1980	--	3	1	--	4
81-84	2	1	4	1	8
85-88	2	6	2	1	11
89-92	2	11	3	--	16
93+	8	14	13	--	35
Total	14	35	23	2	74

RDF = Refuse-Derived Fuel.

Source: Based on database developed by Governmental Advisory Associates (Westport, Connecticut).

Modular facilities employ one or more small-scale combustion units to process lesser quantities of wastes than mass burn refractory⁷ or mass burn waterwall combustors.⁸ This type of plant is usually pre-fabricated and can be shipped fully assembled or in modules. Steam is most commonly generated from the combustion process, and many modular plants utilize a two-chamber design to accomplish this task. Flue gases, which contain incompletely burned materials, are then channeled into a secondary chamber where final combustion takes place. The steam can be sold and/or used to generate electricity, not unlike other mass burning designs.

The refuse-derived fuel (RDF) technologies employ a two-stage production-incineration system. Wastes are pre-processed to produce a more homogeneous fuel product (RDF), than raw MSW. The RDF is either sold to outside customers or burned on-site in a "dedicated" furnace. The refuse is usually shredded to reduce particle size for burning in semi-suspension or suspension-fired furnaces. Ferrous metals can be recovered using magnetic separators. Glass, grit, and sand may be

removed by screening. In some RDF plants, air classifiers, trommel screens, or rotary drums are employed to further process the fuel products, by eliminating additional non-combustible materials.

All waste combustion systems, to greater or lesser degrees, generate an ash residue that is buried in landfills. The ash residue is composed of two basic components: bottom ash and fly ash. Bottom ash refers to that portion of the unburned waste that fall to the bottom of the grate or furnace. Fly ash, on the other hand, represents the small particles that rise from the furnace during the combustion process; they are generally removed from flue-gases using air pollution control equipment such as fabric filters and scrubbers. Most research has implicated fly ash as the major environmental hazard with respect to ash residue, given that heavy metals and organic compounds tend to be concentrated in the fly ash, rather than in the bottom ash. In recent years, lined ash monofills have been developed to better isolate this potentially harmful residue from groundwater supplies.

Data Description

To carry out the study, a database of 176 municipal waste combustion projects (universe) was created. The database initially contained any project that operated for at least 1 year commencing in 1980. Two projects were ultimately dropped from the database, as they relied upon a unique technology. Data were collected through the use of a telephone survey conducted by Governmental Advisory Associates, Inc., using a detailed interview protocol. Selected aspects of the interview format have changed over the 16 years it has been administered. However, the variables selected for the purposes of this study have remained the same. For each plant included in the database, the following variables were extracted:

- Name of Facility
- State and Region Where Located
- Year Commenced Operation
- Year Shut Down (if applicable)
- Type of Technology (mass burn, modular, RDF)
- Tons per Day, Design
- Energy Product (i.e. electricity, steam or both)
- Gross Power Output Rating in Megawatts (MW)
- Pounds per Hour of Steam Produced

⁷ Conventional technology used by older mass-burn facilities; energy is recovered in a boiler that is downstream from the combustor process.

⁸ In the waterwall design, the walls of the furnace consist of closely spaced tubes that circulate water, which cools the furnace walls and absorbs thermal energy to produce steam or electricity.

Original Capital Cost and Year Incurred
 Additional Capital Modification Costs by
 Year Incurred
 Public or Private Sector Ownership
 Public or Private Sector Operation

Descriptive statistics were obtained for all the facilities in the database, which are categorized by technology type. Table 1 summarizes basic data on the plants, showing the years plants began and ceased operation by technology type. A large number of facilities (61) commenced operation in the 1985-1988 time period. Between 1989 and 1992, the number of projects coming on line dropped by almost 40 percent to 37. In the years subsequent to 1992, only nine additional projects came on line. Also, the data show that the dominant technology shifted over time. Among 69 plants that began operation through 1984, 34 (49 percent) were modular facilities. After 1984, of the 107 plants that came on line, only 25 (23 percent) were modular facilities. The dominant technology from 1985 to 1998 was mass burn. Sixty of these plants were built, comprising 56 percent of the projects coming on line during this period. Reliance on RDF technology wavered somewhat over the time period. Of the 69 total projects built through 1984, 23 percent used RDF processes. Of the plants coming on line after 1984, about 21 percent used the RDF technology.

Table 1 also indicates the number of projects that ceased operation by time period and technology type. Each successive time period had an increasing number of closures, with the largest amount (35) occurring since 1992. Of the total sample of 176 municipal waste combustion facilities in operation from 1980 to 1998, 74 have closed. Categorization by technology type, 14 facilities (19 percent) that closed were mass burn, 23 facilities (31 percent) were RDF, and 35 facilities (47 percent) were modular. Both pyrolysis facilities also ceased operation. The high percentage of modular facility closures may be due to age. Most were built between 1980 and 1988 and have or are reaching the end of their useful life. However, the disappearance of modular facilities may also be related to the imposition of new air pollution requirements promulgated since 1991. The additional capital costs associated with the implementation of new technology may be too onerous for plant owners to bear, given the level of expected revenues.

Table 2 shows the distribution of plants by technology type and region.⁹ The Northeast and South regions have had the preponderance of municipal waste combustion facilities. The majority of facilities operating in the Northeast are mass burn; the largest proportion of plants in the South are modular. These breakdowns relate to the entire database. At any point in time, the regional distribution may look somewhat different, given that some plants have shut down, and others came on line.

Table 3 provides further summary statistics with respect to the plants. On average, the initial capital cost of a facility, indexed to 1999 dollars, is \$77 million. Additional capital investment per plant averages \$22 million in 1999 dollars. The average year a project began operations was 1985, with a design capacity of 718 tons per day. The average duration of plant operations is 10.8 years, and the average power output rating for electricity is 28.3 MW. Steam output is 177,248 pounds per hour. With respect to each characteristic, a considerable range is evident between the minimum and maximum values.

Prior to breaking down the data to examine the impact of Federal environmental regulations on capital costs, it is useful to show the evolution of the composition of the group of facilities in operation at each point in time. Tables 4 through 6 show the number of firms (by number of years of operation) operating in each calendar year from 1975 to 1998 for each of the three technology types. (Table 4 actually traces back to calendar year 1965.)

The key features of the tables are the "diagonals" (see, for example, shaded area in Table 4) from a non-zero element in the row labeled with a number and the column and row totals. The diagonal down and to the right from any element contains the numbers of facilities in a cohort (of a particular vintage) that are still operating in the calendar year indicated by the column label. The column total represents the number of firms in operation for the year. If one picks a particular calendar year (column), the numbers indicate the "mix" of vintages of the facilities operating in that year.¹⁰

⁹ The four regions include the following States: Northeast: CT, ME, MA, NH, NJ, NY, PA, RI, VT; South: AL, AR, DE, DC, FL, GA, KY, LA, MD, MS, NC, OK, SC, TN, TX, VA, WV; North Central: IL, IN, IA, KS, MI, MN, MO, NE, ND, OH, SD, WI; West: AK, AZ, CA, CO, HI, ID, MT, NV, NM, OR, UT, WA, WY.

¹⁰ While examining these tables, it is important to remember that facility capacity is not taken into account. If old facilities are replaced by larger scale operations and the hypothesis of increasing returns to scale is indeed true, this could lead to a negatively sloped capital profile or possibly offset increases due to retrofitting.

Table 2. Number and Percent of Projects by Type of Technology and Region

Technology	Northeast		South		North Central		West		Total	
	Number	Percent	Number	Percent	Number	Percent	Number	Percent	Number	Percent
Mass Burn	37	62	24	38	9	26	7	41	77	44
Modular	13	22	30	47	11	31	5	29	59	34
RDF	10	17	8	13	15	43	5	29	38	22
Pyrolysis	--	--	2	3	--	--	--	--	2	1
Total	60	100	64	100	35	100	17	100	176	100

RDF = Refuse-Derived Fuel.

Notes:

Northeast: Connecticut, Massachusetts, Maine, New Hampshire, New Jersey, New York, Pennsylvania, Rhode Island, Vermont
 South: Alabama, Arkansas, Delaware, District of Columbia, Florida, Georgia, Kentucky, Louisiana, Maryland, Mississippi, North Carolina, Oklahoma, South Carolina, Tennessee, Texas, Virginia, West Virginia
 North Central: Illinois, Indiana, Iowa, Kansas, Michigan, Minnesota, Missouri, Nebraska, North Dakota, Ohio, South Dakota, Wisconsin
 West: Alaska, Arizona, California, Colorado, Hawaii, Idaho, Montana, Nevada, New Mexico, Oregon, Utah, Washington, Wyoming

Totals may not equal the sum of components due to independent rounding.

Source: Based on database developed by Governmental Advisory Associates (Westport, Connecticut).

Table 3. Summary Statistics for Total Municipal Waste Combustion Sample

Variable	Mean Value	Minimum	Maximum	Number of Plants
Initial Capital Cost (1999 Dollars) Per Plant	\$77,073,438	\$1,032,339	\$550,385,843	176
Adjusted Additional Capital Costs Per Plant (1999 Dollars)	\$22,238,254	\$62,157	\$263,396,562	70
Year Began Operation	1985	1965	1997	176
Tons Per Day Design (tons)	718.2	13	4,000	176
Average Years of Operation (years)	10.8	1	31	176
Gross Rated Output for Electricity (MW)	28.3*	0.5	90	89
Steam Production (pph)	177,248*	2,500	823,000	151

MW = Megawatts.

pph = pounds per hour.

*Includes those facilities that are burning only MSW as a fuel. All plants that are co-firing coal and MSW are excluded from this number.

Source: Based on database developed by Governmental Advisory Associates (Westport, Connecticut).

Finally, the row totals indicate the number of facilities operating with various years of experience, represented by the row labels. To determine the number of facilities that have closed for each technology type, one can subtract the column total in the latest year of operation, 1998, from the first row total, which represents the total number of plants with at least 1 year of operating experience.

Examining Table 4 (mass burn), one observes that as of 1998, 63 plants have been in operation. This total is down from a high of 68 in 1995. Subtracting the 63 facilities in operation in 1998 from the 77 plants that operated for at least 1 year, one sees that 14 mass burn facilities have been closed. A comparison of mass burn

(Table 4) with modular (Table 5) projects, reveals several differences. First, as of 1998, there are considerably fewer modular plants, 24, than mass burn (63). The decline in modular plant numbers began in 1990, as opposed to 1996 for mass burn plants. Twenty-seven mass burn facilities began operating in the 1990-1998 period, as opposed to one modular plant during the same time period. Of the 59 modular facilities that began operations since 1975, 35 ceased operations by 1998.

RDF facilities represent the smallest total in the database. This type of facility came on line in 1975 and increased in number slowly through 1991. Reaching its peak in 1990/1991 (29 plants), numbers have since declined to 15 operating plants, equaling the 1986 total.

Table 4. Number of Firms by Years of Operating Experience and Calendar Year of Operation, Mass Burn Projects

Years Operating	Calendar Year																																				Total
	65	66	67	68	69	70	71	72	73	74	75	76	77	78	79	80	81	82	83	84	85	86	87	88	89	90	91	92	93	94	95	96	97	98			
1	2	0	1	0	0	2	2	0	0	2	0	1	0	0	0	2	2	0	2	1	4	3	8	11	5	10	5	0	2	5	0	0	0	77			
2	0	2	0	1	0	0	2	2	0	0	2	0	1	0	0	0	2	2	0	2	1	4	3	8	11	5	10	5	0	2	5	0	0	77			
3	0	0	2	0	1	0	0	2	2	0	0	2	0	1	0	0	0	2	2	0	2	1	4	3	8	11	5	10	5	0	2	5	0	77			
4	0	0	0	2	0	1	0	0	2	2	0	0	2	0	1	0	0	0	2	2	0	2	1	4	3	8	11	5	10	5	0	2	5	77			
5	0	0	0	0	2	0	1	0	0	2	2	0	0	2	0	1	0	0	0	2	2	0	2	1	4	3	8	11	5	10	5	0	2	70			
6	0	0	0	0	0	2	0	1	0	0	2	2	0	0	2	0	1	0	0	0	2	2	0	2	1	4	3	8	11	5	10	5	0	72			
7	0	0	0	0	0	0	2	0	1	0	0	2	2	0	0	2	0	1	0	0	0	2	2	0	2	1	4	3	8	10	5	10	5	68			
8	0	0	0	0	0	0	0	2	0	1	0	0	2	2	0	0	2	0	1	0	0	0	2	2	0	2	1	4	2	8	10	5	10	62			
9	0	0	0	0	0	0	0	0	2	0	1	0	0	2	2	0	0	2	0	1	0	0	0	2	2	0	1	1	4	2	8	10	5	51			
10	0	0	0	0	0	0	0	0	0	2	0	1	0	0	2	2	0	0	2	0	1	0	0	0	2	2	0	1	1	4	2	7	10	45			
11	0	0	0	0	0	0	0	0	0	0	2	0	1	0	0	2	2	0	0	2	0	0	0	0	0	2	2	0	1	1	4	2	7	38			
12	0	0	0	0	0	0	0	0	0	0	0	2	0	1	0	0	2	2	0	0	2	0	0	0	0	0	2	2	0	1	1	4	2	7	28		
13	0	0	0	0	0	0	0	0	0	0	0	0	2	0	1	0	0	2	2	0	0	2	0	0	0	0	0	2	2	0	1	1	4	2	21		
14	0	0	0	0	0	0	0	0	0	0	0	0	0	2	0	1	0	0	1	2	0	0	2	0	0	0	0	2	1	0	0	1	3	15			
15	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2	0	1	0	0	1	2	0	0	2	0	0	0	0	2	1	0	0	1	12			
16	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2	0	1	0	0	1	2	0	0	2	0	0	0	0	0	2	1	0	11			
17	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2	0	1	0	0	1	2	0	0	2	0	0	0	0	0	2	1	11			
18	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2	0	1	0	0	1	2	0	0	2	0	0	0	0	0	2	11			
19	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2	0	1	0	0	1	2	0	0	2	0	0	0	0	2	10			
20	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	1	0	0	1	2	0	0	2	0	0	0	0	7			
21	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0	1	1	0	0	2	0	0	0	5			
22	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0	1	1	0	0	2	0	0	5			
23	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0	1	1	0	0	2	0	5			
24	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0	1	1	1	0	2	6			
25	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0	1	1	0	2	5			
26	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0	1	1	0	3			
27	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0	1	1	0	3		
28	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0	1	3			
29	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0	1	2		
30	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	0	0	1			
31	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	0	1			
32	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0			
33	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0			
Total	2	2	3	3	3	5	7	7	7	9	9	10	10	10	10	12	14	14	15	15	19	21	28	39	46	51	59	64	63	63	68	64	64	63			

Source: Based on database developed by Governmental Advisory Associates (Westport, Connecticut).

Table 5. Number of Firms by Years of Operating Experience and Calendar Year of Operation, Modular

Years Oper- ating	Calendar Year																								Total
	75	76	77	78	79	80	81	82	83	84	85	86	87	88	89	90	91	92	93	94	95	96	97	98	
1	2	1	0	2	1	9	8	7	2	2	4	10	2	7	1	0	0	0	0	0	0	0	1	0	59
2	0	2	1	0	2	1	9	8	7	2	2	4	10	2	7	1	0	0	0	0	0	0	0	1	59
3	0	0	2	1	0	1	1	9	8	7	2	2	4	9	2	7	1	0	0	0	0	0	0	0	56
4	0	0	0	2	1	0	1	1	8	8	7	2	2	4	9	2	7	1	0	0	0	0	0	0	55
5	0	0	0	0	2	1	0	1	1	8	7	7	2	2	4	9	2	7	1	0	0	0	0	0	54
6	0	0	0	0	0	0	1	0	1	1	8	6	6	2	2	4	9	2	7	1	0	0	0	0	50
7	0	0	0	0	0	0	0	1	0	1	1	8	5	6	2	2	4	9	1	7	1	0	0	0	48
8	0	0	0	0	0	0	0	0	1	0	1	1	8	5	6	2	2	4	9	1	7	1	0	0	48
9	0	0	0	0	0	0	0	0	0	1	0	1	1	7	5	6	1	2	3	9	0	7	1	0	44
10	0	0	0	0	0	0	0	0	0	0	1	0	1	1	7	4	4	0	1	3	9	0	7	1	39
11	0	0	0	0	0	0	0	0	0	0	0	1	0	1	1	6	4	4	0	1	2	9	0	7	36
12	0	0	0	0	0	0	0	0	0	0	0	0	1	0	1	1	3	4	3	0	1	2	8	0	24
13	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	1	1	2	4	3	0	1	2	7	22
14	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	1	2	3	2	0	1	2	12
15	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	2	3	2	0	1	9
16	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	2	2	2	0	7
17	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	2	2	5
18	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	2	3
19	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	1
Total	2	3	3	5	6	12	20	27	28	30	33	42	42	47	47	45	39	37	32	30	27	25	25	24	

Source: Based on database developed by Governmental Advisory Associates (Westport, Connecticut).

Table 6. Number of Firms by Years of Operating Experience and Calendar Year of Operation, RDF Projects

Years Oper- ating	Calendar Year																								Total
	75	76	77	78	79	80	81	82	83	84	85	86	87	88	89	90	91	92	93	94	95	96	97	98	
1	1	1	1	2	4	0	3	0	2	2	2	2	2	6	5	3	1	0	0	0	0	0	1	0	38
2	0	1	1	1	2	4	0	3	0	2	2	2	2	2	6	5	3	1	0	0	0	0	0	0	37
3	0	0	1	1	1	1	4	0	3	0	2	2	2	1	2	6	5	3	1	0	0	0	0	0	35
4	0	0	0	1	1	1	1	4	0	2	0	2	2	2	1	2	6	3	3	1	0	0	0	0	32
5	0	0	0	0	1	1	1	0	4	0	2	0	2	2	2	1	2	6	3	3	0	0	0	0	30
6	0	0	0	0	0	1	1	0	0	3	0	2	0	1	2	2	1	2	5	3	2	0	0	0	25
7	0	0	0	0	0	0	1	1	0	0	3	0	2	0	1	2	2	1	2	5	3	2	0	0	25
8	0	0	0	0	0	0	0	1	1	0	0	3	0	2	0	1	2	2	1	2	5	3	2	0	25
9	0	0	0	0	0	0	0	0	1	1	0	0	3	0	2	0	1	2	2	1	2	5	3	1	24
10	0	0	0	0	0	0	0	0	0	1	1	0	0	3	0	2	0	1	1	2	1	2	5	3	22
11	0	0	0	0	0	0	0	0	0	0	1	1	0	0	3	0	2	0	1	1	2	1	2	5	19
12	0	0	0	0	0	0	0	0	0	0	0	1	1	0	0	3	0	2	0	1	0	2	1	2	13
13	0	0	0	0	0	0	0	0	0	0	0	0	1	1	0	0	3	0	2	0	1	0	2	1	11
14	0	0	0	0	0	0	0	0	0	0	0	0	0	1	1	0	0	3	0	2	0	1	0	0	8
15	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	1	0	0	2	0	1	0	1	0	6
16	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	0	0	2	0	1	0	1	5
17	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	0	0	1	0	1	0	3
18	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	0	0	1	0	1	3
19	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	0	0	1	0	2
20	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0	1
21	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	0	0	1
22	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	0	1
23	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	1
24	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	1
Total	1	2	3	5	9	8	11	9	11	11	13	15	17	21	26	29	29	27	24	24	19	19	20	15	

RDF = Refuse-Derived Fuel.

Source: Based on database developed by Governmental Advisory Associates (Westport, Connecticut).

Of the 38 facilities, operating since 1975, 15 were still operating in 1998.

Examining the column labeled "1998" in each of the tables, it is apparent that three different mixtures of vintages are represented. The mass burn table has the most entries for projects with 1 year to 12 years of operation, and combined with the low attrition rate, represented the youngest fleet of facilities. The modular table shows somewhat the opposite mixture of plants; those still operating cluster between year 11 and year 19 due to the high attrition and low entry rates. The RDF table shows no facility operating in 1998 with less than 9 years of experience.

Analysis and Findings

Three major analyses of the data were conducted to assess the impact of Federal environmental regulations on municipal waste combustion plants. The first consisted of breaking down initial capital costs (adjusted for inflation) of each project by technology type and vintage. The second consisted of regressing initial capital cost per ton by technology type, vintage, and other selected variables. The third incorporated the concept of the capital profile, assessing its change over time across all facilities and facilities disaggregated by technology type.

Breakdown of Unit Initial Capital Cost by Technology Type and Vintage

For the first level of analysis of the relationship between key variables, the sample was broken down by technology type and vintage of the facility (determined by the year the project began operation). Average capital cost per ton indexed in 1999 dollars was graphed against size in terms of design tons per day (TPD) for each technology and vintage category, using the three major technology types. In addition, the year the plant began operations was divided into three categories, which roughly correspond to three differing regulatory environments prevailing over the 38-year period, 1960 through 1998. The three periods are 1960 through 1981, 1982 through 1990, and 1991 through 1998. The basic concept behind this classification was an attempt to characterize Federal regulatory intensity prevailing at a given time, and to determine if change in unit capital cost could be observed across these different time categories.

The results are shown in Figure 1. If one looks initially at the middle row, which contains data on modular facilities, one observes that:

1. As one moves from the second time period to the latest one, the number of modular facilities coming on line drop off drastically. In the earliest time period, modular facilities are the technology of choice. By the latest time period, only one project began operation.
2. By definition, modular projects always cluster at the low end of tonnage throughput, regardless of the vintage of the plant. As can be observed from tonnages along the horizontal axis, no daily design tonnage exceeds 600 TPD.
3. Adjusted capital costs for the modular facilities show similar distributions across time. There do not appear to be any scale economies across any of the time periods. Additionally, a minimal observable increase in initial capital costs is evident across time periods, due perhaps in part to the smaller combustors, which were initially exempted from air pollution control requirements.

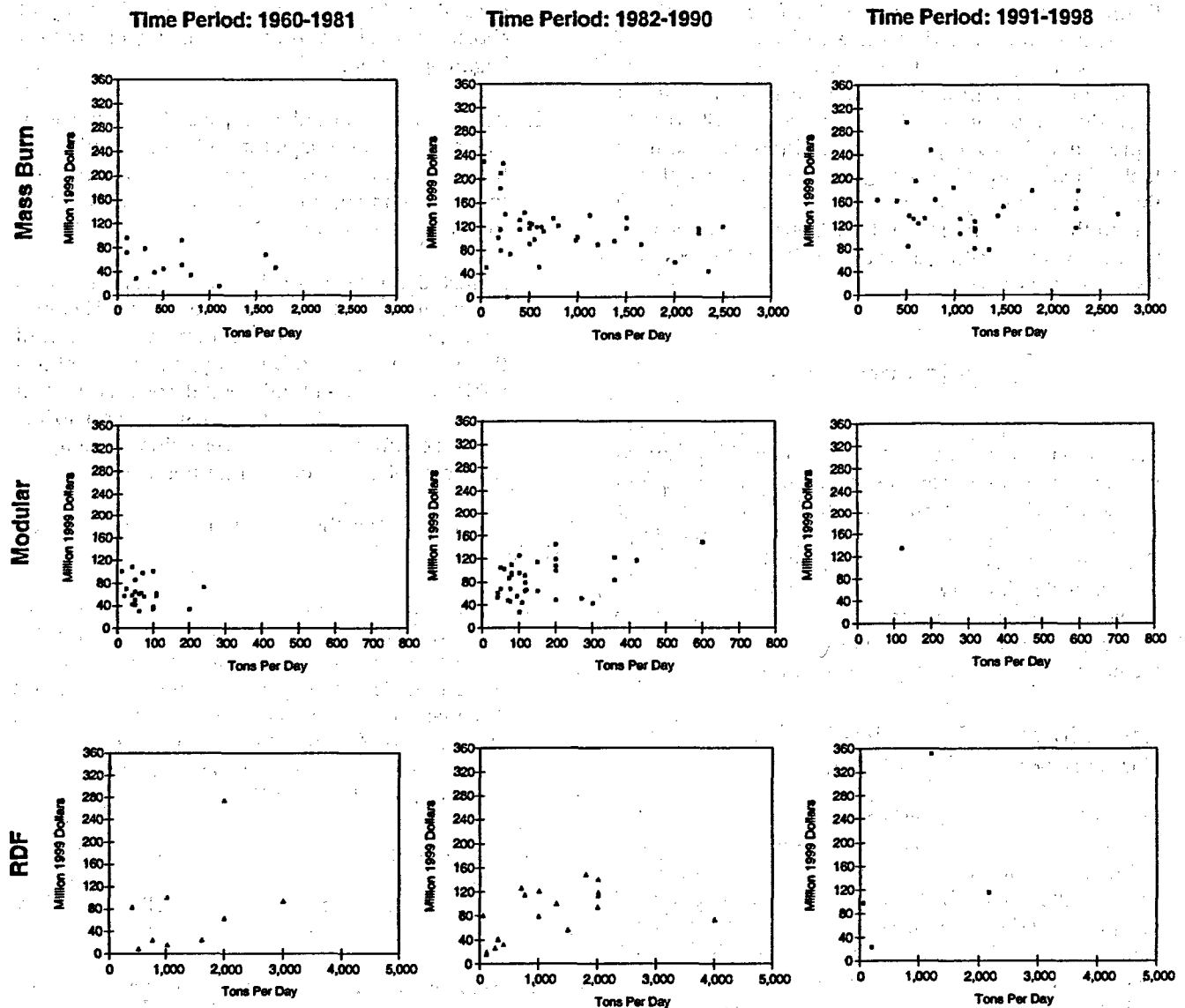
The top row shows the mass burn projects. Several findings are prominent:

1. While modular projects may be the "losing" technology, the opposite is true for mass burn projects. As one moves from the first time period to the last, mass burn is certainly the technology of choice. The majority of projects began operating between 1982 and 1989; in addition, more mass burn facilities came on line in the last time period than for both modular and RDF projects.
2. On average, costs appear to rise over time, controlling for inflation. This may be due to increasing requirements for air pollution control add-ons.
3. Evidence of economies of scale is apparent. As plants become larger, the initial capital cost per ton appears to decrease. This is particularly noticeable in the middle time period and somewhat apparent in the later time period.

The RDF projects, represented in the third row of graphs, present less clear-cut patterns. This is partially due to the nature of these types of plants. Some plants include dedicated boilers on site; others do not. Thus, data for this type of project are not as homogeneous as the other two technology types. Several observations stand out:

1. By the 1991-1998 period, RDF was no longer a technology of choice. During the first two time

Figure 1. Initial Capital Costs by Technology Type and Time Period Operations Began



RDF = Refuse-Derived Fuel.

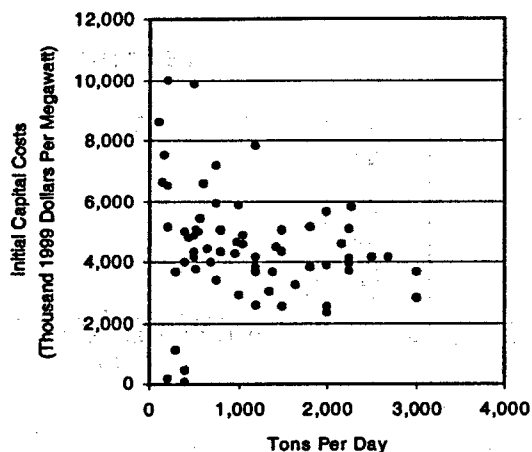
Source: Based on database developed by Governmental Advisory Associates (Westport, Connecticut).

periods, its use increased slightly, which can be viewed as neither "winning" or "losing."

2. Costs tend to rise in relation to size. On average, costs appear to increase somewhat over the first two time periods. From 1991-1998, variation in cost make any conclusion difficult. No economies of scale appear evident. In fact, it appears that initial capital cost is directly related to size.

To further examine the issue of economies of scale, another measure of output—gross megawatts produced—was used. Initial capital cost dollars/megawatt was plotted against tons per day. The results are shown in Figure 2. In this figure, a downward slope is evident. Capital costs per megawatt appear to decrease as design tons per day increase.

Figure 2. Initial Capital Costs in 1999 Dollars per Megawatt by Tons Per Day



Source: Energy Information Administration.

Figure 3 uses the same breakdowns as Figure 1, except that it uses adjusted additional capital costs per ton instead of initial capital costs. Additional capital costs encompass expenditures made after the construction of the plant for retrofit, upgrade, expansion, or additional investment. As reflected on the graphs, the most activity with respect to additional investments occurs among "middle age" plants, i.e., those built between 1982 and 1990. These plants are still young enough to continue operating without major rebuilding, yet may need to invest in environmental control or other upgrades. As might be assumed, the oldest plants show less propensity to make additional capital investments. Costs may simply outweigh investment returns. Finally, the newest projects also reflect a low level of additional investment, which is to be expected as these projects incorporate the latest environmental and technological improvements during construction.

However, while Figure 3 shows the pattern of additional capital investment by plant vintage, it does not reflect at what time the capital investment was made. If the life of a boiler is 20 years, the additional investments may have been made to replace a boiler at the end of its lifespan or in response to regulatory requirements.

Figure 4 plots the year an additional capital investment was made by the year the plant became operational. What is interesting are the number of dots at or above the 1990 line on the y-axis. Despite plant vintage, most additional expenditures came in 1990 or after. This

pattern holds true even for plants built in the late 1980s, indicating that reasons other than pure equipment replacement were forcing the additional capital expenditures.

Finally, Figure 5 summarizes total additional capital dollars spent by municipal waste combustion facilities in each of the three basic time periods. In 1999 dollars, the total for 1960-1981 was approximately \$9.2 million, for 1982 to 1990 it was \$367 million, and for 1991-1998 it was \$1.17 billion.

Estimation of Linear and Log Linear Regression Models Using Initial Capital Costs

Based on the categorizations above, initial linear regressions were estimated, which hypothesized that the initial capital cost of a facility (adjusted for inflation) per daily ton is related to the type of technology employed, the size of the project (in terms of design tons per day), and the region of the country in which the plant is sited. In addition, it was hypothesized that public sector ownership or operation might affect initial capital costs. Regressions were therefore tried with variables of public sector ownership and operation, but these variables were not significant and were therefore dropped. While capital costs were adjusted for inflation (all escalated to 1999 dollars, using the ENR Building Index), no attempt was made at this point to incorporate changes to the facility over time. Each plant only had one data entry, its start date of operation (scaled down by subtracting 1960 from the start date, as 1960 was the earliest start date in the database), its size and its original cost of construction at that point. Only plants employing the three basic technologies discussed above were included.

The estimated equation was as follows:

$$\text{UNIT.CAP} = \alpha + \beta_0 \cdot \text{OP} + \beta_1 \cdot \text{NCEN} + \beta_2 \cdot \text{OWN} + \beta_3 \cdot \text{RDF} + \beta_4 \cdot \text{NOEA} + \beta_5 \cdot \text{OPYR} + \beta_6 \cdot \text{TPD} + \beta_7 \cdot \text{MBMOD} + \beta_8 \cdot \text{SOU}$$

where,

UNIT.CAP = initial capital expenditure/design tons per day indexed to 1999 dollars

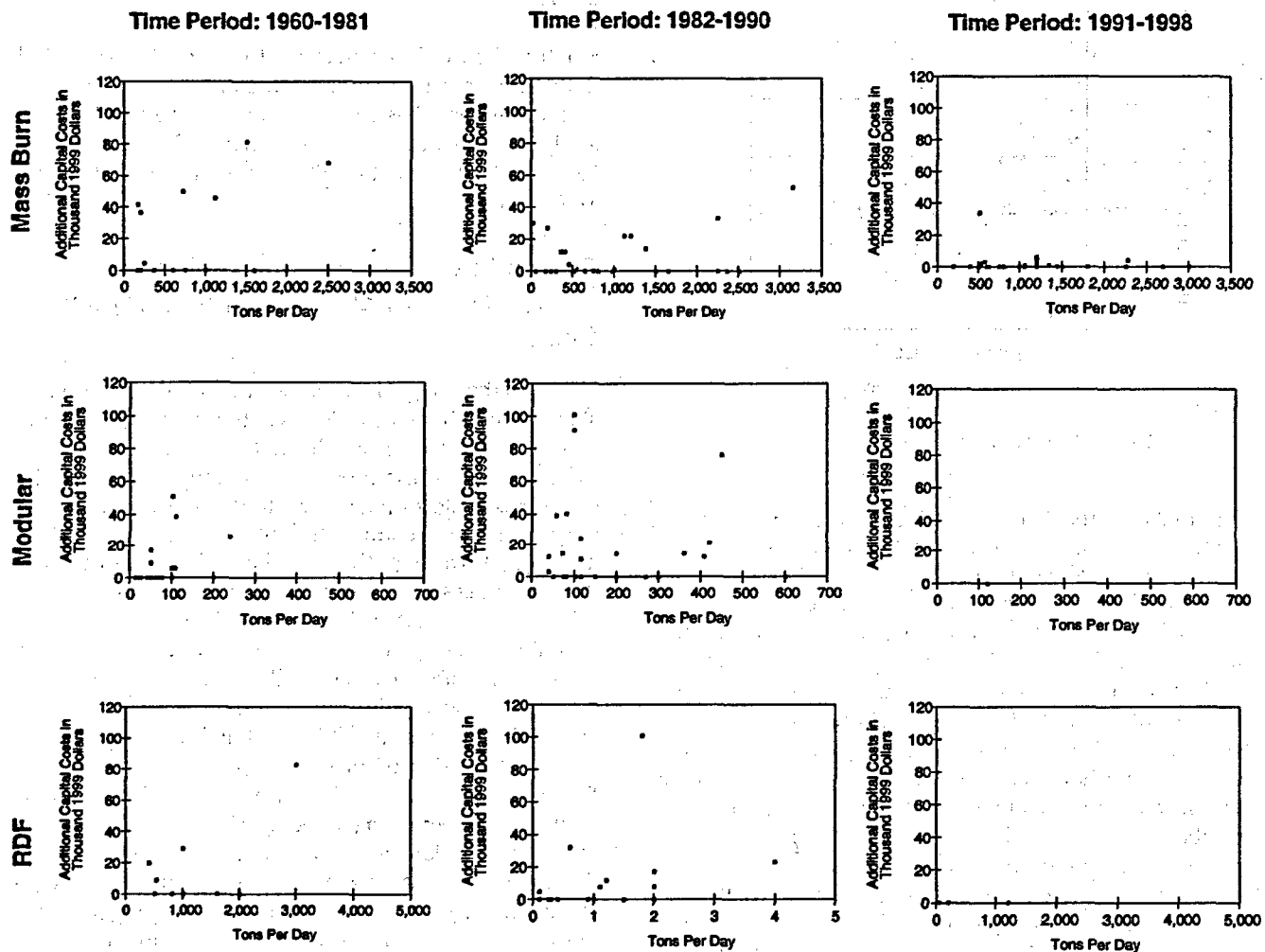
OPYR = year operations began minus 1960 (values going from 0 to 38)

TPD = design tons per day of refuse processed when plant was built

OWN = ownership type dummy variable

OP = operating entity type dummy variable

Figure 3. Additional Capital Costs Per Ton by Technology Type and Time Period Operations Began



RDF = Refuse-Derived Fuel.

Source: Based on database developed by Governmental Advisory Associates (Westport, Connecticut).

TYPE OF TECHNOLOGY = DUMMY VARIABLE

RDF = 1, if plant is RDF; 0, if not

MBMOD = 1, if plant is modular; 0 if not

REGION = DUMMY VARIABLE

NCEN = 1, if plant located in North Central Region (IL, IN, IA, KS, MI, MN, MO, NE, ND, OH, SD, WI); 0, if not.

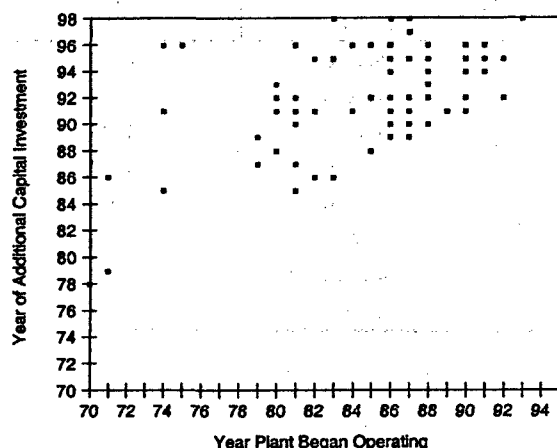
NOEA = 1, if plant is located in the Northeast (CT, ME, MA, NH, NJ, NY, PA, RI, VT); 0, if not.

SOU = 1, if plant located in South (AL, AR, DE, DC, FL, GA, KY, LA, MD, MS, NC, OK, SC, TN, TX, VA, WV); 0, if not.

With the dummy variables in the equation, the base case for technology (RDF=0, MBMOD=0) is Mass Burn and the base case for region (NCEN=NOEA=SOU=0) is the West, which includes the following states: Alaska, Arizona, California, Colorado, Hawaii, Idaho, Montana, Nevada, New Mexico, Oregon, Utah, Washington, and Wyoming.

The overall results from the regression are provided in Table 7. The resultant multiple R-squared is 0.34, indicating that approximately 34 percent of the variation in initial capital cost is explained by its start date, size, technology and region of the country, as well as public

Figure 4. Year of Additional Capital Cost by Year Plant Began Operating

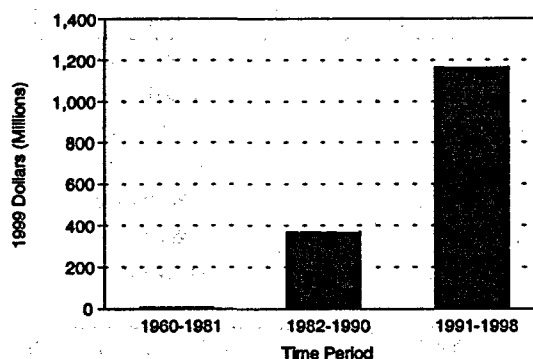


Source: Based on database developed by Governmental Advisory Associates (Westport, Connecticut).

sector ownership and operation. Both the ownership and operation variables are statistically insignificant and are excluded from future analysis. Highly significant is OPYR, which is positively correlated with capital cost. As project vintage (controlling for inflation) increases by one, initial capital cost per ton increases by approximately \$4,000. Also significant is the dummy variable denoting modular facilities. With all other variables constant relative to the null case of mass burn, modular facilities are less costly per ton by about \$17,000. The third significant variable is the SOU regional dummy variable. Finally, while not highly significant, tons per day carries a negative value. This finding indicates that increases in design tons per day (across all facilities) are associated with corresponding decreases in initial capital costs per ton, suggesting that economies of scale exist.

While the equation points to certain relationships, a second equation was tested. This equation stipulates a log-linear relationship between the variables and initial capital cost. In addition, the non-significant variables of public and private sector ownership and operation were dropped. To assess the significance of the EPA regulatory period two dummy variables were created. The first, EPAREG2, takes the value "1" for plants commencing operations between 1982 to 1990 and "0" for all others. The second, EPAREG3, takes the value "1" for all plants commencing operation during the third regulatory period (1991 and later) and takes the value "0" for all others. The null case for this variable is the first regulatory period, representing the years prior to 1982. Table 8 shows the results.

Figure 5. Total Additional Capital Costs by EPA Regulatory Time Period



Source: Based on database developed by Governmental Advisory Associates (Westport, Connecticut).

This equation, including all facilities, regardless of technology, explains more of the variation in initial capital costs than the first regression, about 41 percent of the variation in initial capital costs per ton as opposed to 34 percent. In this equation, the base cases were mass burn, the Northeast region, and the first EPA regulatory period (MB=0, NOEA=0, and EPAREG1=0). This configuration is repeated in all subsequent tables. Using a log linear format, one observes that relative to mass burn facilities, both RDF and modular projects are less costly across all time periods. In addition, project vintage is associated with a significantly positive impact on cost. In this format, the South, West, and North Central regions have a significant impact (at least at approximately the 0.10 level of significance) on cost relative to the Northeast, all showing that costs are less in these regions. Examining the EPA regulatory periods, one observes that relative to the very early years of municipal waste combustion facilities (prior to 1982) when there was a minimal level of environmental regulation, later regulatory periods had a positive but statistically insignificant impact (at the 0.10 level) on initial capital costs.

However, while this equation explains somewhat more of the variations in plant capital costs, 59 percent of the cost variation is still not explained by the stated variables. One aspect that may confound the analysis is the fact that technology types are mixed. As the graphs in Figure 1 show, different technology types behave differently if one looks at initial unit capital costs over time and size. In particular, RDF facilities appear to behave according to a different cost model than do mass or modular facilities.

Table 7. Linear Regression Results Using Initial Capital Costs of Municipal Waste Combustion Facilities

Coefficients	Value	Std. Error	t value	Pr(> t)
Intercept	-3226.5292	15112.0506	-0.2140	0.8312
NCEN	-24347.8245	8725.8862	-2.7900	0.0059
MBMOD	-17152.5854	8039.0935	-2.1340	0.0344
WEST	-16895.7814	11312.6400	-1.4940	0.1373
OPYR	3690.2840	522.5420	7.0620	0.0000
RDF	-12608.0754	8407.7334	-1.5000	0.1357
SOU	-16573.1629	7303.8606	-2.2690	0.0246
TPD	-3.4365	4.5756	-0.7510	0.4537

OPYR = year operations began minus 1960 (values from 0 to 38)

TPD = design tons per day of refuse processed when plant was built

TYPE OF TECHNOLOGY = DUMMY VARIABLE

RDF = 1, if plant uses refuse-derived fuel; 0, if not

MBMOD = 1, if plant is modular; 0 if not

REGION = DUMMY VARIABLE

NCEN = 1, if plant located in North Central Region; 0, if not

SOU = 1, if plant located in South; 0, if not

WEST = 1, if plant located in West; 0, if not

With the dummy variables in the equation, the base case for technology is Mass Burn and the base case for region is the Northeast.

Notes: • Residual standard error: 38624.46237 on 160 degrees of freedom. • Multiple R-Squared: 0.3398.

• F-statistic: $F = 11.76654$ on 7 and 160 degrees of freedom, the $Pr(>F)$ is 0.0000.

Northeast: Connecticut, Massachusetts, Maine, New Hampshire, New Jersey, New York, Pennsylvania, Rhode Island, Vermont

South: Alabama, Arkansas, Delaware, District of Columbia, Florida, Georgia, Kentucky, Louisiana, Maryland, Mississippi, North Carolina, Oklahoma, South Carolina, Tennessee, Texas, Virginia, West Virginia

North Central: Illinois, Indiana, Iowa, Kansas, Michigan, Minnesota, Missouri, Nebraska, North Dakota, Ohio, South Dakota, Wisconsin

West: Alaska, Arizona, California, Colorado, Hawaii, Idaho, Montana, Nevada, New Mexico, Oregon, Utah, Washington, Wyoming

Source: Based on database developed by Governmental Advisory Associates (Westport, Connecticut).

Tables 9-11 show the results obtained by running the log linear equation displayed in Table 8, disaggregating the sample by technology type.

As shown in Table 9, looking only at mass burn facilities, the regression equation in log linear form explains 64 percent of the variation in cost. Highly significant variables are tons per day, the initial year of operation, and at a lesser level of significance, the dummy variables for the second and third EPA regulatory periods. Tons per day has an inverse relationship to cost, indicating that holding all other variables constant, a 10-percent increase in tons per day is associated with a 1.3-percent decrease in initial capital cost per daily ton. Approximately a 3-year or a 10-percent increase in project vintage (or the year the project began operation) is associated with a 5.9-percent increase in unit costs.¹¹ Similarly, the EPA regulatory periods are associated with increasing costs. Compared to the years prior to

1982, the second regulatory period (1982-1990) is associated with a 29-percent increase in cost, and the third regulatory period with a 53-percent increase in cost. With the Northeast as the base case, one observes from the table that plants located both in the North Central region and in the South region have significantly lower initial capital costs than those in the Northeast.

Table 10 illustrates the results for the same equation run for modular facilities. NCEN is the only statistically significant variable. This result can be inferred by the graphs in Figure 1. By definition, there is little variation in tons per day across these facilities.

Finally, Table 11 delineates the results for RDF projects. These projects appear to behave differently than mass burn facilities and the modular projects. First, the sign on tons per day is significantly positive, indicating not only are scale economies not present, but that the

¹¹ Project vintage is measured by a variable that takes a value from 1 to 38, with 38 representing the newest plants, 1 the oldest.

Table 8. Log Linear Regression Results Using Initial Capital Costs of Municipal Waste Combustion Facilities

Coefficients	Value	Std. Error	t value	Pr(> t)
Intercept	9.0079	0.6399	14.0780	0.0000
EPAREG2	0.2061	0.1354	1.5220	0.1299
EPAREG3	0.2833	0.1993	1.4220	0.1570
LOPYR(ln)	0.7229	0.2050	3.5240	0.0006
LTPD(ln)	0.0240	0.0439	0.5480	0.5848
MBMOD	-0.1998	0.1236	-1.6170	0.1078
NCEN	-0.3204	0.1176	-2.7240	0.0072
RDF	-0.4783	0.1139	-4.1970	0.0000
SOU	-0.1792	0.0977	-1.8340	0.0685
WEST	-0.2423	0.1472	-1.6460	0.1018

LTPD = (ln) design tons per day of refuse processed when plant was built

LOPYR = (ln) vintage of facility (year commenced - 60)

TYPE OF TECHNOLOGY = DUMMY VARIABLE

RDF = 1, if plant uses refuse-derived fuel; 0, if not

MBMOD = 1, if plant is modular; 0, if not

REGION = DUMMY VARIABLE

NCEN = 1, if plant located in North Central Region [states below]; 0, if not

SOU = 1, if plant located in South [states below]; 0, if not

WEST = 1, if plant located in West [states below]; 0, if not

EPA Regulatory Period = DUMMY VARIABLE

EPAREG2 = 1, if plant commenced operations between 1982 and 1990; 0, if not

EPAREG3 = 1, if plant commenced operations in 1991 or later; 0, if not

Notes: • Residual standard error: 0.50754 on 159 degrees of freedom. • Multiple R-Squared: 0.4087.

• F-statistic: $f = 12.20832$ on 9 and 159 degrees of freedom, the $Pr(>f)$ is 0.0000.

Northeast: Connecticut, Massachusetts, Maine, New Hampshire, New Jersey, New York, Pennsylvania, Rhode Island, Vermont

South: Alabama, Arkansas, Delaware, District of Columbia, Florida, Georgia, Kentucky, Louisiana, Maryland,

Mississippi, North Carolina, Oklahoma, South Carolina, Tennessee, Texas, Virginia, West Virginia

North Central: Illinois, Indiana, Iowa, Kansas, Michigan, Minnesota, Missouri, Nebraska, North Dakota, Ohio, South Dakota, Wisconsin

West: Alaska, Arizona, California, Colorado, Hawaii, Idaho, Montana, Nevada, New Mexico, Oregon, Utah, Washington, Wyoming

Source: Based on database developed by Governmental Advisory Associates (Westport, Connecticut).

contrary is true. This result runs counter to the findings for mass burn and modular projects. Second, project vintage does not have a statistically significant effect, nor does the EPA regulatory period under which it began operating. Similar to findings for other type of facilities, projects located in the Northeast region are more costly on a per-ton basis than those of other regions, significantly more so with respect to the West and North Central regions.

Average Costs Per Ton Over Time Using the Capital Profile Construct

Although the prior breakdowns did appear to show a variation in capital cost behavior of facilities of differing technologies over time, they did not factor in capital

investments made after initial construction. Using the capital profile, outlined in Appendix B and graphing capital profile in each year of operation against time, one might expect any of three basic types of investment behavior and thus shapes to the graph. If the firm expects EPA regulations to increase costs beyond its ability to maintain some profit level, no additional investment would be made by the facility and the capital profile for that project would be a negatively sloped line.¹² If EPA regulations have no effect on capital/unit capacity and the firm expects to maintain operations, the capital profile will be reflected in a downward sloping line due to the depreciation of the equipment. This downward slope will continue until some replacement is required. At this time, the profile will increase by the amount of the replacement investment, then continue to

¹² The firm would ultimately go into noncompliance and would be forced to cease operations.

Table 9. Log Linear Regression Results Using Initial Capital Costs of Municipal Waste Combustion Facilities: Mass Burn

Coefficients	Value	Std. Error	t value	Pr(> t)
Intercept	10.2452	0.5312	19.2870	0.0000
EPAREG2	0.2949	0.1807	1.6320	0.1072
EPAREG3	0.5262	0.2131	2.4690	0.0160
LOPYR(ln)	0.5943	0.1770	3.3570	0.0013
LTPD(ln)	-0.1271	0.0421	-3.0200	0.0035
NCEN	-0.2255	0.1271	-1.7740	0.0805
SOU	-0.1356	0.0866	-1.5680	0.1214
WEST	0.0385	0.1415	0.2720	0.7862

LTPD = (ln) design tons per day of refuse processed when plant was built

LOPYR = (ln) vintage of facility (year commenced - 60)

REGION = DUMMY VARIABLE

NCEN = 1, if plant located in North Central Region [states below]; 0, if not

SOU = 1, if plant located in South [states below]; 0, if not

WEST = 1, if plant located in West [states below]; 0, if not

EPA Regulatory Period = DUMMY VARIABLE

EPAREG2 = 1, if plant commenced operations between 1982 and 1990; 0, if not

EPAREG3 = 1, if plant commenced operations in 1991 or later; 0, if not

Notes: • Residual standard error: 0.32564 on 69 degrees of freedom. • Multiple R-Squared: 0.6368.

• F-statistic: $f = 17.28255$ on 7 and 69 degrees of freedom, the $Pr(>f)$ is 0.0000.

Northeast: Connecticut, Massachusetts, Maine, New Hampshire, New Jersey, New York, Pennsylvania, Rhode Island, Vermont

South: Alabama, Arkansas, Delaware, District of Columbia, Florida, Georgia, Kentucky, Louisiana, Maryland, Mississippi, North Carolina, Oklahoma, South Carolina, Tennessee, Texas, Virginia, West Virginia

North Central: Illinois, Indiana, Iowa, Kansas, Michigan, Minnesota, Missouri, Nebraska, North Dakota, Ohio, South Dakota, Wisconsin

West: Alaska, Arizona, California, Colorado, Hawaii, Idaho, Montana, Nevada, New Mexico, Oregon, Utah, Washington, Wyoming

Source: Based on database developed by Governmental Advisory Associates (Westport, Connecticut).

decline in linear fashion. This should be reflected on a graph as a horizontal sawtooth pattern about some stationary level of capital. If, however, EPA regulations increase the necessary capital required per unit capacity, one should observe a sawtooth pattern with an upward trend. This upward trend would represent the rate of capital accumulation for meeting emissions standards.

Figure 6 shows the overall trend of average capital costs per design ton for municipal waste combustion projects over time, from 1975 to 1998, using the capital profile. As discussed in a previous section, the capital profile incorporates both an inflation and a depreciation factor, as well as additional investments made over time, also adjusted for inflation and depreciation over time. Despite these adjustments, the curve has an overall upward slope. Since 1975, the average capital costs per design ton of waste have been generally increasing.

Several explanations exist for this finding. The upward cost trend may be a reflection of (a) fundamental shifts in technology; (b) increasing inefficiency in the industry;

or (c) increasing capital investments not associated with increased capacity. The first possibility is unlikely. While technological innovations have occurred with respect to grate configuration, boiler lining, tubing, and furnace design, these advancements constitute only marginal improvements with respect to cost. Over the 1980 to 1998 period, no major new technology has been implemented on a widespread basis. Thus, new technological breakthroughs with embedded higher capital cost do not explain rising costs.

A second explanation may be growing capital inefficiency. This explanation is difficult to rule out completely. While environmental regulation affecting the industry was changing and becoming increasingly stringent over the entire period under study, tax and PURPA regulations created strong financial incentives, making MWC projects attractive investments until 1987. As has been discussed, with the enactment of the Tax Reform Act of 1986, tax incentives were severely curtailed. Thus, financial incentives, which may have introduced capital inefficiencies in the market prior to

Table 10. Log Linear Regression Results Using Initial Capital Costs of Municipal Waste Combustion Facilities: Modular

Coefficients	Value	Std. Error	t value	Pr(> t)
Intercept	9.3974	1.8134	5.1820	0.0000
EPAREG2	0.2274	0.1927	1.1800	0.2435
EPAREG3	0.3479	0.4580	0.7600	0.4510
LOPYR(ln)	0.7582	0.6074	1.2480	0.2177
LTPD(ln)	-0.1299	0.0850	-1.5260	0.1331
NCEN	-0.3588	0.1808	-1.9850	0.0525
SOU	-0.2277	0.1469	-1.5500	0.1273
WEST	-0.0208	0.2280	-0.0910	0.9277

LTPD = (ln) design tons per day of refuse processed when plant was built

LOPYR = (ln) vintage of facility (year commenced - 60)

REGION = DUMMY VARIABLE

NCEN = 1, if plant located in North Central Region [states below]; 0, if not

SOU = 1, if plant located in South [states below]; 0, if not

WEST = 1, if plant located in West [states below]; 0, if not

EPA Regulatory Period = DUMMY VARIABLE

EPAREG2 = 1, if plant commenced operations between 1982 and 1990; 0, if not

EPAREG3 = 1, if plant commenced operations in 1991 or later; 0, if not

Notes: • Residual standard error: 0.39587 on 51 degrees of freedom. • Multiple R-Squared: 0.2784.

• F-statistic: $f = 2.81021$ on 7 and 51 degrees of freedom, the Pr (> f) is 0.0149.

Northeast: Connecticut, Massachusetts, Maine, New Hampshire, New Jersey, New York, Pennsylvania, Rhode Island, Vermont

South: Alabama, Arkansas, Delaware, District of Columbia, Florida, Georgia, Kentucky, Louisiana, Maryland, Mississippi, North Carolina, Oklahoma, South Carolina, Tennessee, Texas, Virginia, West Virginia

North Central: Illinois, Indiana, Iowa, Kansas, Michigan, Minnesota, Missouri, Nebraska, North Dakota, Ohio, South Dakota, Wisconsin

West: Alaska, Arizona, California, Colorado, Hawaii, Idaho, Montana, Nevada, New Mexico, Oregon, Utah, Washington, Wyoming

Source: Based on database developed by Governmental Advisory Associates (Westport, Connecticut).

1987, can no longer be used as an explanation for the increase in capital costs.

A final reason for the rising capital costs depicted in Figure 6 may be the increasing level of capital investments made over the period, which were not associated with an appreciable increase in capacity, nor additional technological efficiency. Air pollution control add-ons, implemented in response to changing mandates incorporated in the Clean Air Act, may have had this effect. Reduction of air emissions can be achieved by monitoring the composition of the refuse that is burned, improving combustor technology to achieve a more complete burn, thereby lowering noxious emissions and cleaning up the emissions from the plant.

All three approaches are mandated by EPA. Requirements are clear in terms of the level of back-end air pollution control equipment that must be in place. By adding on this type of equipment, a plant increases the level of investment, but does not affect throughput. While pollution control equipment changes the nature of

the product—producing energy with a lower level of emissions—this positive benefit does not directly offset the cost of the additional investment required.

Average Capital Cost (Using Capital Profile) Per Ton Over Time by Technology Type

Average capital profiles per ton over time are shown by technology type in Figure 7 (mass burn), Figure 8 (modular) and Figure 9 (RDF). Analyzing the sample, one observes the differing behavior of each technology type. In Figure 7, mass burn facilities show a steep positive slope throughout the mid- to late 1980's, which then flattens, assumes a gradual rise and then begins to decline. The steep slope may reflect the myriad of new projects that came on line in the 1980s. Averages are pushed up by new projects entering the mix, which contributes to a lesser proportion of older facilities. These facilities, with a large amount of depreciated capital stock, tend to have a downward influence on average total cost per ton. The dramatic rise could also

Table 11. Log Linear Regression Results Using Initial Capital Costs of Municipal Waste Combustion Facilities: RDF

Coefficients	Value	Std. Error	t value	Pr(> t)
Intercept	2.7998	5.0866	0.5500	0.5869
EPAREG2	-0.1660	0.6667	-0.2490	0.8054
EPAREG3	0.0192	1.0688	0.0180	0.9858
LOPYR(ln)	1.9705	1.7056	1.1550	0.2589
LTPD(ln)	0.3582	0.1120	3.1980	0.0037
NCEN	-0.6244	0.3211	-1.9450	0.0631
SOU	-0.0710	0.3983	-0.1780	0.8599
WEST	-1.2786	0.4597	-2.7820	0.0101

RDF = Refuse-Derived Fuel.

LTPD = (ln) design tons per day of refuse processed when plant was built

LOPYR = (ln) vintage of facility (year commenced - 60)

REGION = DUMMY VARIABLE

NCEN = 1, if plant located in North Central Region [states below]; 0, if not

SOU = 1, if plant located in South [states below]; 0, if not

WEST = 1, if plant located in West [states below]; 0, if not

EPA Regulatory Period = DUMMY VARIABLE

EPAREG2 = 1, if plant commenced operations between 1982 and 1990; 0, if not

EPAREG3 = 1, if plant commenced operations in 1991 or later; 0, if not

Notes: • Residual standard error: 0.72437 on 25 degrees of freedom. • Multiple R-Squared: 0.5363.

• F-statistic: $f = 4.12972$ on 7 and 25 degrees of freedom, the $Pr(>f)$ is 0.0038.

Northeast: Connecticut, Massachusetts, Maine, New Hampshire, New Jersey, New York, Pennsylvania, Rhode Island, Vermont

South: Alabama, Arkansas, Delaware, District of Columbia, Florida, Georgia, Kentucky, Louisiana, Maryland,

Mississippi, North Carolina, Oklahoma, South Carolina, Tennessee, Texas, Virginia, West Virginia

North Central: Illinois, Indiana, Iowa, Kansas, Michigan, Minnesota, Missouri, Nebraska, North Dakota, Ohio, South Dakota, Wisconsin

West: Alaska, Arizona, California, Colorado, Hawaii, Idaho, Montana, Nevada, New Mexico, Oregon, Utah, Washington, Wyoming

Source: Based on database developed by Governmental Advisory Associates (Westport, Connecticut).

be linked to favorable tax treatment and financing and/or increased investment in capital stock.

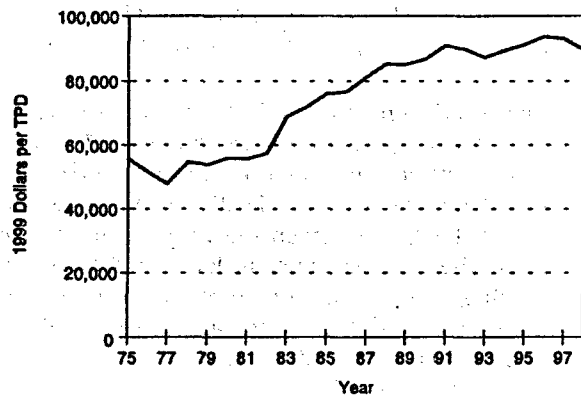
In addition, new projects tend to be more costly than those of a previous era and are already embedded with up-to-date control and boiler technology. The spike in costs during the 1993-1995 period possibly reflects the implementation of the 1991 Air Pollution Control regulations for larger projects. It is still too early to determine if the downward turn in the slope during the most recent years is an ongoing trend or just a temporary halt in additional investments. It does likely reflect the fact that no new projects are coming on line, so average cost increases are solely reflective of additional investments made in upgrades and modifications.

With respect to modular facilities, shown in Figure 8, average total capital costs/TPD rose gradually across time, beginning in 1978. It appears that regulations have

not significantly affected capital costs of these facilities. One upward spike exists from 1989 to 1991. This marked increase coincides with the beginning of more stringent emission standards and could represent the exit of facilities that were no longer viable and therefore had lower capital costs per unit of output. The exiting of older facilities during this period might have caused average costs to increase. The final downturn could be associated with the continued depreciation of existing facilities, without the entry of new projects.

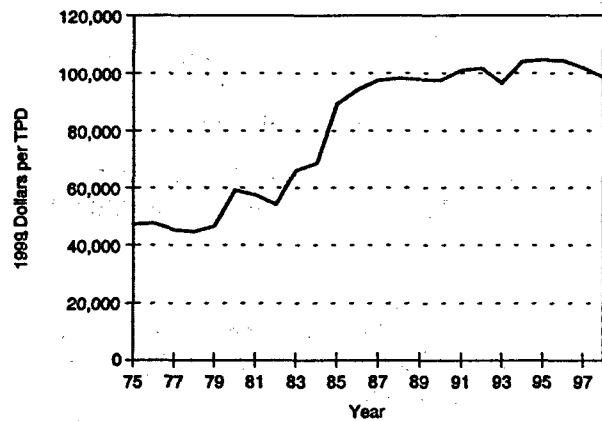
RDF facilities' average capital cost/unit output shows a rather distinct pattern. The increase in 1981 is associated with entry of four new facilities. The gentle negative slope from 1988 through 1994 seems to indicate a slow depreciation of total capital among the RDF facilities. However, averages began to rise as of 1995, perhaps indicating a response among existing projects to the newly promulgated EPA regulations.

Figure 6. Average Total Capital Costs Adjusted for Depreciation by Year: All Projects



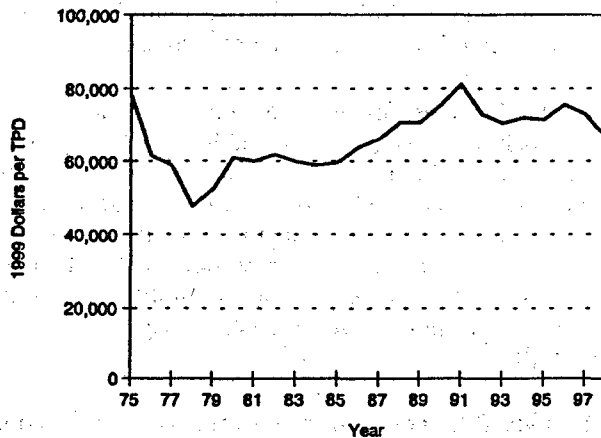
TPD = Tons Per Day.
Source: Based on database developed by Governmental Advisory Associates (Westport, Connecticut).

Figure 7. Average Total Capital Costs Adjusted for Depreciation by Year: Mass Burn



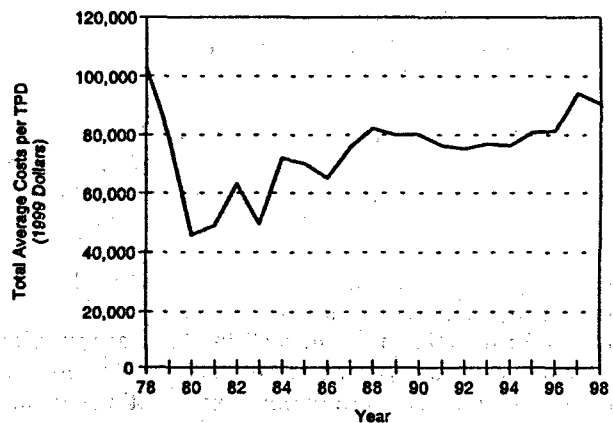
TPD = Tons Per Day.
Source: Based on database developed by Governmental Advisory Associates (Westport, Connecticut).

Figure 8. Average Total Capital Costs Adjusted for Depreciation by Year: Modular



TPD = Tons Per Day.
Source: Based on database developed by Governmental Advisory Associates (Westport, Connecticut).

Figure 9. Average Total Capital Costs Adjusted for Depreciation by Year: RDF



RDF = Refuse-Derived Fuel.
TPD = Tons Per Day.
Source: Based on database developed by Governmental Advisory Associates (Westport, Connecticut).

Regressions Using the Capital Profile

The regressions cited above used initial capital costs per design TPD indexed to 1999 dollars as the dependent variable. The following log-linear regressions use the same independent variables, but introduce the concept of the capital profile as the dependent variable. The capital profile provides a snapshot of capital expenditures of a facility as of its most recent year of operation. For plants currently in operation, that year would be

1998. (For plants no longer operating, the capital profile would represent capital expenditures through their final year of operation.) The construction of the capital profile has already been discussed elsewhere in this paper. Suffice it to say that this profile includes both initial capital costs and additional capital expenditures made over the life of the facility, depreciated and then indexed to 1999 dollars. This approach results in one data point per plant, which summarizes both the original capital

investment and the additional expenditures (capital additions) over the life of the project (see Appendix B).

Similar to the regression involving only initial capital costs, the equation was estimated for each of the three major technology types and is as follows:

$$\text{TOTUNIT.CAP} = \beta_0 + \beta_1 \cdot \text{LTPD} + \beta_2 \cdot \text{SOU} + \beta_3 \cdot \text{LOPYR} + \beta_4 \cdot \text{NCEN} + \beta_5 \cdot \text{WEST} + \beta_6 \cdot \text{EPAREG2} + \beta_7 \cdot \text{EPAREG3}$$

where,

TOTUNIT.CAP (ln) = capital profile in last operating year/design tons per day indexed to 1999 dollars.

LTPD (ln) = tons per day

SOU = dummy variable for region, 1 if in South, 0 if in other region

LOPYR (ln) = Vintage of facility (year commenced operation - 60)

NCEN = dummy variable for region, 1 if in North Central, 0 if in other region

WEST = dummy variable for region, 1 if in West, 0 if in other region

EPAREG2 = Dummy Variable EPA Regulatory Period: 1 = 1982-1990, 0, if not

EPAREG3 = Dummy Variable EPA Regulatory Period: 1 = 1991 or later, 0, if not.

This regression equation is estimated for the sample of firms in operation between the years 1975 and 1998. Tables 12, 13, and 14 summarize the results of estimation of this regression for each of the three technology types.

Looking across technology types, one finds that the most robust equation as measured by the multiple R-Squared is that for mass burn facilities (Table 12). Each variable is statistically significant at the 0.05 level, with the exception of the Western region. The equation explains about 75 percent of the variation in unit total capital costs. The estimated equation exhibits the following characteristics:

1. The negative coefficient for LTPD reflects the increasing returns to scale effects, which were hypothesized. As the designed capacity of the facility is increased, the number of constant dollars capital required per ton per day design declines. A 10-percent increase in tonnage results in about a 2-percent decrease in capital costs/TPD. This constitutes some slight scale economies for the mass burn plants. This finding is similar to the result of the regression using initial capital costs.
2. As with the earlier estimations, projects in the South, North Central, and Western regions have a

lower capital profile (lower annualized costs per ton) than those in the Northeast region. This difference is statistically significant at least at a 0.05 level, except for projects in the Western region.

3. The coefficient for LOPLYR, which represents project vintage, is a positive number and is highly significant in the equation. Because LOPLYR is based on the year the facility began operation minus 1960, the newer the project vintage, the larger the number. Thus, the later the project came on line, the greater the total unit capital costs associated with it. This increase may be related to additional capital requirements of regulations.
4. Finally, with respect to the dummy variables representing EPA regulatory periods, both EPAREG2 and EPAREG3 have a statistically significant impact on total capital costs. As compared with the base case of plants built during the earliest EPA regulatory period, total capital cost rises with each subsequent period. The second EPA regulatory period increases costs by 83 percent, compared to the initial period; the third regulatory period is associated with a 182-percent increase.

Modular facilities appear to exhibit substantially different behavior, as shown in Table 13. The equation explains only 29 percent of the variation in total costs, which is consistent with the nature of these types of facilities. Modular units tend to be smaller in design capacity and are available in somewhat fixed increments. Additionally, expansion possibilities are quite limited by design. Several factors may explain the findings:

1. Retrofitting or additional capital costs invested in these projects may be minimal. As earlier graphs showed, average total capital costs were relatively flat over time. Thus, there was little variation in capital costs to explain.
2. Furthermore, a number of modular projects began to drop out over time, without making required additional investments. This fact would tend to negate the effect of both vintage as well as the EPA regulatory period.

As shown in Table 14, the regression model also has only moderate explanatory power for RDF projects, accounting for about 45 percent of the variation in total capital costs per tons per day. The equation yields the following findings:

Table 12. Log Linear Regression Results Using Capital Profile Estimates of Municipal Waste Combustion Facilities: Mass Burn

Coefficients	Value	Std. Error	T Value	Pr(> t)
Intercept	10.2263	0.5321	19.2180	0.0000
EPAREG2	0.6021	0.1809	3.3270	0.0014
EPAREG3	1.0376	0.2135	4.8600	0.0000
LOPYR (ln)	0.4738	0.1773	2.6720	0.0094
LTPD (ln)	-0.1687	0.0422	-4.0000	0.0002
NCEN	-0.4176	0.1273	-3.2790	0.0016
SOU	-0.1816	0.0868	-2.0920	0.0401
WEST	-0.0712	0.1418	-0.5020	0.6173

LTPD = (ln) design tons per day of refuse processed when plant was built

LOPYR = (ln) vintage of facility (year commenced - 60)

REGION = DUMMY VARIABLE

NCEN = 1, if plant located in North Central Region [states below]; 0, if not

SOU = 1, if plant located in South [states below]; 0, if not

WEST = 1, if plant located in West [states below]; 0, if not

EPA Regulatory Period = DUMMY VARIABLE

EPAREG2 = 1, if plant commenced operations between 1982 and 1990; 0, if not

EPAREG3 = 1, if plant commenced operations in 1991 or later; 0, if not

Notes: • Residual Standard Error: 0.32621 with 69 degrees of freedom. • Multiple R-Squared: 0.7482.
• F-Statistic: $f = 29.29123$ on 7 and 69 degrees of freedom. • the $Pr(>f)$ is 0.0000.

Northeast: Connecticut, Massachusetts, Maine, New Hampshire, New Jersey, New York, Pennsylvania, Rhode Island, Vermont

South: Alabama, Arkansas, Delaware, District of Columbia, Florida, Georgia, Kentucky, Louisiana, Maryland,

Mississippi, North Carolina, Oklahoma, South Carolina, Tennessee, Texas, Virginia, West Virginia

North Central: Illinois, Indiana, Iowa, Kansas, Michigan, Minnesota, Missouri, Nebraska, North Dakota, Ohio, South Dakota, Wisconsin

West: Alaska, Arizona, California, Colorado, Hawaii, Idaho, Montana, Nevada, New Mexico, Oregon, Utah, Washington, Wyoming

Source: Based on database developed by Governmental Advisory Associates (Westport, Connecticut).

1. Vintage is associated with a statistically significant effect on total capital costs. An increase in project vintage of 10 percent is associated with a 52-percent increase in total capital costs.
2. Contrary to mass burn and modular projects, tons per day is associated with a small, however statistically insignificant, positive effect on total capital costs.
3. Similar to findings for other technologies, plants in the Northeast region have the highest capital costs. The coefficients of each of the regional variables are negative, the North and the West significantly so.
4. Both the second and the third regulatory periods are associated with reduced total costs (though only the second period cost reductions are statistically significant), relative to the earliest EPA period (prior to 1982). This finding runs counter to results obtained for both mass burn and modular facilities.

As shown with previous equations, results for this category of facilities demonstrate different patterns.

RDF facilities encompass a variety of front-end preparation technologies as well as boiler technologies. For example, in some instances, RDF is mixed with other fuels and burned to generate energy; in other cases, it is used exclusively as a fuel. It is possible that the producers in this category are sufficiently diverse so as to render any simple description essentially useless.

Conclusion

The finding of major significance is that unit capital costs (capital costs per design ton), while controlling for inflation and adding in a depreciation factor, increase for firms of the same vintage as time progresses. In other words, at any given point in time, facilities of later vintages (built at a later time) have higher capital costs per ton than do projects built in prior years. This finding holds true in pooled equations including facilities of all technologies, as well as for mass burn facilities. The

Table 13. Log Linear Regression Results Using Capital Profile Estimates of Municipal Waste Combustion Facilities: Modular

Coefficients	Value	Std. Error	T Value	Pr(> t)
Intercept	8.7098	1.8400	4.7340	0.0000
EPAREG2	0.1454	0.1956	0.7430	0.4606
EPAREG3	0.4240	0.4647	0.9120	0.3658
LOPYR (ln)	0.8634	0.6163	1.4010	0.1673
LTPD (ln)	-0.1232	0.0863	-1.4270	0.1597
NCEN	-0.3154	0.1834	-1.7190	0.0916
SOU	-0.2660	0.1490	-1.7850	0.0802
WEST	-0.0167	0.2313	-0.0720	0.9428

LTPD = (ln) design tons per day of refuse processed when plant was built

LOPYR = (ln) vintage of facility (year commenced - 60)

REGION = DUMMY VARIABLE

NCEN = 1, if plant located in North Central Region [states below]; 0, if not

SOU = 1, if plant located in South [states below]; 0, if not

WEST = 1, if plant located in West [states below]; 0, if not

EPA Regulatory Period = DUMMY VARIABLE

EPAREG2 = 1, if plant commenced operations between 1982 and 1990; 0, if not

EPAREG3 = 1, if plant commenced operations in 1991 or later; 0, if not

Notes: • Residual Standard Error: 0.40168 with 51 degrees of freedom. • Multiple R-Squared: 0.2930.

• F-Statistic: $f = 3.01944$ on 7 and 51 degrees of freedom. • the Pr (>f) is 0.0099.

Northeast: Connecticut, Massachusetts, Maine, New Hampshire, New Jersey, New York, Pennsylvania, Rhode Island, Vermont
 South: Alabama, Arkansas, Delaware, District of Columbia, Florida, Georgia, Kentucky, Louisiana, Maryland, Mississippi, North Carolina, Oklahoma, South Carolina, Tennessee, Texas, Virginia, West Virginia
 North Central: Illinois, Indiana, Iowa, Kansas, Michigan, Minnesota, Missouri, Nebraska, North Dakota, Ohio, South Dakota, Wisconsin
 West: Alaska, Arizona, California, Colorado, Hawaii, Idaho, Montana, Nevada, New Mexico, Oregon, Utah, Washington, Wyoming

Source: Based on database developed by Governmental Advisory Associates (Westport, Connecticut).

relationship, while still positive, is not statistically significant for modular and RDF facilities when the sample is disaggregated. The results point to the effect of changing regulations and the increased capital investment necessary to meet air emissions and other environmental standards.

Furthermore, it appears that at least for mass burn facilities, EPA regulatory periods are significantly associated with total capital expenditures at a facility. Controlling for region and vintage, plant owners and operators invest more capital dollars in a facility as one moves across regulatory periods. However, at this point, it cannot be conclusively stated that capital cost increases are due to environmental regulation alone. The issue of regulatory impact remains highly complicated, given the fact that different firms will respond differently to the same set of regulations. One company may opt to stall, another to challenge the regulations in court, a third to comply in advance with potential change, a fourth to close the facility.

Several secondary conclusions are also evident. Particularly with mass burn facilities, some indications of

scale economies are present. In both regressions using initial capital costs and total capital costs, size of the plant was significantly related to cost and carried a negative coefficient. Thus, as design tonnage increased, costs tended to decrease, holding all other factors constant. Furthermore, the study shows that plants with different technologies behave differently over time. Confronted with regulatory hurdles, the mass burn projects have tended to integrate changes into their capital base, despite higher average capital costs that have resulted. Modular plants, however, have opted to cease operations. Currently, across all technologies, construction of new facilities has slowed nearly to a halt. Looking to the future, mass burn and RDF projects may begin to drop out in greater numbers, mimicking the behavior of the modular projects.

To reach a firm conclusion about the direct impacts of regulation and other factors, additional data on both capital and operating costs of municipal waste combustion projects is necessary. Both capital and operating costs must be documented in a consistent manner across the facilities selected, and precise dates of capital

Table 14. Log Linear Regression Results Using Capital Profile Estimates of Municipal Waste Combustion Facilities: RDF

Coefficients	Value	Std. Error	T Value	Pr(> t)
Intercept	-5.4745	6.6658	-0.8210	0.4192
EPAREG2	-1.6887	0.8736	-1.9330	0.0646
EPAREG3	-1.6308	1.4006	-1.1640	0.2553
LOPYR (ln)	5.1677	2.2352	2.3120	0.0293
LTPD (ln)	0.1901	0.1468	1.2950	0.2071
NCEN	-1.2188	0.4208	-2.8970	0.0077
SOU	-0.1640	0.5219	-0.3140	0.7560
WEST	-1.5653	0.6024	-2.5980	0.0155

LTPD = (ln) design tons per day of refuse processed when plant was built

LOPYR = (ln) vintage of facility (year commenced - 60)

REGION = DUMMY VARIABLE

NCEN = 1, if plant located in North Central Region [states below]; 0, if not

SOU = 1, if plant located in South [states below]; 0, if not

WEST = 1, if plant located in West [states below]; 0, if not

EPA Regulatory Period = DUMMY VARIABLE

EPAREG2 = 1, if plant commenced operations between 1982 and 1990; 0, if not

EPAREG3 = 1, if plant commenced operations in 1991 or later; 0, if not

Notes: • Residual Standard Error: 0.94926 with 25 degrees of freedom. • Multiple R-Squared: 0.4541.

• F-Statistic: $f = 2.97038$ on 7 and 25 degrees of freedom. • the $Pr(>f)$ is 0.0207.

Northeast: Connecticut, Massachusetts, Maine, New Hampshire, New Jersey, New York, Pennsylvania, Rhode Island, Vermont

South: Alabama, Arkansas, Delaware, District of Columbia, Florida, Georgia, Kentucky, Louisiana, Maryland, Mississippi, North Carolina, Oklahoma, South Carolina, Tennessee, Texas, Virginia, West Virginia

North Central: Illinois, Indiana, Iowa, Kansas, Michigan, Minnesota, Missouri, Nebraska, North Dakota, Ohio, South Dakota, Wisconsin

West: Alaska, Arizona, California, Colorado, Hawaii, Idaho, Montana, Nevada, New Mexico, Oregon, Utah, Washington, Wyoming

Source: Based on database developed by Governmental Advisory Associates (Westport, Connecticut).

additions and changes and reasons for these changes would have to be provided

However, even if such data became available, the application of a traditional cost function raises a number of issues, which have been mentioned throughout this document. Most notably is the modeling of firm behavior with respect to the decision to retrofit, replace equipment, or exit the industry entirely due to the impact of the cost of EPA regulations on profitability. If two firms are identical with exact cost structures, and if one firm opts to replace equipment and upgrade in response to regulations and the other decides not to replace equipment, then the two firms become different and this divergence must be measured. This difference could be due to geographic location, variations in the regional energy market, or external factors.

A second major issue discussed is the measurement of outputs of a municipal waste combustion facility. A cost function relates unit inputs (capital and labor) to unit outputs. Defining outputs of a municipal waste combustion project is made more complicated by the fact

that there are two outputs directly related to each other. The first is energy, be it electricity or steam. The second is waste disposal, or tons of waste diverted from other forms of disposal. Standard methods of estimation would have to be adjusted to account for the multiple output problem.

A third issue is the modeling of the entire pollution control process and level of outputs. There are, after all, various technologies and approaches addressing pollution reduction. Emissions reduction and technological change, with attendant changes in levels of input and output with respect to air pollution control, are a third output of a municipal waste combustion project. These inputs and outputs must be included or accounted for in a cost estimation function.

This paper has raised initial methodological issues and identified further work that must be done to model the economic behavior of these unique types of facilities. Hopefully, additional research will be conducted, which will shed further light on the relationship between cost and regulation.

Appendix A. List of Projects Included in Sample

Table A1. List of Projects Included in Sample

Site	State	Technology	TPD	Year Begun	Year Closed
Adirondack Resource Recovery Facility	NY	MB	400.00	1992	
Akron	OH	RDF	1,000.00	1979	1995
Alaska Solid Waste	AK	RDF	200.00	1991	1995
Albany (Answers)	NY	RDF	800.00	1981	1995
Albany Steam Plant	NY	MB	600.00	1981	1994
Alexandria/Arlington	VA	MB	975.00	1988	
Ames	IA	RDF	200.00	1975	
Anoka County, Elk River	MN	RDF	1,500.00	1989	
Auburn	ME	MOD	200.00	1981	1990
Auburn-(Mid-Maine Waste Action)	ME	MB	200.00	1992	
Babylon	NY	MB	750.00	1989	
Baltimore (Monsanto)	MD	Py	1,000.00	1976	1981
Baltimore County	MD	RDF	1,200.00	1976	1991
Barron County	WI	MOD	80.00	1986	
Batesville	AR	MOD	100.00	1981	1996
Bay County Energy System	FL	MB	510.00	1987	
Bellingham/Femdale	WA	MOD	100.00	1986	1997
Blytheville	AR	MOD	70.00	1975	1980
Braintree	MA	MB	240.00	1970	1983
Bridgeport RESCO	CT	MB	2,250.00	1988	
Bristol	CT	MB	650.00	1988	
Broward County-North	FL	MB	2,250.00	1991	
Broward County-South	FL	MB	2,250.00	1991	
Camden	NJ	MB	1,050.00	1991	
Carthage/Panola	TX	MOD	40.00	1986	
Cassia County	ID	MOD	50.00	1980	1991
Cattaraugus County	NY	MOD	112.00	1983	1992
Center	TX	MOD	40.00	1986	
Central Mass, Millbury	MA	MB	1,500.00	1988	
Charleston County	SC	MB	644.00	1989	
Chicago NW	IL	MB	1,600.00	1970	1996
Cleburne	TX	MOD	115.00	1986	
Collegeville (St. John's University)	MN	MOD	65.00	1981	1987
Columbus	OH	RDF	2,000.00	1984	1995
Commerce	CA	MB	360.00	1987	
Concord Regional	NH	MB	500.00	1989	
Crossville	TN	MOD	60.00	1978	1980
Dade County	FL	RDF	3,000.00	1986	
Davis County	UT	MB	400.00	1988	
Delaware County	PA	MB	2,688.00	1992	
Delaware Reclamation	DE	RDF	1,000.00	1984	1993
Detroit	MI	RDF	4,000.00	1989	
Duluth	MN	RDF	400.00	1981	
Durham	NH	MOD	108.00	1980	1996

Table A1. List of Projects Included in Sample (Continued)

Site	State	Technology	TPD	Year Begun	Year Closed
Dutchess County	NY	MB	506.00	1988	
Dyersburg	TN	MOD	100.00	1980	1992
Easton WMS Town	PA	RDF	300.00	1986	1988
Essex County	NJ	MB	2,277.00	1991	
Fairfax County	VA	MB	3,000.00	1990	
Fergus Falls	MN	MOD	94.00	1988	
Fisher Guide	MI	MOD	100.00	1985	
Fort Dix	NJ	MOD	80.00	1986	
Fort Leonard Wood	MO	MOD	75.00	1982	1991
Fort Lewis	WA	MOD	120.00	1997	
Fort Rucker	AL	Py	50.00	1984	1988
Franklin	KY	MOD	75.00	1986	1988
Gahanna	OH	RDF	1,000.00	1981	1984
Galax	TN	MB	55.00	1986	1993
Gatesville	TX	MOD	13.00	1980	1991
Glen Cove	NY	MB	225.00	1983	1991
Gloucester Coun	NJ	MB	575.00	1995	
Hampton County	SC	MOD	270.00	1985	1993
Hampton/NASA	SC	MB	200.00	1980	
Harford County	MD	MOD	360.00	1993	
Harrisburg	PA	MB	720.00	1971	
Harrisonburg	VA	MOD	100.00	1982	
Haverhill & Lawrence RDF	MA	RDF	901.00	1985	1998
Haverhill (Mass Burn)	MA	MB	1,650.00	1989	
Heartland Recycling	IA	RDF	100.00	1988	1993
Hempstead	NY	MB	2,505.00	1989	
Harrisburg	PA	MB	720.00	1971	
Harrisonburg	VA	MOD	100.00	1982	
Haverhill & Lawrence RDF	MA	RDF	901.00	1985	1998
Haverhill (Mass Burn)	MA	MB	1,650.00	1989	
Heartland Recycling	IA	RDF	100.00	1988	1993
Hempstead	NY	MB	2,505.00	1989	
Hempstead (Parsons and Whittemore)	NY	RDF	2,000.00	1978	1980
Hennepin Energy	MN	MB	1,200.00	1990	
Henrico County	VA	RDF	250.00	1983	1988
Hillsborough County	FL	MB	1,200.00	1987	
Honolulu	HI	RDF	2,160.00	1990	
Humboldt	TN	RDF	50.00	1989	1992
Huntington	NY	MB	750.00	1991	
Huntsville	AL	MB	690.00	1990	
Indianapolis	IN	MB	2,362.00	1988	
Jackson County	MI	MB	200.00	1987	
Jacksonville Naval Air Station	FL	MOD	40.00	1980	1983
Johnsonville	SC	MOD	50.00	1981	1985
Kent County	MI	MB	625.00	1990	
Key West	FL	MOD	150.00	1986	
La Crosse County(French Island)	WI	RDF	400.00	1993	

Table A1. List of Projects Included in Sample (Continued)

Site	State	Technology	TPD	Year Begun	Year Closed
Lake County	FL	MB	528.00	1991	
Lakeland	FL	RDF	300.00	1983	
Lancaster County	PA	MB	1,200.00	1991	
Lane County	OR	RDF	500.00	1978	1982
Lee County	FL	MB	1,200.00	1995	
Lewisburg	FL	MOD	60.00	1980	1990
Lisbon	CT	MB	500.00	1995	
Long Beach	NY	MOD	200.00	1988	
MERC Biddeford	ME	RDF	607.00	1987	
MacArthur, Islip	NY	MB	518.00	1990	
Madison	WI	RDF	250.00	1979	1993
Marion County	OR	MB	550.00	1986	
Mayport Naval Station	FL	MOD	50.00	1979	1993
McKay Bay	FL	MB	1,000.00	1985	
Miami	OK	MOD	108.00	1982	1993
Miami International Airport	FL	MOD	60.00	1983	1991
Mid-CT-Hartford	CT	RDF	2,000.00	1988	
Milwaukee	WI	RDF	1,600.00	1977	1982
Montgomery County-Conshocken PA	PA	MB	1,200.00	1992	
Montgomery County-MD	MD	MB	1,800.00	1995	
Montgomery County (North)-OH	OH	MB	300.00	1987	1996
NHVT S.W. Project	NH	MB	200.00	1987	
Nashville	TN	MB	1,120.00	1974	
New Hanover County	NC	MOD	450.00	1984	
New York (Betts Ave.)	NY	MB	1,000.00	1965	1996
Newport News (Fl. Eustis)	VA	MOD	40.00	1980	1988
Niagara Falls	NY	MB	2,500.00	1980	
Norfolk MB	VA	MB	360.00	1967	1986
Norfolk Naval	VA	MB	160.00	1976	1986
North Andover	MA	MB	1,505.00	1985	
North Little Rock	AR	MOD	100.00	1976	1989
North Slope Borough	AK	MOD	100.00	1981	
Oceanside	NY	MB	750.00	1965	1984
Olmstead County	MN	MB	200.00	1987	
Oneida County	NY	MOD	200.00	1985	1995
Onondaga County	NY	MB	990.00	1995	
Osceola	AR	MOD	50.00	1980	
Oswego County	NY	MOD	200.00	1986	
PERC Orrington	ME	RDF	1,100.00	1988	
Palestine	TX	MOD	25.00	1980	1991
Palm Beach County	FL	RDF	2,000.00	1989	
Park County-Livingston	UT	MOD	75.00	1981	1986
Pascagoula	MS	MOD	150.00	1985	
Pasco County S.W.R.R.F	FL	MB	1,050.00	1991	
Perham	MN	MOD	116.00	1986	1998
Pidgeon Point	DE	MOD	600.00	1987	1993
Pinellas County	FL	MB	3,150.00	1983	

Table A1. List of Projects Included in Sample (Continued)

Site	State	Technology	TPD	Year Begun	Year Closed
Pittsfield	MA	MOD	240.00	1981	
Polk County	MN	MOD	103.00	1988	
Pope-Douglas	MN	MOD	80.00	1988	
Portland	ME	MB	500.00	1988	
Portsmouth	NH	MOD	200.00	1982	1987
Ramsey/Washington	MN	RDF	1,200.00	1987	
Red Wing	MN	MOD	72.00	1982	
Robbins	IL	RDF	1,200.00	1997	1998
Robertson County	TN	RDF	50.00	1990	1995
Rochester (Monroe County)	NY	RDF	2,000.00	1979	1984
S.W.R.R.F. (Baltimore)	MD	MB	2,250.00	1985	
SEMASS	MA	RDF	1,800.00	1988	
SERRF	CA	MB	1,380.00	1988	
Salem	VA	MOD	100.00	1978	1994
Saugus RESCO	MA	MB	1,500.00	1974	
Savage (Richards Asphalt)	MN	MOD	57.00	1982	1995
Savannah	GA	MB	500.00	1987	
Siloam Springs	AR	MOD	18.00	1975	1980
Sitka	AK	MB	24.00	1985	1988
Skagit County	WA	MB	178.00	1988	1994
Southeast Resource Recovery Facility	CT	MB	600.00	1992	
Southeast Tidewater Energy Project	VA	RDF	2,000.00	1988	
Spokane	WA	MB	800.00	1991	
Springfield	MA	MOD	408.00	1988	
St. Croix County	WI	MOD	115.00	1987	1995
Stanislaus	CA	MB	800.00	1989	
Sumner County	TN	MB	200.00	1981	
Tacoma	WA	RDF	530.00	1979	1998
Tacoma Steam Plant #2	WA	RDF	300.00	1990	1998
Thief River Falls	MN	RDF	100.00	1985	1998
Tuscaloosa	AL	MOD	300.00	1984	1993
Union County	NJ	MB	1,440.00	1994	
University City	NC	MB	235.00	1989	1995
Wallingford	CT	MOD	420.00	1989	
Walter B. Hall	OK	MB	1,125.00	1986	
Warren Energy	NJ	MB	450.00	1988	
Waukesha	WI	MB	175.00	1971	1991
Waxahachie	TX	MOD	50.00	1982	1991
Westchester RESCO	NY	MB	2,250.00	1984	
Westmoreland County	PA	MOD	50.00	1988	
Wheelabrator Falls	PA	MB	1,500.00	1994	
Windham	CT	MOD	108.00	1981	1994
Yankton	SD	RDF	100.00	1989	1992
York County	PA	MB	1,344.00	1991	

MB = Mass Burn.

MOD = Modular.

RDF = Refuse-Derived Fuel.

TPD = Tons Per Day.

Appendix B. Rationale for the Use of a Capital Profile

The standard econometrics method employed in analysis of firm costs is estimation of the cost function.¹³ The basic premise is that the cost of production for a profit maximizing firm can be summarized as a function of input prices and output levels. Under certain restrictions, one can recover all information regarding production technology from such a function.¹⁴ To apply this methodology one must have observations on each of the input prices and output levels over a sequence of time periods.

MWC facilities present somewhat unique complications, which make the estimation of a cost function difficult. Unlike most firms, a municipal waste combustion facility has multiple outputs which are a) energy in the form of electricity or steam and b) the diversion of solid waste from alternative disposal sites. The levels of these outputs are not independent or even jointly produced by a single process. Kilowatt hours of electric power or pounds of steam generated by the facility depend directly on the quantity (and to some extent, the quality) of the material burned during the combustion stage. However, the quantity of material is also a measure of waste diversion or level of waste disposed. In equation form:

$$\text{Cost} = C(\text{wage}_{\text{Labor}}, \text{rent}_{\text{Capital}}, \text{Solid Waste}, \text{kWh}(\text{Solid Waste}))$$

The last term in the equation "(Solid Waste)," is in parenthesis to show the nesting of waste quantity in the quantity of energy produced. The interrelationship between the two terms makes estimation of this cost function more complicated than that of a single output or joint production from a single process.¹⁵ If it were possible to estimate a straightforward cost function, one could then derive the capital demand, as a function of input prices and output levels.

Estimation of a cost function presents a number of additional difficulties:

1. Detailed operating data on each facility do not exist. In particular, the series of rental rates for capital, i.e., the price per unit time of service of one year's worth of burning capacity for one ton per day, would have to be constructed from the raw data.
2. The owners and operators of the MWC facilities are sometimes public entities and may have objectives other than profit maximization.
3. The capital demand function derived from the cost function is the cost minimizing level of capital, which depends on the actual level of output, not productive or design capacity. However, capital additions for the purpose of air emissions reduction are based on the design capacity of the waste combustion boilers. Thus, if one uses actual output as an output measure, and therefore, a lower tonnage number than capacity, in conjunction with a capital cost that is dependent on design capacity, the effects of EPA regulations may be overstated.
4. No model or function relates time to regulatory changes. One needs to explicitly incorporate time into the estimation process to allow for the determination of any differential in capital cost between "pre-EPA" and "EPA" years. Normally, time may be associated with changes in the quality of inputs, technology changes, or productivity changes. In the case of MWC facilities and other like industries, time is also related to regulatory shifts.

¹³ This methodological approach was developed by Keith A. Heyen, Governmental Advisory Associates, Inc.

¹⁴ See, for example, Varian, H., *Microeconomic Analysis*, 3rd edition (New York, New York: W.W. Norton and Company, 1992).

¹⁵ Generation from a single process is generally assumed in applications where the outputs are similar in nature, e.g., local and toll service in telecommunications. See, e.g., Evans, D. S., and Heckman J.J., "Multiproduct Cost Function Estimates and Natural Monopoly Tests for the Bell System," In D. S. Evans, ed., *Breaking Up Bell* (Amsterdam, New York: North-Holland, 1983).

The Capital Profile Model

To address these problems it was deemed necessary to forgo direct estimation of the cost function and focus only on the capital equipment component. Actual capital purchased is substituted for capital required based on a level of inputs and outputs. One major drawback of this approach is that facilities may be overcapitalized due to tax or other investment incentives. Such overcapitalization may result in the purchasing of an excess of air pollution control equipment, since the level of pollution control is based on boiler design capacity and not actual tonnage throughput.

The information available on the capital stock includes two types of measures that contain random components: initial capital investment and additional capital investment. In each period, the firm (facility owner or operator) must decide if it is necessary to augment the capital stock and, if so, by how much. One such model for this process would take the following form:

Investment:

$$I_t = \begin{cases} C_t^* - C_t & \text{if } C_t < C_t^* \\ 0 & \text{if } C_t \geq C_t^* \end{cases} \quad (1)$$

Capital Stock:

$$C_t = C_{t-1} \cdot (1 - \delta(t, y)) + I_t$$

where,

C_t is the actual capital

C_t^* is the required capital, and is a function of capacity, technology type, year of initial operation, and EPA standards

δ = depreciation factor

y = initial time period of operation

t = current time period

C_t^* represents the physical capital necessary to achieve energy production (and waste diversion) at levels up to the design capacity of the facility for a given technology type and vintage and to meet EPA emissions standards

at time t . The initial capital investment (and, therefore, capacity) decision is not explicitly modeled, since that decision depends on local waste disposal needs and landfill availability. What is of interest for the present purposes is an estimate of

$$\left. \frac{\partial C_t^*}{\partial t} \right|_{\substack{\text{technology} \\ \text{start year} \\ \text{capacity}}}$$

Specifically, one seeks to observe the change in capital investment per facility, given its technology, design capacity, and the year it began its operation.

The above model does not allow the making of definitive statements regarding a causal relationship between EPA emissions standards and firm capital costs. Rather, the goal is to find evidence of an association between the two.¹⁶ As mentioned above, the limitations inherent in survey data and the irregular sampling interval of this particular survey required the researchers to abstract from the model described above.¹⁷ The simplified structure entailed construction of a sequence of actual capital stock dollar figures, C_t . This sequence is used as the dependent variable in a regression in order to estimate the change of capital expenditures over time, controlling for technology type and capacity, as an approximation to the slope of interest as follows:

$$\left. \frac{\partial C_t}{\partial t} \right|_{\substack{\text{technology} \\ \text{start year} \\ \text{capacity}}}$$

The regression methodology employed herein is based on several important assumptions:

1. As of the time period of interest, 1980-1998, EPA regulations, particularly in the latter period, incorporated the concept of "Best Available Control Technology" (BACT) type and have a direct effect only on the capital equipment necessary for operation. Neither technology type nor capacity is affected by the type of air pollution control equipment selected.

¹⁶ What would be required to test claims of causality is a structural model of the decision process at the firm level. See Rust, John P., "Optimal Replacement of GMC Bus Engines: An Empirical Model of Harold Zurcher," *Econometrica*, Vol. 55, No. 5, 1987, and Kennet, D. Mark, "A Structural Model of Aircraft Engine Maintenance," *Journal of Applied Econometrics*, Vol. 9, 1994, for examples of these kinds of structural models of capital equipment used in production processes.

¹⁷ More precisely, estimation of this model would require annual observations on those factors that affect C_t^* . The resulting stochastic specification of C_t would generate some form of a discrete/continuous choice model. The discrete component being whether or not to invest and the continuous component would be the amount of additional investment. The structure of such models is discussed in, e.g., Heyen, K.A., "Semiparametric Estimation of Discrete/Continuous Choice Models," Ph.D. dissertation, University of Wisconsin - Madison, 1992.

2. The expenditure on additional equipment to meet EPA standards depends only on the design combustion capacity of boilers at the facility.
3. The combustion technology has not changed in any substantial way over the time period of interest.¹⁸
4. The technologies employed at the facilities can be divided into three groups: mass burn, modular, and refuse-derived fuel. Within each group the firms differ only by number of years in operation, initial year of operation, and capacity.
5. Firms invest in capital equipment to expand capacity, replace deteriorated equipment or to modify current facilities to meet EPA emissions standards.

Assumptions (1) and (2) imply that the type of additional capital investments for the purpose of meeting EPA standards will be relatively narrow for a given facility, since it is determined by the principle of best available technology.¹⁹ Assumptions (3) and (4) allow for treatment of all facilities in the same vintage/year cohort as similar. Facilities are only allowed to differ over a small number of characteristics. In addition, assumptions (1) through (3), incorporate the notion that replacement investment does not materially affect productivity or capacity.

Underlying these assumptions is the contention that a facility is not reinvesting to lower costs or to increase productivity. Rather, reinvestment occurs to replace worn out equipment or to incorporate additional pollution control systems. A firm's decision to enter or to exit the business is not considered here, and its decision to operate in a given period is predicated on the expected profitability of the facility during that period. Under the model presented here, if a firm operates profitably, the capital investment amount during that period is determined by the vintage of the facility, the need to replace equipment, and the prevailing pollution control regulations.

Under these assumptions, it is reasonable to consider the time path of the capital stock for each facility. In the

present setting, one is interested in the quantity of physical capital in dollars expended that is required to produce some level of output at each point in time and in changes to this investment amount over time, adjusting for normal depreciation and inflation. The concept of a capital profile is borrowed from the labor economics literature, wherein the researcher is interested in construction of an earnings profile or path over time for an individual. This profile is then analyzed, assessing the impact of education, experience and other demographic or socio-economic factors on the level of earnings. The objective is to characterize and test for changes in the slope of the profile over time.

Applying this concept to MWC facilities, one assesses changes in capital expenditures over time. If the slope is positive, i.e., there is increased expenditure per unit capacity over the range of years in which EPA regulations forced a modification of facilities, holding constant the technology type and age of the facility, then there is an indication of an impact of regulation on capital spending. The positive slope does not provide conclusive evidence, but points to the EPA regulations as a possible cause for increasing capital outlays on the facilities.

To make meaningful comparisons between firms of various sizes, it is necessary to construct the capital profile on a per unit of output capacity basis. This enables one to superimpose time paths for large and small facilities on the same diagram. If there exist increasing returns to scale effects, this should appear as the larger firm having the lower capital/unit capacity profile. To distinguish replacement investment from net additions to capital, a method for accounting for capital depletion is needed. The industry standard is to use a boiler lifetime of 25 years, so a straight-line depreciation factor of 0.04 was used.²⁰ To obtain a measure of capital equipment in place, a price index for energy facility construction is used to deflate expenditures.

The method for construction of the capital profile is summarized as:

$$C_t = \sum_{j=0}^J \frac{I_j}{P_{t_j}} \cdot [1 - \delta \cdot (t - t_j)] \quad (2)$$

¹⁸ This statement refers to efficiency at the combustion stage. It is assumed that new designs incorporate the current emissions control technology and are more efficient when considering both outputs (combustion and emissions).

¹⁹ A structural model of capital investment would include expectations of future emission standards. The BACT assumption and uncertainty about innovations in emissions control technology make long-term planning difficult to model in this context. The planning aspect is ignored so firms make year-to-year decisions.

²⁰ One might consider the use of a straight-line method to be inappropriate in this case because tax incentives and accelerated depreciation methods were available for use by the firms. These considerations are important for the viability decision by the owners. Once the decision to operate is made, what is needed here is the most accurate measure of actual physical capital in place at each point in time.

where,

J = the number of additional capital investments

I_j = j^{th} investment, I_0 is the initial investment

t_j = year of investment j

P_{t_j}

= ENR Building Price Index for time period t_j

δ = constant depreciation factor

As an example, consider a facility in which there is an initial investment of \$1,000 and one subsequent addition of \$500 in the next year using 0.10 as the depreciation factor over a period of 4 years. If the price index is 1.0 in the first year and 1.05 in the second, then the deflated amounts are \$1,000 and \$476.19, respectively. The capital profile would then be calculated as follows:

Year	Initial Investment	Depreciated Initial	Additional Investment	Depreciated Additional	Total Capital
1	1,000	1,000			1,000.00
2		900	476.19	476.19	1,376.19
3		800		428.57	1,228.57
4		700		380.95	1,080.95

The elements of the Total Capital column would then be divided by the design combustion capacity reported in the associated year.

The capital profiles of each facility, as constructed in the previous chart, were used as the dependent variable in a sequence of regressions. The estimation of a linear regression implies not only that the slopes are constant, but that the "scale effects" and number of years in operation move the capital profile up or down by a fixed factor over the entire time period. This is somewhat restrictive but does provide a good first look at the behavior of capital equipment in place.²¹

When viewing the regression results, it is important to understand that all the data points in the capital profile are not random. Equation (2) has "imputed" values for those time periods, t , where no additional investment is made.²² Specifically, actual data exist only for those years in which the facilities were surveyed. In non-survey years, cost values were imputed using the deflation and depreciation factor on the previously existing data point. Thus, the values of C_t in these time periods are deterministic, not missing. The resulting estimated function can not be interpreted as a conditional expectation function and should be regarded as a summary of the sample information on the shape of C_t . The standard summary statistics for the regressions are presented for completeness and to indicate "goodness of fit."

²¹ One strategy is to write the regression coefficients as functions of the initial year of operation. This approach is equivalent to working with cohorts. A problem associated with implementation of this method is the small number of facilities starting in most years.

²² There is a vast literature detailing the types of remedies for missing data. For a summary of the basic issues see, e.g., Greene, W.H., *Econometric Analysis* (Upper Saddle River, New Jersey: Prentice-Hall, 1997).

Forces Behind Wind Power

by Louise Guey-Lee

Introduction

In the past several years, a number of new wind farms have begun commercial operation. Industry sources have estimated that more than 900 megawatts (MW) of wind capacity was under construction in 1999. A major portion of this capacity was constructed outside of California, the birth place of the wind power industry in the United States.¹ While the economics of wind turbine technology is improving, it is generally not yet competitive with fossil fuels.² Just as the outlook for wind improves, it can also improve for other energy sources. Thus, despite the encouraging portrayal of wind turbines, they face uncertainty in the future. This paper looks at the forces behind recent wind energy development.

Current Status and Recent Events

In 1997, wind power generation capacity of 1,579 MW produced 3,254,117 megawatt-hours (MWh) of electricity.³ More than 99 percent of generation was by independent power producers, and nearly all of it was located in California. During 1998 and 1999, wind farm activity expanded into other States, motivated in part by financial and regulatory incentives and, in the case of Iowa and Minnesota, State mandates. Iowa, Minnesota, and Texas each had capacity additions exceeding 100 MW that came on line in 1999 (Table 1). During 1999, wind farm capacity that came on line consisted of state-of-the-art wind turbines manufactured primarily by

Zond, a subsidiary of Enron Wind Corporation (392 MW); NEG Micon (325 MW); and Vestas (159 MW).⁴ Less than 32 percent of new wind power construction was located in California in 1999.

A number of recent events have triggered an interest in wind energy. Significant interest has arisen in the ability of renewable energy to survive as a viable energy source, compared with less expensive fossil fuels, as the electric power industry moves from a regulated to a competitive environment. Because renewable energy sources are generally perceived to be more environmentally benign than other energy sources, much recently enacted and/or proposed Federal and State legislation on electric competition contains provisions encouraging consumption of renewable energy. Hence, in those instances, electric restructuring may actually promote renewable energy use rather than restrain it. Wind energy, which is more economically competitive than most other renewable energy options, should benefit most from this effort.

Another event that increased interest in wind energy was the expiration of the federal production tax credit for any projects beginning operation after June 30, 1999. This tax credit was established by the Energy Policy Act of 1992 and provided a 1.5 cent per kilowatt-hour tax credit for the first 10 years of the project's life. Since all projects in operation by June 30, 1999, would be eligible for the tax credit, most of the capacity that came on line in 1999 came on by that date. Although the credit

¹ For a brief history of early developments in the wind power industry, see "Wind Energy Developments: Incentives in Selected Countries," in Energy Information Administration, *Renewable Energy: Issues and Trends 1998*, DOE/EIA-0628(98) (Washington, DC, March 1999). In the early years the Public Utility Regulatory Policies Act of 1978 (PURPA) was instrumental in creating a market for renewable power. It required utilities to purchase power from qualified facilities (including renewable nonutility generators) at prices that were more favorable than they are today. Now some restructuring proposals advocate repeal of PURPA in the belief that PURPA's provisions are inconsistent with the move to competitive electric markets.

² For a complete assessment and assumptions, see Energy Information Administration, *Annual Energy Outlook 2000*, DOE/EIA-383 (2000) (Washington, DC, December 1999).

³ Energy Information Administration (EIA), *Renewable Energy Annual 1999 With Data for 1998*, DOE/EIA-0603(99) (Washington, DC, March 2000), Tables 4 and 5. See the EIA website http://www.eia.doe.gov/cneaf/solar.renewables/rea_data99/rea_sum.html (January 2001). Electric utilities had wind net generation of 5,977 megawatt-hours and nonutilities had wind gross generation of 3,248,140 megawatt-hours in 1997.

⁴ American Wind Energy Association, "Wind Energy Projects Throughout the United States." See website <http://www.awea.org/projects/index.html> (July 7, 2000).

actually expired, it was reinstated in December 1999, it is retroactive to July 1999, and extends until the end of 2001. The current schedule for new capacity is less ambitious than 1999, but substantial (Table 1). A total of nearly 400 MW of new wind power construction (including a significant share of repowered capacity in California) was expected for 2000.

Additionally, in June of 1999, the Secretary of Energy announced the start of a new initiative, "Wind Powering America." The stated goal of this program is to have 80,000 MW of wind power generation capacity in place by 2020 and have wind power provide 5 percent of the Nation's electricity generation.⁵ Year-end 1998 wind power capacity was about 1,698 MW,⁶ so this goal represents an enormous increase in capacity additions. The initiative is mentioned here because of its potential importance and the attention it is drawing to wind energy. However, the full impact of the program on wind energy will be over the long-term future and is a concern more so for the Energy Information Administration's (EIA) *Annual Energy Outlook*, and less so for this paper, which covers the recent past and near-term future.⁷

Another long-term impact on renewable energy sources is concern over global warming and formulating a policy to reduce greenhouse gases in accordance with the Kyoto Protocol. A United Nations conference with representatives from more than 160 countries met in Kyoto, Japan, in 1997 to negotiate binding limits for greenhouse gas emissions for developed nations. Carbon dioxide is the major greenhouse gas. The target for the United States is to reduce carbon dioxide to 7 percent below 1990 levels in the 2008-2012 time frame. Adopting a carbon tax to accomplish this goal would increase the price of fossil fuels (particularly coal) but have little impact on the cost of renewables, which have zero or net zero carbon dioxide emissions. Assuming a carbon tax is imposed, analysis indicates that an increase in the consumption of renewable energy, led by wind, would make a significant contribution to achieving the targeted level of reduced emissions.⁸ The next United Nations Conference of Parties (COP) meeting to develop strategies to achieve the goals of the Kyoto Protocol was held in November 2000 in the Hague, Netherlands.⁹ No

significant agreement was reached at that time, but future meetings are expected.

Table 1. United States Wind Energy Capacity by State, 1998, and New Construction, 1999 and 2000 (Megawatts)

State	Existing ^a 1998	New Construction	
		1999	2000
Alaska	*	.58	.10
California	1,487	^b 290.33	^b 208.50
Colorado	0	16.00	0
Hawaii	20	0	39.75
Iowa	*	237.45	0.60
Kansas	0	1.50	0
Maine	0	0	6.10
Massachusetts	*	0	7.50
Michigan	1	0	0
Minnesota	129	139.56	32.00
Nebraska	0	1.32	0
New Mexico	0	0.66	0
New York	0	0	18.15
Oregon	25	0	0
Pennsylvania	0	0	26.17
South Dakota	0	0	0.75
Tennessee	0	0	1.98
Texas	34	145.82	25.10
Utah	0	0	.23
Vermont	1	0	5.00
Wisconsin	0	21.78	0
Wyoming	1	71.25	28.12
Total	1,698	926.24	395.05

^a Defined as net summer capability.

^b Includes a substantial portion of repowered capacity.

* = Less than 0.5 megawatts capacity.

NA = Not available.

-- = Not applicable.

Sources: 1998 Capacity: Energy Information Administration, *Renewable Energy Annual 1999 With Data for 1998*, DOE/EIA-0603(99) (Washington, DC, March 2000) and New Construction: Based on data in American Wind Energy Association (AWEA), "Wind Energy Projects Throughout the United States," <http://www.awea.org/projects/index.html> (July 7, 2000).

⁵ For more details, see the Department of Energy's website for this initiative: <http://www.eren.doe.gov/windpoweringamerica>.

⁶ Energy Information Administration, *Renewable Energy Annual 1999 With Data for 1998*, DOE/EIA-0603(99) (Washington, DC, March 2000).

⁷ For an update on the status of the Wind Initiative's activities, see U.S. Department of Energy, *Wind Power Today*, DOE/GO-102000-0966 (Washington, DC, April 2000).

⁸ Energy Information Administration, *Impacts of the Kyoto Protocol on U.S. Energy Markets and Economic Activity*, SR/OIAF/98-03 (Washington, D.C., March 1998).

⁹ Energy Information Administration, *International Energy Outlook 2000*, DOE/EIA-0484(2000) (Washington, DC, March 2000).

This paper is divided into two main sections followed by an appendix. The first section includes a technical discussion of expectations for wind turbine performance and efforts to improve it. The second section provides an overview of the world in which the wind power industry is developing. This discussion includes a broad view of the impact of electric power industry restructuring, as well as Federal and State incentives. These two main sections are supplemented by an Appendix of State Wind Profiles that takes a snapshot of the status of electricity restructuring in each State, the type of incentives or green power programs available to wind, and status of wind energy development through 2000. References are included so more current information can be obtained as needed.¹⁰

Wind Turbine Performance

The following sections provide an overview of the turbine technology being installed in today's wind farms. These turbines have generation capacities at or above 225 kilowatts (kW).¹¹ The discussion examines (1) wind resource issues and related siting considerations, (2) factors affecting wind turbine performance, (3) physical and operational characteristics of wind farm turbines and (4) operation and maintenance (O&M) considerations. The discussion focuses on wind farm turbines manufactured by NEG Micon, Vestas, and Zond, as they represent most of new installed capacity in the United States. The discussion indicates that each of their designs is equally adaptable to a variety of wind farm sites. The discussion shows how O&M considerations can be managed to ensure that the cost of O&M for a wind farm can be controlled and minimized.

A major caveat in evaluating information presented in this section is the availability of data. Performance data on operating wind turbines are frequently proprietary and extremely closely guarded. Thus, although some historical data are available, the data used in this chapter are often based upon engineering sources and not actual commercial operational performance data.

Factors Affecting Wind Turbine Performance

*Wind Resources and Wind Turbine Machine Basics*¹²

Winds are created by atmospheric temperature and pressure variations caused by the sun heating air during the day, so general wind patterns coincide well with electricity demand during the daytime. During nighttime, temperature variations are lessened; therefore, winds are less severe. Although geostrophic winds (or global winds) determine the prevailing direction and magnitude in an area, the surface winds (up to an altitude of 100 meters) such as sea breezes and mountain winds are key factors in calculating the usable energy content of the wind at a particular site. Wind direction is influenced by the sum of global and local effects; when larger scale winds are light, local winds may dominate the wind patterns.

The wind resource is seldom a steady, consistent flow. It varies with the time of day, season, height above ground, and type of terrain. An area's surface roughness and obstacles are also important determinants in wind resource. High surface roughness and larger obstacles in the path of the wind result in slowing the wind by creating turbulence. Wind speed generally increases with height above ground.

A wind turbine converts the force of the wind into a torque (turning force) that turns the turbine blades, which are connected to the shaft of an electric generator. The amount of energy that the wind transfers to the blades depends on the density of the air, the blade area, and the wind speed. Wind speed determines how much energy is available for conversion to electricity. For wind farm applications, developers seek sites with an annual average wind speed of at least 7.0 meters per second (15.7 miles per hour), measured at a wind turbine hub height above ground of 50 meters (164 feet).

¹⁰ While this paper acknowledges the importance of some obstacles to the development process, such as congestion on the transmission and distribution system and mitigation of environmental problems (avian mortality, noise and visual obstruction), the paper will focus on elements that support development rather than those that deter it. The latter issues are the subject of future study.

¹¹ American Wind Energy Association, "Wind Industry Members Directory: Wind Turbine Manufacturers and Dealers." See website <http://www.awea.org/directory/wtgmfr.html> (October 2000). Vestas has a 225 kW turbine.

¹² Unless noted otherwise, based on information in Danish Wind Turbine Manufacturers Association, "Guided Tour on Wind Energy." See website <http://www.windpower.dk/tour/index.htm> (1999).

Wind power density, measured in watts per square meter of blade surface, is used to evaluate the wind resource available at a potential site. The wind power density indicates how much energy is available for conversion by a wind turbine. The power available at a given wind speed varies with the cube (the third power) of the average wind speed.¹³ Wind power developers think in terms of ranges of wind power density, termed wind power classes. Sites with a wind power class rating of 4 or higher are preferred for large-scale wind plants (see Table 2), which have installed capacity of at least 10 MW.¹⁴ For any given wind power class, the wind power density range and wind speed range increases with hub height; a hub height of 50 meters is the approximate hub height for utility-scale turbines. For instance, NEG Micon turbine hub heights range from 40-55 meters for 600 kW and 750 kW turbines, to 49-80 meters for their 900 kW to 1.5 MW turbines.¹⁵ Depending on rotor diameter, Vestas turbine hub heights range from 35-65 meters for their 600 kW and 660 kW models, to 60-100 meters for their 1.5 MW and 1.65 MW models.¹⁶ The Zond turbine hub height is 53 meters for their 750 kW turbines, with an optional 65 meter height for the 48 meter and 50 meter rotor diameter versions of the 750 kW turbine.¹⁷

The goal of wind turbine design is to convert as much of the power in wind, illustrated by the wind power classes in Table 2, into turbine generator power output. The power curve for a wind turbine shows this relationship of wind speed to turbine power output by plotting turbine power output (e.g., kilowatts) as a function of wind speed (e.g., meters per second). Power curve values vary among turbines because turbine design approaches differ. The impact of design on power curve values is illustrated by comparing the wind speeds at which various turbines achieve rated power. For instance, the Zond Z-48 turbine achieves 750 kW rated power output at a lower wind speed (11.6 meters/second) than does the NEG Micon Multi-power 48 (16 meters/second) (Table 3). The shape of the power curve also varies with turbine design. For instance, the NEG Micon Multi-power 48, which uses a generator that operates at constant speed, produces less than 750 kW output at wind speeds less than or greater than 16 meters/second (Table 3), the speed at which it achieves

Table 2. Definition of Classes of Wind Power Density for 50 Meter (164 Feet) Hub Height

Wind Power Class	Wind Power Density (W/m ²)	Speed ^a m/s (mph)
4	400 - 500	7.0 (15.7) - 7.5 (16.8)
5	500 - 600	7.5 (16.8) - 8.0 (17.9)
6	600 - 800	8.0 (17.9) - 8.8 (19.7)
7	> 800	> 8.8 (19.7)

^aMean wind speed is based on the Rayleigh speed distribution of equivalent wind power density. Wind speed is for standard sea-level conditions. To maintain the same power density, speed increases 3 percent /1000 m (5 percent/5000 ft) of elevation.

W/m² = Watts per square meter.

Notes: Vertical extrapolation of wind speed from 10 meter baseline height based on the 1/7 power law.

Source: D.L. Elliott, C.G. Holladay, W.R. Barchet, H.P. Foote, W.F. Sandusky, *Wind Energy Resource Atlas of the United States*, DOE/CH 10093-4 (Washington, DC, October 1986), Table 1.1.

rated power. In contrast, the variable speed generator used in the Zond Z-48 design enables the turbine to maintain rated output of 750 kW over the range of wind speeds listed in Table 3, starting with 11.6 meters per second (the speed at which it first achieves 750 kW output), because the generator speed varies with wind speed to maintain rated output. Power output per unit of rotor swept area offers a way to compare performance among wind turbines. Restated, the goal of wind turbine design is to obtain the highest value of power output per unit of rotor swept area (Table 3) for the lowest capital cost.

Siting Factors Affecting Wind Turbine Performance

Several performance factors contribute to the selection of a wind farm site. Choosing a terrain with the least number of obstacles, least roughness, and the most expansive views is generally a good practice. The orientations of trees and shrubs and erosion patterns along a terrain provide clues to prevailing wind directions.

¹³ E. Eggleston, American Wind Energy Association, "Wind Energy FAQ: How Can I Calculate the Amount of Power Available at a Given Wind Speed?" See website <http://www.awea.org/faq/windpower.html> (February 1998).

¹⁴ Personal communication between Donald M. Hardy, PanAero Corporation (Lakewood, CO) and William R. King, SAIC, 1999.

¹⁵ NEG Micon turbine specifications. See website <http://www.awea.org/directory/negmicon.html> (October 23, 2000).

¹⁶ Vestas turbine specifications. See website <http://www.awea.org/directory/vestas.html> (October 23, 2000).

¹⁷ Enron Wind Corporation turbine specifications. See website <http://www.awea.org/directory/enronwind.html> (October 23, 2000).

Table 3. Utility-Scale Wind Turbines—Performance Comparison

Turbine Manufacturer/ Model (Rotor Diameter/ Rated Power)	Rotor Swept Area (m ²)	Power Output (kW)					Power Output/Rotor Swept Area (W/m ²)				
		Wind Speed (meters/second)					Wind Speed (meters/second)				
		11.6	14	15	16	17	11.6	14	15	16	17
NEG Micon/Unipower 64 NM 1500C/64 (64 meters/1500 kW)	3,217	1,168	1,490	1,542	1,562	1,564	363	463	479	486	486
Vestas/V66 (66 meters/1650 kW)	3,421	1161	1,549	1,616	1,641	1,650	339	453	472	480	482
NEG Micon/Multi-power 48 NM 750/48 (48.2 meters/750 kW)	1,824	610	730	746	750	745	334	400	409	411	408
Vestas/V47 (47 meters/660 kW)	1,735	569	651	660	660	660	328	375	380	380	380
Zond/Z-48 (48 meters/750 kW)	1,810	750	750	750	750	750	414	414	414	414	414

m² = Square meters

W/m² = Watts per square meter

Source: NEG Micon, Vestas, and Zond wind turbine specification sheets for design information (rotor diameter, swept area, and rated power output). Power output at different wind speeds from manufacturer contacts, 1999.

Meteorological data, preferably spanning periods greater than 20 years, are used to screen potential sites. Meteorologists collect wind data for weather forecasts and aviation, and that information is often used to assess an area's potential for wind energy. However, wind speeds and wind energy are not measured with great enough precision when monitored for weather forecasting to enable placement of turbines within a site. For example, wind speed is influenced by surface roughness, obstacles, and contours of the local terrain. The impact of these factors may be estimated when screening for potential wind farm sites.

Land conditions, which affect the cost of site preparation, are a factor in wind farm economics and in site selection. The earth must be able to withstand the combined weight of a tower foundation and the tower, turbine, and rotor. The earth and geography leading to and including the site must be accessible to large, heavy trucks and cranes used to haul wind turbine components on to the site and to install the turbines. The cost of building a road to the site must also be factored into site selection.

Connection to the electric grid presents other issues that must be addressed when choosing a wind farm site. Grid connection may be a component of total project

cost, depending on the terms of the wind electricity purchase agreement between the wind farm developer and the electric utility. For example, the Southwest Mesa Wind Energy Project in Texas uses 700 kW NEG Micon turbines, which produce 600 volt electricity.¹⁸ Electricity travels from the turbine to a field transformer to the wind farm substation to the utility transmission line. Therefore, the following transmission capital must be included in the project cost: field transformers, substation, and transmission lines to connect each element, ending with connection to the utility line. Congestion on the regional transmission system is also a consideration. It would be undesirable to locate a new wind farm where the transmission system would not accommodate the power generated.

Once a potential site is selected, meteorological data are measured at points within the site as part of wind turbine "micrositing." Micrositing refers to the actual placement of turbines within a wind farm site to optimize electricity production.

Capacity Factor

Capacity factor is defined as the actual annual wind farm energy output, in kilowatthours, divided by the rated maximum turbine output, in kilowatts, times 8,760

¹⁸ NEG Micon, Southwest Mesa Wind Energy Project: Development, Construction, and Installation of a 75 MW Wind Farm, video, 1999.

hours/year. For a 100 kW turbine producing 175,000 kWh in a year, the capacity factor would be:

Capacity Factor

$$\begin{aligned} &= ((175,000 \text{ kWh/year}) / (100 \text{ kW} \times 8,760 \\ &\quad \text{hours/year})) \times 100 \\ &= 20 \text{ percent} \end{aligned}$$

Factors affecting the magnitude of the capacity factor include wind resource intermittency, the wind farm site's wind speed distribution, turbine design, and turbine reliability. The degree of wind resource intermittency may vary both daily and seasonally. For a given turbine design, turbines sited where the wind resource is more intermittent will have a lower capacity factor. The wind farm site's wind speed distribution, and the associated average annual wind speed, affect annual electricity output. The annual electricity output for a wind turbine increases with average annual wind speed, since more hours of operation at a higher wind speed mean a higher average kilowatt power output from the turbine. Thus, for a given turbine design, wind farm sites with higher mean wind speeds have higher capacity factors. Historical data show wind farm capacity factors in the range of 25 percent to nearly 36 percent (Table 4). An objective of turbine design is to maximize annual power output, which would increase the capacity factor. Higher capacity factors, compared to Danish data and DOE 1997 baseline data for class 4 winds, are projected for the Zond Z-750 Series turbines (Table 4) because the Zond Z-750's variable speed generator design, taller tower, and larger rotor swept area enable a greater amount of wind energy to be converted to electrical energy. Finally, an increase in turbine reliability would be reflected in an increase in the capacity factor.

Annual electricity production can be estimated from the turbine's power curve, which plots kilowatt output as a function of wind speed.¹⁹ Alternatively, electricity production from wind turbines may be estimated by statistical means.²⁰

Contrary to conventional steam or nuclear power generation, the wind turbine with the larger capacity factor

may not have an economic advantage over a wind turbine with a lower factor. For example, compare two wind turbines with the same rotor diameter but different generator capacities in a location with daily wind gusts or seasonal wind variations that are above the mean daily or seasonal speed. The turbine with the larger generator may be more economical because it enables higher power output, thus more electricity, when the wind turbine can take advantage of higher wind speeds. This strategy would tend to lower the capacity factor, using less of the available capacity of a larger generator. However, the strategy is economical if the value of the electricity production can be increased more than the incremental cost of the larger turbine over a smaller capacity turbine. The value of the electricity depends on daily or seasonal variations in electricity price. For instance, increased electricity production from a larger turbine has more value if produced during peak, rather than off-peak, periods of a utility's load curve.

Physical and Operational Characteristics of Wind Farm Turbines

To understand the advances in wind farm technology, general knowledge of a wind turbine and its components is essential. Recent advances in component design in addition to site-specific optimization have been instrumental in improving energy output and reducing operation and maintenance costs. The text box that follows on page 84 provides a brief summary of the components in a wind turbine (see also Figure 1).

Physical Characteristics

During the past quarter century, extensive public- and private-sector efforts were made to optimize wind turbine design, including development of advanced rotor blade materials, design concepts, advanced turbine designs, and other wind energy conversion systems (WECS) components, such as towers.

This section discusses the results of these efforts and their impact on enabling wind farm developers to optimize WECS design based on site requirements. Information focuses on technology deployed by

¹⁹ Divide the kilowatt output that corresponds to the site's average wind speed by the turbine's rated maximum output to estimate a capacity factor. Then multiply the estimated capacity factor by 8,760 hours per year to estimate annual electricity production. This estimated value is somewhat lower than the actual annual production because any percent increase in wind speed above the mean results in a power of three increase in the wind turbine electricity output. See American Wind Energy Association, "Wind Energy FAQ: How Does a Wind Turbine's Energy Production Differ from Its Power Production?" See website <http://www.awea.org/faq/basicen.html> (October 23, 2000).

²⁰ The Weibull and Rayleigh probability density functions are commonly used to estimate annual electricity production when precise site data are lacking. Both distributions are variations of a bell curve. The Weibull distribution has two parameters: mean value and shape; the Rayleigh distribution is a Weibull distribution with the shape parameter equal to 2. See Danish Wind Turbine Manufacturers Association, "Describing Wind Variations: Weibull Distribution." See website <http://www.windpower.dk/tour/wres/weibull.htm> (October 23, 2000).

Table 4. Examples of Wind Farm Capacity Factors

Wind Farm Location (Developer)	Wind Farm Capacity (MW)	Turbine Manufacturer/ Model	Turbine Description			Capacity Factor (percent)
			Max. Power Output (kW)	Hub Height (m)	Rotor Swept Area (m ²)	
Denmark	27.6-28.8 ^a	Micon	600 ^b	40-70	1810-1452	28.5 (historical) ^c
Denmark	19	Vestas	500 ^d	40	1195-1521	25.2 (historical) ^e
Hypothetical, Class 4 Winds ^f	25	DOE 1997 baseline technology	500	40	1,134	26.2 (based on historical)
Hypothetical, Class 6 winds ^g	25	DOE 1997 baseline technology	500	40	1,134	35.5 (based on historical)
Storm Lake II, Iowa (Enron) ^h	80	Zond Z-750	750	63	1,963	32 (historical) 38 (projected)
Lake Benton I, Minnesota (Enron) ⁱ	107	Zond Z-750	750	51	1,810	28 (historical) 35 (projected)

^a"Wind Turbine Performance Summary," *WindStats Newsletter*, Vol. 11, No. 1 through 4, four consecutive quarters of data from winter 1998 through autumn 1998, wind farm section of tables with Danish data. During the winter 1998 and spring 1998 quarters, 46 turbines were operating. During the summer 1998 and autumn 1998 quarters, 48 turbines were operating.

^bNEG Micon. See website <http://www.negmicon.dk/English/products/> (November 1999). The 600 kW turbine comes in two rotor diameters: 48 meter (1810 m² swept area) and 43 meter (1452 m² swept area). Hub height options for the 48 meter model are 46 meters, 60 meters, and 70 meters. Hub height options for the 43 meter model are 40 meters, 46 meters, and 56 meters.

^c"Wind Turbine Performance Summary," *WindStats Newsletter*, Vol. 11, No. 1 through 4, four consecutive quarters of data from winter 1998 through autumn 1998, wind farm section of tables with Danish data. An annualized average capacity factor was calculated by averaging the four seasonal capacity factors provided in the *WindStats Newsletter*.

^dTurbine information for the Vestas 500 kW model from personal communication between Soren Christensen, Project and Sales Coordinator, Vestas-American Wind Technology, Inc., and William R. King, SAIC, November 1999. The 40-meter hub height is common in Denmark. The 500 kW turbine comes in three rotor diameters: 39 meters (1195 m² swept area), 42 meters (1385 m² swept area), and 44 meters (1521 m² swept area).

^e"Wind Turbine Performance Summary," *WindStats Newsletter*, Vol. 11, No. 1 through 4, four consecutive quarters of data from winter 1998 through autumn 1998, wind farm section of tables with Danish data. An annualized average capacity factor has been calculated by averaging the four seasonal capacity factors provided in the *WindStats Newsletter*.

^fU.S. Department of Energy (Office of Utility Technologies) and Electric Power Research Institute, *Renewable Energy Technology Characterizations*, TR-109496 (Washington, DC, December 1997), p. 6-12.

^gU.S. Department of Energy (Office of Utility Technologies) and Electric Power Research Institute, *Renewable Energy Technology Characterizations*, TR-109496 (Washington, DC, December 1997), p. 6-12.

^hAssumed Generation for Historical Capacity Factor: Energy Information Administration, Form EIA-900, "Monthly Nonutility Power Report," Other Data: Enron Wind Corporation. See website <http://www.wind.enron.com/newsroom/casestudies/stormlake.html> (October 23, 2000). Note: Historical capacity factor is preliminary, calculated with preliminary generation data for 12 consecutive months during 1999 and 2000.

ⁱAssumed Generation for Historical Capacity Factor: Energy Information Administration, Form EIA-900, "Monthly Nonutility Power Report," Other Data: Enron Wind Corporation. See website <http://www.wind.enron.com/newsroom/casestudies/lb1.html> (October 23, 2000). Note: Historical capacity factor is preliminary, calculated with preliminary generation data for 12 consecutive months during 1999 and 2000.

Source: Energy Information Administration.

Enron/Zond, Vestas, and NEG Micon, the current major wind farm developers in the United States.

Technology Advances for Improved Wind Farm Performance and Reliability. The current generation of utility-scale wind turbines uses technology developed over the past 20 years. Advances in technology have resulted in lower installed cost per kilowatt of a wind turbine, improved turbine performance, and improved turbine reliability and reduced maintenance cost.

Following are some of the major improvements that have made these benefits possible:

- **Airfoil Design.** Over the past 20 years, international research efforts have led to new airfoils designed specifically for horizontal axis wind turbines. In the United States, the Zond Energy Systems Z-750 series utility-scale turbines use airfoil designs developed at the National Renewable Energy Laboratory (NREL). The results of

Turbine Component	Function
Nacelle	Contains the key components of the wind turbine, including the gearbox, yaw system, and electrical generator.
Rotor blades	Captures the wind and transfers its power to the rotor hub.
Hub	Attaches the rotor to the low-speed shaft of the wind turbine.
Low speed shaft	Connects the rotor hub to the gearbox.
Gear box	Connects to the low-speed shaft and turns the high-speed shaft at a ratio several times (approximately 50 for a 600 kW turbine) faster than the low-speed shaft.
High-speed shaft with mechanical brake	Drives the electrical generator by rotating at approximately 1,500 revolutions per minute (RPM). The mechanical brake is used as backup to the aerodynamic brake, or when the turbine is being serviced.
Electric generator	Usually an induction generator or asynchronous generator with a maximum electric power of 500 to 1,500 kilowatts (kW) on a modern wind turbine.
Yaw mechanism	Turns the nacelle with the rotor into the wind using electrical or other motors.
Electronic controller	Continuously monitors the condition of the wind turbine. Controls pitch and yaw mechanisms. In case of any malfunction (e.g., overheating of the gearbox or the generator), it automatically stops the wind turbine and may also be designed to signal the turbine operator's computer via a modem link.
Hydraulic system	Resets the aerodynamic brakes of the wind turbine. May also perform other functions.
Cooling system	Cools the electrical generator using an electric fan or liquid cooling system. In addition, the system may contain an oil cooling unit used to cool the oil in the gearbox.
Tower	Carries the nacelle and the rotor. Generally, it is advantageous to have a high tower, as wind speeds increase farther away from the ground.
Anemometer and wind vane	Measures the speed and the direction of the wind while sending signals to the controller to start or stop the turbine.

similar research by European manufacturers are incorporated into the blade design of European turbines. NREL's airfoils, when used with stall-regulated turbines, have produced 23 percent to 30 percent more electricity annually in the field.

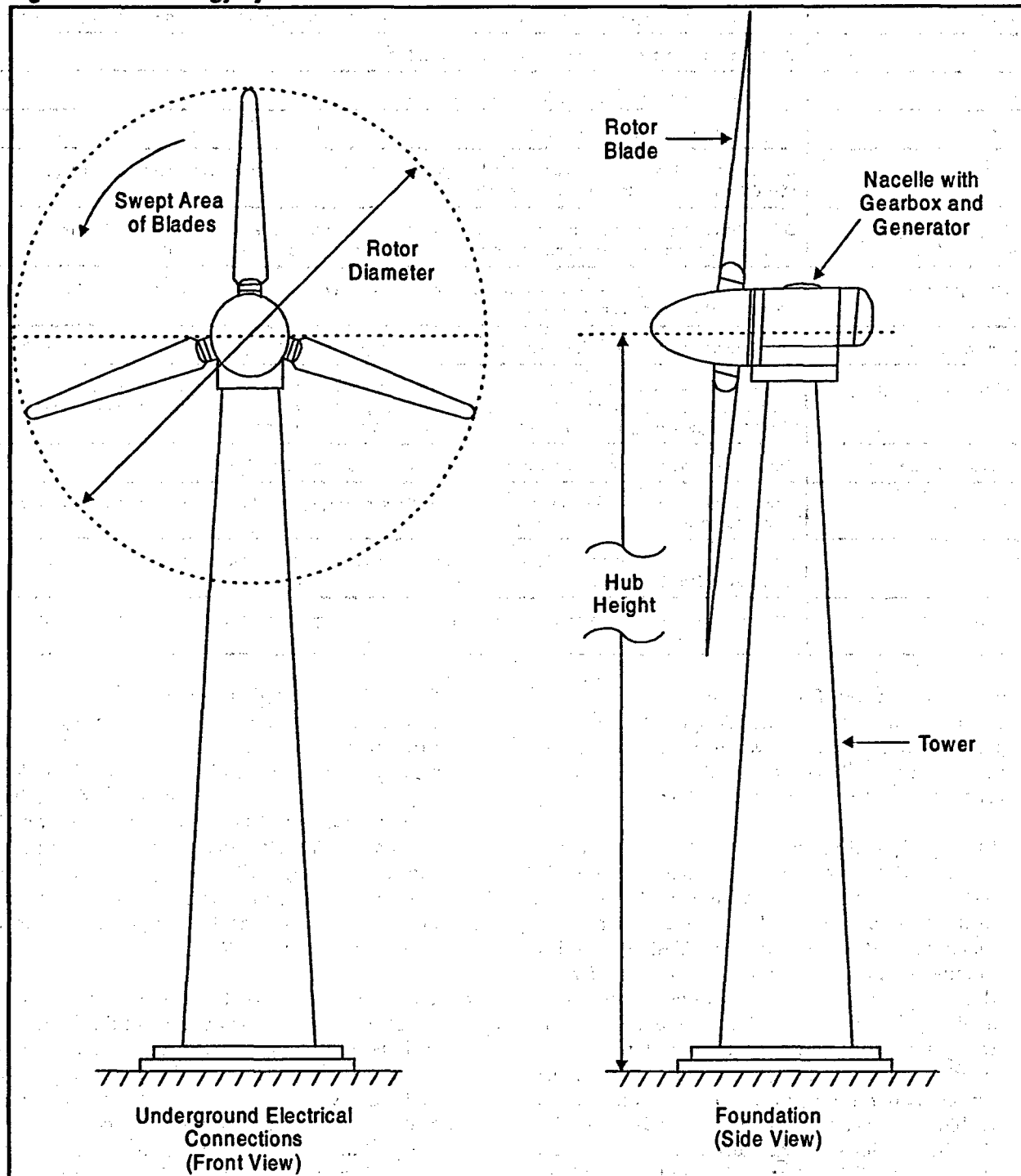
- **Structural Testing Improvements.** Structural test bed facilities have been constructed for full-scale testing of turbines. Tests are performed on prototypes to validate design assumptions, test materials, and make corrections. Testing includes fatigue testing, strength static testing, and non-destructive analysis such as photoelastic stress analysis. International efforts have resulted in safety and performance certification standards for wind turbines. In the United States, the Underwriters Laboratories, Incorporated (UL), certifies turbines using international standards issued by the International Electrotechnical Commission (IEC). The NREL National Wind Technology

Center has developed test procedures to assess compliance with standards. For instance, their test procedures to assess compliance with power quality, structural load, blade structural load, power performance, and noise standards have been accepted by the American Association of Laboratory Accreditors and by certifying parties throughout the world. Additionally, NREL has developed a wind turbine design evaluation quality system to enable design certification by international organizations.

- **Power Electronics Advances.** Power electronics enable variable speed operation of the Zond Z-750 turbine, improving electricity generation efficiency and reducing structural loads by allowing a lightweight, low-cost configuration. In both the United States and Europe, improvements in inverter design²¹ and smart controls and reduction of the cost of such components has contributed to

²¹ The inverter converts "direct current" (DC) to "alternating current" (AC). This is necessary in some turbine designs because variations in wind speeds can cause variations in the "frequency" (e.g., 60 cycles per second) of AC power production, which must be tightly controlled in order to be usable. In contrast, DC "power conditioning" issues are easier to manage. Therefore, wind turbines often convert AC-generated wind power to DC, condition it, and use the inverter to convert it back into AC electricity.

Figure 1. Wind Energy System Schematic



Source: Canada Center for Mineral and Energy Technology (Ottawa, Canada, 1999)

addressing power quality more cost-effectively. Remote access and control of wind systems via modem or satellite has also become common place in most sites.

- **Smart Aerodynamic Control Devices.** Smart, reliable controls reduce the likelihood that high winds and generator load loss will cause significant damage to turbines. In addition, such controls enable turbine operation to adapt to natural wind speed variations, insect-impact accumulations, and minor blade damage, which cause inefficient rotor output.
- **Modeling and Wind Characterization Capabilities.** New computer simulation codes allow a wide array of system architectures to be designed for various applications, while simulating results using local wind regimes for particular sites. Wind characterization has reached a greater degree of accuracy through the use of sophisticated instrumentation and monitoring capabilities.

Capability to Optimize WECS Design. Currently, European turbine manufacturers supply the majority of the world market for utility-scale wind turbines.²² Enron Wind Corporation's Zond Energy Systems subsidiary was the fifth largest manufacturer worldwide in 1999 with 9 percent of market. Zond is the only U.S. manufacturer presently manufacturing utility-scale turbines. Zond's Z-750 turbine is the first U.S. machine in several years to be installed in large numbers in wind power plants owned by independent power producers. Enron, which purchased Zond Energy Systems in California in 1996 and German manufacturer Tacke in 1997, has plans to develop a 1 MW next-generation turbine by 2002. In addition, another U.S. company, The Wind Turbine Company, has announced similar plans for a 1 MW machine. Both companies are developing their 1 MW-scale machines under DOE's Next-Generation Turbine Development Program.

The general trend is toward wind turbines with maximum power output of 1 MW or more. European firms—such as Danish companies Vestas and NEG Micon—currently have more than 10 turbine designs in the megawatt range with commercial sales. Due to decreasing wind development sites with adequate wind regimes on the landmass, Europe has recently focused on developing larger-than-megawatt turbines for offshore wind farms. Because expensive foundations are

required for offshore applications, the cost of such wind plants can be up to 30 percent higher. However, due to stronger winds offshore (as well as the water's smoother surface than land), the higher production will offset the higher installation costs over the life of the facility. Aside from this, Vestas and Micon still lead the markets in manufacturing advanced, land-based, utility-scale turbines. In 1999, Micon and Vestas were the number one and number two wind turbine manufacturers worldwide, sharing about 40 percent of the global market.²³

Wind turbine design is dictated by a combination of technology, prevailing wind regime, and economics. Wind turbine manufacturers optimize machines to deliver electricity at the lowest possible cost per kilowatthour (kWh) of energy. Design efforts benefit from knowledge of the wind speed distribution and wind energy content corresponding to the different speeds and the comparative costs of different systems to arrive at the optimal rotor/generator combination. Optimizing for the lowest overall cost considers design factors such as relative sizes of rotor, generator, and tower height. For example, small generators (i.e., a generator with low rated power output in kW) require less force to turn than larger ones. Therefore, fitting a large wind turbine rotor with a small generator will produce electricity during many hours of the year (harvesting energy at lower wind speeds), but will capture only a small portion of high-speed wind energy. Conversely, a large generator will be efficient at high wind speeds, but unable to turn at low wind speeds. For a given turbine rated output (e.g., 750 kW), rotor diameter can be a design variable, specifying a smaller rotor diameter for turbines that will operate at sites with high wind speeds. In addition, system design can be optimized further and performance efficiency can be increased with innovative tower design, increased tower height to 50-70 meters (which increases energy output), and lighter weight turbines.

In general, most utility-scale wind turbines on the market today are three-bladed systems that use asynchronous generators and sophisticated controls to monitor and regulate turbine operation in different conditions and the quality of power delivered to the grid. The following synopses provide a general overview of the current technologies utilized by the three major utility-scale wind turbine manufacturers to optimize design.²⁴ NEG Micon has the simplest design while Zond the most complex design:

²² BTM Consult ApS, *International Wind Energy Development-World Market Update 1999* (Aalborg, Denmark, March 2000), p. 15.

²³ *Ibid.*, p. 15.

²⁴ Information is based on manufacturer literature and on personal communications between Donald M. Hardy, PanAero Corporation (Lakewood, CO) and William R. King, SAIC, 1999.

- **NEG Micon.** This design approach is the simplest of the three major manufacturers; the basic design is about 20 years old. The blades have a fixed pitch and rotate at a constant speed (fixed rpm). Parts are bolted to the frame in a way that makes it easy to remove and replace a part. The turbine is connected directly to the electricity grid. The power flowing through the grid is used to maintain a constant turbine speed through electromechanical means.
- **Vestas.** This turbine has a variable pitch design; a computer system controls blade pitch. Like the NEG Micon machine, the turbine operates at a constant speed. The Opti-Slip technology incorporated into the design allows slight speed variation to relieve stress on the turbine.²⁵ The Opti-Slip technology acts like a spring, allowing an increase in speed to relieve stress, then returning to a rated speed. Like the NEG Micon turbine, the Vestas machine is connected directly to the grid without power electronics; speed is controlled electromechanically by the grid.
- **Zond.** The Zond turbine has both a variable pitch blade design and a variable speed rotor and electric generator design. Together, these design elements enable the turbine to convert wind energy to rated turbine power output over a broader range of wind speeds than possible with the constant speed generator design employed in the NEG Micon and Vestas turbines. Because of the variable speed design, electricity from this turbine must flow through power conditioning equipment prior to entering the grid. The power conditioning equipment converts the variable frequency AC from the generator into DC, then (via an inverter) to 60 cycle AC that is also synchronous with the grid.

Operational Characteristics

Wind turbine manufacturers have developed basic wind turbine designs that can be modified to optimize the turbine for reliable operation at a specific site. The wind farm developer provides the manufacturer with site characteristics that will have an impact on the turbine's capacity factor and on the reliability of turbine operation. Factors include annual distribution of wind speed, annual variation in site temperature, frequency of

lightning, and salty air in coastal regions. Modifications to enable operation in climates that are hotter or colder than the design temperature operating range, operation in coastal environments with salty air, and enhanced lightning protection will add to the cost of the turbine system. The following discussion covers some of these modifications.²⁶

Ability to Operate Over a Range of Wind Speeds. Currently available wind turbine designs enable reliable operation over a range of wind speeds. Rotor diameter can be modified from a standard diameter to one slightly larger for sites with low wind speeds or one slightly smaller for sites with high wind speeds.

Protecting Turbines in High Winds. Wind turbines are designed to operate up to a certain wind speed. Winds above this speed could damage the turbine, so all turbines are designed with a cut-off or shutdown mechanism. The following examples discuss such mechanisms for each major manufacturer:

- **NEG Micon.** The turbine operates at a fixed rotation per minute (rpm). Its blade is shaped so that the energy conversion efficiency of the turbine drops at high speeds and the turbine stalls. The turbine has two braking systems. The tip of each blade turns 90 degrees at high centrifugal force to exert drag that stops the blade. A disk brake system exerts hydraulic pressure to release the brake as long as electricity is available.
- **Vestas.** Blade pitch control is used to stall the turbine. Pitch control is achieved by feathering the blades. Disk brakes also can stop the machine.
- **Zond.** The blades have variable pitch control to enable feathering at wind speeds above the rated 50 to 60 mph range.

Ability to Operate in Hot or Cold Climates. In hot climates, the transmission cooling system is upgraded, and blades are made with epoxy resins that withstand heat and ultraviolet light. In cold climates, a heater is added to ensure that generator oil, transmission fluid, and hydraulic systems are maintained at adequate operating temperatures. Black blades are advantageous as a deicing mechanism in cold climates because they absorb heat. For example, the NEG Micon turbine

²⁵ For a given design, wind speeds beyond certain levels can damage the turbine. By varying the "pitch" (angle) of the blade tips at higher wind speeds, the blades will turn slower, reducing stress on the blade.

²⁶ Unless noted otherwise, information in this section is based on manufacturer literature and on personal communications between Donald M. Hardy, PanAero Corporation (Lakewood, CO) and William R. King, SAIC, 1999.

operates optimally in the -20°C to 35°C range.²⁷ Below -20°C, a cold weather package is installed; above 35°C, a hot weather package is installed.

Ability to Operate in Coastal Salty Air. Paint sealants and nacelle designs that inhibit penetration of salty air are used to protect the turbine, generator, blades, and tower from corrosion. The sealant is baked on at the factory.

Lightning Protection. Lightning is attracted to the tallest structure in an area, making wind turbines a prime target. Turbines are designed with a lightning protection system, and lightning damage may be included in the warranty. For instance, Vestas offers "Total Lightning Protection" in its 600 kW and 1.65 MW turbines, providing a route for the lightning to travel through the turbine to the ground.²⁸ Vestas blades are protected by a 50 mm² copper conductor, enabling lightning to travel along the blade without a significant increase in temperature. The lightning travels from the blade to the blade hub into the nacelle. The rear of the nacelle is protected by a lightning conductor. Lightning protection in the nacelle protects the wind vane and anemometer. Lightning is carried down the tower to the earthing system through two parallel copper conductors. The earthing system, which provides grounding for the turbine, consists of a thick copper ring conductor placed one meter below the surface and one meter from the turbine's concrete foundation. The copper ring is attached to two diametrically opposed points on the tower and to two copper-coated earthing rods on either side of the foundation. Additionally, the turbine transformer is also protected.

Compatibility with Grid Power Quality. "Power quality" refers to voltage stability, frequency stability, and absence of various forms of electrical noise (e.g., flicker or harmonic distortion) on the electrical grid. Power companies deliver three phases of alternating current and power, each with a smooth sinusoidal shape, with few jags, breaks, or surges in any phase (less than 9 percent harmonic distortion). Once the wind is strong enough to turn the rotor and generator, the turbine connects and is synchronized to the grid's phase. Lack of synchronization may lead to rotor overspeeding and overtaking of equipment components. The impact on the turbine could be costly equipment wear and tear.

Wind turbine designs and balance of system components are available currently that enable grid-connected wind

farms to provide electric power in a form compatible with grid power quality. Different manufacturers have different solutions, as seen in the following examples:

- **NEG Micon and Vestas.** The design does not require power electronics to maintain power quality. The grid electromechanically controls the turbine to keep blade rotation speed at a fixed rotation rate (e.g., rpm). This control solves the power conditioning problem but captures less wind energy than do other solutions.
- **Zond.** Because the turbine design incorporates a generator that is variable speed rather than constant speed, power electronics are required in the design to maintain power quality. While power electronics add to system cost, they enable the turbine to convert more wind energy into electricity.

Electronic controllers in modern wind turbines prevent damage from power surges by constantly monitoring grid voltage and frequency. For example, disturbances in the grid may lead to "islanding," which refers to a power outage in one part of the grid while the wind-connected section of the grid is still supplied with power. If disturbances are large enough to cause islanding, electronic controllers automatically disconnect the turbines from the grid, and aerodynamic brakes are used to stop the rotor. As connection to the grid is re-established, electronic controllers protect the turbine from power surges.

An asynchronous or induction generator, which generates alternating current, is presently used for wind farm applications. These inexpensive generators may be described as an electric motor that operates in reverse, generating rather than consuming electricity. Wind cranks the rotor, which creates an electromagnetic force in the generator. The faster the rotor moves (greater than the generator stator's rotating magnetic field), the more current is induced in the generator and converted to electricity, which is fed into the grid. One of the most important properties of an induction motor is that it will reduce its speed, as increases in wind speed lead to an increase in torque on the motor, leading to less wear and tear on the gearbox. Another beneficial feature is that the generator must be magnetized by power from the grid before it works, facilitating its synchronization with grid power.

²⁷ Personal communication between Jesper Michaelsen, Marketing Manager, NEG Micon USA, Inc., and William R. King, SAIC, 1999.

²⁸ Vestas, manufacturer literature, 1999.

Current Federal R&D To Improve WECS Performance and Reliability

The objective of the U.S. Department of Energy (DOE) Wind Energy Program is to enable the U.S. wind industry to complete the research, testing, and field verification needed to fully develop cost-effective and reliable advanced wind technology.²⁹ Activities are classified under one of three research areas: applied research, turbine research (which includes large, utility-scale turbines), and cooperative research and testing. The cooperative research and testing activity offers the wind industry the facilities to test their turbines and turbine components and provides a turbine certification test program. This activity helps the industry control costs by limiting the extent to which turbine manufacturers in the United States need to invest in and staff such facilities.

Applied Research.³⁰ The Applied Research Program seeks to understand the basic scientific and engineering principles that govern wind technology and underlie the aerodynamics and mechanical performance of wind turbines. The program also seeks to improve the cost and reliability of different wind turbines by conducting applied research in the following areas:

- **Aerodynamics and Structural Dynamics.** The objective is to lower turbine cost and increase turbine life, possibly by developing lighter, more flexible turbines. Such turbines may be made possible through an understanding of complex wind/wind turbine interactions and using such information to improve design codes. Data for such analyses come from both highly instrumented experimental wind turbines and turbine testing in the NASA Ames Research Center low turbulence wind tunnel. The advantage of the low turbulence wind tunnel is that it enables three-dimensional testing of the dynamic response of full-scale wind turbines to steady wind inflow, as the tunnel eliminates normal atmospheric turbulence.
- **Systems and Components.** The objective of this research is to advance the design of wind turbine components and subsystems beyond the current generation. The Advanced Research Turbine (ART) Test Bed tests innovative approaches to component design. The highly instrumented ART turbines also

support testing of large-scale turbine components such as generators, rotors, data acquisition systems, and controls. The ART Test Bed is being used in FY 2000 for the Long-Term Inflow and Structural Testing Program (LIST), which aims to understand inflow and resulting loads on turbines.

- **Materials, Manufacturing, and Fatigue.** This research aims to reduce capital and maintenance costs by improving blade strength and reliability during the manufacturing process. Activity areas include the development of advanced manufacturing techniques and blade fabrication and testing.
- **Avian Research.** This research uses analyses of bird deaths at current wind turbine sites to develop strategies to avoid bird fatalities. Research has addressed impacts of wind turbines on individual birds protected under legislation such as the Migratory Bird Treaty Act of the Endangered Species Act, as well as impacts on specific species. Research has been conducted to survey what species use a wind resource area, what part of the site they use, and when they use it. Research also focuses on studies of factors that may affect the impact of wind turbines on birds. Factors include analyses of the impact of topography, weather, habitat fragmentation, urban encroachment, habitat loss, species abundance, distribution, bird behavior, and turbine type and location. Preliminary results of survey and factors research indicate that wind turbines can be installed without causing any biologically significant impacts on bird species.

Turbine Research.³¹ The objective of this research is to assist the U.S. wind power industry in developing competitive, high-performance, reliable wind turbine technology for global energy markets. The program funds competitively selected industry partners in their development of advanced technologies. Wind turbines in various sizes from 10 kW to more than 1 MW are constructed and tested.

Currently, some of the research projects include: a Near-Term Research and Testing contract with Zond Energy Systems; Next-Generation Turbine Development contracts with the Wind Turbine Company and Zond

²⁹ U.S. Department of Energy and National Renewable Energy Laboratory, *Wind Power Today*, DOE/GO-102000-0966 (Washington, DC, April 2000), p. 28.

³⁰ *Ibid.*, pp. 29-30.

³¹ U.S. Department of Energy and National Renewable Energy Laboratory, *Wind Power Today*, DOE/GO-102000-0966 (Washington, DC, April 2000), p. 31-32.

Energy Systems; Small Wind Turbine Projects with Bergey Windpower Company, WindLite Corporation, and World Power Technology; and a cold weather turbine development contract with Northern Power Systems.

Cooperative Research and Testing. The Federal Government, through the National Wind Technology Center at the National Renewable Energy Laboratory, offers cooperative research, testing and certification, and standards programs to wind turbine manufacturers.³² Without these programs, the industry would bear the costs, which would be reflected in a higher wind turbine cost. Cooperative research enables turbine manufacturers to leverage their R&D efforts with related Federal efforts and ensures, through commitment of manufacturer resources, that R&D worthwhile to them is pursued. Wind turbine blade testing includes three types of tests—ultimate static strength, fatigue, and non-destructive—to identify and correct problems before going into full-scale production. Modal testing provides useful information about the structural dynamic characteristics of a wind turbine system. This information is used to avoid designs that are susceptible to fatigue-related failure and excessive vibrations. Testing of full-scale wind turbine drivetrains on a 2.5 MW Dynamometer Test Stand located at NREL was initiated in mid-1999. The dynamometer can test turbine drivetrains as large as 2 MW both to identify weak points in the design and to measure the lifetime of systems. Receipt of certification services enable U.S. manufacturers to show that their turbines meet international standards; such certification is needed for U.S.-made turbines to sell in many foreign markets.

Operation and Maintenance for Wind Farm Turbines

Modern wind turbines are designed for about 120,000 hours of operation over a 20-year lifetime.³³ During this period, planned preventive maintenance and breakdown maintenance are performed. Additionally, system components may be replaced as their performance degrades; such replacements also are performed to extend the

operating life of the turbine. Generally, maintenance costs are low for new turbines and increase as the turbine ages. Failure of wind turbine system components can be characterized by a relatively higher initial rate of failure followed by a lower failure rate through most of the turbine's design life until components begin to wear. During the initial period, assembly defects are detected and rectified. Commonly, wind turbines are sold with a 2- to 5-year manufacturer warranty covering the cost to repair these design-related breakdowns.³⁴ Wind turbine models are available today for which minimal initial failure rate problems may be expected because the current turbine design is (1) a variation of past designs that have proven successful in the field and (2) manufactured with adequate quality assurance procedures. The reliability of new turbine designs improves over time as field experience enables resolution of technical problems. Field experience is particularly important for more complex designs, including those that deviate more from past design generations.

The average annual maintenance cost for newer turbines is approximately 1.5 percent to 2.0 percent of the cost of the machine.³⁵ Most of the maintenance expenses are associated with the routine service of turbines. Wind turbine manufacturers and service contractors certified to perform maintenance on a manufacturer's turbines can be contracted on an annual basis to perform planned preventive maintenance. For example, the cost of a preventive maintenance contract for a 750 kW turbine ranges from \$12,000 to \$14,000 per year, per turbine.³⁶ Maintenance on a 600 kW or 660 kW turbine can be performed for a comparable cost, \$12,500 per year, per turbine.³⁷ Comparable maintenance on a 1.65 MW turbine would increase to \$18,000 per year, per turbine.³⁸ Some analyses state the cost of preventive maintenance in terms of dollars per kilowatthour of electricity output. When expressed in these units, turbines with higher annual kilowatthours of electricity output have lower per-kilowatthour maintenance cost. A turbine with higher electricity output either has a higher maximum kilowatt output rating or a higher capacity factor. Such analyses have stated a maintenance cost of around \$0.01

³² *Ibid.*, p. 32.

³³ Danish Wind Turbine Manufacturers Association, "Operation and Maintenance Costs for Wind Turbines." See website <http://www.windpower.dk/tour/econ/oandm.htm> (October 23, 2000).

³⁴ Personal communication between Donald M. Hardy, PanAero Corporation (Lakewood, CO) and William R. King, SAIC, 1999.

³⁵ Danish Wind Turbine Manufacturers Association, "Operation and Maintenance Costs for Wind Turbines." See website <http://www.windpower.dk/tour/econ/oandm.htm> (October 23, 2000).

³⁶ Personal communication between Donald M. Hardy, PanAero Corporation (Lakewood, CO) and William R. King, SAIC, 1999.

³⁷ Personal communication between Soren Christensen, Project & Sales Coordinator, Vestas-American Wind Technology (North Palm Springs, CA), and William R. King, SAIC, November 1999.

³⁸ *Ibid.*

per kWh.³⁹ Larger generation capacity turbines are serviced at the same frequency and cost as smaller ones, which results in a lower maintenance cost per installed kW; however, over time stresses and strains inherent in operation of larger capacity turbines cause more wear and tear on system components, leading to accelerated component replacement.

Additionally, wind farms benefit from the economy of scale related to semi-annual maintenance visits, administration, and inspection. Wind farm operators increase the life of a turbine by replacing certain components, such as rotor blades, generators, and gearboxes, which are subject to more wear before the end of the turbine's design life. The price of replacement components is usually 15 percent to 20 percent of the price of the turbine and can extend the life of the turbine by the same or longer amount.⁴⁰

Planned Maintenance

Planned maintenance covers all preventive maintenance, including routine checks, periodic maintenance, periodic testing, blade cleaning, and high voltage equipment maintenance. Routine checks are performed monthly for every machine using a checklist that includes inspection of the gearbox and oil levels, inspection for oil leaks, observation of the running machine for unusual drive train vibrations, brake disc inspection, and inspection of all emergency escape equipment.

Periodic maintenance takes place approximately every 6 months and includes checking the security of all supports and attachments, high-speed shaft alignment, brake adjustment and pad wear, and yaw mechanism performance; greasing bearings; inspecting cable terminations; and replacing oil filters. For pitch-regulated machines, the pitch calibration is also checked. In addition, this may be the time to replace components that are known to fail after a few years of operation, such as anemometers, wind vanes, and batteries.

Periodic testing of the overspeed protection system should be conducted to ensure proper operation of this feature. Blade cleaning should be a maintenance consideration when the performance of the turbine is affected due to dirt buildup; however, because of the high cost of equipment for accessing the blades, this task should be evaluated for cost-effectiveness. High voltage

equipment maintenance is usually contracted to the utility company.

Electrical Safety Maintenance

Regular maintenance of the turbine's electrical systems and a complete set of replacement parts minimize downtimes caused by electrical faults and ensure operational efficiency. A maintenance program may consist of monthly inspection of breakers, security, and battery voltages; annual checks of relay settings, oil levels, ground connections, and corrosion; 2-year interval testing of protection mechanisms, oil quality and levels, and high voltage circuit breakers; and 4-year inspections of all the switchgear, the grid transformer, and all wiring.

In addition, since some components need to be ordered, carrying a comprehensive set of replacement parts may be the difference between minor downtime or shutdown of the entire wind farm to await delivery. For this reason, a full set of protection relays, transformer windings, bushings, moving contacts, fuses, and gaskets must be stocked on-site.

Breakdown Maintenance

The frequency of wind turbine shutdowns or breakdowns is affected by operational factors and design complexity. More major system faults are generally categorized as human error, "acts of God," design faults, or system component wear and tear. Operational factors that affect breakdown frequency include overspeeding, excessive vibration, low gearbox oil pressure, yaw error, pitch error, unprompted braking, synchronization failure, loss of grid, and loss of batteries. A significant portion of wind turbine maintenance events can be detected by wind turbine system controllers, which can sense problems such as loose connections due to vibration or defective sensors.

Wind turbine designs, evolving with new research and development breakthroughs, have in some cases become more complex. Initially, a turbine that incorporates several new design concepts may experience an increase in breakdown frequency when compared to older proven turbine designs. Breakdowns may be caused by the design of a specific part or by problems that arise when parts incorporated into the new design do not

³⁹ U.S. Department of Energy (Office of Utility Technologies) and Electric Power Research Institute, *Renewable Energy Technology Characterizations*, TR-109496 (Washington, DC, December 1997), p. 6-13. Danish Wind Turbine Manufacturers Association, "Operation and Maintenance Costs for Wind Turbines." See website <http://www.windpower.dk/tour/econ/oandm.htm> (October 23, 2000).

⁴⁰ Danish Wind Turbine Manufacturers Association, "Operation and Maintenance Costs for Wind Turbines." See website <http://www.windpower.dk/tour/econ/oandm.htm> (October 23, 2000).

function together as a system. Field experience enables technical problems to be detected, facilitating their resolution through additional development.

Beyond the initial period of resolving technical problems in a new turbine design, more complex machines may experience higher expenditures on periodic planned maintenance and higher replacement part costs. Expected higher expenditures do not necessarily reflect on the reliability of the turbine; they reflect more on the cost of maintaining and replacing complex parts. The cost-effectiveness of the turbine depends on such costs being covered by the incremental electricity production benefit that rationalizes the new design.

In Europe, gradual changes in wind turbine design during the past 20 years have been accompanied by testing and certification and by the hours of field experience needed to demonstrate wind turbine reliability. This process of turbine design, testing, certification, and field experience has resulted in the NEG Micon and Vestas wind turbines deployed in wind farms currently being developed in the United States and worldwide. In the United States, the U.S. Department of Energy, the National Renewable Energy Laboratory, and Underwriters Laboratories, Inc., have worked together to provide comparable turbine testing and certification for U.S. wind turbine companies.⁴¹

Summary

Research and development throughout the past 20 years has resulted in a current generation of utility-scale wind turbines, with maximum electricity generating capacity often exceeding 500 kW per turbine, designed for about 120,000 hours of operation over a 20-year lifetime. In the United States, wind farm development activity in 1999 was motivated by the June 1999 expiration of the Federal production tax credit, and dominated by installation of utility-scale turbines manufactured by NEG Micon and Vestas, both Danish firms, and by Zond Energy Systems, a subsidiary of Enron Wind Corporation, a U.S. firm. Research and development for utility-scale turbines has been directed toward increasing the amount of wind energy that a turbine can convert into electricity for the lowest amount of capital investment and the lowest on-going operating cost. Following are examples of the R&D efforts that have contributed to current utility-scale turbine technology:

- Improvements in the aerodynamics of wind turbine blades, resulting in higher capacity factors and an increase in the watts per square meter of swept area performance factor.
- Development of variable speed generators to improve conversion of wind power to electricity over a range of wind speeds.
- Development of gearless turbines that reduce the on going operating cost of the turbine.
- Development of lighter tower structures. A by-product of advances in aerodynamics and in generator design is reduction or better distribution of the stresses and strains in the wind turbine. Lighter tower structures, which are also less expensive because of material cost savings, may be used because of such advances.
- Smart controls and power electronics have enabled remote operation and monitoring of wind turbines. Some systems enable remote corrective action in response to system operational problems. The cost of such components has decreased. Turbine designs where power electronics are needed to maintain power quality also have benefitted from a reduction in component costs.

In the United States, the Zond Z-750 series turbine represents a very innovative but less gradual design change. Enron Wind Corporation wind farms, which use the Zond Z-750 technology, address the risk of the design innovation with performance contracts that guarantee turbine electricity production, in addition to power curve and reliability guarantees normally included in wind turbine performance contracts. The results of R&D have been incorporated into utility-scale wind turbine design more gradually in Europe, followed by operation in wind farms to assess reliability over time.

Near-term R&D efforts are expected to continue in directions that increase the efficiency with which wind turbines convert wind energy to electricity. For instance, researchers report that further optimization of blade design is possible.⁴² Taller towers and rotor/generator systems with maximum power ratings exceeding 1 MW will continue to be improved. Other areas of

⁴¹ National Renewable Energy Laboratory, *Certification Program Opens Markets to U.S. Turbines*, DOE/GO-10099-820 (Golden, Colorado, June 1999), p. 16.

⁴² U.S. Department of Energy and National Renewable Energy Laboratory, *Wind Power Today*, DOE/GO-102000-0966 (Washington, DC, April 2000), p. 31-32.

development that affect turbine cost include advanced manufacturing methods and use of alternative, more cost-effective materials for turbine system, and tower fabrication.

The result of turbine R&D has been a reliable utility-scale wind turbine generator that can be optimized for operation in a variety of wind farm locations. For example, annual wind farm capacity factors of 28.5 percent to 32 percent have been achieved in Denmark and the United States, respectively, and capacity factors of 35 percent to 38 percent are projected for wind farm capacity that was recently installed in Minnesota and Iowa, respectively (Table 4).

The Changing World for Wind Power

In addition to technological improvements in wind turbines, governmental and private efforts to increase the Nation's consumption of renewable-based electricity have grown. Because wind energy is generally the most economically competitive, widely available renewable electricity source other than hydropower, some of these efforts have had their greatest impact on wind power.

Federal Incentives

A wide variety of Government actions can be used to influence energy markets and achieve Government objectives. These actions, broadly called incentives, include taxes, payments, trust funds, insurance, low-cost loans, research and development, and varieties of regulation. For a more detailed discussion of issues surrounding incentives for renewable energy, see the article, "Incentives, Mandates, and Government Programs for Promoting Renewable Energy," contained in this report.

The most significant Federal incentive for wind power is the production tax credit established by the Energy Policy Act of 1992 (EPACT). This credit expired in June 1999, but now has been reinstated and applies to profit wind and closed loop biomass projects in operation by December 31, 2001.⁴³ This type of incentive (when compared to an investment tax credit) rewards energy production and thus supports project performance/

success. Eligible projects receive a tax credit of 1.5 cents per kilowatthour of electricity produced, adjusted for inflation, for the first 10 years of the project's life. Even when leveled over the full life of a project, this benefit is significant. Immediately prior to the expiration of the production tax credit, a rush of projects came on line in spring 1999. Since then, development has continued, but at a slower pace. This tax credit was valued at more than \$20 million for 1998, virtually all of which was for wind.⁴⁴

EPACT also created the Renewable Energy Production Incentive (REPI). This incentive is paid to wind generation facilities owned by State and local government entities and not-for-profit electric cooperatives that are tax exempt. Qualifying facilities are eligible for annual incentive payments of 1.5 cents per kilowatthour (1993 dollars and indexed for inflation) for the first 10 years of operation subject to the availability of annual appropriations in each Federal fiscal year of operation. REPI payments for fiscal year 1998 production were \$4 million, of which wind accounted for about \$32,000. The majority of the funds were used for biomass digester gas, wood waste, and landfill methane.

Another Federal incentive is research and development expenditures and efforts. Applied research and development (R&D) activity is considered a support program because, when successful, it reduces the capital and/or operating costs of new products or processes. The mission of the Wind Energy Systems Program is to establish wind energy as a regionally diversified, cost-effective power generation technology, through a coordinated research effort with industry and utilities that will minimize technical and institutional risks for U.S. companies competing in domestic and international markets. In addition to improving existing turbines, DOE and industry are improving particular turbine components. The National Renewable Energy Laboratories (NREL) and Sandia National Laboratories have worked since 1994 with industry on cost-shared projects to develop the cutting-edge wind turbine components needed to create larger, more cost-effective turbines. Already since 1980, the cost of wind generation has declined from 35-40 cents per kilowatthour to a projected 6 cents in 2000.⁴⁵ The DOE Wind Energy Program was funded at around \$33 million in fiscal year 2000.⁴⁶

⁴³ Biomass projects must utilize biomass grown exclusively for energy production.

⁴⁴ 1993-2004: Office of Management and Budget, *Analytical Perspectives, 2000* (Washington, DC, 1999).

⁴⁵ Energy Information Administration, *Annual Energy Outlook 2000*, DOE/EIA-0383(2000), National Energy Modeling System run AEO2k.d100199A.

⁴⁶ U.S. Department of Energy, Office of Chief Financial Officer, *FY 2001 Budget Request to Congress - Budget Highlights*, DOE/CR-0068-8 (Washington, DC, February 2000).

Federal Electric Power Industry Restructuring

Competition in the electric power industry holds promise for more efficient operations at generating facilities and a reduction in costs, which should lead to lower electricity prices. However, concern has arisen that higher cost, but environmentally friendly, energy sources (i.e., renewables) will lose out to less environmentally friendly fuels used for producing electricity having a low short-run marginal cost. To protect the environment, Federal and many State restructuring plans include incentives to promote the use of renewable energy. Hence, competition and the restructuring of the electric power industry, when accompanied by environmental provisions, could be a push for new renewable energy development.

The administration and members of Congress have proposed a number of plans to restructure the electric power industry. Efforts have been expended to get a consensus legislative package out of Congress, but no agreement is forthcoming, because so many differences still remain.⁴⁷ The administration's latest electric industry competition plan, as of April 15, 1999, would provide for phasing in retail competition by 2003 and support for renewable energy through regulatory mechanisms, including a renewable portfolio standard (RPS), public benefit fund (PBF), and net metering.⁴⁸

State Incentives

With Federal legislation promoting electric wholesale competition in place, 25, or just half the States, have comprehensive restructuring policies in effect (Table 5). Many of the States with plans to implement retail competition also have regulatory mechanisms to support renewable energy. As with the Administration's proposed electric competition plan, the most important regulatory mechanisms for support of renewable energy are the RPS, PBF, and net metering. Currently, 10 States (Arizona, Connecticut, Maine, Massachusetts, Nevada, New Jersey, New Mexico, Pennsylvania, Texas, and Wisconsin) have an RPS in place.⁴⁹ Thirteen States (California, Connecticut, Delaware, Illinois, Massachusetts, Montana, New Jersey, New Mexico, New York, Oregon, Pennsylvania, Rhode Island, and Wisconsin) use a system benefits charge (SBC) to support a PBF. The provisions within a State's RPS or SBC to support renewable

energy may differ substantially among the States. Net metering is used by a number of States to support relatively small facilities, so it is generally more applicable for solar energy than for wind. All of these activities are documented in detail for each State in Appendix A.

Other State financial incentives support wind energy:

- **Net Metering.** Provisions vary by State and utility, but usually apply only to very small generators that typically use solar or wind energy. This system usually permits a customer operating a small generator to purchase extra electricity when needed. Also, any excess power at the end of the month can be sold back to the utility. Pricing schemes vary by individual utility circumstances.
- **Accelerated Depreciation.** For example, in Minnesota this incentive is modeled after the Federal income tax Modified Accelerated Cost Recovery Schedule (MACRS) schedule for depreciation of equipment, thus improving the owner/operator's tax position.⁵⁰
- **Sales Tax Exemption.** This type of incentive may exempt from sales tax all of the cost of wind energy equipment and all materials used to construct wind energy systems. Alternatively, the sales of wind power itself may be exempt from sales tax.
- **Property Tax Exemption.** This incentive excludes from property taxation all or part of the value added by wind energy systems.
- **Special Grants.** These grants may be given for research and development of wind energy resources or technology.
- **Loans.** States may offer low interest loans under certain conditions to wind project developers. However, frequently these loans are restricted to small projects, so the benefit is limited.

Some of these provisions have been in place a number of years, while others have recently been enacted. In the early years, investment tax credits were popular but later found flawed as they rewarded development, not performance.

⁴⁷ For an "Electric Utility Restructuring Weekly Update" see the U.S. Department of Energy's website: http://www.eren.doe.gov/electricity_restructuring/weekly.html (summer 2000).

⁴⁸ For more details on the administration's proposed Comprehensive Electricity Competition Act, see website <http://www.doe.gov/policy/ceca.htm> (summer 2000).

⁴⁹ As of summer 2000.

⁵⁰ Refers to a 5-year, 200-percent, double declining balance, accounting method.

Table 5. Renewable Incentives and Support Programs by State and Status of Implementing Electric Power Industry Restructuring

States	Renewable Portfolio Standard	System Benefits Charge	Green Pricing ^a
With Comprehensive Restructuring Policies:			
Arizona	x		
Arkansas			
California		x	x
Connecticut	x	x	
Delaware		x	
District of Columbia			
Illinois		x	
Maine	x		
Maryland			
Massachusetts	x	x	
Michigan			x
Montana		x	x
Nevada	x		
New Hampshire			
New Jersey	x	x	
New Mexico	x	x	x
New York		x	
Ohio			
Oklahoma			
Oregon		x	x
Pennsylvania	x	x	
Rhode Island		x	
Texas	x		x
Virginia			
West Virginia			
Remaining States:			
Alabama			x
Alaska			
Colorado			x
Florida			
Georgia			
Hawaii			
Idaho			
Indiana			
Iowa			x
Kansas			x
Kentucky			x
Louisiana			
Minnesota			x
Mississippi			x
Missouri			x
Nebraska			x
North Carolina			
North Dakota			x
South Carolina			
South Dakota			x
Tennessee			x
Utah			x
Vermont			
Washington			x
Wisconsin	x	x	x
Wyoming			x
Total	10	13	22

^aUtility programs available to at least some customers in the State. Some programs start in 2000.

Sources: Electricity Restructuring Status: Energy Information Administration, Status of State Electric Industry Restructuring Activity as of May 2000, Website: http://www.eia.doe.gov/cneaf/electricity/chg_str. Renewable Portfolio Standard and System Benefit Charge: Wiser, R., Porter, K. and Bolinger, M., Lawrence Berkeley National Laboratory, "Comparing State Portfolio Standards and System-Benefits Charges Under Restructuring," Memorandum (August 23, 2000) to various officials of the U.S. Department of Energy and the National Renewable Energy Laboratory. Green Pricing: U.S. Department of Energy Website: <http://www.eren.doe.gov/greenpower> (June 2000).

Other Support

Green pricing/marketing, which lets renewables compete on a basis of consumer demand, also provides support for development of renewable energy, including wind power. Proponents of this type of support argue that as consumer awareness of the benefits of renewable energy is raised, they may choose to consume more renewable energy even if it requires paying a small premium to do so. So far, these programs can be characterized as lively, if small in impact. By the end of 1999, 50 utility green pricing programs were in place across the United States.⁵¹ Premiums for wind power range from a low of 1 cent per kilowatthour to upwards of 5 cents per kilowatthour in a handful of cases.⁵² According to data compiled by the National Renewable Energy Laboratory, green pricing/marketing activities resulted in the addition of nearly 100 MW of new wind capacity by July 2000.⁵³

Developments

What developments have these incentive and electric power industry restructuring policies spawned? Industry sources estimate that more than 900 MW of new or repowered wind capacity was constructed in 1999 (Table 1). Where and why did this development take place? States with new capacity include Alaska, California, Colorado, Iowa, Kansas, Minnesota, Nebraska, New Mexico, Texas, Wisconsin, and Wyoming (See Appendix A.). Capacity additions in these States vary in significance. Iowa, Minnesota, and Texas had the most capacity added, States, followed by Colorado, Wisconsin and the others, including California, which has a significant repowering program.

Together, Iowa and Minnesota installed two large wind projects in 1999: Storm Lake, Iowa (193 MW), and Lake Benton II, Minnesota (104 MW).⁵⁴ Neither of these States has yet passed restructuring legislation. Thus, several primary factors influenced the projects:

- Availability of good wind resources and land

- Improved wind technology
- Federal production tax credits
- Presence of a State law mandating development of renewable and/or wind capacity
- Various State incentives examples, of which are tax advantages (accelerated depreciation, property and sales tax exemptions), low interest loans, grants, access laws, net metering, and green pricing. These incentives currently are available in Minnesota and/or Iowa.

Texas has several moderately sized projects that together add up to more than 140 MW of added new capacity. These projects include McCamey, Texas (75 MW), Culberson County, Texas (30 MW), and Big Spring, Texas (35 MW). Projects were constructed using the federal production tax credit and in response to the demand from green pricing programs. Since the time commitments to these projects were made, Texas passed restructuring (with retail competition to begin in 2002) and also a renewable portfolio standard, both of which will affect the future. Other States, such as California, Colorado, Oregon, and Wisconsin, are in the process of developing projects at least in part as a result of green pricing programs.

Conclusions

Although the economics of wind energy have improved over the last decade, wind energy is generally not yet competitive with traditional fossil fuel technologies.⁵⁵ Enactment of State electric restructuring legislation that includes support for renewable energy and the reinstatement of the federal production tax credit will provide an impetus for wind energy. Until wind energy is competitive, the future for wind energy is likely to be in those States providing additional support to renewable energy. This support may take the form of financial incentives, regulatory programs (such as a renewable

⁵¹ R. Wiser, M. Bolinger, E. Holt, Lawrence Berkeley National Laboratory, "Customer Choice and Green Power Marketing: A Critical Review and Analysis," in Proceedings of ACEEE 2000 Summer Study on Energy Efficiency in Buildings (Pacific Grove, California, August 2000).

⁵² For recent or more detailed information, see the U.S. Department of Energy's website: <http://www.eren.doe.gov/greenpower>.

⁵³ Lori Bird and Blair Swezey, National Renewable Energy Laboratory, "Estimates of Renewable Energy Developed to Serve Green Power Markets," July 2000 on the Department of Energy's green power website: http://www.eren.doe.gov/greenpower/new_gp_cap.shtml (July 2000).

⁵⁴ Minnesota's other large wind project was the Lake Benton I facility with 107 MW of capacity, which came on line in 1998.

⁵⁵ For analysis of issues related to integrating renewable energy and wind power into the U.S. energy supply, see Energy Information Administration, *Annual Energy Outlook 2000*, DOE/EIA-383(2000) (Washington, DC, December 1999).

portfolio standard or system benefits charge), or green pricing, in which wind will be competing for benefits with other renewable energy sources. Electric retail competition, without the State's support of renewable energy, could be a setback to the penetration of wind energy. Commitments such as those evident in

Minnesota and Texas should continue to support wind energy. Further advances in technology and performance are expected to lower costs and improve project economics, making wind more competitive with other energy sources, renewable and nonrenewable.

Appendix A. State Wind Profiles: A Compendium

This appendix presents assessments of State-level wind energy programs.⁵⁶ Each assessment begins with the major issue likely to affect wind energy: the status of electricity restructuring and implementation of retail competition in each State.⁵⁷ The assessments follow with information about State incentives and support from green power programs available for wind power (in addition to possible Federal incentives discussed earlier) and ends with the status of wind power development through 2000. A list of sources of information follows at the end of the appendix. This list can be used to obtain more up to date information as needed.

Alabama. Because Alabama is a low-cost State and for other reasons, action on restructuring has been slow to progress. In February 2000 the Public Services Commission scheduled hearings to address two key issues: whether the electric power industry restructuring towards competition is in the best interests of consumers and what the regulatory/jurisdictional role of the Public Services Commission would be in a market-based system. Alabama has a green pricing program starting in 2000 that could promote wind energy when available. Alabama has no existing identified wind capacity and no new wind capacity was planned for 2000.

Alaska. In May 1999, the State Public Utility Commission received a report which investigated the possibility for deregulation in Alaska. Included in the report was consideration of creating retail pilot programs, encouragement of power trading markets, and creation of a central dispatch point and an Independent Systems Operator (ISO). An adjunct effort by the State Senate has reorganized the Public Utility Commission (PUC) into the Regulatory Commission of Alaska and a panel of five new commissioners. In April 2000 a Senate bill was introduced that, if passed, would implement retail choice in the rail belt (Anchorage and Fairbanks) by September 2001.

Alaska has two small wind facilities in rural areas. The one in Kotzebue began with 500 kilowatts (kW) of capacity installed and has plans for future expansion. This project was funded in part by a grant from DOE's Wind Turbine Verification Program. A small 225 kW facility is also located on St. Paul Island. Following the success in Kotzebue, other remote communities are proposing to build new wind facilities. Wales, Alaska, planned to have a new 100 kW facility on line in 2000.

Arizona. Arizona began retail competition for some of its consumers in 1999. This phasing in was to continue until completion in January 2001. In April 2000 the Arizona Corporation Commission approved a renewable portfolio standard that will require utilities and other electricity providers to derive 1.1 percent of their energy from renewable sources (including wind) by 2007. In turn, 50 percent of that must come from solar energy. Funds from the existing system benefits charge may be used for renewable portfolio standard compliance costs.

Arizona has other incentives for renewable energy, possibly including wind. However, they are generally directed towards fairly small operations. Among them is a Qualified Environmental Technology Facilities Credit. This incentive allows a credit toward the personal or corporate income taxes in the amount of 10 percent of the cost of construction of a qualified environmental technology manufacturing, producing or processing facility.

A personal income tax provision allows a 25 percent tax credit on the cost of a solar or wind energy device up to \$1,000. The Revolving Energy Loans for Arizona (RELA) Program provides loans up to \$500,000 to companies that manufacture renewable equipment or acquire it for use in their own processes. The Solar and Wind Energy Equipment Tax Exemption of up to \$5,000 applies to solar and wind energy equipment. Finally, Arizona

⁵⁶ Note: Some States may have wind turbines that are so small or so dispersed they are not counted in the usual surveys of wind capacity. This could include turbines used for water pumping on ranches or farm land. In this analysis these States are described as "having no identifiable wind generating capacity" even though they may have a small amount.

⁵⁷ Information for this appendix was taken from various websites, and is current as of summer 2000.

has net metering provisions depending on the utility's service area. Arizona Public Service Company permits net metering for facilities under 10 kW, while Tucson Electric Power Company allows net metering for facilities under 100 kW.

To date, Arizona has no identified wind facilities and none were planned for 2000.

Arkansas. The status of deregulation is that Senate Bill (SB) 791 will restructure Arkansas' electric power industry and allow retail access by January 2002. In December 1999 the Public Service Commission began work on a series of reports to facilitate implementation of retail competition. No incentives for wind power exist and there are no existing or planned wind facilities identified for 2000.

California. The process of restructuring began in September 1996 when the California State legislature passed Assembly Bill (AB) 1890 to begin restructuring California's electric power industry. The retail electricity market opened officially for all consumers in California on March 31, 1998. The following measures support renewable energy:

- **Renewable Setaside.** AB 1890 also established a system benefits charge of 0.7 percent on all electricity sold by California's Investor Owned Utilities. Funds (estimated at total of \$540 million) would be used to support development of renewable energy during a 4-year transition period to open competition beginning in 1998. Legislation extending the setaside for ten years through January 1, 2012 was signed into law in September 2000. It authorizes collection of \$135 million per year for investment in renewable sources.
- **Net Metering.** Solar and wind installations equal to or under 10 kW in capacity are eligible.
- **Green Power.** Any number of "green power" programs are supported by the "customer side" account portion of the setaside program mentioned above. The customer side account provides rebates of up to 1.5 cents per kilowatthour to customers who purchase energy from renewable electric service providers registered with the Energy Commission. Rebates for industrial customers are limited to \$1,000 per year. Renewable products may be marketed using these rebates and/or as part of

the separate, private Green-e certified program. To be recognized by the green-e program, a product must have 50 percent or more renewable content and meet other requirements.⁵⁸ Many of these include wind power explicitly in their renewable generation portfolio. Two municipal utilities, Los Angeles Department of Water and Power and the City of Palo Alto, have green pricing programs that promote wind energy.

- **Research and Development.** The Public Interest Energy Research Program (PIER) supports the public interest research development and demonstration that utilities were required to do before deregulation. It makes \$62 million available annually through 2001.

California has a mature wind industry. At the end of 1998, EIA estimates that California's wind net summer capability stood at 1,487 megawatts (MW).⁵⁹ A number of new and repowered projects with capacity totaling 290 MW came on line in 1999 and nearly 210 MW more were planned for 2000. For details, see the American Wind Energy Association's website: <http://www.awea.org/projects/california.html>. Further into the future, the new technologies account of the renewable set aside program is expected to support development of some additional new wind capacity.

Colorado. Several bills to allow retail competition and restructure the electric power industry were introduced in the legislature in 1998. None, however, have passed the State legislature. The Colorado Electricity Advisory Panel, created by SB 152, released a final report in November 1999. The majority of the panel opposed restructuring and retail competition, because of their concern that Colorado already has low electricity rates, and that prices might rise under open competition. In addition, it is believed that rate impacts would be disproportionately shared among classes of consumers with low-income, fixed income, rural, residential and small consumers seeing the greatest increases. On another front, the Colorado Public Utilities Commission adopted rules in January 1999 which requires investor-owned utilities (IOU's) to itemize the fuel sources used for "generated and purchased" electricity; thus, increasing public awareness. Unbundled billing has been implemented and the utilities provide this information to customers twice a year. Also, Colorado has net metering for qualified facilities equal to or less than 10 kW in capacity.

⁵⁸ For details, visit the Green-e website: <http://www.green-e.org> (summer of 2000).

⁵⁹ Energy Information Administration, *Renewable Energy Annual 1999 With Data for 1998*, DOE/EIA-0603(99) (Washington, DC, March 2000), p. 96.

Colorado has one investor owned utility with a green pricing program. To encourage development of wind resources, Public Service Company of Colorado (PSCo) has opened its green power program, WindSource. As customers sign up to buy electricity from wind power, PSCo is developing the needed capacity. So far in response to demand, PSCo has put more than 16 MW of wind capacity in operation in Ponnequin, Colorado. In addition, five municipal utilities and three electric cooperatives have green pricing programs to promote wind energy.

Connecticut. The State of deregulation is that phasing in of retail competition began in January 1, 2000. The law also includes a 7 percent renewable portfolio standard to be met by 2009 and a provision for establishing a system benefits charge rising to 0.1 cents per kilowatthour (kWh) to support renewable technologies. Fourteen million dollars is budgeted for the fund in 2000. Connecticut has net metering for renewable facilities under 100 kW. Connecticut has no wind facilities and none were planned for 2000, although Connecticut entities may invest in out-of-State wind projects, power from which would be eligible for complying with the State RPS.

Delaware. The status of deregulation is that Delaware has a law that provides for phasing in retail competition beginning in October 1999, to be completed by April 2001. In September 1999 the Delaware PUC issued final orders for restructuring. Delaware has a public benefit fund for renewable energy and efficiency, but no decision has been made as to how the fund is to be spent. The legislature has enacted net metering for renewable facilities equal to or under 25 kW in capacity. Delaware has no existing wind facilities and no new wind facilities were planned for 2000.

District of Columbia. The District of Columbia PSC approved Potomac Electric Power Company's (PEPCO) restructuring settlement in January 2000. Government and commercial consumers will have retail access, and a pilot program for residential consumers was to begin by January 2001. The District of Columbia has no incentives for wind power, no existing wind projects identified and no new wind facilities were planned for 2000.

Florida. Florida has been slow to take action towards electric utility restructuring. In April 1998, House Bill (HB) 1888 died in committee without a hearing. In April 1999, the legislature adjourned with no further effort taken on restructuring. In January 2000 House issued a report on the state of the electric power industry in Florida. Following that in April 2000 Senate Bill 2020 was introduced and would require a study of electric utility deregulation and energy policy in Florida.

In February 1999, the Public Services Commission ruled that investor-owned utilities must disclose the sources of generation and purchased power to consumers. The Florida Energy Efficiency and Conservation Act of 1980 requires the Florida Public Service Commission to encourage the use of renewables, including wind. Florida has no identified wind facilities and no new facilities were planned for 2000.

Georgia. In early 1998 Georgia's PSC issued a report that investigated electric industry restructuring and made recommendations. No further action has been taken since then. Georgia has no incentives for renewable energy. It has no identified wind power facilities, but a small 1.98 MW facility was planned for 2000.

Hawaii. An April 1999 legislative resolution provided that the PUC submit (prior to the 2000 legislative session) a report on restructuring and competition in electric markets. Hawaii offers an income tax credit allowing individuals and corporations a credit of 20 percent of the cost of equipment and assembly of a residential or non-residential wind energy system to be applied in the year the system was purchased and placed in operation. There is no limit on the total amount of credit. At the end of 1998, Hawaii had wind facilities operating with total capacity of 20 MW. Hawaii had three new projects planned to come on-line in 2000. Potentially they would add a total of nearly 40 MW of wind capacity.

Idaho. Electricity deregulation in Idaho is on hold. Investigations concluded that Idaho is a low-cost State for electricity and should be concerned about prices rising in a competitive market. Idaho has several mechanisms that could support potential wind projects. For example, net metering is available to all technologies with facilities equal to or under 100 kW in capacity, not just renewable facilities. Another incentive consists of a personal income tax credit up to \$5,000 for 40 percent of the cost of a solar, wind, or geothermal device used for heating or electricity generation. Low-interest loans are available to residential and commercial consumers for renewable projects to generate electricity for their own use. Projects that intend to sell electricity are excluded. Loan amounts are limited to \$10,000 for residential consumers and \$100,000 for commercial consumers.

Idaho has no identified wind facilities and none were planned for 2000.

Illinois. Regarding the status of electricity restructuring in Illinois, phasing in of retail competition for industrial and commercial customers was to begin in October 1999 and be completed by October 1, 2000. Residential

customers will receive a 5 percent rate reduction by October 1, 2001. In addition, as part of a court settlement, ComEd is required to make a one-time allocation of \$250 million to an environmental and energy efficiency fund.

Illinois has a system benefits charge in place that supports renewables including potential wind projects. The charge is a flat rate of \$0.50/month for residential and small commercial customers. Larger customers pay \$37.50/month. The fund is budgeted for \$5 million every year for 10 years. Fifty percent of the funds collected go toward the Renewable Energy Resources Trust. Effective April 2000, Commonwealth Edison established an experimental net metering program for solar or wind generating systems equal to or less than 40 kW in capacity. Illinois has no identified wind facilities and none were planned for 2000.

Indiana. In March 1999 a restructuring bill, HB 648, was introduced, but failed to move beyond a committee hearing. It was opposed by utilities, organized labor, and consumer and environmental groups. Indiana has several incentives for renewables that can benefit the development of wind power. First is the property tax incentive, which exempts from property taxes the entire renewable energy device and affiliated equipment. Second is net metering for qualifying facilities generating less than 1,000 kWh per month. To date, this incentive has benefitted operators of small wind turbines. The third is demand side management programs. The Indiana Utility Regulatory Commission's 1995 ruling on demand side management programs allows for the inclusion of renewable energy systems (including wind facilities) in such utility programs. Indiana has no wind facilities identified and there were no plans to build any in 2000.

Iowa. According to data from the American Wind Energy Association, Iowa had a number of small wind facilities in operation before 1999. Some of these facilities were too small to be included in EIA data and some were just not yet reporting. They included a 2.25 MW project in Algona, Iowa, developed by Cedar Falls Utilities using Zond designed equipment with support from the DOE/EPRI Turbine Verification Program. In 1999, a 1990 State law, mandating that utilities in Iowa collectively take an average of 105 MW of electricity from renewables, was a factor (although not the only one) in the major development of approximately 240 MW of new wind capacity. This development includes some of the following facilities:

- 112.5 MW in Alta, Iowa, developed by Enron using Zond equipment to sell power to MidAmerican

- 80.2 MW in Alta, Iowa, developed by Enron and Northern Alternative Energy (NAE) using Zond equipment to sell power to Alliant/IES
- 42 MW in Clear Lake, Iowa, developed by FPL using NEG-Micon equipment to sell power to Alliant/IES.

Other factors influencing development include the following State provisions:

- **Grants for Energy Efficiency and Renewable Energy.** Sponsored by the Iowa Energy Center, these grants include support for a wide variety of research activities, including among them wind resource assessment.
- **Guaranteed Buy Back Rates.** Within certain set limits, utilities are obligated to purchase renewable power at incentive buy back rates which are higher than the utilities' avoided cost.
- **Alternative Energy Loan Program.** This program offers 0 percent interest loans for up to half of the project cost with a maximum of \$250,000 for entities in the residential, commercial, and industrial sectors.
- **Property Tax Incentive.** Any city or county in Iowa has the option to assess wind energy equipment at a special valuation for property tax purposes following State guidelines. For the first year, wind energy conversion equipment is assessed at 0 percent of the total cost. In the second through the sixth years the equipment is assessed at an additional 5 percent per year. From the seventh year onward, the assessment is set at 30 percent of total cost.
- **Sales Tax Incentive.** This statute exempts from Iowa State sales tax the total cost of wind energy equipment and all materials used in the manufacture, installation, or construction of wind systems.
- **Net Metering.** This ruling allows Iowa customers with alternative energy generation systems to sell electricity back to the utilities on a netted basis. Utilities are obligated to buy excess electricity at their avoided cost. To date, this program has not been particularly popular due to impediments imposed by the utilities.
- **Research and Outreach Programs.** The Iowa Energy Center has been involved in assessing the

State's wind resources and developing a model to be used for siting wind turbines. It also administers a loan program which offers 0 percent interest loans for up to half the project cost up to a maximum of \$250,000 and as long as funds allocated for wind portion of the renewable loan program are available.

In addition, one municipal utility, Cedar Falls has a green pricing program to promote wind energy.

The status of deregulation in Iowa is that a proposed restructuring bill died at the end of the legislative session in Spring 2000. The Iowa Department of Natural Resources proposed adding a renewable portfolio standard with a goal of 4 percent renewable electricity by 2005 and 10 percent renewable electricity by 2015, but the restructuring legislation failed to pass. A 600 kW wind project was proposed for Spirit Lake to come on-line in 2000.

Kansas. The status of deregulation is that several bills were introduced in the 1999 legislative session to restructure the electric power industry, but no action was taken before adjournment. There are two existing programs that include incentives for wind power development.

- **Renewable Energy Grant Program.** This provides support in small amounts of funds (less than \$50,000) for development of renewable energy, including wind, and excluding research and development.
- **Kansas Electric Utilities Research Program (KEURP).** is a cooperative venture among seven electric utilities performing applied research to proactively seek and deliver technologies enhancing the value of electric services to its members, utility customers, and the State of Kansas. In the past this has included a collaborative project with DOE to conduct a wind siting study.

In addition, two investor owned utilities have green pricing programs to promote wind energy exclusively. So far, Kansas completed one small 1.5-MW wind project in 1999 and has no plans for any new wind facilities in 2000.

Kentucky. The Kentucky Task Force on Electric Restructuring, established by HRJ95, completed its final report and found that retail prices in Kentucky could rise under open competition. Kentucky has one municipal utility sponsoring a green pricing program

that can promote wind energy when available. Kentucky has no incentives for renewable energy, no identified wind facilities, and no new wind facilities were planned for 2000.

Louisiana. In March of 1999 the Public Services Commission issued an order stating that "...a deliberate and cautious approach is still warranted" for restructuring the electric industry. A schedule was set to study the issues through August 2000. Louisiana has no incentives for wind energy, no existing wind facilities identified, and no new wind facilities were planned for 2000.

Maine. The Restructuring Act of 1997 allows electric power to be sold directly to retail consumers by largely deregulated power providers competing with one another beginning March 2000. By the end of 1999 the Maine PUC had finalized rules necessary to implement restructuring on schedule. Electric bill charges were to be unbundled beginning in 1999. Maine has the highest renewable portfolio standard in the United States—some 30 percent. However, counting electricity from hydro-power, biomass, and gas cogeneration, Maine already exceeds this using existing renewable capacity. Maine also has a net metering program for small facilities under 100 kW in capacity. Recently, Maine revised the net metering program to be consistent with retail access. Under the old provisions customers could sell excess power to the utility. According to new provisions customers will accumulate a rolling credit, which will roll over for 12 months, after which the credit goes away. Maine has no currently identified wind facilities, but a 20 MW project on Reddington Mt. was in the process of being permitted with plans to be on line by December 2000.

Maryland. Restructuring legislation provides for a phase-in of retail competition starting in July 2000 and ending July 2002. In January 2000 the Maryland PSC approved PEPCO's restructuring plan and PEPCO customers were scheduled to begin retail direct access by July 2000. While Maryland has several incentives for solar energy, it has no incentives for wind, no identified wind facilities, and no new wind projects were planned for 2000.

Massachusetts. Open retail competition began in March 1998. Accompanying restructuring is a renewable portfolio standard that includes wind. Retailers are required to take 1 percent of their supply from new renewables in 2003. This requirement increases by 0.5 percent per year until 2009, and 1 percent per year thereafter. To support implementation of the renewable

portfolio standard, Massachusetts also has mandated the disclosure of fuel mixes to end use customers. The State has also established the Massachusetts Renewable Energy Trust Fund, which is supported by a system benefits charge which began collection in 1998. Implementation of the full program is proceeding and includes potential benefits for wind. Massachusetts also has a net metering program for all qualified facilities (as defined by PURPA and FERC) at or below 60 kW of capacity according to legislation enacted in 1997. Net excess generation is purchased at the electric utilities full avoided cost.

Massachusetts has various other renewable incentives of less importance, including the following. The State has an alternative energy patent exemption, which offers both corporate and personal income tax deductions for any income received from the sale of a patent or collection of royalties for patents that benefit development of alternative energy for 5 years from the time the deduction is granted. A corporate income tax credit permits corporations to deduct solar or wind expenditures for space or water heating from their taxable income. The State also exempts solar and wind facilities from corporate excise tax for the length of the project's depreciation period. Massachusetts has a special grant program for partnerships with the private sector and local communities. These grants support development of fuel cells, wind, and solar photovoltaics.

The State's renewable energy systems credit provides for a 15-percent credit (with a maximum limit of \$1,000) against State income tax for the cost of a renewable energy system installed at an individual's primary residence. The local property tax exemption for solar, wind, and hydro exempts these facilities from local property taxes. Massachusetts also exempts from State sales tax, solar, wind, and heat pump systems operating in an individual's primary residence.

Massachusetts has only two small wind facilities identified—each with capacity under 0.5 MW. One new wind project with capacity of 7.5 MW was planned for 2000.

Michigan. Recently enacted electricity restructuring legislation allows all customers retail choice by January 2002. One way Michigan supports wind is with a program, Green Rate, in which customers pay a monthly premium to have all their power sourced to the Traverse City 600-kW wind project. Great Lakes Energy Cooperative has a second green pricing program to promote wind power. There were no other plans to add wind capacity in 2000.

Minnesota. So far, electric power restructuring has had little effect on wind power development. Although restructuring legislation was introduced to both the House and Senate, it never passed. Of far greater importance to wind energy development in Minnesota is a unique "quid pro quo" law regarding storage of spent nuclear fuel. A law passed in 1994 allows Northern States Power (NSP) to store nuclear waste in dry caskets near one of its nuclear power plants in exchange for a commitment to develop new wind capacity. According to plan 425 MW of wind power capacity would come on line by 2002 with 400 more megawatts to follow by 2012.

This legislation is not the only factor affecting development. Minnesota has a number of State incentives and programs that, when taken in combination, can help make wind projects viable. These incentives include:

- **Corporate Income Tax Credit.** Minnesota has accelerated depreciation provisions in the State tax code that mirror the federal Modified Accelerated Cost Recovery Schedule (MACRS). That is a 5-year, 200-percent double declining balance accounting method.
- **Special Grant Program.** Minnesota provides a 1.5 cent per kilowatthour grant for 10 years to wind projects 2 MW or smaller in size on a first come first served basis up to a statewide total of 100 MW wind power capacity. This program is meant to encourage establishment of dispersed wind generation infrastructure.
- **Agricultural Improvement Loan Program.** This program provides low interest loans up to \$100,000 to farmers for improvements or additions to permanent facilities. Wind energy conversion equipment has qualified since 1995.
- **Value-Added Stock Loan Participation Program.** This program can provide small, low-cost loans to farmers wishing to buy into wind generation cooperatives. There has been very little activity for wind in this program thus far, because the maximum amount of capital available is usually insufficient to finance even a small wind project.
- **Property Tax Exemption.** This provision excludes from property taxation all or part of the value added by wind systems. The value is determined on a sliding scale. Some small systems have the total value exempt, while all systems 12 MW or greater in capacity have 25 percent of the value taxed.

- **Sales Tax Incentive.** Minnesota exempts from sales tax the total cost of wind energy devices, including equipment and all materials used to manufacture, install, construct, or repair such systems.
- **Easements.** Minnesota provides for wind easements. An easement that benefits the property cannot add value to the property for tax purposes.
- **Green Pricing.** Minnesota has one investor owned utility (Minnesota Power), four electric cooperatives, and one municipal utility promoting wind power to customers who wish to pay a premium for clean energy.
- **Net Metering.** Minnesota offers net metering to wind facilities with 40 kW of capacity or less. Utilities must purchase any excess power generated at the average retail rate.
- **Public Benefit Fund.** In addition to developing wind capacity in exchange for storing nuclear waste, the 1994 law also required Northern States Power to contribute \$4.5 million to a fund beginning in 1999 and equal or greater amounts in successive years. These payments would continue indefinitely until either the law is changed or the casks can be shipped to a national nuclear-waste storage or disposal site. Money in this fund will be used to help finance projects that produce electricity from nontraditional sources and also benefit local economies in Minnesota.

With the support of the federal production tax credit, the 1994 State law, and various other State incentives, Minnesota brought on line nearly 140 MW of wind generating capacity in 1999. The following facilities are representative of those that came on line in 1999:

- 107.25 MW in Lake Benton, Minnesota (Lake Benton I), developed by Enron using Zond equipment.
- 103.5 MW in Pipestone County, Minnesota (Lake Benton II), developed by Enron using Zond equipment and now owned by FPL Energy, LLC.
- 11.25 MW in Lakota Ridge, Minnesota, developed by Northern Alternative Energy using NEG Micon equipment
- 11.88 MW in Shaokatan Hills, Minnesota, developed by Northern Alternative Energy using Vestas equipment.

Furthermore, facilities with a total of 30 MW capacity at 17 dispersed sites were to be developed by Northern Alternative Energy with plans to be on line by the end of 2000.

All of the projects listed above have power purchase agreements with Northern States Power. Additional wind capacity, being proposed, is expected to be developed in the future to meet Northern States Power's complete long-term commitment under the 1994 law. Also, a 1.98 MW project for Chandler Hills is in the preliminary stages of planning.

Mississippi. Pending enactment of authorizing legislation, Mississippi's electric power suppliers were set to implement retail competition starting January 2001 and ending December 2004. The City of Oxford, North East Mississippi Electric Power Association, has a green program that started in 2000 that can promote wind energy when available. Mississippi has no identified wind facilities and no new wind capacity was planned for 2000.

Missouri. Several bills to restructure the electric power industry and allow retail access were introduced in the legislature in the winter of 1999, but none were passed. Missouri has a loan program for renewables and potential wind projects. Funds are loaned to schools, local governments and small businesses. One investor owned utility, Missouri Public Service (Utilicorp United) has a green pricing program to promote wind power when it's available. Missouri has no identified wind facilities and had no plans to build any in 2000.

Montana. The status of deregulation in Montana is that retail competition is being phased in with a targeted end date of July 1, 2002, though extensions may be granted up to July 1, 2006 (depending on the utility and service area involved). Montana has required since May 1997 that electric bills be unbundled. In terms of renewable energy support, Montana has a number of incentives that could be applied to wind and these will be detailed here. However, the State has no existing wind facilities identified and had no plans for any capacity additions in 2000.

Montana has a system benefits charge that went into effect July 1, 1999, and will continue 4 years until July 1, 2003. Electricity suppliers will contribute 2.4 percent of their 1995 revenues to the fund. Electric utilities will be responsible for spending the monies. Funds allocated to renewable energy could be spent for wind to conduct research and development (R&D) or to actually build a facility.

Montana's support programs also include the following. First is net metering, which can apply to wind generators with capacity equal to or under 50 kW. There is also an income tax credit that could apply to wind. This program allows a 35-percent tax credit for an individual, partnership, or corporation that makes an investment of \$5,000 or more in wind electricity generating system or facilities to manufacture equipment. Another provision of Montana law exempts from property taxation the value added by a qualified renewable energy source, including wind. Montana is also one of four States that provides for the creation of wind easements for the purpose of protecting and maintaining proper access to sunlight and wind. Finally, one electric cooperative has a green pricing program that can promote wind.

Nebraska. Nebraska has been exploring electricity restructuring, but this effort is still in the investigative stage. Nebraska has several programs that could benefit potential wind projects, including a wind easement law. This law allows property owners to create binding wind easements for the purpose of protecting and maintaining proper access to wind energy. Another is a low interest loan program that can support development of future wind projects. Finally, one municipal utility has a green pricing program promoting wind power. Nebraska has one 1.5 MW wind facility on line in Springview not yet included in EIA data (but supported in part by the DOE Wind Turbine Verification Program), and one 1.32 MW wind facility operating in Lincoln. No additions were planned for 2000.

Nevada. In June 1999, Nevada enacted new restructuring legislation, which amended a 1997 law. The PUC has set a schedule to begin retail competition for the largest commercial customers in November 2000. Retail competition will be open to all customers by the end of 2001.

Nevada has a few incentive programs for wind, but none of particular significance. These programs include a renewable portfolio standard requiring utilities to have 0.2 percent of their electricity from renewables by January 1, 2001 increasing to 1 percent by 2009. Half of that is required to be solar. There is also a net metering law, but only for facilities of 10 kW capacity or less and only for the first 100 customers of each utility. A property tax incentive provides that any value added by a qualified renewable energy source shall be subtracted from the assessed value of any residential, commercial or industrial building for property tax purposes. Nevada has no identified wind facilities and none were planned for 2000.

New Hampshire. The State enacted HB1392 in 1996, requiring the PUC to implement retail choice by July 1998. However, implementation of restructuring was delayed due to continuing Federal litigation concerning the PUC's efforts to set stranded costs and rates for Public Service of New Hampshire (PSNH). In June 2000 SB472 was signed into law. This legislation is aimed at lowering PSNH's rates and allowing customers to choose an energy supplier. In September 2000 the New Hampshire Public Utilities Commission issued orders approving PSNH's restructuring settlement agreement and a schedule for phasing in retail competition will be set.

New Hampshire has several small-scale support programs which could apply to wind, if facilities were built. The first of these includes a net metering provision, which is currently under revision by the State PUC. Under new rules there would be full net metering and credits would roll over at the end of each month. Capacity would be limited to 25 kW. Second, a demonstration grants program provides grants between \$5,000 and \$10,000 for renewable demonstration/education projects. In a recent year, all the grants were for PVs, although wind is eligible. Third, a local option property tax statute allows each city or town to offer an exemption on residential property taxes in the amount of the assessed value of the eligible renewable energy system used on the property.

New Hampshire has no identified wind facilities and had no plans for building any in 2000.

New Jersey. In February 1999, the State enacted legislation to restructure New Jersey's electric power industry, providing for the beginning of retail competition in August 1999. Since then, one agreement between the Board of Public Utilities and Connectiv provided for a delay of retail competition until November 1999. New Jersey has a number of support programs for renewable energy development. First, New Jersey also provides for a 4-percent renewable portfolio standard to be met by 2012 using non-hydroelectric sources of renewable energy. Second, New Jersey has a public benefit fund that will total \$265 million for 2000-2008. Wind is an eligible technology. However, the New Jersey Board of Public Utilities has yet to issue a final rule on how these will be administered. In addition, since 1999 New Jersey has had net metering for wind and PV generators with no limit on generator size. Another incentive for renewables is the exemption from New Jersey's 6 percent State tax. New Jersey has no identified wind facilities and had no plans for any in 2000.

New Mexico. Legislation to restructure New Mexico's electric power industry was enacted in April 1999. According to current plans, consumer choice will begin with residential and other small consumers in the beginning of 2002, followed by other larger users at a later date. The restructuring legislation contains a provision for a system benefits charge to be levied on all kilowatt-hour sales in New Mexico. These funds will be used by the New Mexico Department of Environment to support activities including development of renewable energy by school districts and the governing entities of cities towns and villages. New Mexico also has a limited renewable portfolio standard. It provides for up to 5 percent of electricity to come from renewable resources by 2002 if it can be shown renewable resources are available in New Mexico and if the cost of standard offer service does not increase.

New Mexico also has a net metering program that benefits small renewable facilities under 10 kW in capacity. The State has one investor owned utility, Southwestern Public Service, with a green pricing program that can apply to wind energy. New Mexico has one small wind facility in operation, a 0.66 MW facility in Clovis and no new facilities were planned for 2000.

New York. With regard to electricity industry restructuring, New York is currently phasing in retail competition statewide. Each utility has its own timetable of targets. Some utilities have reached full retail access, while others expect to by the end of 2001. Although it is not entirely clear how the industry will change as restructuring transpires, New York presently has some support for renewable energy (including wind). In the past, a surcharge levied on intrastate sales of gas and electricity by investor-owned utilities provided funds for, among other things, research, development and commercialization of renewable technology as well as financial support to further market penetration of renewable energy. For the future, the New York Public Services Commission ordered utilities to provide unbundled billing by April 2000, which will identify electricity provided by green sources. Also, the PSC has set rules for a new system benefits charge to fund R&D for renewable energy. The fund will run through 2001 and be administered by the New York State Energy Research and Development Authority (NYSERDA). New York has net metering, but it is for solar only and does not apply to wind energy.

One 11.5 MW facility was planned by PG&E Generating for Madison, New York, to be on line in 2000. Some of the electricity is intended to be sold to green power providers. NYSERDA will provide \$2 million as

assistance. A small project was planned for Wyoming county to come on line in 2000.

North Carolina. Restructuring is under investigation in North Carolina. In March 1999, the Research Triangle Institute submitted its report with recommendations to the North Carolina Public Utilities Commission, but no further action was expected in 1999. In April 2000 the Study Commission, which was established by Senate Bill 38 in 1997, issued its final report. It recommends opening retail electricity markets to half of consumers by January 2005 and the remainder by January 2006, as well as, creating a public benefits fund that could benefit renewables. It also proposed providing a choice for green energy or alternatively a renewable portfolio standard.

Presently, North Carolina has one incentive that could support wind energy development. The income tax credit provides a credit against corporate and personal income taxes in the amount of 10 percent of the cost of equipment and installation of a wind energy system not to exceed \$1,000 for any single installation. North Carolina has no wind facilities identified as in operation and none were planned for 2000.

North Dakota. In November 1998, the Electric Utilities Committee submitted its report to the legislature on restructuring, but no action has yet been taken. The next legislature meets in 2001. North Dakota has several incentives that could support wind energy. The personal income tax credit allows any taxpayer to deduct 5 percent of the cost of equipment and installation of a geothermal, solar or wind energy device for a period of 3 years. The property tax incentive exempts from local property taxes any solar, wind, or geothermal energy device for the first 5 years of operation. North Dakota also has a net metering program for renewable generators equal to or under 100 kW in capacity. In North Dakota Minnakota Power Cooperative has a green pricing program to promote wind energy development. North Dakota has a few small identified wind facilities too small to be included in EIA survey data. Two are operated by Indian tribes. Together, these facilities represent less than 0.5 MW of capacity. No new wind facilities were planned to come on line in 2000.

Ohio. In July 1999, Ohio enacted legislation to restructure the Ohio's electric power industry. In October 1999, the PUC issued an initial set of rules for transition to a competitive market. Since that time a number of utilities have submitted transition plans for PUCO's approval. Retail competition was to be phased in beginning January 1, 2001. Ohio has net metering

available for wind facilities with no size limit on the generator. Ohio's tax system exempts certain equipment, including wind generators, from property taxation, the State sales and use tax, as well as the State franchise tax where applicable. Ohio has no identified wind facilities and none were planned for 2000.

Oklahoma. In April 1997, SB 500 was enacted to provide for electricity restructuring. It targeted retail competition to begin July 2002. Subsequently, SB 888 was enacted, which would bring in retail competition earlier. In October 1998, the Joint Electricity Task Force began a series of studies on implementing restructuring. The last of these studies was to be completed by October 1999. In late Spring 2000 the State legislature was working on a compromise bill to establish rules for implementing electric power industry restructuring. Oklahoma has a provision for net metering that could benefit wind energy development. Customers can request the utility to pay for extra power generated, but the utilities are not required to comply. Oklahoma has no identified wind facilities, and none were planned for 2000.

Oregon. In July 1999, Oregon enacted legislation that will deregulate the electric power industry and allow for customer choice.⁶⁰ The law will phase in open competition for industrial and commercial customers, but residential customers will have a portfolio of electricity products from which to choose. Products are provided by the incumbent utility and include a green power option. Generation companies will be chosen by the utility through competitive bidding, acting as a middleman for residential customers. The bill also requires disclosure of fuel sources, emissions and price, and creates a "public purpose fund" with funds set aside for renewables including wind. Beginning in October 2001 renewables would receive about 17 percent of the fund each year for 10 years. Separately, the governor signed into law a bill to implement net metering for renewable facilities less than 2.5 kW in size.

Oregon already has some other renewable incentives in place. The first is the corporate income tax that permits a 35-percent investment credit up to \$100,000 for construction of systems that produce energy from renewable sources, including wind. The second is the Small Scale Energy Loan Program (SELP). A 1980 amendment to the Oregon constitution authorizes the sale of bonds to finance small-scale, local energy projects, potentially including wind. Third, Oregon's property tax exemption for renewable devices states that the added value to any property (whether residential,

commercial, or industrial) derived from the installation of a qualifying renewable energy device shall not be included in the assessment of the property's value for property tax purposes. The fourth is net metering for wind generators with capacity equal to or under 25 kW.

Oregon has four green pricing programs supporting wind energy development. They are sponsored by two investor owned utilities, one electric cooperative, and one municipal utility. One example is Portland General Electric's (PGE) green pricing program open to large industrial and wholesale customers. PGE has contracted to supply this program in part with energy from Oregon's existing wind farm, the 24.9 MW Vansycle facility, which started operations in December 1998. No new wind facilities were planned for either 1999 or 2000.

Pennsylvania. In 1999, Pennsylvania began phasing in retail competition in stages. In September 1999, utilities were required to mail information packages to all consumers that had not chosen a competitive supplier with the hope of getting them in the new system by January 2000. Disclosure of fuel mix is encouraged. In addition, Pennsylvania has an RPS, SBC, and net metering, but provisions vary for each utility service territory. Separately, the PECO Unicom merger established a fund that has \$12 million budgeted for wind over a 5-year period.

Pennsylvania also has green power programs that could benefit future wind projects, when they are built. Green Mountain Energy opened its program in 1998 and sells three products: electricity with 1-percent, 50-percent, and 100-percent renewable sources at a modest increase in cost compared to traditional energy sources. Another program, Connectiv Energy is the first program in Pennsylvania to be certified by the green-e program. It offers Nature's Power 50 and Nature's Power 100 made from 50-percent and 100-percent renewable energy, respectively. The Energy Cooperative Association sponsors another green power program. Pennsylvania has one 10 MW wind facility, owned by American National Power, which was dedicated in May 2000 in Somerset County, Pennsylvania. Green Mountain Power markets power from this facility. A new 15.6 MW wind facility at Mill Run in Fayette County was planned to go on line in 2000.

Rhode Island. The Rhode Island Utility Restructuring Act of 1996 provides for electricity restructuring and open retail competition was to be phased in during 1998. By September 1999 only a small number of consumers had chosen alternative electricity providers. Rhode

⁶⁰ *Wind Power Monthly*, June 1999, p. 38.

Island has a non-bypassable system benefits charge to support the development of renewable energy and demand side management programs. The charge is set at \$.0023 per kilowatthour for a minimum of 5 years beginning in 1996. Rhode Island also has a net metering program created in 1985 that benefits a few small wind generating facilities equal to or under 25 kW in capacity. Rhode Island had no plans for new wind facilities in 2000.

South Carolina. With regard to deregulation, the South Carolina legislature discussed a new bill introduced in the Senate and debated the issues in the Spring of 2000. The Bill did not pass that session. South Carolina has no incentive programs for wind energy development, and no existing wind facilities identified. No additions were planned for 2000.

South Dakota. Deregulation in South Dakota has been under investigation. Findings of these activities assert that restructuring would not be good for South Dakota. Because the State has some of the lowest rates in the Nation, it is expected electricity prices would go up under open retail competition. Existing law permits retail wheeling for new, large customers.

South Dakota has a property tax incentive that exempts renewable energy systems on residential and commercial property from local property taxes for 3 years after installation with certain restrictions. The East River Electric Cooperative has a green pricing program that can promote wind energy planned to start in 2000. South Dakota has no identified wind facilities, but the Rosebud Sioux tribe had a 750 kW facility planned to come on-line in 2000.

Tennessee. Because the TVA provides most of Tennessee's electricity cheaply, little interest exists in restructuring the electric industry, although it has been investigated. Tennessee has a loan program that offers loans up to \$100,000 for renewable projects including wind. The Tennessee Valley Authority (TVA) has a green power program that could apply to wind energy when available. Tennessee has no existing wind projects identified, but TVA proposed a 1.98 MW project for Buffalo Mountain in Anderson County to come on line in 2000.

Texas. Texas enacted legislation to restructure the electric power industry and permit retail competition. The State's electricity industry will begin open competition by 2002, and by 2009 State utilities will be required to develop 2,000 MW of new renewable-based power. Some of this capacity could use wind energy.

This would achieve a standard of about 3 percent renewable electricity for utilities by January 2009. By the winter of 2000 rules to implement the standard were finalized by the PUC.

Prior to this, in October 1998, the Texas PUC adopted a renewable energy tariff rule that allows all utilities in Texas to offer customers the opportunity to buy renewable energy. If a utility chooses to offer a renewable energy tariff, its customers buying renewable energy may be charged a premium above their standard energy cost to cover any cost of a renewable resource that exceeds the utility's average system cost, plus marketing costs and possible utility profit. Two utility green pricing programs are sponsored by the investor owned utilities: TXU Electric and the Texas-New Mexico Power Company. Two municipal utilities also have programs. Texas also has net metering for renewable generators with capacity equal to or under 50 kW.

By the end of 1999 Texas had three large wind facilities on line. They were (1) Culberson County with 65 MW of Kenetech and Zond turbines, (2) Big Spring, Texas, with 35 MW of Vestas Turbines, and (3) McCamey, Texas, with 75 MW of NEG Micon turbines. In addition, several smaller projects, including the 6 MW facility in Fort Davis, Texas, received support from the DOE Wind Turbine Verification Program. Two new projects were planned for 2000. One was a 21.6 MW facility in King Mountain and the other is a 3.5 MW plant in Fort Stockton.

Utah. Deregulation in Utah is under investigation. Utah has a renewable energy income tax credit. For residential systems, the credit is 25 percent of the cost of installation up to \$2,000 per system. For commercial systems, the credit is 10 percent of the cost of installation up to \$50,000 per system. Utah has no identified wind facilities operating, but a 225 KW facility in Camp Williams, Riverton, was planned for 2000. Utah Power (PacifiCorp) has a new green power program that could apply to wind energy when available.

Vermont. Alternative proposals for restructuring date back as early as December 1996, but the issue of stranded costs has been a stumbling block to enacting any legislation. At present, all of the utilities have power purchase contracts with Hydro Quebec and local independent power producers that are above market price. To provide a path to a solution, the Department of Public Service has already permitted temporary rate increases, until contracts can be renegotiated. According to restructuring plans filed with the Public Service Board in March 1999, Central Vermont Public Service and

Green Mountain Power will divest themselves of their major generating assets and merge into one distribution company. Other details have yet to be announced. Vermont has net metering for small wind facilities with capacity equal to or under 15 kW or for farm system generators 100 kW or less in size.

Vermont has one 6 MW wind facility in operation in Searsburg, Vermont, not yet included in EIA data. This project was supported in part by a grant from the DOE Wind Turbine Verification Program. Vermont also had plans for new wind facilities in 2000.

Virginia. Early in 1999, the Virginia Electric Utility Restructuring Act was signed into law. It provides for retail competition to be phased in beginning January 1, 2002, through until January 1, 2004. Virginia has recently enacted net metering for residential wind generators with capacity equal to or under 10 kW and for non-residential wind generators 25 kW or less in size. Virginia has no existing wind facilities identified and had no plans for new wind facilities in 2000.

Washington. In October 1999, a plan—Reliability 2000—to restructure the electric power industry was proposed, but has yet to be passed. Among programs that could support wind projects, one is an exemption from the State corporate excise tax. Another is net metering for wind generators 25 kW or less in capacity. A third type of support is Washington's research and outreach programs that provide prospective renewable developers technical assistance, education, workshops, and other field assistance. Washington has three utility green pricing programs that can promote wind energy when available. Washington has no existing wind facilities identified and none immediately planned for 2000.

West Virginia. In March 2000 the legislature approved the Electricity Restructuring plan submitted by the Public Services Commission. It will allow retail choice by January 2001. West Virginia has no existing wind facilities identified and none were planned for 2000.

Wisconsin. Wisconsin is one State that has not restructured its electric power industry, but it has a renewable portfolio standard and public benefits fund. Early legislation signed into law in April 1998 mandated utilities to create 50 MW of power from renewable sources by 2000. Subsequently, Wisconsin's "Reliability 2000" legislation went into effect in October 1999. In addition to overhauling the State's transmission system, the law

provides for an RPS and PBF. The RPS provision requires 0.5 percent of retail energy sales to come from renewable energy sources (excluding electricity from hydroelectric facilities 60 MW and higher in capacity). This percentage would be boosted to 2.2 percent in 2011. A small portion of the public benefits fund would go to encourage the development or use of renewable applications. Some of these renewable provisions could benefit wind energy development in the future.

A number of other incentives for wind energy already exist:

- **Solar and Wind Energy Equipment Exemption.** This tax incentive exempts taxpayers from any value added by a qualified renewable energy source for property tax purposes.
- **Solar and Wind Access Laws.** Wisconsin statutes allow property owners with wind or solar energy systems to apply for permits which will guarantee unobstructed access to solar and wind resources.
- **Net Metering.** Net metering is available to all customer classes for systems with capacity of 20 kW or less. For electricity from renewable energy the utilities pay the retail rate for net excess generation.
- **Green Pricing.** Madison Gas and Electric plans to offer a green pricing program to support its new 11.22 MW wind farm in eastern Wisconsin. Customers can choose to purchase 100 kWh blocks for a monthly premium of around \$5. Wisconsin Electric's pilot program, Energy for Tomorrow, with 9,000 participants was so successful it is being extended to more customers.

A Clean Energy Rebate Program was proposed in State Senate Bill 56 introduced in February 1999. Under its provisions, an individual may receive a rebate of up to \$2,000 from the State for installing a wind or solar system.⁶¹ Madison Gas and Electric and the Wisconsin Electric Power Company are two investor-owned utilities with green pricing programs to promote wind energy; in addition, one electrical cooperative has a program.

By the end of 1998, Wisconsin had one 1.2 MW facility on line in De Pere, Wisconsin, (supported in part by the DOE Wind Turbine Verification Program) not yet

⁶¹ Personal communication with John Stolzenberg, Wisconsin Legislative Staff, April 29, 1999.

included in EIA data. Three facilities followed in 1999. They were (1) Nagara Escarpment-11.2 MW of Vestas turbines, (2) Lincoln Township-9.24 MW of Vestas turbines, and (3) Byron-1.32 MW of Vestas turbines. There were no plans for any new wind facilities immediately in 2000.

Wyoming. The Wyoming Public Service Commission issued a paper analyzing electric industry restructuring in September 1997. Some follow-up action was taken, but no further activity of significance has taken place since June 1998. Wyoming has only one renewable incentive, a solar/wind access law which provides very little benefit to wind energy. On the other hand, some of the wind power being developed in Wyoming is to be used to support diversified programs in other States such as Colorado. Pacific Power (PacifiCorp), an investor owned utility, has a green power program.

Wyoming has two large projects in Foote Creek Rim. The first is a 41.4 MW facility that came on line in mid-1999. Average wind speeds are 25 miles per hour at the site, thus promising greater potential for wind generation. The project is owned 80 percent by PacifiCorp, an investor-owned utility based in Portland, Oregon, and 20 percent by Eugene (Oregon) Water and Electric Board, a municipal utility. Sea West and Tomen Corporation built the project using 69 Mitsubishi turbines. The second Foot Creek Rim project was Public Service Company's (PSCo) 25 MW project nearby. It uses 33 750-kW turbines manufactured for the most part by NEG Micon's new facility in Illinois. Other projects include Foot Creek Rim III, a small 1.8 MW facility developed by Seawest and Tomen Power for Bonneville Power Administration, and a 3.3 MW facility by Fort Collins Light and Power (of Colorado) in Medicine Bow.

An additional 10 MW facility on Simpson Ridge was planned for completion in 2000. In mid-2000 Bonneville Power announced another purchase power agreement with Seawest to construct a new wind facility and provide more green power. According to plans the new Foot Creek Rim IV project was to have 28 wind turbines with a total capacity of 16.8 MW and be operating by the end of 2000. A small 1.32 MW project in Medicine Bow was planned to be on line during the summer of 2000.

Sources⁶²

Information on restructuring the electric power industry was taken from the following websites:

EIA's Status of State Electric Utility Deregulation Activity, website:
http://www.eia.doe.gov/cneaf/electricity/chg_str/tab5rev.html

U.S. Department of Energy, Electric Utility Restructuring Weekly Update, website:
http://www.eren.doe.gov/electricity_restructuring/weekly.html

Strategic Energy Ltd's Electricity Competition Update, website:
<http://www.sel.com/retail.html>

and

Electricitychoice.com, website:
<http://www.electricitychoice.com>

Information on State incentives and green pricing was taken from:

North Carolina Solar Center's Database of State Incentives for Renewable Energy (DSIRE), website:
<http://www.ncsc.ncsu.edu/dsire.htm>

K. Porter, National Renewable Energy Laboratory (NREL), and R. Wiser, Lawrence Berkeley National Laboratory, "A Status Report on the Design and Implementation of State Renewable Portfolio Standards and System Benefit Charge Policies," presented at Windpower Conference 2000 (Palm Springs, California, May 2000). See the NREL website: <http://www.nrel.gov/analysis/emma>

U.S. Department of Energy, The Green Power Network website:
<http://www.eren.doe.gov/greenpower>

Wiser, R., Porter, K. and Bolinger, M., Lawrence Berkeley National Laboratory. "Comparing State Portfolio Standards and System-Benefits Charges Under Restructuring," Memorandum (August 23, 2000) to various officials of the U.S. Department of Energy and the National Renewable Energy Laboratory, as well as, from contacts with State Energy Commissions and the Public Utility Commissions.

Information on wind capacity in place under construction in 1999 or planned for construction in 2000 was taken from:

The American Wind Energy Association's project database (as updated on July 7, 2000) on the website:
<http://www.awea.org/projects/index.html>

⁶² Information for this appendix was taken from various websites and is current as of the summer of 2000.

Various articles in *Wind Power Monthly* and *Wind Energy Weekly*.

Information regarding projects in the Wind Turbine Verification Program was obtained from the Depart-

ment of Energy, Wind Energy Program, website: <http://www.eren.doe.gov/wind/weu.html>.

Glossary

Alternating Current (AC): An electric current that reverses its direction at regularly recurring intervals, usually 50 or 60 times per second.

Amorphous Silicon: An alloy of silica and hydrogen, with a disordered, noncrystalline internal atomic arrangement, that can be deposited in thin-layers (a few micrometers in thickness) by a number of deposition methods to produce thin-film photovoltaic cells on glass, metal, or plastic substrates.

Availability Factor: A percentage representing the number of hours a generating unit is available to produce power (regardless of the amount of power) in a given period, compared to the number of hours in the period.

Avoided Costs: The incremental costs of energy and/or capacity, except for the purchase from a qualifying facility, a utility would incur itself in the generation of the energy or its purchase from another source.

Baseload: The minimum amount of electric power delivered or required over a given period of time at a steady state.

Biofuels: Wood, waste, and alcohol fuels produced from biomass (plant) feedstocks.

Biomass: Organic nonfossil material of biological origin constituting a renewable energy source.

Capacity Factor: The ratio of the electrical energy produced by a generating unit for the period of time considered to the electrical energy that could have been produced at continuous full-power operation during the same period.

Capacity, Gross: The full-load continuous rating of a generator, prime mover, or other electric equipment under specified conditions as designated by the manufacturer. It is usually indicated on a nameplate attached to the equipment.

Capital Cost: The cost of field development and plant construction and the equipment required for the generation of electricity.

Cast Silicon: Crystalline silicon obtained by pouring pure molten silicon into a vertical mold and adjusting the temperature gradient along the mold volume during cooling to obtain slow, vertically-advancing crystallization of the silicon. The polycrystalline ingot thus formed is composed of large, relatively parallel, interlocking crystals. The cast ingots are sawed into wafers for further fabrication into photovoltaic cells. Cast-silicon wafers and ribbon-silicon sheets fabricated into cells are usually referred to as polycrystalline photovoltaic cells.

Climate Change (Greenhouse Effect): The increasing mean global surface temperature of the Earth caused by gases in the atmosphere (including carbon dioxide, methane, nitrous oxide, ozone, and chlorofluorocarbons). The greenhouse effect allows solar radiation to penetrate the Earth's atmosphere but absorbs the infrared radiation returning to space.

Cogeneration: The production of electrical energy and another form of useful energy (such as heat or steam) through the sequential use of energy.

Demand-Side Management, DSM: The planning, implementation, and monitoring of utility activities designed to encourage consumers to modify patterns of electricity usage, including the timing and level of electricity demand. It refers only to energy and load-shape modifying activities that are undertaken in response to utility-administered programs.

Direct Current (DC): An electric current that flows in a constant direction. The magnitude of the current does not vary or has a slight variation.

Electric Utility Restructuring: With some notable exceptions, the electric power industry historically has been composed primarily of investor-owned utilities. These utilities have been predominantly vertically integrated monopolies (combining electricity generation, transmission, and distribution), whose prices have been regulated by State and Federal government agencies. Restructuring the industry entails the introduction of competition into at least the generation phase of electricity production, with a corresponding decrease in regulatory control. Restructuring may also modify or

eliminate other traditional aspects of investor-owned utilities, including their exclusive franchise to serve a given geographical area, assured rates of return, and vertical integration of the production process.

Emission: The release or discharge of a substance into the environment; generally refers to the release of gases or particulates into the air.

EPACT: The Energy Policy Act of 1992 addresses a wide variety of energy issues. The legislation creates a new class of power generators, exempt wholesale generators, that are exempt from the provisions of the Public Holding Company Act of 1935 and grants the authority to the Federal Energy Regulatory Commission to order and condition access by eligible parties to the interconnected transmission grid.

Exempt Wholesale Generator (EWG): A nonutility electricity generator that is not a qualifying facility under the Public Utility Regulatory Policies Act of 1978.

Externalities: Benefits or costs, generated as a by-product of an economic activity, that do not accrue to the parties involved in the activity. Environmental externalities are benefits or costs that manifest themselves through changes in the physical or biological environment.

Firm Power: Power or power-producing capacity intended to be available at all times during the period covered by a guaranteed commitment to deliver, even under adverse conditions.

Fuelwood: Wood and wood products, possibly including coppices, scrubs, branches, etc., bought or gathered, and used by direct combustion.

Generation (Electricity): The process of producing electric energy from other forms of energy; also, the amount of electric energy produced, expressed in watt-hours (Wh).

Geothermal Energy: As used at electric utilities, hot water or steam extracted from geothermal reservoirs in the Earth's crust that is supplied to steam turbines at electric utilities that drive generators to produce electricity.

Giga: One billion.

Green Marketing/Pricing: In the case of renewable electricity, green pricing represents a market solution to the various problems associated with regulatory

valuation of the nonmarket benefits of renewables. Green pricing programs allow electricity customers to express their willingness to pay for renewable energy development through direct payments on their monthly utility bills.

Grid: The layout of an electrical transmission and distribution system.

Incentives: Subsidies and other Government actions where the Governments' financial assistance is indirect.

Independent Power Producer (IPP): A wholesale electricity producer (other than a qualifying facility under the Public Utility Regulatory Policies Act of 1978), that is unaffiliated with franchised utilities in the area in which the IPP is selling power and that lacks significant marketing power. Unlike traditional utilities, IPPs do not possess transmission facilities that are essential to their customers and do not sell power in any retail service territory where they have a franchise.

Integrated Resource Planning, IRP: In the case of an electric utility, a planning and selection process for new energy resources that evaluates the full range of alternatives, including new generation capacity, power purchases, energy conservation and efficiency, cogeneration, district heating and cooling applications, and renewable energy resources, in order to provide adequate and reliable service to electrical customers at the lowest system cost. Often used interchangeable with least-cost planning.

Kilowatt (kW): One thousand watts of electricity (See Watt).

Kilowatthour (kWh): One thousand watt-hours.

Levelized Cost: The present value of the total cost of building and operating a generating plant over its economic life, converted to equal annual payments. Costs are levelized in real dollars (i.e., adjusted to remove the impact of inflation).

Marginal Cost: The change in cost associated with a unit change in quantity supplied or produced.

Megawatt (MW): One million watts of electricity (See Watt).

Merchant Facilities: High-risk, high-profit facilities that operate, at least partially, at the whims of the market, as opposed to those facilities that are constructed with close cooperation of municipalities.

Methane: The most common gas formed in coal mines; a major component of natural gas.

Modular Burner: A relatively small two-chamber combustion system used to incinerate municipal solid waste without prior processing or sorting; usually fabricated at a factory and delivered to the incineration site.

Net Metering: Arrangement that permits a facility (using a meter that reads inflows and outflows of electricity) to sell any excess power it generates over its load requirement back to the electrical grid to offset consumption.

Net Summer Capability: The steady hourly output that generating equipment is expected to supply to system load, exclusive of auxiliary power, as demonstrated by testing at the time of summer peak demand.

Nonutility Generation: Electric generation by end-users, independent power producers, or small power producers under the Public Utility Regulatory Policies Act, to supply electric power for industrial, commercial, and military operations, or sales to electric utilities.

Nonutility Power Producer: A corporation, person, agency, authority, or other legal entity or instrumentality that owns electric generating capacity and is not an electric utility. Nonutility power producers include qualifying cogenerators, qualifying small power producers, and other nonutility generators (including independent power producers) without a designated, franchised service area that do not file forms listed in the Code of Federal Regulations, Title 18, Part 141.

Operations and Maintenance (O&M) Cost: Operating expenses are associated with operating a facility (i.e., supervising and engineering expenses). Maintenance expenses are that portion of expenses consisting of labor, materials, and other direct and indirect expenses incurred for preserving the operating efficiency or physical condition of utility plants that are used for power production, transmission, and distribution of energy.

Peaking Power: Generation used to satisfy demand for electricity during the hours of highest daily, weekly, or seasonal loads (demands).

Peak Watt: A manufacturer's unit indicating the amount of power a photovoltaic cell or module will produce at standard test conditions (normally 1,000 watts per square meter and 25 degrees Celsius).

Photovoltaic Cell: An electronic device consisting of layers of semiconductor materials fabricated to form a junction (adjacent layers of materials with different electronic characteristics) and electrical contacts and being capable of converting incident light directly into electricity (direct current).

Photovoltaic Module: An integrated assembly of interconnected photovoltaic cells designed to deliver a selected level of working voltage and current at its output terminals, packaged for protection against environment degradation, and suited for incorporation in photovoltaic power systems.

Public Benefits Fund (PBF): program, funded through a generation or transmission interconnection fee on electricity used, to fund various public purpose programs, such as, low-income energy assistance, energy efficiency, consumer energy education, and renewable energy technologies development and demonstration.

Public Utility Regulatory Policies Act of 1978 (PURPA): One part of the National Energy Act, PURPA contains measures designed to encourage the conservation of energy, more efficient use of resources, and equitable rates. Principal among these were suggested retail rate reforms and new incentives for production of electricity by cogenerators and users of renewable resources.

Pulpwood: Roundwood, whole-tree chips, or wood residues.

Pyrolysis: The thermal decomposition of biomass at high temperature in the absence of oxygen.

Quadrillion Btu: Equivalent to 10 to the 15th power Btu.

Qualifying Facility (QF): A cogeneration or small power production facility that meets certain ownership, operating, and efficiency criteria established by the Federal Energy Regulatory Commission (FERC) pursuant to the Public Utility Regulatory Policies Act of 1978 (PURPA). (See the Code of Federal Regulations, Title 18, Part 292.)

Refuse-Derived Fuel (RDF): Fuel processed from municipal solid waste that can be in shredded, fluff, or densified pellet forms.

Renewable Energy Source: An energy source that is regenerative or virtually inexhaustible. Typical examples are wind, geothermal, and water power.

Renewable Portfolio Standard, RPS: Mandate that ensures that renewable energy constitutes a certain percentage of total energy generation or consumption.

Ribbon Silicon: Single-crystal silicon derived by means of fabricating processes that produce sheets or ribbons of single-crystal silicon. These processes include edge-defined film-fed growth, dendritic web growth, and ribbon-to-ribbon growth.

Roundwood: Logs, bolts, and other round timber generated from the harvesting of trees.

Silicon: A semiconductor material made from silica, purified for photovoltaic applications.

Single Crystal Silicon (Czochralski): An extremely pure form of crystalline silicon produced by the Czochralski method of dipping a single crystal seed into a pool of molten silicon under high vacuum conditions and slowly withdrawing a solidifying single crystal boule rod of silicon. The boule is sawed into thin wafers and fabricated into single-crystal photovoltaic cells.

Solar Energy: The radiant energy of the sun, which can be converted into other forms of energy, such as heat or electricity.

Subsidy: Financial assistance granted by the Government to firms and individuals.

System Benefits Charge, SBC: A non-bypassable fee on transmission interconnection; funds are allocated among public purposes, including the development and demonstration of renewable energy technologies.

Tipping Fee: Price charged to deliver municipal solid waste to a landfill, waste-to-energy facility, or recycling facility.

Transmission System (Electric): An interconnected group of electric transmission lines and associated equipment for moving or transferring electric energy in bulk between points of supply and points at which it is transformed for delivery over the distribution system lines to consumers, or is delivered to other electric systems.

Turbine: A machine for generating rotary mechanical power from the energy of a stream of fluid (such as water, steam, or hot gas). Turbines convert the kinetic energy of fluids to mechanical energy through the principles of impulse and reaction, or a mixture of the two.

Watt (Electric): The electrical unit of power. The rate of energy transfer equivalent to 1 ampere of electric current flowing under a pressure of 1 volt at unity power factor.

Watt (Thermal): A unit of power in the metric system, expressed in terms of energy per second, equal to the work done at a rate of 1 joule per second.

Watt-hour (Wh): The electrical energy unit of measure equal to 1 watt of power supplied to, or taken from, an electric circuit steadily for 1 hour.

Wind Power Class: A classification method used to describe the usable (for electricity generation) wind resource at a particular site. A classification of 1 denotes the least amount of energy, while a classification of 7 denotes the greatest amount of energy.

Wood Pellets: Fuel manufactured from finely ground wood fiber and used in pellet stoves.

Coal Combustion: Nuclear Resource or Danger

By Alex Gabbard



Alex Gabbard at the coal pile for ORNL's steam plant.

Over the past few decades, the American public has become increasingly wary of nuclear power because of concern about radiation releases from normal plant operations, plant accidents, and nuclear waste. Except for Chernobyl and other nuclear accidents, releases have been found to be almost undetectable in comparison with natural background radiation. Another concern has been the cost of producing electricity at nuclear plants. It has increased largely for two reasons: compliance with stringent government regulations that restrict releases of radioactive substances from nuclear facilities into the environment and construction delays as a result of public opposition.

Americans living near coal-fired power plants are exposed to higher radiation doses than those living near nuclear power plants that meet government regulations

Partly because of these concerns about radioactivity and the cost of containing it, the American public and electric utilities have preferred coal combustion as a power source. Today 52% of the capacity for generating electricity in the United States is fueled by coal, compared with 14.8% for nuclear energy. Although there are economic justifications for this preference, it is surprising for two reasons. First, coal combustion produces carbon dioxide and other greenhouse gases that are suspected to cause climatic warming, and it is a source of sulfur oxides and nitrogen oxides, which are harmful to human health and may be largely responsible for acid rain. Second, although not as well known, releases from coal combustion contain naturally occurring radioactive materials--mainly, uranium and thorium.

Former ORNL researchers J. P. McBride, R. E. Moore, J. P. Witherspoon, and R. E. Blanco made this point in their article "Radiological Impact of Airborne Effluents of Coal and Nuclear Plants" in the December 8, 1978, issue of Science magazine. They concluded that Americans living near coal-fired power plants are exposed to higher radiation doses than those living near nuclear power plants that meet government regulations. This ironic situation remains true today and is addressed in this article.

The fact that coal-fired power plants throughout the world are the major sources of radioactive materials released to the environment has several implications. It suggests that coal combustion is more hazardous to health than nuclear power and that it adds to the background radiation burden even more than does nuclear power. It also suggests that if radiation emissions from coal plants were regulated, their capital and operating costs would increase, making coal-fired power less economically competitive.

Finally, radioactive elements released in coal ash and exhaust produced by coal combustion contain fissionable fuels and much larger quantities of fertile materials that can be bred into fuels by absorption of neutrons, including those generated in the air by bombardment of oxygen, nitrogen, and other nuclei with cosmic rays; such fissionable and fertile materials can be recovered from coal ash using known technologies. These nuclear materials have growing value to private concerns and governments that may want to market them for fueling nuclear power plants. However, they are also available to those interested in accumulating material for nuclear weapons. A solution to this potential problem may be to encourage electric utilities to process coal ash and use new trapping technologies on coal combustion exhaust to isolate and collect valuable metals, such as iron and aluminum, and available nuclear fuels.

Makeup of Coal and Ash

Coal is one of the most impure of fuels. Its impurities range from trace quantities of many metals, including uranium and thorium, to much larger quantities of aluminum and iron to still larger quantities of impurities such as sulfur. Products of coal combustion include the oxides of carbon, nitrogen, and sulfur; carcinogenic and mutagenic substances; and recoverable minerals of commercial value, including nuclear fuels naturally occurring in coal.

The amount of thorium contained in coal is about 2.5 times greater than the amount of uranium

Coal ash is composed primarily of oxides of silicon, aluminum, iron, calcium, magnesium, titanium, sodium, potassium, arsenic, mercury, and sulfur plus small quantities of uranium and thorium. Fly ash is primarily composed of non-combustible silicon compounds (glass) melted during combustion. Tiny glass spheres form the bulk of the fly ash.

Since the 1960s particulate precipitators have been used by U.S. coal-fired power plants to retain significant amounts of fly ash rather than letting it escape to the atmosphere. When functioning properly, these precipitators are approximately 99.5% efficient. Utilities also collect furnace ash, cinders, and slag, which are kept in cinder piles or deposited in ash ponds on coal-plant sites along with the captured fly ash.

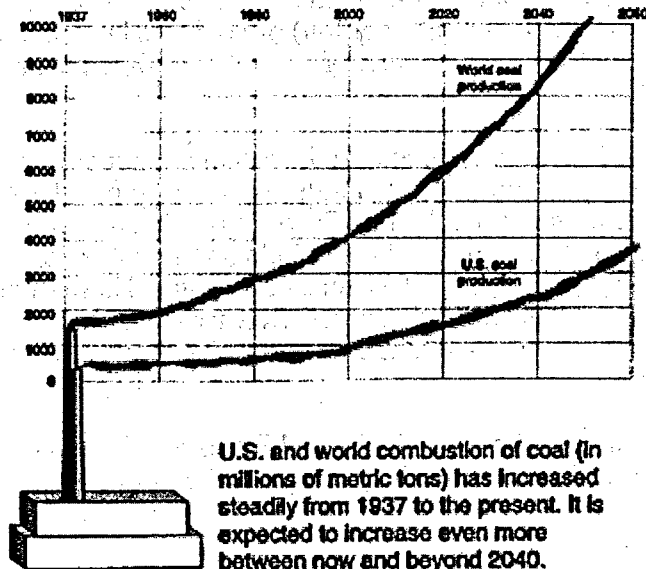
Trace quantities of uranium in coal range from less than 1 part per million (ppm) in some samples to around 10 ppm in others. Generally, the amount of thorium contained in coal is about 2.5 times greater than the amount of uranium. For a large number of coal samples, according to Environmental Protection Agency figures released in 1984, average values of uranium and thorium content have been determined to be 1.3 ppm and 3.2 ppm, respectively. Using these values along with reported consumption and projected consumption of coal by utilities provides a means of calculating the amounts of potentially recoverable breedable and fissionable elements (see sidebar). The concentration of fissionable uranium-235 (the current fuel for nuclear power plants) has been established to be 0.71% of uranium content.

Uranium and Thorium in Coal and Coal Ash

As population increases worldwide, coal combustion continues to be the dominant fuel source for electricity. Fossil fuels' share has decreased from 76.5% in 1970 to 66.3% in 1990, while nuclear energy's share in the worldwide electricity pie has climbed from 1.6% in 1970 to 17.4% in 1990. Although U.S. population growth is slower than worldwide growth, per capita consumption of energy in this country is among the world's highest. To meet the growing demand for electricity, the U.S. utility industry has continually expanded generating capacity. Thirty years ago, nuclear power appeared to be a viable replacement for fossil power, but today it represents less than 15% of U.S. generating capacity. However, as a result of low public support during recent decades and a reduction in the rate of expected power demand, no increase in nuclear power generation is expected in the foreseeable future. As current

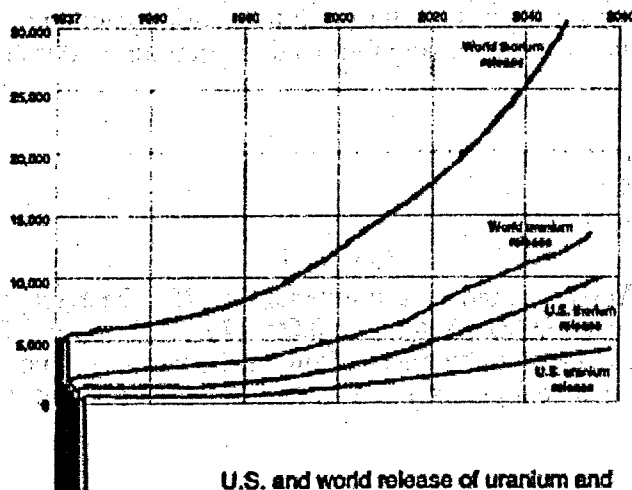
nuclear power plants age, many plants may be retired during the first quarter of the 21st century, although some may have their operation extended through license renewal. As a result, many nuclear plants are likely to be replaced with coal-fired plants unless it is considered feasible to replace them with fuel sources such as natural gas and solar energy.

U.S. AND WORLD COAL COMBUSTION (millions of tons)

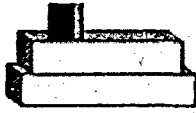


As the world's population increases, the demands for all resources, particularly fuel for electricity, is expected to increase. To meet the demand for electric power, the world population is expected to rely increasingly on combustion of fossil fuels, primarily coal. The world has about 1500 years of known coal resources at the current use rate. The graph above shows the growth in U.S. and world coal combustion for the 50 years preceding 1988, along with projections beyond the year 2040. Using the concentration of uranium and thorium indicated above, the graph below illustrates the historical release quantities of these elements and the releases that can be expected during the first half of the next century, given the predicted growth trends. Using these data, both U.S. and worldwide fissionable uranium-235 and fertile nuclear material releases from coal combustion can be calculated.

U.S. AND WORLD RELEASE OF URANIUM AND THORIUM



U.S. and world release of uranium and



thorium (in metric tons) from coal combustion has risen steadily since 1937. It is projected to continue to increase through 2040 and beyond.

Because existing coal-fired power plants vary in size and electrical output, to calculate the annual coal consumption of these facilities, assume that the typical plant has an electrical output of 1000 megawatts. Existing coal-fired plants of this capacity annually burn about 4 million tons of coal each year. Further, considering that in 1982 about 616 million short tons (2000 pounds per ton) of coal was burned in the United States (from 833 million short tons mined, or 74%), the number of typical coal-fired plants necessary to consume this quantity of coal is 154.

Using these data, the releases of radioactive materials per typical plant can be calculated for any year. For the year 1982, assuming coal contains uranium and thorium concentrations of 1.3 ppm and 3.2 ppm, respectively, each typical plant released 5.2 tons of uranium (containing 74 pounds of uranium-235) and 12.8 tons of thorium that year. Total U.S. releases in 1982 (from 154 typical plants) amounted to 801 tons of uranium (containing 11,371 pounds of uranium-235) and 1971 tons of thorium. These figures account for only 74% of releases from combustion of coal from all sources. Releases in 1982 from worldwide combustion of 2800 million tons of coal totaled 3640 tons of uranium (containing 51,700 pounds of uranium-235) and 8960 tons of thorium.

Based on the predicted combustion of 2516 million tons of coal in the United States and 12,580 million tons worldwide during the year 2040, cumulative releases for the 100 years of coal combustion following 1937 are predicted to be:

U.S. release (from combustion of 111,716 million tons):

Uranium: 145,230 tons (containing 1031 tons of uranium-235)

Thorium: 357,491 tons

Worldwide release (from combustion of 637,409 million tons):

Uranium: 828,632 tons (containing 5883 tons of uranium-235)

Thorium: 2,039,709 tons

Radioactivity from Coal Combustion

The main sources of radiation released from coal combustion include not only uranium and thorium but also daughter products produced by the decay of these isotopes, such as radium, radon, polonium, bismuth, and lead. Although not a decay product, naturally occurring radioactive potassium-40 is also a significant contributor.

The population effective dose equivalent from coal plants is 100 times that from nuclear plants

According to the National Council on Radiation Protection and Measurements (NCRP), the average radioactivity per short ton of coal is 17,100 millicuries/4,000,000 tons, or 0.00427 millicuries/ton. This figure can be used to calculate the average expected radioactivity release from coal combustion. For 1982 the total release of radioactivity from 154 typical coal plants in the United States was, therefore, 2,630,230 millicuries.

Thus, by combining U.S. coal combustion from 1937 (440 million tons) through 1987 (661 million tons) with an estimated total in the year 2040 (2516 million tons), the total expected U.S. radioactivity release to the environment by 2040 can be determined. That total comes from the expected combustion of 111,716 million tons of coal with the release of 477,027,320 millicuries in the United States. Global releases of radioactivity from the predicted combustion of 637,409 million tons of coal would be 2,721,736,430 millicuries.

For comparison, according to NCRP Reports No. 92 and No. 95, population exposure from operation of 1000-MWe nuclear and coal-fired power plants amounts to 490 person-rem/year for coal plants and 4.8 person-rem/year for nuclear plants. Thus, the population effective dose equivalent from coal plants is 100 times that from nuclear plants. For the complete nuclear fuel cycle, from mining to reactor operation to waste disposal, the radiation dose is cited as 136 person-rem/year; the equivalent dose for coal use, from mining to power plant operation to waste disposal, is not listed in this report and is probably unknown.

During combustion, the volume of coal is reduced by over 85%, which increases the concentration of the metals originally in the coal. Although significant quantities of ash are retained by precipitators, heavy metals such as uranium tend to concentrate on the tiny glass spheres that make up the bulk of fly ash. This uranium is released to the atmosphere with the escaping fly ash, at about 1.0% of the original amount, according to NCRP data. The retained ash is enriched in uranium several times over the original uranium concentration in the coal because the uranium, and thorium, content is not decreased as the volume of coal is reduced.

All studies of potential health hazards associated with the release of radioactive elements from coal combustion conclude that the perturbation of natural background dose levels is almost negligible. However, because the half-lives of radioactive potassium-40, uranium, and thorium are practically infinite in terms of human lifetimes, the accumulation of these species in the biosphere is directly proportional to the length of time that a quantity of coal is burned.

Although trace quantities of radioactive heavy metals are not nearly as likely to produce adverse health effects as the vast array of chemical by-products from coal combustion, the accumulated quantities of these isotopes over 150 or 250 years could pose a significant future ecological burden and potentially produce adverse health effects, especially if they are locally accumulated. Because coal is predicted to be the primary energy source for electric power production in the foreseeable future, the potential impact of long-term accumulation of by-products in the biosphere should be considered.

*The energy content of nuclear fuel
released in coal combustion is greater
than that of the coal consumed*

Energy Content: Coal vs Nuclear

An average value for the thermal energy of coal is approximately 6150 kilowatt-hours(kWh)/ton. Thus, the expected cumulative thermal energy release from U.S. coal combustion over this period totals about 6.87×10^{14} kilowatt-hours. The thermal energy released in nuclear fission produces about 2×10^9 kWh/ton. Consequently, the thermal energy from fission of uranium-235 released in coal combustion amounts to 2.1×10^{12} kWh. If uranium-238 is bred to plutonium-239, using these data and assuming a "use factor" of 10%, the thermal energy from fission of this isotope alone constitutes about 2.9×10^{14} kWh, or about half the anticipated energy of all the utility coal burned in this country through the year 2040. If the thorium-232 is bred to uranium-233 and fissioned with a similar "use factor", the thermal energy capacity of this isotope is approximately 7.2×10^{14} kWh, or 105% of the thermal energy released from U.S. coal combustion for a century. Assuming 10% usage, the total of the thermal energy capacities from each of these three fissionable isotopes is about 10.1×10^{14} kWh, 1.5 times more than the total from coal. World combustion of coal has the same ratio, similarly indicating that coal

combustion wastes more energy than it produces.



Views of the Tennessee Valley Authority's Bull Run and Kingston Steam Plants. These coal-fired facilities generate electricity for Oak Ridge and the surrounding area.

Consequently, the energy content of nuclear fuel released in coal combustion is more than that of the coal consumed! Clearly, coal-fired power plants are not only generating electricity but are also releasing nuclear fuels whose commercial value for electricity production by nuclear power plants is over \$7 trillion, more than the U.S. national debt. This figure is based on current nuclear utility fuel costs of 7 mills per kWh, which is about half the cost for coal. Consequently, significant quantities of nuclear materials are being treated as coal waste, which might become the cleanup nightmare of the future, and their value is hardly recognized at all.

How does the amount of nuclear material released by coal combustion compare to the amount consumed as fuel by the U.S. nuclear power industry? According to 1982 figures, 111 American nuclear plants consumed about 540 tons of nuclear fuel, generating almost 1.1×10^{12} kWh of electricity. During the same year, about 801 tons of uranium alone were released from American coal-fired plants. Add 1971 tons of thorium, and the release of nuclear components from coal combustion far exceeds the entire U.S. consumption of nuclear fuels. The same conclusion applies for worldwide nuclear fuel and coal combustion.

Another unrecognized problem is the gradual production of plutonium-239 through the exposure of uranium-238 in coal waste to neutrons from the air. These neutrons are produced primarily by bombardment of oxygen and nitrogen nuclei in the atmosphere by cosmic rays and from spontaneous fission of natural isotopes in soil. Because plutonium-239 is reportedly toxic in minute quantities, this process, however slow, is potentially worrisome. The radiotoxicity of plutonium-239 is 3.4×10^{11} times that of uranium-238. Consequently, for 801 tons of uranium released in 1982, only 2.2 milligrams of plutonium-239 bred by natural processes, if those processes exist, is necessary to double the radiotoxicity estimated to be released into the biosphere that year. Only 0.075 times that amount in plutonium-240 doubles the radiotoxicity. Natural processes to produce both plutonium-239 and plutonium-240 appear to exist.

Conclusions

For the 100 years following 1937, U.S. and world use of coal as a heat source for electric power generation will result in the distribution of a variety of radioactive elements into the environment. This prospect raises several questions about the risks and benefits of coal combustion, the leading source of electricity production.

First, the potential health effects of released naturally occurring radioactive elements are a long-term issue that has not been fully addressed. Even with improved efficiency in retaining stack emissions, the removal of coal from its shielding overburden in the earth and subsequent combustion releases large quantities of radioactive materials to the surface of the earth. The emissions by coal-fired power plants of greenhouse gases, a vast array of chemical by-products, and naturally occurring radioactive elements make coal much less desirable as an energy source than is generally accepted.

Second, coal ash is rich in minerals, including large quantities of aluminum and iron. These and other products of commercial value have not been exploited.

Third, large quantities of uranium and thorium and other radioactive species in coal ash are not being treated as radioactive waste. These products emit low-level radiation, but because of regulatory differences, coal-fired power plants are allowed to release quantities of radioactive material that would provoke enormous public outcry if such amounts were released from nuclear facilities. Nuclear waste products from coal combustion are allowed to be dispersed throughout the biosphere in an unregulated manner. Collected nuclear wastes that accumulate on electric utility sites are not protected from weathering, thus exposing people to increasing quantities of radioactive isotopes through air and water movement and the food chain.

Fourth, by collecting the uranium residue from coal combustion, significant quantities of fissionable material can be accumulated. In a few year's time, the recovery of the uranium-235 released by coal combustion from a typical utility anywhere in the world could provide the equivalent of several World War II-type uranium-fueled weapons. Consequently, fissionable nuclear fuel is available to any country that either buys coal from outside sources or has its own reserves. The material is potentially employable as weapon fuel by any organization so inclined. Although technically complex, purification and enrichment technologies can provide high-purity, weapons-grade uranium-235. Fortunately, even though the technology is well known, the enrichment of uranium is an expensive and time-consuming process.

Because electric utilities are not high-profile facilities, collection and processing of coal ash for recovery of minerals, including uranium for weapons or reactor fuel, can proceed without attracting outside attention, concern, or intervention. Any country with coal-fired plants could collect combustion by-products and amass sufficient nuclear weapons material to build up a very powerful arsenal, if it has or develops the technology to do so. Of far greater potential are the much larger quantities of thorium-232 and uranium-238 from coal combustion that can be used to breed fissionable isotopes. Chemical separation and purification of uranium-233 from thorium and plutonium-239 from uranium require far less effort than enrichment of isotopes. Only small fractions of these fertile elements in coal combustion residue are needed for clandestine breeding of fissionable fuels and weapons material by those nations that have nuclear reactor technology and the inclination to carry out this difficult task.

Fifth, the fact that large quantities of uranium and thorium are released from coal-fired plants without restriction raises a paradoxical question. Considering that the U.S. nuclear power industry has been required to invest in expensive measures to greatly reduce releases of radioactivity from nuclear fuel and fission products to the environment, should coal-fired power plants be allowed to do so without constraints?

If increased regulation of nuclear power plants is demanded, then we can expect a significant redirection of national policy in regulation of radioactive emissions from coal combustion

This question has significant economic repercussions. Today nuclear power plants are not as economical to construct as coal-fired plants, largely because of the high cost of complying with regulations to restrict emissions of radioactivity. If coal-fired power plants were regulated in a similar manner, the added cost of handling nuclear waste from coal combustion would be significant and would, perhaps, make it difficult for coal-burning plants to compete economically with nuclear power.

Because of increasing public concern about nuclear power and radioactivity in the environment, reduction of releases of nuclear materials from all sources has become a national priority known as "as low as reasonably achievable" (ALARA). If increased regulation of nuclear power plants is demanded, can we expect a significant redirection of national policy so that radioactive emissions from coal combustion are also regulated?

Although adverse health effects from increased natural background radioactivity may seem unlikely for the near term, long-term accumulation of radioactive materials from continued worldwide combustion of coal could pose serious health hazards. Because coal combustion is projected to increase throughout the world during the next century, the increasing accumulation of coal combustion by-products, including radioactive components, should be discussed in the formulation of energy policy and plans for future energy use.

One potential solution is improved technology for trapping the exhaust (gaseous emissions up the stack) from coal combustion. If and when such technology is developed, electric utilities may then be able both to recover useful elements, such as nuclear fuels, iron, and aluminum, and to trap greenhouse gas emissions. Encouraging utilities to enter mineral markets that have been previously unavailable may or may not be desirable, but doing so appears to have the potential of expanding their economic base, thus offsetting some portion of their operating costs, which ultimately could reduce consumer costs for electricity.

Both the benefits and hazards of coal combustion are more far-reaching than are generally recognized. Technologies exist to remove, store, and generate energy from the radioactive isotopes released to the environment by coal combustion. When considering the nuclear consequences of coal combustion, policymakers should look at the data and recognize that the amount of uranium-235 alone dispersed by coal combustion is the equivalent of dozens of nuclear reactor fuel loadings. They should also recognize that the nuclear fuel potential of the fertile isotopes of thorium-232 and uranium-238, which can be converted in reactors to fissionable elements by breeding, yields a virtually unlimited source of nuclear energy that is frequently overlooked as a natural resource.

*The amount of uranium-235 alone dispersed
by coal combustion is the equivalent of
dozens of nuclear reactor fuel loadings*

In short, naturally occurring radioactive species released by coal combustion are accumulating in the environment along with minerals such as mercury, arsenic, silicon, calcium, chlorine, and lead, sodium, as well as metals such as aluminum, iron, lead, magnesium, titanium, boron, chromium, and others that are continually dispersed in millions of tons of coal combustion by-products. The potential benefits and threats of these released materials will someday be of such significance that they should not now be ignored.--Alex Gabbard of the Metals and Ceramics Division

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Where to?



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MOC 2004

7/13/05

Energy Policy and Conservation Report

DRAFT



**MINNESOTA
DEPARTMENT OF
COMMERCE**

**July 2004
Revised December 2004**



STATE OF MINNESOTA

Office of Governor Tim Pawlenty

130 State Capitol • 75 Rev. Dr. Martin Luther King Jr. Boulevard • Saint Paul, MN 55

August 23, 2004

Commissioner Glenn Wilson
Department of Commerce
85 Seventh Place East, Suite 500
St. Paul, MN 55101

Dear Commissioner Wilson:

I am pleased to accept the Department of Commerce's draft Energy Policy and Conservation Report for 2004. A key finding of this comprehensive report is that Minnesota's energy system, with a few notable exceptions, continues to provide Minnesotans with high quality service at a reasonable cost. The energy we use is vital to the quality of the lives of our citizens, as well as the state's economic and environmental health.

Ensuring the quality, reliability and affordability of our energy system took years of hard work, wise policies and significant investment to develop a balanced portfolio of energy sources and a strong delivery and transmission system. There is much good news for Minnesotans chronicled in this report, including:

- Retail prices for natural gas and electricity in Minnesota continue to be relatively low, in relation to other states;
- Minnesota ranks 3rd in the nation in the amount of renewable energy installed in the state, a testament to this Administration's commitment to the development of Minnesota's wind energy resource;
- Minnesota's Conservation Improvement Plan program consistently ranks as a leader among conservation and energy efficiency programs around the country. We will continue to protect and enhance this important program;

August 23, 2004

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- Late last year, the Minnesota Public Utilities Commission's approved Xcel Energy's Metropolitan Emissions Reduction Proposal to clean up three of the utility's metropolitan area coal-fired generation facilities, resulting in the single largest decrease in Clean Air Act emissions in Minnesota's history.

In addition, the draft report identified a number of challenges that lie ahead, many of which involved the reliability of electric service in the state. Ensuring that Minnesotans have the electricity they need when they need it is vital, and is this Administration's top energy priority.

In the wake of August 14, 2003 blackout – which I personally experienced – I requested from you an evaluation of the reliability of Minnesota's electric system. Chapter two of this report is that evaluation. The draft report finds that Minnesota's electric system is sound and reliable in all essential respects, but that our electric utilities have not kept up with the state's growing population and economy in some key areas. In particular, the report noted:

- There are at least 26 sites around the state where the electric grid does not meet basic reliability standards. Such deficiencies in our electric system are simply not acceptable. I understand you are working through the Public Utilities Commission to ensure that the utilities responsible for those areas address these weaknesses.
- Significant new and additional infrastructure transmission investments need to be planned for and made over the next decade. New transmission lines are needed, and existing lines must be upgraded, to continue reliable electric service in the state, and the development of Minnesota's wind energy resources.
- While enhanced conservation efforts, expanded renewable energy development and an upgraded transmission system can go a long way toward reducing the need to build new power plants, new power plants will be needed to meet Minnesota's growing energy needs.

August 23, 2004

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- Computers and technological manufacturing systems are much more sensitive to fluctuations in power quality than are light bulbs. A reliable energy system needs to meet the power quality needs of an increasingly digital economy.

Addressing these challenges in the most cost effective manner with the lowest environmental impacts is essential to the vitality of Minnesota's economy and the protection of its natural resources. Your draft report identified these challenges, and outlines the policies and strategies the Department will be pursuing to meet those challenges. However, the draft report did not include specific recommendations to address the challenges identified. As you develop your policy and budget initiatives for the upcoming legislative session, I ask that you prepare legislative and administrative recommendations for my review to address the key challenges raised in the report.

My compliments on an excellent draft report. I look forward to your specific recommendations.

Sincerely



Tim Pawlenty
Governor

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Introduction

Every four years, the Department of Commerce¹ is required by Minnesota Statutes, section 216C.18² to issue the State Energy Policy and Conservation Report “designed to identify major emerging trends and issues in energy supply, consumption, conservation, and costs.” This report – informally referred to as the Quadrennial or “Quad” Report – is published in fulfillment of that requirement.³

Under Governor Pawlenty’s Administration, the guiding principles of Minnesota’s energy policy are to ensure that:

- Minnesota has a reliable energy-provision system into the future;
- the state’s energy system meets Minnesota’s economic needs;
- Minnesota’s energy costs remain low, compared to the rest of the nation; and
- the environmental impacts of the energy produced and consumed in the state are reduced.

The goal of these guiding principles is to maintain Minnesota’s current reliable, low-cost energy in order to promote job growth and economic development, while lowering the environmental impacts of the production, delivery and use of that energy.

Achieving this goal requires weaving seven energy policy strategies that build on many elements in the present electricity system while making important systemic improvements now and in the future. These seven energy policy strategies are:

Energy Policy Strategy No. 1 – Continue the operation of facilities that provide safe, reliable, low-cost power and do not emit air pollution. The Department supported legislation in 2003 to allow additional spent fuel storage at Xcel Energy’s Prairie Island nuclear generation facility. Minnesota’s utilities project the need for over 4000 megawatts of mostly baseload and some intermediate resources in the next ten years. During this time period, the licenses will expire of both of Xcel Energy’s (Xcel) nuclear generation facilities in Minnesota, Prairie Island and Monticello. These facilities combined provide over 1600 megawatts of baseload generation without emitting any air pollution in the state. If the federal Nuclear Regulatory Commission does not re-license these two facilities, Minnesota’s baseload needs and air pollution problems will expand significantly.

Energy Policy Strategy No. 2 – Encourage coal-fired power generation facilities to convert to less polluting fuels, or to install state-of-the-art emissions control technologies. The Department, with Governor Pawlenty’s leadership, helped to establish a strong and broad coalition of support for Xcel’s Metropolitan Emissions Reduction Program. The coalition, including representatives of the legislature, the business community, energy and environmental

¹ Please see Appendix 1 for a description of the Energy Functions within the Department of Commerce.

² The text of Minn. Stat. 216C.18 is provided in Appendix 8.

³ Appendix 2 provides energy data in compliance with Minn. Stat. § 216C.18, subd. 1. Minn. Stat. 216C.18, subd. 1a stipulates that the Minnesota Public Utilities Commission provide a section on such a rate design policy. That section may be found in Appendix 7.

regulators, public health officials, citizens and environmentalists, supported the re-powering with natural gas of two of Xcel's oldest and dirtiest coal plants, and the installation of state-of-the art control technologies on a third.

Energy Policy Strategy No. 3 – Encourage the generation of reasonably priced, environmentally superior electricity from low-polluting or renewable fuels. The Department supported legislation in the 2003 legislature to expand wind development incentives, and to firm up the state's Renewable Energy Objectives (REO). Under the REO, Minnesota's utilities are required to make a good faith effort to have 10 percent of the electricity they provide to Minnesotans come from renewable energy sources by 2015. The Department supported legislation to require utilities to prove to the Public Utilities Commission that utilities are making the required effort, applying performance criteria developed by the Department and adopted by the Commission.

Energy Policy Strategy No. 4 – Enhance the state and region's energy delivery infrastructure to assure reliability and provide access for electricity from low-cost and/or environmentally superior sources. The Department supported the permitting and construction of the new transmission line from the Buffalo Ridge in southwest Minnesota to the twin cities, as well as other transmission line proposals. In addition, the Department advocated strongly at the Public Utilities Commission (Commission) that Minnesota's transmission owning utilities provide a schedule for addressing numerous, identified weaknesses in the state's transmission grid. The Department is also very active in regional reliability discussions, at Midwest Independent System Operator (MISO) – the Department holds a seat on the MISO Advisory Board) – and at the Organization of MISO States meetings.

Energy Policy Strategy No. 5 – Support research, development and deployment of new, environmentally superior energy technologies. The Department supported approximately \$20 million in funding for hydrogen research and other renewable energy research and development at the University of Minnesota in the 2003 legislature. The Department is also a leader in the Minnesota Renewable Hydrogen Initiative, a partnership of industry, university, government and non-government organizations, to guide the state's effort to grow and promote Minnesota's renewable hydrogen industry. In addition, the Department is very active on ethanol and biodiesel program developments in the state, especially with regard to the marketing of E85 fuels (E85 is a transportation fuel, containing 85 percent ethanol and 15 percent gasoline).

Energy Policy Strategy No. 6 – Support the state's conservation programs. The Department opposed efforts in the 2003 and 2004 legislative sessions to divert conservation funds for other purposes to ensure that Minnesota's energy conservation efforts do not decrease. The Department also sought and received approval from the Legislative Audit Commission for a program evaluation of Minnesota's Conservation Improvement Plan (CIP) program. CIP is the nation's premier conservation program, resulting in conservation investments totaling approximately \$75 million annually in the state. The program audit will ensure that these funds are spent economically and efficiently. The results of the audit should be available by the end of 2004.

Energy Policy Strategy No. 7 – Reduce regulatory and government barriers. The Department believes that state regulatory requirements for new energy infrastructure investments should be sufficient to weed out bad projects from good (or refine projects to improve them), but should not act as a barrier to critical infrastructure investments necessary to providing reliable electric service to Minnesota consumers. The Department advocated for having a single administrative law judge oversee development of a joint administrative record for both Commission and EQB decisions regarding the need and siting of a proposed generation project. Generally, the administrative record is developed separately and in different timeframes for each decision-making body, and usually by different ALJs. Current law allows these proceedings to be combined, but a combined proceeding has been the rare exception rather the rule. The Department will seek other opportunities for efficiencies in regulatory oversight.

Much has been done up through 2003, but there is plenty more to do on all these strategies. However, the Department's primary focus will be on reliability; assuring the state's current and long term energy reliability.

The Department defines reliability as more than just keeping the lights on and preventing large regional blackouts such as the one that affected the Eastern U.S. on August 14, 2003. The Department's definition includes the long-term adequacy of supply; security and sufficiency of the transmission grid, and local power quality at the distribution level. As discussed more fully in chapter three, this emphasis on reliability will take many forms:

- Focus on utility operations, maintenance and system control measures;
- Promote greater investments in and upgrades of transmission and distribution infrastructure;
- Continue streamlining the state's regulatory review process to increase certainty of obtaining timely decisions;
- Reach out to neighboring states and provinces to create collaborative, multi-jurisdictional solutions to grid operations issues;
- Improve power quality and service standards; and finally
- Allow economic efficiency principles to guide our actions, whenever possible.

Lastly, the last several years have seen increased amounts of renewable energy development in Minnesota, particularly in many of our rural communities. In addition to the reliability benefits gained by diversifying our energy generation mix, renewable energy development can create economic development benefits as well. The Department will continue to work with other state agencies to ensure that the energy needs for the system as a whole are balanced with economic development and other community goals.

Chapter One

SUMMARY OF MAJOR ENERGY LEGISLATION SINCE 2000

Since the last Quad Report in 2000, the Minnesota Legislature has passed two major pieces of energy policy legislation. The 2001 Legislature passed the Minnesota Energy Security and Reliability Act of 2001 (“MESRA” – Laws of Minnesota 2001, chapter 212). In 2003, the legislature dealt with the issue of continued operation of Xcel Energy’s nuclear generation facilities at Prairie Island and Monticello (Laws of Minnesota 2003, special session chapter 11). This chapter will briefly summarize these two pieces of legislation, and the regulatory or administrative actions that have followed from them.

THE MINNESOTA ENERGY SECURITY AND RELIABILITY ACT OF 2001

The Minnesota Energy Security and Reliability Act of 2001 (MESRA) was enacted in response to a Department of Commerce initiative issued in September, 2000 entitled “Keeping the Lights On.” MESRA had three key parts:

1. Essential Energy Infrastructure
2. Distributed Energy Resources
3. Other Reliability and Planning Provisions

Essential Energy Infrastructure

MESRA made a number of changes to the procedures by which essential energy infrastructure is planned for and approved, by reforming and recodifying the Power Plant Siting Act (Minn. Stat. 116C.57 et seq); establishing a new statewide transmission planning process (Minn. Stat. 216B.2525); and by making a few minor amendments to the state's Certificate of Need statute (Minn. Stat. 216B.243). Each of these three energy infrastructure changes is discussed below.

Power Plant Siting Act Reform

The 2001 legislature recodified the Power Plant Siting Act, reforming that statute in many respects. The most significant of these reforms involved the interplay between the Public Utilities Commission, which is charged with determining the need for proposed energy projects above a specified capacity, and the Environmental Quality Board (EQB), which is responsible for conducting environmental review of proposed energy projects. Prior to the 2001 session, the EQB found itself bogged down in controversy over whether a proposed transmission project was “needed.” Certain projects, because of size, length or capacity thresholds, were not required to receive a certificate of need (CON) from the Commission.

The 2001 legislature amended the CON statute, to decrease the capacity and length criteria for transmission lines for which a CON would be required from the Commission prior to construction. In addition, the legislature specified that when the Commission has issued a CON for a project, the EQB may not consider issues of need in the siting or routing of the project.

Issues of need include: the size, type and timing of the project; alternative system configurations; and voltage. In other words, the EQB may only consider the location of the project, to minimize the environmental impacts of the proposed project.

In addition, MESRA provided for expedited and local permitting processes for projects that have historically not been overly contentious, such as small generation facilities; natural gas generation facilities; transmission lines between 100 and 200 kilovolts; transmission line upgrades along existing transmission rights of way; and transmission lines of between 200 and 300 kilovolts less than 10 miles in length.

In response to these statutory changes, the EQB initiated two administrative rulemakings. The Board acted to revise its general power plant siting rules (Minnesota Rules, chapter 4400); this rulemaking was completed in early 2003. The other rulemaking (Minnesota Rules, chapter 4410) was initiated to specify the entity responsible for gathering the information on the potential environmental impacts of a proposed project, along with alternatives to the project, in a CON proceeding before for the Public Utilities Commission. That rulemaking was completed as of November 12, 2003, and the Board designated itself as the entity responsible for gathering that information. A general discussion of review and siting for large energy facilities may be found in Appendix 5.

State Transmission Planning

Prior to 2001, utilities planned for transmission upgrades among themselves, without public or regulatory input into that planning process. MESRA created a state transmission planning process, in which each transmission owning utility in the state is required to:

- identify and address inadequacies in the utility's transmission system;
- solicit public input from the public and local governments on those inadequacies; and
- file a plan with the Minnesota Public Utilities Commission by November 1 of each odd numbered year.

Under the statute, a transmission-owning utility could propose to have the Commission "certify" a project, and add that project to the Commission's "List of Priority Projects." The effect of having a project certified and listed is that such a project does not need a separate CON from the Commission. The Commission is to make decisions on which projects to certify as priority projects by June of the following year.

The Commission adopted rules for the state transmission plan process in June 2003. The Commission has received two sets of submissions under this statute, one in 2001, and one in 2003 (as mentioned above). The most recent plan⁴ (filed on November 3, 2003) was submitted

⁴ A copy of this plan can be viewed or downloaded at <http://www.minnelectrans.com/>.

jointly by the Minnesota utilities subject to the planning requirement, and was approved by the Commission on May 27, 2004.

No utility has requested certification of a proposed project under the statute in either the 2001 or 2003 submission. From informed comments made to the Department, the consensus of the transmission owning utilities is that the new certification process could actually more onerous than the single-project certificate of need process. The showing required for certification is the same under either process, but other aspects of the single-project CON process has thus far made that process preferable to utilities.

Even so, the planning process has been noteworthy, in a couple of respects. First, the transmission owning utilities actively worked to make their planning process open to public scrutiny and comment. The utilities divided the state into six planning zones, and held at least one open, public planning meeting in each zone. The other interesting aspect of the 2003 filing was that, although the utilities identified dozens of "inadequacies" in the state's transmission system, the utilities did not include a proposal to address any of these inadequacies. However, the Commission, at the Department's request, has ordered utilities to provide a schedule for addressing those system inadequacies.

Certificate of Need Reform

In addition to the changes to the CON statute discussed previously, MESRA made three other changes to the CON statute:

- it allowed for a consolidated proceeding for determining the need for a generation facility and any transmission lines directly associated with the proposed facility;
- it made minor amendments to the need criteria to be applied by the Commission, in determining if a project is needed; and
- it expanded the list of projects which are exempt from the CON requirements, to include projects to an existing generating facility to increase its efficiency, as long as the capacity of the facility is not increased by more than 10 percent or 100 megawatts, whichever is greater.

Distributed Energy Resources

Distributed energy resources refers both to *demand side* technologies, such as conservation improvements, and *supply side* technologies, such as small "distributed" generation facilities are installed on or in close proximity to load, and some distance from central station generation facilities and the electric grid. Distributed energy resources are important resources for a number of policy and technical reasons, including their ability to improve the operation and reliability of the electricity delivery system. MESRA included a number of reforms to promote the deployment of distributed energy resources.

Public buildings conservation

MESRA established a goal of achieving 30 percent savings in new and existing public buildings throughout the state (Minn. Stat. 16B.32 and 16B.325). The legislation directed the Departments of Administration and Commerce to develop a conservation benchmark for all public buildings and to establish guidelines for designing new buildings.

The Departments of Administration and Commerce refer to this initiative as the B3 project – “Buildings, Benchmarks and Beyond.” On January 15, 2003, the agencies released the initial version of these guidelines. Developed by a consortium of state agencies, institutions of higher learning and county government – led by the Departments of Administration and Commerce – these guidelines will be applied to all new buildings receiving funding from the State of Minnesota after January 1, 2004. The next task to be undertaken will be to collect building profile and energy usage data on Minnesota's 10,000-plus buildings.

Conservation improvement plan (CIP) reforms

MESRA made changes to the CIP program (Minn. Stat. 216B.241) that should result in more energy conservation than in the past. These changes include: (1) increased the spending required for conservation programs by municipal utilities and cooperative electric associations to the same level required of investor-owned utilities; (2) increased the focus of all CIP spending on programs that actually reduce energy use; and (3) established consistent statewide reporting and program evaluation to allow assessment of statewide progress and evaluation of the effectiveness of conservation programs.

Distributed generation

MESRA included a number of provisions to encourage small supply-side resources, generically referred to as distributed generation.⁵ The purpose of these provisions was to:

- provide cost savings and reliability benefits to customers;
- enhance both the reliability of electric service and economic efficiency in the production and consumption of electricity; and
- promote the use of distributed resources in order to provide electric system benefits during periods of capacity constraints.

⁵ “Distributed generation” under MESRA means small generation facilities “fueled by natural gas or a renewable fuel, or another similarly clean fuel or combination of fuels, of no more than ten megawatts of interconnected capacity.”

To achieve these goals MESRA directed the Commission to develop and issue by order generic standards for utility tariffs for interconnection and operation of distributed generation facilities (Minn. Stat. 216B.1611). The Commission asked the Department of Commerce to organize and lead two distributed generation work groups:

- a technical work group to make recommendations to the Commission regarding uniform interconnection guidelines for distributed generation;
- a rate work group to develop guidelines to ensure that prices for electric services provided by the electric utility are reasonable and nondiscriminatory while prices charged for power provided by the generator to the utility reflect the value of power.

The Department has submitted the reports of these two workgroups, and parties are awaiting further Commission action.

In addition, MESRA required each utility to:

- implement tariffs consistent with standards issued by the Commission;
- to maintain records and file reports annually regarding applications for interconnection of distributed generation on the utility's system;
- allow customers the opportunity to determine that a portion of the energy supplied to them would be generated by distributed generation (Minn. Stat. 216B.169); and
- use 5 percent of the utility's required CIP spending to underwrite the costs of distributed generation projects, to the extent that cost-effective projects are available in the service territory of the utility (Minn. Stat. 216B.2411).⁶

Renewable Energy

The 2001 Legislature included several provisions in MESRA to promote the development and use of renewable energy in Minnesota. The most significant of these provisions is the Renewable Energy Objective (REO - Minn. Stat. 216B.1691). The REO applies to each utility responsible for procuring energy to serve Minnesota retail electric consumers. Essentially, the REO requires each of these utilities to make a good faith effort to ensure that at least one percent of the energy the utility provides to Minnesota consumers is generated by an eligible renewable energy source by 2005, and to increase this amount to 10 percent by 2015.

MESRA also required each utility to give their customers the option to purchase some or all of the customer's electricity needs from energy generated by renewable sources ("green pricing" -- Minn. Stat. 216B.169). Rates charged for green power offerings must be based on the difference

⁶ This provision was amended in 2003 to authorize (rather than require) use of 5 percent of a utility's required CIP spending only if the utility is meeting certain specified renewable energy goals.

between the cost of the renewable energy and the same amount of nonrenewable energy. Utilities may generate their own renewable energy or purchase credits from a renewable energy provider certified by the Minnesota Public Utilities Commission, if the Commission establishes the credit program.

Other Reliability and Planning Provisions

Distribution Reliability Standards

MESRA required the Commission to adopt safety, reliability, and service quality performance and reporting standards for investor-owned electric utilities (Minn. Stat. 216B.81). The statute requires cooperative and municipal utilities to adopt their own standards subsequently, which are to be as consistent as possible with the Commission's standards. The standards must specify:

1. average call center response time;
2. customer disconnection rate;
3. meter-reading frequency;
4. complaint resolution response time;
5. service extension request response time;
6. recording of service and circuit interrupter data;
7. summary reporting;
8. historical reliability performance reporting;
9. notices of interruptions of bulk power supply facilities and other interruptions of power; and
10. customer complaints.

The Commission conducted a rulemaking to develop these standards, and the new rules went into effect January 28, 2003 (Minn. Rules, chapter 7826). The rules require utilities to file an annual reliability report, an annual safety report and an annual service quality report. These three reports should contain information necessary for the Commission to assess each utility's performance in the areas of safety, reliability and service quality.

These utility distribution reliability reports have begun to be filed with the Commission. Three significant difficulties are apparent. First, the filings are of varying quality and accuracy. Each utility identifies, collects, and records service interruptions somewhat differently and each utility has its own method to normalize their reliability data for the effects of severe weather, among other things. Second, there is no framework for examining the reasonableness and appropriateness of a utility's proposed goals. For various reasons, the historical reliability data filed by the utilities does not necessarily provide an accurate picture of the actual level of service quality being provided, particularly with respect to the reliability indices identified in the rules. Given the uncertainty of the data, it cannot reliably be used as a base case for either a qualitative or quantitative comparison among utilities. Third, the rules do not contain any ability to impose terms, conditions and penalties upon a utility that does not meet the service quality standards.

Despite these failings, the ability to record and report distribution-level reliability data accurately, set appropriate reliability goals and improve service performance should increase with each annual filing. The utilities have either recently implemented new reliability tracking systems to comply with the rules, or they soon will be implementing new reliability tracking systems. These tracking systems will improve the accuracy and consistency of the data, and should allow for useful comparisons of a utility's performance from year-to-year.

Preventative Maintenance Authority

MESRA gave the Commission the explicit authority to require investor-owned utilities to "make adequate infrastructure investments and undertake sufficient preventative maintenance with regard to generation, transmission, and distribution facilities" (Minn. Stat. 216B.79). This authority has not yet been exercised by the Commission, and it does not extend to municipal or cooperative electric utilities.

State Energy Plan

MESRA required the Department of Commerce to:

prepare a state energy planning report and submit it to the legislature by December 15, 2001 and update the report by December 15, 2002. The report must identify important trends and issues in energy consumption, supply, technologies, conservation, environmental effects, and economics, and must recommend energy goals relating to the energy needs of the state. The report must recommend goals for the role of energy conservation, utilization of renewable energy resources, deployment of distributed generation resources, other modern energy technologies, and traditional energy technologies, and affordability of energy services for all Minnesotans (Laws of Minnesota 2001, chapter 212, article 7, section 35).

The initial report was issued in January of 2002, and is available on the Department's website.⁷ The follow-up report, which contains the policy recommendations of the Department of Commerce under the Ventura Administration, was issued in January of 2003, and is also available electronically.⁸

State Reliability Administrator

MESRA created the position of "Reliability Administrator" within the Department of Commerce to "act as a source of independent expertise and a technical advisor to the commissioner, the commission, the public, and the legislative electric energy task force on issues related to the

⁷ www.state.mn.us/mn/externalDocs/Energy_Planning_Report_121602022402_2002PlanningRpt.pdf.

⁸ www.me3.org/energyplanupdate2002.pdf.

reliability of the electric system" (Minn. Stat. 216C.052). MESRA requires the Reliability Administrator to:

- model and monitor the use and operation of the energy infrastructure in the state, including generation facilities, transmission lines, natural gas pipelines, and other energy infrastructure;
- develop and present to the commission and parties technical analyses of proposed infrastructure projects, and provide technical advice to the commission; and
- present independent, factual, expert, and technical information on infrastructure proposals and reliability issues at public meetings hosted by the task force, the environmental quality board, the department, or the commission.

The administrator is appointed by the Commissioner of Commerce for a four-year term. The Commissioner is to oversee and direct the administrator's work; review the administrator's expenses; and approve the administrator's budget. To the extent the administrator's expenses are consistent with the budget approved by the commissioner, the Department of Commerce is required to pay expenses incurred by the administrator and assess energy utilities to reimburse Commerce for these expenses (not to exceed \$1 million annually for general administrative costs). The statute creating the administrator expires June 30, 2006. Ken Wolf, the current Reliability Administrator was appointed by Commissioner Jim Bernstein in May 2002, for a term that could extend to May 2006.

Major projects of the Reliability Administrator have included:

- facilitating a technical workgroup on distributed generation interconnection standards;
- introductory presentations at the six public meetings on the state transmission planning process;
- facilitating a technical workgroup to establish the scope for an RFP for an engineering consultant to conduct a study of the amount of intermittent electricity resources that could reliably be integrated into Xcel Energy's electric system; and
- planning and convening a symposium on the August 14, 2003 blackout (see appendix 3 for a summary of that symposium).

THE 2003 "PRAIRIE ISLAND 2" BILL

Faced with the prospect of having to shut down and replace Xcel Energy's Prairie Island nuclear generation facility (over 1000 megawatts of baseload generation capacity) for lack of spent nuclear fuel storage capacity, the 2003 legislature responded by passing Laws of Minnesota

2003, special session chapter 11, known to some as the “Prairie Island 2” bill. The legislation consisted of four articles.

Article 1 – Spent Fuel Storage

The first article dealt with the issue of additional spent nuclear fuel storage in the state (Minn. Stat. 116C.83). The 1994 legislature authorized Xcel to fill and place seventeen dry spent fuel casks at Prairie Island but that capacity was only sufficient to allow operation of the facility until 2007. The 2003 legislation authorized sufficient additional dry cask storage at Prairie Island to allow that nuclear generation facility to continue to operate until the end of current licenses in 2013/2014.

In addition, the legislation delegated approval of a future storage facility or dry casks at either the Prairie Island or Monticello nuclear generation facilities from the Minnesota legislature to the Minnesota Public Utilities Commission. Xcel Energy's Monticello nuclear generation facility is expected to run out of spent fuel storage capacity at that facility in 2010. A decision by the Commission on a request to approve additional storage capacity in the state is not effective until the end of the following legislative session, in order to give the legislature an opportunity to review the Commission's decision (pro or con) and to change that decision if the legislature deems necessary. Article 1 also provides for recovery of expenses by Xcel Energy, not to exceed \$2.5 million a year, for a settlement with the Mdewakanton Dakota Tribal Council at Prairie Island regarding additional storage at Prairie Island (Minn. Stat. 216B.1645).

Article 2 – Renewable Energy Development

The focus of the second article was on the development of the state's renewable energy resources. The legislature required Xcel Energy to spend at least \$16 million on renewable energy development each year that the nuclear facility is in operation and spent nuclear fuel is stored in the state (the “renewable development fund” -- Minn. Stat. 116C.779). In addition, the Legislation passed in 2003 establishes a goal of moving Minnesota towards incorporating hydrogen into its energy mix (MN Session Laws 2003, 1st Special Session, Chapter 11). The legislation:

- ordered Xcel Energy's ratepayers to fund \$10,000,000 for the University of Minnesota Initiative for Renewable Energy and Environment to support basic and applied research and demonstration activities, including hydrogen production and improvements to fuel cell technologies.
- directed the Department of Commerce and the Department of Employment and Economic Development to issue a request for proposals for the construction of a wind-to-hydrogen demonstration project that demonstrates all components of a future hydrogen economy, namely, hydrogen production, storage, and distribution.
- required the Department of Employment and Economic Development to develop a targeted program to promote and encourage hydrogen production.

- required Xcel Energy to transfer roughly \$20 million over the next 5 years to the University of Minnesota for the University's Initiative for Renewable Energy and the Environment, for hydrogen and other renewable research and development at the University.

The 2003 legislation also makes the renewable energy objective a requirement for Xcel (rather than a "good faith" objective) above the renewable capacity mandated in the 1994 legislation (825 megawatts of wind, 125 megawatts of biomass), and requires the utility to invest in another 300 megawatts of wind energy capacity (above the 1994 amounts) by 2010. In addition, the legislation:

- requires the Commission to issue an order by June 2004⁹ establishing the criteria and standards by which the Commission will measure an electric utility's efforts to meet the renewable energy objectives to determine whether the utility is making the required good faith effort.
- authorized the Commission to establish a renewable energy credits trading program for the REO, whereby utilities could purchase certified renewable energy credits rather than to generate or procure the renewable energy directly. One workshop on this topic was held in February 2004, with another one slated for June 2004. This work is on-going;
- required each electric utility to report on its plans, activities, and progress with regard to these objectives to the Commission in resource plan filings or in separate reports every two years, whichever is more frequent (previously reporting was only through resource plans); and
- required the Department of Commerce to report to the legislature every odd-numbered year on utilities' progress in increasing the amount of renewable energy provided to retail customers, and make any recommendations for legislative change.

The 2003 legislation increased the amount of small wind energy capacity that can qualify for production incentives (Minn. Stat. 216C.41). The renewable energy production incentive (REPI) provides 1.5 cents per kilowatt-hour produced by eligible facilities. Previously, the REPI was capped at 100 megawatts of small wind energy facilities funded from the State's general fund. That cap was reached by early 2003. The 2003 legislation increased the cap by another 100 megawatts and paid for the REPI increase out of Xcel's renewable development fund (the \$16 million required spending referred to above). The second 100 megawatts has also been fully subscribed.

⁹ The Commission's order is available at the Commission's website at www.puc.state.mn.us/docs/orders/04-0075.pdf.

Article 3 – Metro Emissions Reduction Program

The third article of the 2003 legislation contained a number of miscellaneous energy provisions, the most important of which facilitated Commission approval of Xcel Energy's Metropolitan Emissions Reduction Program (MERP) proposal: (1) to convert two metro area coal-fired generation facilities to use natural gas, and add significant pollution control technology to a third; and (2) to recover the costs of these projects in a rate rider without having to file for a rate case. The Commission approved this proposal in December, 2003 (more on this proposal can be found in the Key Issues section on environmental protection).

Article 4 – Mesaba Energy Project

The fourth article provided for a number of regulatory incentives for an “innovative energy project” on the Iron Range, which would generate electricity by using “coal as a primary fuel in a highly efficient combined cycle configuration with significantly reduced sulfur dioxide, nitrogen oxide, particulate, and mercury emissions” when compared with traditional technologies. The regulatory incentives include:

- an exemption from demonstrating need for the facility or associated transmission facilities;
- a grant of eminent domain authority for transmission routes approved by the Environmental Quality Board; and
- the possibility of entering into a power purchase agreement with Xcel Energy to provide 450 megawatts of capacity and energy, subject to the approval of the PUC.

The Iron Range project at issue is a 750+ MW generation facility known as the “Mesaba Energy Project” that creates a synthetic gas from coal (coal gasification). It would be located in Hoyt Lakes, Minnesota, on the site of the LTV mining operation.

Chapter Two

POLICY FOCUS ON ELECTRIC RELIABILITY

Reliable electric service is critical for the way we live today. It is essential for work, leisure, and social interaction. Minnesota law requires that energy service be safe, adequate, and reasonably priced, to help fuel Minnesota's economy. The reliability of electric service in Minnesota is one of the Department's top priorities.

A key to understanding the difficulty of maintaining the reliability of the electric system is that electricity, unlike natural gas and petroleum, cannot be stored. At every moment, there must be enough electric generation and transmission capacity and energy available and balanced *instantaneously* with when the electricity is needed. In other words, the electricity must be generated and transmitted at the same time that a consumer turns on his microwave. Consumers of all types – residential, commercial, industrial – have come to expect and rely on electric utilities to provide that level of reliability.

Failure to maintain instantaneous balance in electric supply and demand will cause disruptions, outages or "reliability events." There are three types of reliability events: a) region-wide, bulk power blackouts; b) localized outages due to problems at the distribution line level; and c) power quality fluctuations. All three of these types of outages were experienced in the August 14, 2003 blackout which affected the east coast and Midwestern U.S., and each will be discussed in this chapter.

In addition, this chapter discusses:

- the long term adequacy of electric supply in Minnesota;
- the reliability of the regional electricity transmission system, often referred to as the transmission "grid" or the "bulk power" system; and
- the reliability of the local distribution system, the part of the electricity delivery system that serves end-use customers.

This chapter concludes with a discussion of the Department's six policy strategies for maintaining reliable electric service in the state.

Reliability of electric service can be divided into two basic components: adequacy and security. "Adequacy" is the ability of utilities to supply customers' electric service requirements, taking into account scheduled and unscheduled outages. "Security" is defined as the system's ability to withstand sudden unexpected disturbances without collapsing.

RESOURCE ADEQUACY

Rising demand, rising prices, a new energy mix

Minnesota's consumption of electricity is expected to increase at an average rate of about 1.5 percent annually over the next few years, based on the combined projections of all utilities serving Minnesota customers.¹⁰ Since there is not enough excess generating capacity available to meet this increase in demand, significant new generation and transmission facilities will be needed in the near future, to serve the electric needs of the state and the region. Electric utilities engage in resource planning to determine the combination of power plants that most economically meets the increased demand.

The capacity expansion plans of electric utilities indicate that the fuel mix for electric generation will likely change somewhat in the coming years. Natural gas may increase as a source of electricity, although concerns have been raised recently about the extent to which this fuel should be used for this purpose. There are also plans to significantly increase wind generation in the state. In addition, utilities are required by law to make a good faith effort to include electricity generated from renewable sources in their mix of resources used to serve their customers.

As noted above, demand for electricity in our state, and in the Midwest region, continues to increase. As a result of this growing demand for electricity and limitations due to aging electric infrastructure in the region, additional generation and transmission infrastructure will be needed in both the near and longer term. Ensuring that this new infrastructure is constructed and placed into service in a manner that does not adversely impact the environment, energy costs or other public interests is a challenge that state and regional policy makers must address.

Growth in Demand Greater Than Growth in Supply

Minnesota's utilities are members of the Mid-Continent Area Power Pool (MAPP), an organization created to ensure reliability of electric service in the region. Currently, all companies that own or use electric generation and transmission facilities in Minnesota, North Dakota, South Dakota, Nebraska, Missouri, Manitoba and parts of Wisconsin, Iowa and Montana belong to the MAPP. MAPP was formed in 1972 as one of the ten "regional reliability councils" created by the electric industry after a massive blackout in 1968. MAPP is a voluntary organization that establishes standards and practices for reliability of electric service, under the national umbrella organization for the regional reliability organizations, the North American Electric Reliability Council.

The United States portion of the MAPP region has a peak demand occurring in the summer season. In its Ten-Year Reliability Assessment, released in September 2003, MAPP estimated that the region's summer reserve margin would be 21.9 percent in 2003, well above the MAPP-designated reserve requirement of 15 percent.¹¹ However, MAPP projects the summer reserve

¹⁰ A simple trend line estimates that the increase will be between 1 and 2 percent annually over the next few years.

¹¹ A reserve margin is a measure of the system's generating capability above the amount required to meet peak load requirement.

margin to decline to 9.3 percent by 2012 as the region's increasing power needs absorb the current surplus power. Some, but not nearly all, of this growth in electric demand may be met through energy conservation. Conservation programs are an important tool to manage load growth in Minnesota. The programs reduce the demand for electricity and require less lead-time for implementation compared with new generation resources. However, the Department expects that growth in the demand for electricity in Minnesota will outstrip the contribution of conservation towards balancing supply and demand in the state in a cost-effective manner. Moreover, the pressure that demand growth places on utilities is not even. Some utilities, such as Great River Energy and Xcel Energy, will likely have greater needs for new electric infrastructure, due to the fact that their electric demand or "load" is growing faster than the loads of other providers.

Need for base load resources

In Minnesota, no base load plants (facilities that constantly run to serve the steady level of ongoing electric demand) have been proposed for construction and none have been built since the 1980s. In fact, only three non-mandated combustion generation projects greater than 50 MW have obtained all necessary permits and completed construction in the past five years.¹² These three projects are either peaking facilities (plants used only in times of highest demand, such as a hot summer day) or intermediate facilities (facilities that are more expensive to operate than base load plants, but less expensive than peaking plants – used when all available base load resources have been "dispatched"). Another three generation projects, none of which are base load plants, either recently obtained the necessary permits or are expected to do so soon.¹³ Finally, there is one additional generation project, proposed as an intermediate facility, that is in the middle of the process of seeking the necessary permits.¹⁴ As provided in their integrated resource plans and other filings, Minnesota's utilities project a need for additional base load generation capacity of 2730 megawatts by 2015 and another 695 megawatts of intermediate generation capacity by that time.¹⁵ Note that these projections do not include the possible need for replacing the capacity and energy currently provided by Xcel Energy's Prairie Island and Monticello nuclear generation facilities. The operating licenses of both Monticello and Prairie Island facilities expire during this planning period (2010 for Monticello and 2013/2014 for the Prairie Island units). If these facilities are not re-licensed by the federal Nuclear Regulatory Commission, the baseload resource problem expands by another 1600 megawatts. Baseload and intermediate resources are more difficult for utilities to build than peaking or intermittent resources, in that baseload and intermediate resources are more expensive to construct, and generally have greater environmental impacts.

¹² Specifically, Xcel Energy's Black Dog addition, Great River Energy's Pleasant Valley station, and Great River Energy's Lakefield Junction station.

¹³ Specifically, Minnesota Municipal Power Agency's Faribault Energy Park, Trimont Wind I's wind farm (under sale to Great River Energy), and Xcel Energy's Blue Lake addition.

¹⁴ Specifically, Calpine Corporation's Mankato Energy Center (part of which is under contract to Xcel Energy).

¹⁵ Subsequent to the formulation of this draft report, various utilities filed new integrated resource plans (IRP). Based upon its review of these new filings, the Department has revised its intermediate capacity number to reflect updated information pertaining to revised demand and supply forecasts, system plant additions and the forward movement of the IRP planning horizons.

Increased reliance on natural gas generation

All of the new combustion generation resource additions referred to above (both completed and proposed) are fueled by natural gas. Natural gas generation facilities have long been a small part of Minnesota's supply mix, and have traditionally relied on the summer surplus of natural gas pipeline capacity that is available since most consumer furnaces are not being used to heat homes and businesses. However, the state's usage of natural gas-fueled generation is increasing beyond those "summer peak" applications. The reasons for this upward trend in the use of natural gas are that natural gas is superior to coal and nuclear fuel in its overall environmental impacts, and that natural gas plants can be constructed more quickly. Natural gas-fired generation is also more nimble in that the facility can be started up or shut down quicker and easier than other types of facilities. However, only a limited number of natural gas generation facilities can be added to the existing natural gas pipeline infrastructure without significant upgrades to the pipeline system.

SECURITY OF THE TRANSMISSION SYSTEM

The nation's bulk power system is like the interstate highway system, carrying the majority of the power from generators to load centers (where the customers are). Like the interstate highway system, the nation's bulk power electrical system has evolved into an interconnected transmission grid. In most instances, the interconnected nature of the transmission grid is a benefit because interconnection allows regions to import solutions to their supply needs and to lower overall costs by accessing cheaper generation in neighboring regions. This exchange of power allows for more efficient use of the electric system overall. However, the transmission line that allows a region to import a solution may also allow that region to export a problem.

Lack of Investment in Transmission Infrastructure

The most significant electricity issue currently facing the state is that of ensuring that Minnesota consumers continue to enjoy the benefits of a reliable electric transmission infrastructure capable of providing those consumers with access to low-priced generation. The increase in wholesale electricity marketplace activity since 1996 has resulted in a significant decrease in the amount of transmission capacity that is available to move power over the regional, interconnected transmission grid. While the amount of new generation capacity constructed in the United States has increased, the amount of transmission capacity available to transport that power has not grown to accommodate new demands on the transmission system. Investment in the transmission system in 1999 was less than one-half the investment in 1979 even while peak demand for electricity grew and is expected to continue growing.

In Minnesota, utilities have not generally proposed the construction of new major transmission capacity, preferring instead to purchase energy from the grid, or to build natural gas peaking or intermediate plants. Given the congestion of the transmission system into and out of Minnesota, these options may not be as available to utilities as they have been.

Only one large transmission line has been proposed and approved in the recent past. That project is an Xcel Energy transmission project to provide an outlet in southwestern Minnesota for wind generation from the Buffalo Ridge (near the cities of Benson and Pipestone). The transmission would allow Xcel Energy to satisfy the wind energy mandates imposed on the utility by the 1994 legislature. The project has been approved by the Commission and Xcel is currently in the process of procuring a route permit from the Minnesota Environmental Quality Board.

Electric Transmission Constraints

As a rule, large electric generators and consumers of electricity generally are not located in the same place. In order for the power to be delivered from the place of generation to the place of consumption, preferred transmission line pathways must be developed. Eventually, transmission constraints, or bottlenecks, develop in those areas where a transmission line delivers the maximum level of power that it can safely and reliably carry. Bottlenecks limit energy transactions. This, in turn, may lead to higher energy costs. More importantly, such transmission constraints can threaten system reliability.

Many major transmission lines into and out of Minnesota are nearing operational limits that could affect reliability. For example, the major transmission lines from Minnesota into Wisconsin currently operate at reliability limits during summer peak times to satisfy power requirements in the region. In addition, the transmission system cannot, without future upgrades or new additions, support additional generation from Canada.

One Minnesota utility has found it necessary to build peaking capacity to meet its expected load as a result of the increasingly constrained transmission system. The utility found that, due to transmission constraints, it could not transmit the power it could acquire from generation facilities located elsewhere to where it was needed to meet the summer demand of its consumers.

Renewable development constrained

Minnesota has a tremendous capacity for renewable energy development, especially its wind energy resources. Currently, Minnesota has over 550 megawatts of wind energy capacity installed. That number could increase by up to 6 times over the next decade, to something approaching 3000 megawatts.

However, that development will be stymied without sufficient transmission capacity to bring that energy to load centers, where it can be used to serve consumer needs. The capacity of the line proposed by Xcel Energy to deliver wind energy generated in southwestern Minnesota to the Twin Cities is completely subscribed to carry wind energy currently under contract to Xcel to fulfill a portion of its wind mandate. Expansion of the wind energy resource in southwestern Minnesota, as with other parts of the state, will require additional transmission capacity. As policy makers struggle with how best to encourage renewable energy development in the state, they should keep in mind that transmission capacity, not production subsidies, tax credits or mandates, may be the limiting factor for that development.

Potential Electric Transmission Solutions

One obvious way to alleviate constraints on the power system would be to construct additional transmission lines and facilities and upgrade existing power lines. In a recent filing to the Commission, Minnesota's transmission owning entities identified 26 inadequacies in the state's transmission infrastructure which need to be addressed to ensure reliable service to Minnesota consumers. The Department is actively encouraging those utilities to follow through in fixing these identified inadequacies in a timely manner.

A less obvious option is the construction of relatively small-scale, distributed or dispersed generation resources in strategic locations. "DG" facilities, as these are often referred to, can potentially be used to reduce the strains on transmission lines at heavily used locations and to relieve system congestion. As mentioned in Chapter 2, on August 20, 2001, in response to a change in Minnesota law (Minnesota Statute 216B.1611, subdivision 2), the Commission initiated a proceeding to establish generic standards for utility tariffs for interconnection and operation of distributed generation facilities of 10 megawatts or less. In its initial Order on this issue, the Commission stated:

Most electricity is generated at large power plants, then transmitted long distances to where it is needed. This arrangement has resulted from the economies of scale in generation, especially for plants driven by fossil fuels or nuclear fission. "Distributed generation," in contrast, refers to the practice of generating electricity close to where it is needed, in plants designed to meet only the local need. Interest in distributed generation has grown as the cost advantage of large generating plants over small generating plants has declined, and as the demands on the transmission system have increased.

Many benefits have been attributed to distributed generation. It may reduce the need for long-distance transmission of electricity. That is, an electric system with a lot of distributed generation may be able to operate with fewer resources devoted to transmission than can a system of the same size with little distributed generation. An electric system with a lot of distributed generation may be more reliable as well. The use of many small generators instead of a few large generators suggests that the failure of any one generator would affect a smaller portion of the utility's customers. Similarly, a reduced reliance on long-distance transmission suggests that a transmission line failure would affect fewer customers. For a customer, having a back-up generator may provide some protection against any type of electric system failure. Finally, facilitating privately-owned distributed generation may

make it easier for customers to adopt a means of generating electricity – such as solar power – that better reflect their values and preferences.

The Commission, subsequent to this Order, asked the Department to form two work groups, one on DG technical interconnection standards, the other on DG rate issues. The Department did so, and submitted the recommendations of the work groups to the Commission. Once the Commission acts on these recommendations to establish standards, each utility under its jurisdiction is to file specific distributed generation tariffs for its system. (Xcel Energy already has a distributed generation tariff for small facilities, but the company would need to modify its filing to conform to the generic standards set by the Commission.)

In addition, a variety of demand-side options can also be used to address system congestion. Reduced consumption of electricity through energy conservation practices is the least costly, most effective and efficient tool that all electricity consumers can practice to manage or reduce the demand for the use of transmission facilities. Timing electricity use so that consumers' demand for electricity is spread throughout a 24-hour period, avoiding so-called "peak" consumption times during the day can also help alleviate constraints.

MAPP & MISO Issues

Day-to-day operation of the electricity system is conducted by the individual utilities and the regional reliability entities, MAPP (Mid-Continent Area Power Pool) and MISO.

MISO stands for the Midwest Independent System Operator. Minnesota's four investor-owned utilities (Xcel, Minnesota Power, Otter Tail Power Company, and Interstate Power and Light) have joined MISO, and have transferred functional control (but not ownership) of their transmission facilities to MISO, after receiving approval from the Commission. As an "independent system operator", MISO's operations and activities are subject to the approval of the Federal Energy Regulatory Commission.

MISO's primary function is to monitor the bulk power transmission system and to develop policies and procedures that ensure that every electric industry participant has access to the transmission system, and that transmission lines are used in a way that minimizes congestion and maintains system reliability.

MISO has a much larger geographical footprint than MAPP, but not every MAPP member belongs to MISO. MISO members include utilities with more than 100,000 miles of transmission lines covering 1.1 million square miles from Manitoba, Canada, to Kentucky. In many respects, MISO covers two disparate regions. The eastern half of MISO is made up of densely populated states, many of which have deregulated their electric industries. The western half, of which Minnesota is a part, is composed of sparsely populated states that for the most part continue to comprehensively regulate their electric utilities. There is a great deal of overlap between the western territory served by MISO and MAPP, although many MAPP members are

not members of MISO. The differences in membership, organizational structure and mission between MAPP and MISO create a tension that must be managed so as to not allow these differences to pose reliability or other problems for Minnesota consumers.

Another potential problem arises from the fact that utilities in MISO operate under a different protocol compared to utilities that are not MISO members. As a result of this disparity, there are “seams” between members and non-member utilities. A “seam” is defined as a barrier resulting from differences in market rules and designs and other regional practices that inhibit or preclude the ability to transact capacity and/or energy.

For many years now, the Department has worked closely with MAPP and its Minnesota members. The Department is now also actively engaged in numerous MISO stakeholder groups including holding a seat on the MISO Advisory committee and being an associate member of the Organization of MISO States. The MISO Advisory committee advises the MISO Board of Directors on key operational and organization issues. Minnesota holds its seat on the Advisory committee until 2005.

ELECTRICITY DISTRIBUTION

If the transmission system is analogous to the interstate highway system, the local electric distribution system can be thought of as local streets and roads, distributing electricity to retail customers. The number and frequency of distribution level reliability disturbances or “outages” is much greater than outages in the transmission system, but distribution outages typically affect fewer customers than transmission outages that often affect a larger area. From the perspective of the customer who loses electric service, the distinction as to whether the service interruption is a transmission or distribution outage is immaterial. Accordingly, distribution reliability is an important part of overall electric service reliability.

Efforts to address distribution reliability issues tend to focus more clearly on an individual utility rather than an interconnected system. Minnesota has been addressing the specific issues of customer service quality and customer outages through industry-wide rulemakings and through proceedings related to specific utilities. (See Chapter Two for a discussion of the Commission’s safety, reliability, and service quality standards for distribution utilities, Minnesota Rules, chapter 7826.)

In addition, in an effort that goes well beyond the requirements of these rules, the Department and the Office of the Attorney General negotiated with Xcel to gain a number of significant service quality remedies above and beyond what Xcel must do under the Commission’s rules, such as:

- Pay customer refunds totaling \$1 million to customers who experienced the longest outages during the time period of the investigation.

- Increased spending on maintenance items such as tree trimming and cable replacement in the amount of \$15-20 million by January 1, 2005 (the lack of tree trimming maintenance was a key contributing factor of the August 14th blackout).
- File a revised service quality plan, in the form of a Commission-approved customer tariff, which includes strict and well-defined service quality standards with noncompliance payments in the millions of dollars for such areas as:
 1. customer complaints,
 2. number of outages per customer,
 3. length of outages per customer,
 4. customer call response time, and
 5. natural gas leak response time.
- Submit to an independent review of Xcel's new customer outage system currently being developed to be certain that concerns raised in the investigation are addressed.
- Agree to a number of customer communication and reporting provisions.

The settlement, approved with modifications by the Commission, is the strongest customer service program in Minnesota and, to our knowledge, the region. It will be reviewed after two years of implementation, to be fine-tuned and strengthened if needed.

Power Quality Fluctuations

Today's economy, and certainly tomorrow's digital economy, is heavily reliant on technology using microprocessors that create smart devices that automatically provide needed services and information. The problem created by microprocessors is that the "quality" of the electricity provided must be raised -- unprotected microprocessors demand "near-perfect power" to function properly. A similar need for perfection exists in other infrastructures, where existing and future advanced systems are predicated on the perfect functioning of today's communications, transportation, and financial services. "Power quality" in this instance refers to the technical characteristics of the electricity provided. Examples of power quality problems include minuscule power interruptions and voltage fluctuations. The same electrical disturbances that were previously unnoticeable on mechanical equipment can severely upset high-tech equipment operations.

The traditional level of power quality is not sufficient for the "digital society" of tomorrow. In many industrial and highly sensitive computerized applications, there is a need for an increase in power quality from today's outage/availability average of about 99.0 percent (approximately 8 hours of outage per year or "two nines" of reliability) to 99.9999 percent (approximately 32 seconds of outage per year or "six nines" of reliability). Such near-perfect power is needed for error-free operation of the microprocessor chips finding their way into just about everything, including billions of embedded applications. Thus, even when there is no failure of the electric

lines, a voltage fluctuation over those lines that go into an end-use appliance can have adverse consequences for the consumer, especially when that electrified appliance is a computer or sensitive digital equipment.

The problem of power quality may be huge. In its 2003 “Electricity Sector Framework for the Future” report, the Electric Power Research Institute estimates that these minuscule fluctuations in power quality may potentially cost upwards of \$100 billion annually in the U.S., or an additional cost of 50 cents for each dollar spent on electricity. If that figure is anywhere close to true, that is a staggering sum.

STATE POLICY ON ELECTRIC RELIABILITY

As mentioned in the introduction, the continuing reliability of electric service is one of the guiding principles of Minnesota’s energy policy and is one of the Department’s top priorities in the coming years. Accordingly, the Department, in concert with other state agencies and interested persons, will seek to preserve and enhance the reliability of the electric system in Minnesota through pursuit of the following six reliability strategies.

Reliability Strategy No. 1: Increased Focus on Utility Operations, Maintenance and System Control Measures

As the August 14th 2003 blackout demonstrated, the operators of the electricity system need to ensure that their operations, maintenance and system control measures are demonstrably adequate. Such an undertaking has three parts. One part focuses on the day-to-day operations and maintenance procedures of a utility. Inadequate tree trimming — a maintenance issue — was a key cause of the August 14th blackout. The second part is control measures that monitor the operations of the transmission system. Again, a contributing factor to the August 14th blackout was computer outages that prevented the utility from understanding what was happening on the transmission system and reacting to the contingencies in time for the necessary actions to be taken.

The third part deals with communications between the entities responsible for the grid, be it among utilities, among independent transmission system operators or between independent transmission system operators and utilities. The need for constant instantaneous balance between the generation of electricity and its use requires constant communication to keep the system operating smoothly.

Minnesota should expect each transmission owner to comply with all national, regional, state and industry operation and maintenance standards. Some form of annual certification from the utilities to the state would help ensure that each of the three parts is adequately being addressed.

Reliability Strategy No. 2: Encouraging Infrastructure Investment

A strong, interconnected transmission bulk power grid enhances reliability. It provides the capacity to handle peak demands and permits the economic and physical flow of power from where it is generated to where it is needed. Unfortunately, investment in transmission has been lagging, thereby threatening the reliability of the state's and the nation's transmission system.

As noted above, Minnesota's transmission utilities have identified at least 26 inadequacies in the transmission infrastructure needed to serve Minnesota customers. The Department will be working very hard to ensure that those inadequacies are addressed in a timely fashion. In addition, as mentioned previously, new legislation passed in 2001 gives the Commission the authority to require public utilities to make infrastructure investments if necessary for the provision of adequate, reliable electric service. This explicit authority, which many believe was implicit in the Commission's authority already, has not yet been used, but the Department will not hesitate to call on the Commission to use that authority if reliability to Minnesota consumers appears to become compromised.

Reliability Strategy No. 3: Encouraging Multi-State Solutions

Many forms of infrastructure, such as transportation, communications and fuel pipelines, have slowly evolved from being local in scale to become regional and then national and international networks. The electric grid has followed a similar pattern. Federal regulatory interests are advancing that evolution, moving determinedly toward a policy framework intended to lessen individual states' roles in the administration of a wholesale electric marketplace.

These factors have dramatically changed the traditional integrated utility model. Due to continuing growth in electricity demand and the opportunity to purchase lower cost power over the grid, interstate power delivery has become a key strategy used by the state's utilities. Minnesota's interconnections provide significant reliability and economic benefits to Minnesota electric utilities and their customers. It allows for:

- sharing of reserve generation capacity thereby avoiding the costs and impacts of generation facility construction;
- improved reliability by providing for a larger pool of resources for purchasing power at lower costs when unforeseen events occur; and
- access to more sources of economic wholesale energy.

Most Minnesota utilities rely on electricity generated outside of Minnesota to meet their customers' needs. Several municipal utilities receive power from regional and federal agencies whose sources are as far away as Wyoming. In some manner, all Minnesota utilities use the regional grid to import power at various times, to varying degrees and from diverse resources. Thus, regional, interstate transmission lines and multi-state arrangements benefit Minnesotans.

Though the trend toward increased interstate electricity commerce provides the benefits noted above, questions arise in the wake of cascading power outages as to whether a highly integrated grid is less reliable than smaller, less connected systems that meet local needs with local generation. The answers to these questions are not simple. For example, local generation would need to have backup systems to continue to meet electricity demands when any part of the local system fails or is taken down for maintenance. Such backup systems would be very expensive and may be problematic to build if only local sources of supply to meet Minnesota needs are allowed. Moreover, the move to construct such a system would take an untold amount of time and resources.

In many respects, however, the “local generation to meet local needs” question has already been answered. As noted above, Minnesota’s utilities, with the support and concurrence of Minnesota’s regulators, have constructed their electric systems in such a way as to connect the state electrically to all of its neighboring states and provincial jurisdictions in the north central U.S. and central Canada. Additionally, most of Minnesota’s major utilities serve customers in adjacent states as well as Minnesota. As a result, Minnesota’s utilities must work with multiple state regulatory jurisdictions, and Minnesota policy makers cannot readily act in isolation.

Most of the states in the MAPP region, including Minnesota, continue to comprehensively regulate their electric utilities, to ensure reliable electric service within pre-determined utility service territories – the traditional regulatory model for electric utilities. However, each state applies that model in its own way. While the electricity policies of the states in the MAPP region vary, all states have the common objective of ensuring that utilities provide reliable, reasonably priced electricity to consumers. Achieving these objectives is critical to supporting sustainable economic growth. While it is likely that states in our region will continue to focus principally on individual state needs, the arena in which the regional transmission grid is planned, expanded and operated has broadened. Thus, state regulators and policy makers must develop knowledge and practices that can support regional grid development in the collective public interest.

In doing so, states whose utilities are members of MISO have an opportunity to preserve their right to manage grid enhancement issues in a way that recognizes each state’s unique characteristics and substantial historical investments. The Organization of MISO States (OMS) is the primary avenue to do this. The OMS is a non-profit, self-governing organization of representatives from each state with regulatory jurisdiction over entities participating in the MISO. The purpose of the OMS is to coordinate regulatory oversight among the states, including recommendations to MISO, the MISO Board of Directors, the FERC, other relevant government entities, and state commissions as appropriate. The OMS has a broad and complex mission focusing on the development of a cost-effective, economically efficient Regional Transmission Organization in the Midwest by working with both the MISO and FERC. However, there is still a need to preserve a focus on the distinct characteristics of the upper Midwest through common dialogue, beginning with Minnesota’s neighboring jurisdictions. These deliberations should identify and consider opportunities and strategies for enhancing

reliability – both supply adequacy and security – in an economic and environmentally beneficial manner. The Department will continue to work to ensure that Minnesota will be a leader in this discussion.

Reliability Strategy No. 4: Realigning and Integrating Regulatory Review

Electric utilities wishing to build infrastructure in Minnesota face a series of disconnected proceedings in front of multiple state agencies, reviewing sometimes redundant information. State regulatory requirements should be sufficient to weed out bad projects from good (or refine projects to improve them), but should not act as a barrier to critical infrastructure investments necessary to providing reliable electric service to Minnesota consumers.

In Minnesota, planning for new generation resources to meet the demands of Minnesota electricity consumers is performed through Integrated Resource Planning on a utility-specific basis. Each state-regulated electric utility in this state is required to file an Integrated Resource Plan for approval on a biennial basis that projects the future resource needs over a fifteen year planning horizon. New generation resources as well as proposals to reduce and manage demand for electricity are analyzed together to develop a plan for meeting the utility customers' needs. However, there is no mechanism for reviewing and evaluating the combined resource needs of all of Minnesota utilities together in order to get "the big picture," something policy makers have been clamoring for.

Such a mechanism exists for transmission infrastructure needs. Minnesota recently established a "State Transmission Plan" process. Every two years, all of the transmission-owning utilities are required to identify inadequacies in the transmission system serving Minnesota consumers. These inadequacies and proposed solutions are then discussed in public meetings around the state and ultimately submitted to the Commission for review. From this process, the state gets a somewhat global view of the state of the Minnesota transmission system.

Once planned for, most projects to build or enhance the electricity infrastructure, whether it is a transmission line or new generation facility, are scrutinized by at least three different state agencies: the Department, the Environmental Quality Board and finally the Commission.¹⁶

Such a project will generally need a Certificate of Need (CON) from the Commission. This process begins with an application for a CON, and a technical/policy review of the proposal by the Department. Parties then advocate before the Commission as to whether the project is "needed" (including a review of the environmental impacts of the project conducted by the EQB). In this process, alternatives to the proposed project are considered, including conservation and renewable alternatives.

If the Commission issues a CON, the utility must usually then apply to the EQB for a site permit for a transmission line or power plant. During the actual siting process additional, more detailed environmental review of the project is performed by EQB, including an additional analysis of

¹⁶ A more detailed discussion of the regulatory process is found in Appendix 5.

alternatives to the project. Power plants also need an emissions permit from the Minnesota Pollution Control Agency, and usually a water consumption permit from the Minnesota Department of Natural Resources. Permits and approvals from other federal, state and local entities may also be required.

Running this gauntlet of agencies and procedures can easily take two to three years. The length and complexity of the regulatory process must be addressed. There is significant overlap in the substantive review of projects. For example, energy conservation is potentially reviewed in three separate proceedings: resource planning, CON, and the conservation improvement plan (CIP) process.¹⁷ Renewable energy achievements are reviewed in two proceedings, resource planning and CON.

These redundancies have the effect of increasing the regulatory burden on the utility and regulatory agencies. Simultaneously the redundancies decrease the effectiveness of the conservation goals established in resource planning by potentially reducing their importance. In addition, these redundancies potentially act as barriers to the construction of projects that are needed to enhance the overall reliability of the electricity grid. Ideally, determinations by the Commission in the resource planning process should guide subsequent processes such as CIP and CON.

The Department will seek to have these processes re-aligned and integrated, to reduce the overall regulatory burden on project developers, state agencies and others who participate in Commission and Board proceedings, without reducing necessary input from, and notice to, the public. An example of this initiative is the Department's advocacy for a single administrative law judge to oversee development of a joint administrative record for both Commission and EQB decisions regarding the need and siting of a proposed generation project. Generally, the administrative record is developed separately for each decision-making body, and usually by different ALJs. Current law allows these proceedings to be combined, but a combined proceeding has been the rare exception rather the rule.

Reliability Strategy No. 5: Developing Power Quality Standards

Minnesota's present electric delivery infrastructure, like most systems around the country, is not very well equipped to handle the power quality demands of high-end digital customers. Further, the system would be hard pressed to support levels of security, quality, reliability, and availability needed for economic prosperity into the future while under continued stress. The existing infrastructure is vulnerable to human error, natural disasters, and intentional physical and cyber attacks. Appropriate use of emerging technologies may be able to address these issues to some extent. Building reasonable distributed generation proposals into the consideration of alternatives to new transmission infrastructure may be an appropriate method for locating strategic sites.

¹⁷ CIP is a program to implement a statutory requirement that electric and gas utilities spend a specified percentage of their gross operating revenues on conservation programs and activities.

The cost of power quality interruptions for Minnesota has not been quantified in an independent, authoritative study. Although the problem is certain to exist, the degree of attention it deserves cannot be fully ascertained because the cost the problem represents is unknown. Minnesota consumers expect that their electricity service will meet their needs both for general purposes such as lighting and for more highly technical needs. There is a need to ensure that electric power is adequate to meet the increasingly sophisticated energy needs of consumers. The Department will seek to develop information about the costs Minnesotans incur due to power quality fluctuations, and if necessary, to develop standards or other strategies to ensure that Minnesota consumers have the benefit of the power quality they need to conduct their business.

Reliability Strategy No. 6: Letting Economic Efficiency Guide Energy Policy

Low-cost, reliable power is critical to Minnesota's economic well-being. Yet, the economics of energy policy often gets subsumed by other, albeit important policy goals such as local economic development. To address the reliability threats to the electricity system it is important that policymakers and regulators making decisions understand the economic consequences of their actions and, perhaps take a larger, longer-term view of things. That is, the cost of policies that differ from a basic approach of ensuring reliable power in a least-cost manner should be reasonably known so that decisions to pursue such policies are fully informed.

This information is critical because the more energy dollars that are diverted into projects based upon non-economic criteria, the more expensive basic electric service becomes. In addition, other problems may go unsolved due to the lack of funding. Funding for transmission infrastructure has been at reduced levels recently. Partly, this reduction is due to the fact that decisions by utilities, independent power producers, policy makers and others have diverted significant funds to generation projects that were justified on factors other than least cost, economic criteria. Such diversions are not a "free lunch" – they result in intended and unintended costs on the electric system. These costs show up in two areas. First, more expensive generation is constructed, since the generation projects have not been selected on a least cost basis. Second, these more expensive projects displace other energy projects that might have been more "needed" to solve reliability issues, locally or in the region. Thus the result of the lack of focus on least cost planning principles is that the costs of electricity in the region is higher than it might otherwise be, and that the overall reliability of the system is lower than it otherwise could be.

To raise the overall reliability and reduce the cost of the electric system, economic efficiency needs to play a greater role in decisions. One example is the optimal level of conservation a utility should achieve. Establishing better ties between the level of conservation determined in resource planning and in other proceedings would improve economic efficiency. Using this approach would make the least cost level of conservation the standard, rather than resetting the level of conservation in every proceeding.

Chapter Three

PORTFOLIO DIVERSIFICATION – RENEWABLE AND MODERN ENERGY TECHNOLOGIES

It is common knowledge within the investment community that the best financial portfolios are those that balance risk and that don't put all resources in one investment product. Similarly, the electric portfolio can be seen as being made more reliable and perhaps less prone to price volatility by ensuring a healthy mix of traditional and less traditional technologies. In addition, energy efficiency and conservation, discussed in the next chapter, are also an important part of the electricity portfolio because an electron saved is an electron that never needed to be produced.

Traditional non-renewable fuels for the generation of electricity include nuclear, coal, petroleum, and natural gas. These fuels provide the vast majority of our energy today. Supplies of non-renewable fuels are finite. Renewable energy technologies, on the other hand, could be considered infinite. A rule of thumb in defining a renewable fuel is that its source can replenish itself within a human generation - on the order of 25 years. Additional desirable characteristic of many forms of renewable energy are that they are highly biodegradable and have very low toxicity. For example, wind and solar energy are considered infinitely renewable, and hydro and biomass resources take only months or years to replenish the energy source. Other fuels that are considered renewable are in fact, waste fuel sources. For example, mixed municipal solid waste is from a waste stream that is a mixture of household and construction products.

What is most significant about renewable energy technologies is that many of them have evolved from hypothetical research to market ready resources. For example, wind energy, although limited by its intermittent nature, has evolved to the point where the price of electricity generated by wind is competitive with other forms of electricity on the market today.

RENEWABLE ENERGY

Besides the price of wind energy becoming competitive, the price of other renewable energy has declined significantly, with re-powering existing hydro facilities, and biomass co-firing also showing prices that are competitive with new natural gas and coal technologies. As the costs of electricity generated using traditional fuels increases, either due to increased fuel prices (natural gas, in particular) or increased emissions control measures, prices for renewable energy will continue to become more attractive.

Renewable Energy Policies and Programs

Recognizing the importance of diversifying its electricity portfolio, Minnesota has a number of state programs and policies to encourage renewable energy development. (See Appendix 2 for an overview table of these programs).

Renewable Energy Objective

Described more fully in Chapter Two, the Renewable Energy Objective (Minnesota Statute 216B.1691) requires each electric utility to make a good faith effort to generate or procure renewable energy so that 10 percent of the energy provided to retail customers in Minnesota by 2015 is generated by eligible renewable technologies. The term “eligible energy technology” is defined as an energy technology that generates electricity from the specified renewable energy sources (solar, wind, hydroelectric with a capacity of less than 60 MW, or biomass) that was not mandated by state law or Commission order prior to August 1, 2001. In other words, the renewable energy that Xcel Energy developed to fulfill the mandates from the 1994 legislation authorizing dry cask storage of spent nuclear fuel at Prairie Island does not count toward Xcel’s REO.

Green Pricing

Green pricing is a voluntary customer choice program that allows electricity consumers to purchase “green” electricity, generally at a higher price than the service based on the utility’s portfolio of resources to meet customers’ needs. All Minnesota electric utilities are required to provide this option to customers. Customers may or may not choose to purchase “green” power to increase renewable energy use.

Under these programs, the electric utility procures renewable electricity on behalf of customers who purchase it to support cleaner energy sources. If demand for energy under a utility’s “green” pricing programs grows, the utility procures more renewable energy for these interested customers. A benefit of a green pricing program is that the electric utility can generally offer the power at a much lower price than an individual customer could obtain by installing and operating a renewable energy system.

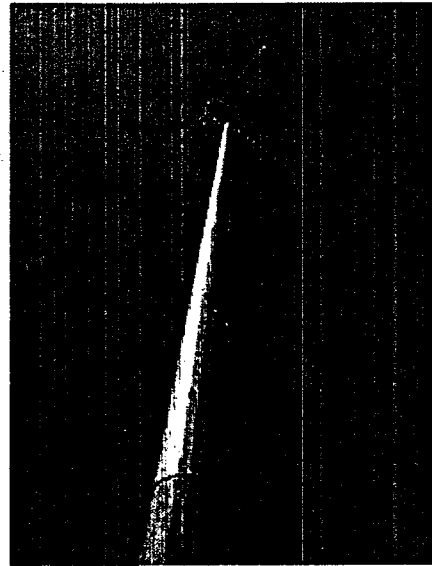
From July 1, 2002 - June 30, 2003, electric utility green pricing programs in Minnesota sold 24,703 MWh of renewable electricity. Over 25 MW of renewable energy have been certified for use in green pricing programs, with 14 MW added in 2003 alone.

Renewable Energy Tradable Credits

The Renewable Energy Objective (216B.1691) and Green Pricing (216B.169) create the possibility of a market for renewable energy. Under the notion of Renewable Energy Tradable Credits, electricity from renewable sources may be treated as a separate electricity commodity with additional value attributes. Many renewable energy contracts between electric utilities and energy producers now contain language specifying the ownership of the renewable or green attributes, commonly called renewable credits or “green credits.” These green credits could potentially be used for green pricing programs and renewable energy objectives or for emissions credits in pollution reduction markets.

Net Metering

Net metering is a state policy that allows small renewable electric generators to offset their consumption at the retail rate. All electric utilities in the state are required to offer a net metering option to their customers. Minnesota was one of the first of 37 states to enact net metering (MN Statute 216B.164 and MN Rule 7835). In 2003 there were 105 net metered wind facilities (less than 40 kilowatt capacity) in Minnesota, an estimated 1.5 MW of wind energy capacity that generated 663,000 kilowatt-hours of electricity in excess of what they consumed. The efficiencies of these small machines is much lower than larger turbines due to design, technology, and installation techniques but they can produce enough electricity to offset up to the equivalent power of 5 or 6 homes when the wind blows at average speeds. There were also twenty four solar energy facilities which generated no excess electricity.



(LEFT) 10-kW net metered wind turbine at Macalester College in St. Paul (Source: Minnesota Public Radio, Mary Losure)

(RIGHT) 35-kW net metered refurbished wind turbine near Glenwood (Source: Carl Nelson)

****SIDEBAR: CLEAN ENERGY RESOURCE TEAMS (CERTS)**

In 2002, the Legislative Commission on Minnesota Resources provided funding for the creation of Clean Energy Resource Teams (CERTs). The CERTs teams are designed to give citizens a voice in local energy planning by bringing together interested community, industry and government stakeholders to:

- Develop a common level of understanding on energy issues and technologies;
- Complete an inventory of available energy resources;

- Develop energy action plans that prioritize cost and community effective energy efficiency and renewable energy projects; and
- Work to implement those projects to the extent possible in each region.

The Department is working closely with the Minnesota Project and the University of Minnesota Regional Sustainable Development Partnerships to implement CERTs.

END SIDEBAR**

Wind Energy

Wind energy technologies that generate electricity have become the most visible form of renewable energy in Minnesota. Minnesota has a very significant wind resource, especially in the part of the state that experiences the greatest consistent wind speeds, the area commonly known as the Buffalo Ridge in very southwestern part of Minnesota. The only major drawback of wind energy from an energy standpoint is that the wind energy is an intermittent resource – the wind does not blow, or blow consistently, throughout the day or throughout the year. As a result, wind energy, by itself, cannot be relied upon for baseload or peaking purposes – it cannot be “dispatched” (turned on or off as needed). However, this drawback can be mitigated by being matched with another type of generation resource that has the ability to “follow” the wind energy (turned on or up when the wind is not blowing, turned off or down when wind energy is being generated). Because wind may be considered essentially a “free” fuel and emits no pollutants or other emissions, wind can provide Minnesotans with clean, reasonably priced electricity, provided, however, that sufficient transmission capacity exists to bring the wind-generated electricity from sparsely populated areas to population centers, where the wind can be used.¹⁸

The economics for large wind farms are very competitive, with contracts being executed for a price as low as 2.5 cents/kWh in good wind resource areas (including federal tax credit and depreciation, but no state incentives). Individual turbine projects cost more than traditionally fueled generating facilities per kWh to install but the upfront capital investment can be recovered in less than 10 years in a large part of Minnesota, depending on the wind resource, utility buyback rate, and the extent of transmission constraints.

Wind turbine technology is getting more efficient. For example, annual capacity factors exceeding 40 percent are being experienced at a number of southeast Minnesota monitoring sites with moderate wind speeds. Standard wind turbine sizes are now exceeding 1.5 megawatts, twice what it was five years ago. Larger turbines tend to produce electricity more efficiently than small turbines.

As turbine towers become taller (260 feet is now the standard height), areas north and east of the Buffalo Ridge are becoming viable sites for large wind farms. Individual turbines and wind farms are already moving into Mower, Dodge, Rice, and Stevens counties. Further expansion

¹⁸ The costs associated with wind-generated electricity are generally made up of: 1) the capital costs of the wind turbines; 2) the costs associated with siting, constructing, interconnecting and maintaining the turbines and appurtenant facilities; 3) managing intermittency through load following and other techniques; and 4) the costs of transmitting the electricity to where it can be used.

will be dependent on the price offered by utilities, which is a function of the utilities' avoided costs and the need for electricity. Transmission has also been a factor limiting further development in the southwest portion of the state. Xcel Energy is in the process of siting a major high voltage transmission line in the Buffalo Ridge area. While this project will help to mitigate the area's transmission constraint, additional transmission will be necessary to continue to develop this resource.

****SIDEBAR: Community Wind Rebate**

In 2003 the Department of Commerce received U.S. Department of Energy funding through the Legislative Commission on Minnesota Resources to offer rebates for community wind energy projects. Following a strong response to a request for proposals, the following two community wind projects were chosen that will be completed by June 2005:

Carleton College and Northfield Public Schools (joint application) proposed installing two 1.65 MW wind turbines (3.3 MW total)

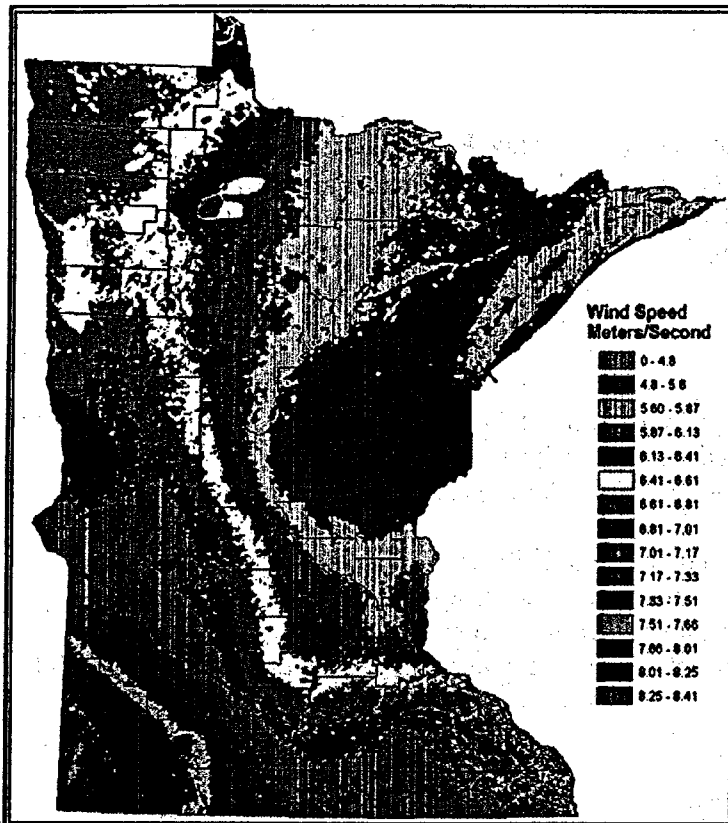
University of Minnesota-Morris West Central Research and Outreach Center proposed installing two 0.95 MW wind turbines (1.9 MW total)
END SIDEBAR**

Xcel Energy has roughly 500 megawatts (MW) of wind energy capacity installed, and is expected to install an additional 1,000 MW over the next several years. In total, this amount would represent over 15 percent of its total generation capacity. An independent wind intermittency study is currently being conducted about the costs of managing this amount of wind on their system. The study should be available by fall of 2004.

Minnesota's local wind market is active, as evidenced by the response to a \$21 million solicitation for renewable energy and energy efficiency projects under a U.S Department of Agriculture program. Over \$7.9 million was awarded to 35 wind projects nationally, 21 of which were in Minnesota. Four million dollars was awarded to Minnesota representing over 50 percent of the wind-related funding.

Wind Production Incentive

The Minnesota Wind Production Incentive provides 1.5 cents/kWh to qualifying small energy projects less than 2 MW in size. Currently 200 MW are subscribed or queued in the program with an additional 52 MW on a waiting list. Since its inception in 1997, nearly \$10.4 million has been paid to wind energy producers under this program through June 2004.



Minnesota State Wind Incentive Program

Wind resource map of Minnesota showing average annual wind speeds at 70 meters above ground level.

	Projects (#)	Enrolled (MW)	Operating (MW)	2003 Electricity (MWh)
First 100 MW ¹⁹	102	100	100	186,874
Second 100 MW ²⁰	26	100	29.6	6,651
Waiting List	36	52	na	na

Wind Monitoring Program

The Department of Commerce has been actively involved in statewide wind resource monitoring since 1982. This program collects and tabulates various wind speeds around the State. The Department also uses the data to generate statewide maps of the wind resource, providing a graphical representation of the potential that exists for wind development throughout the state. The current map was developed using Geographic Information Systems (GIS) and wind-flow modeling software programs. The highest data confidence exists in the western and southern parts of the state due to the large number of monitoring towers. The Department is working to expand wind monitoring in the other parts of Minnesota to determine wind speeds more accurately in these regions. Such information is crucial for identifying potential wind energy areas in Minnesota.

¹⁹ The money for this part of the incentive program comes from the state's General Fund.

²⁰ The money for this part of the incentive program comes from Xcel Energy's Renewable Development Fund.

Biomass Energy

Biomass is a large and varied category of renewable energy, loosely defined as direct derivatives from plant and perhaps animal products or by-products. This category can encompass everything from trees, vegetation and agricultural products, to manure, and wastewater. Biomass energy production can be generally divided into three categories: combustion, digestion, and decay.

Biomass Combustion

Biomass combustion consists of the direct combustion of the biomass product or a derivative of the product to produce heat, which is used directly or for producing electricity. The most common example of a biomass combustion facility is a fireplace.

Currently nearly all commercial biomass combustion facilities in Minnesota use waste products - waste logging, manufacturing, or trimming residues. The cheapest methods for using biomass are for direct heating, often via a boiler, or for co-firing in an existing fossil fuel plant. The biomass can also be gasified then combusted, using techniques similar to coal gasification. Saint Paul's 33 MW District Energy Heating and Cooling System is an example of a high efficiency biomass project that uses urban waste wood.

****SIDEBAR: District Energy in Saint Paul**

District Energy in downtown Saint Paul is an example of a renewable-fueled combined heating, cooling, and power facility. The energy system used by District energy is 80 percent fueled by urban waste wood but can also use natural gas, coal, and oil. Their facilities provide:

- Heating for approximately 155 buildings and 300 homes representing over 27 million square feet of building space, including the State Capitol;
- Cooling for more than 60 buildings representing over 10 million square feet of building space;
- Electricity generation of 33 MW of capacity.

END SIDEBAR**

****SIDEBAR: Little Falls Ethanol Plant Biomass Project**

Sebesta Blomberg & Associates received \$2 million through the U.S Department of Agriculture 2002 energy solicitation to implement a biomass cogeneration demonstration project at the Central Minnesota Ethanol Coop in Little Falls. The project is designed to use wood waste, primarily sawdust from local sawmills. Using gasification and thermal oxidation of sawdust the project is expected to supply all of the thermal energy needs of the plant for both process steam and drying of the distiller's dried grains. The project is expected to be on line in the first quarter of 2005. If successful, this project could improve ethanol operations by reducing operating costs, environmental emissions, fossil fuel consumption, and increasing facility revenue by creating co-product streams of heat, electricity, and liquid fuels. The project is also intended to create a modular design for biomass cogeneration that could be replicated at other ethanol plants across Minnesota.

END SIDEBAR**

Biomass Digestion

Biomass can be anaerobically digested to produce biogas, a combination of methane, carbon dioxide, and trace gases. The biogas can then be used for heating, producing electricity, or both. Anaerobic digestion of animal manures, waste water effluent, or food wastes are most common. The Haubenschild Family farm at Princeton, Minnesota, using dairy manure, is a well-documented case study of a dairy operation generating electricity, heat, and value-added fertilizer from the enhanced manure resource.

A Department study in 2003 found that on-farm manure digester systems are generally limited to dairy farms with 400 cows or more; this size allows for economically producing electricity without additional funding sources. Smaller sizes may be feasible for heat recovery only, especially when a covered lagoon is being installed for manure management. Swine digesters require very large sized farms greater than 10,000 swine to begin considering electricity generation. However, it is possible to produce methane for its heating value on smaller swine farms. Since there are many transaction costs associated with generating electricity in small-sized systems, it may not be worth the complexity of interconnection and additional costs to set up manure digester systems in such circumstances. However, manure digesters may be a good compromise alternative where regulations, permitting, or neighbor objections pose difficulties for a new or expanded farm operation.

Mixed waste digesters can incorporate manure, food processing waste, or other digester-suitable material. A possible benefit of digesters for large facilities is that they can reduce the load on municipal wastewater treatment facilities. Wastewater treatment facilities can sometimes be retrofitted to capture methane to heat the digester and/or facility, and sometimes generate additional electricity.

****SIDEBAR: Wastewater Treatment Facility Upgrades**

Rochester Public Utilities

The Rochester Public Utilities Wastewater Treatment Facility generates biogas as a major byproduct of its wastewater treatment process and in 1980 installed two 400 kW generators that can supply 25 percent of the summer electricity load. Recently, Rochester upgraded to two 1,000 kW turbocharged engines that will increase both the size and efficiency of the electric generation. In addition, the new configuration will include a combined heat and power design to use the waste heat from the electricity generation to heat the anaerobic digester and increase biogas production by 25 percent.

Albert Lea Public Utilities

The Albert Lea Public Utilities Wastewater Treatment facility was recently retrofitted to capture methane gas to generate electricity using four combustion microturbines. Previously it used the methane in a boiler to generate heat for the digester facility or burned the methane in an

atmospheric flare. It is expected that the facility will generate and offset 800,000 kWh/yr of usage at the plant, or equal to the electricity consumption of about 100 average Minnesota homes.

END SIDEBAR**

Biomass Decay

Landfill gas is a waste fuel from the decay of municipal solid waste (MSW). MSW in Minnesota is estimated to contain approximately 60 percent biomass in (paper and organic materials) ("Statewide MSW Composition Study" March 2000, Solid Waste Management Coordinating Board). There are currently four landfill gas-to-electricity recovery projects in Minnesota totaling 24.2 MW. The US EPA's Landfill Methane Outreach Program (LMOP) estimates that 25 other landfills in MN may be good candidates for heat or electricity generation. Heat recovery is generally the most cost-effective method. Many landfills have to collect and flare methane emissions and capturing this resource for heating or electricity production can make both good energy policy and economic sense.

Hydroelectric Energy

Minnesota has approximately 195 MW of hydroelectric generation located within the state, the largest being Minnesota Power's Thompson Dam at 75 MW. Minnesota also imports a significant amount of hydroelectric power from Manitoba, Canada.

While the ability to add more hydroelectric facilities depends on the flows of water and surrounding terrain, certain niche opportunities may exist for hydroelectric expansion. A 1996 assessment report released by the U.S. Department of Energy lists 40 sites in Minnesota with an additional 137 MW of hydropower potential: 12 upgrades to existing power generation sites (72 MW), 21 additions to existing dam sites with no power generation (51 MW), and 7 undeveloped sites (14 MW). Minnesota offers a production incentive for certain hydroelectric facilities. Redwood Falls and Blue Earth County are currently receiving the state hydroelectric production incentive for having refurbished their facilities.

Solar Energy

Solar energy can be used for producing heat and electricity in Minnesota. A common misconception is that the amount of sunlight received in an area is based on temperature. In reality, solar energy resource quality depends on naturally occurring cloud cover as well as air clarity. As a consequence, Minnesota has better solar resources than Houston, Texas and almost as good resources as Jacksonville, Florida.

Solar heat generation is more cost effective than solar electricity installations, although not necessarily more common. Simply designing or positioning a home or building and its windows to use some of the sun's passive solar gain can offset annual heating needs up to 35 percent. Solar thermal applications can also heat pools, pre-heat building indoor ventilation air, actively heat buildings, and heat domestic hot water.

Solar electric systems are not currently cost-effective for utility applications or strict cost-effective requirements. However, some consumers are exploring and using solar. A 34 kilowatt (kW) system was recently installed in Minneapolis and is the largest system in the five-state region. Solar electricity may also be used in the future during high-cost, high-demand time periods for electric utilities.



1 kW met metered dual axis tracking solar system located at Dodge Nature Center, West St. Paul, MN
Source: Dodge Nature Center

****SIDE BAR: Minnesota Solar Rebate Program**

The Minnesota Solar Rebate Program is operated by the Department of Commerce with funding from Xcel Energy's Renewable Development Fund.

The program leverages 80 percent cost-sharing by participants. To date, the 46 participants have increased the amount of grid-connected solar electricity in Minnesota over 100 percent in less than two years. The solar rebate program is one tool that will be used in the federal Million Solar Roofs Initiative.

END SIDEBAR**

****SIDEBAR: Minnesota Million Solar Roofs Initiative**

The Department coordinates the Minnesota Million Solar Roofs Initiative using federal funding chosen in a competitive process by the U.S. Department of Energy. The Minnesota Million Solar Roofs Initiative is a state chapter of the federal Million Solar Roofs Initiative which seeks to:

- encourage and document 500 installations by 2010 in Minnesota;
- educate consumers, builders, installers, utilities, and code officials about solar technologies;
- reduce the barriers and transaction costs associated with installing solar technologies; and

- emphasize broad stakeholder participation by consumers, utilities, government, and business.

END SIDEBAR**

Biofuels

Biofuels for non-transportation uses generally consist of biodiesel and vegetable oils. Biodiesel fuel has become well known in Minnesota's transportation sector, but it can also be used as a fuel for generating heat or electricity. Biodiesel can be used in a boiler or furnace as a fuel oil replacement, electric diesel generator, and, along with vegetable oils, in a combustion turbine.

Diesel Generators

Diesel fuel is used in peaking diesel generators that account for more than 1,600 MW of peaking capacity in Minnesota, which approaches the combined capacity of the Prairie Island and Monticello nuclear power plants. Diesel generators have a low installed cost, high operating costs, low permitting requirements, and do not operate many hours of the year. However, they do operate primarily during periods of high summer demand and can be an air emissions concern. Many of these plants are older and can have locally high emissions.

To reduce emissions and produce renewable energy, diesel generators, for example, can use percentage blends of biodiesel. Using higher blends of biodiesel (greater than 20 percent) is being investigated for compatibility with various types and generations of generators (older generators may not have certain parts that are compatible for long-term use of biodiesel). Using biodiesel in these generators may be a low-cost method of reducing many air emissions, but further demonstration and research in a larger number of generator types may be necessary. Although more research is needed on nitrogen oxide (NOx) biodiesel emissions, biodiesel does significantly reduce hydrocarbon (HC) emissions. NOx and HC are both precursors to ground-level ozone formation.

****SIDEBAR: UMN Biodiesel Generator Testing**

The University of Minnesota Center for Diesel Research performed both laboratory and field demonstration tests of diesel electric generator performance and emissions when using biodiesel blended fuel.

Based on lab test results (among other findings, better fuel economy and reductions in particulate emissions of up to 30 percent and NOx reductions of up to 19 percent.), a B20 biodiesel blend combined with supplemental charge air-cooling was demonstrated on a standby generator at the School of Environmental Studies at the Minnesota Zoo in Apple Valley. Emissions reductions comparable to laboratory demonstration results were measured in the Zoo field test.

END SIDEBAR**

GSHPs reduce the need for non-renewable heating sources but are most cost- and energy-effective where natural gas service is unavailable and/or where electric or propane heat is currently being used. GSHPs are also most cost-effective in commercial, industrial, and

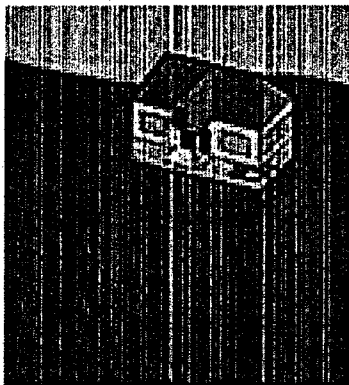
institutional facilities, but are more common in the residential sector due to longer payback acceptance. Several Minnesota electric utilities offer small rebates or electric rates for GSHPs.

OTHER ENERGY TECHNOLOGIES

This discussion of non-renewable fuel sources (nuclear, coal, natural gas) focuses on fuels and technologies that show efficiency or emissions improvements over traditional generating sources or pertinent to policy issues in Minnesota.

Ground Source Heat Pumps

Ground source heat pumps (GSHP) use the latent heat of the earth to heat and cool a building. The most common construction is a series of buried coils or wells that have a liquid solution flowing through closed piping. Transferring the constant 55 degree (F) temperature of the earth from a depth of 10 feet or more into a thermal-exchange system reduces the need for heating in the winter and cooling in the summer, since the building air can be heated or cooled more efficiently than using outdoor air temperatures as a starting point.

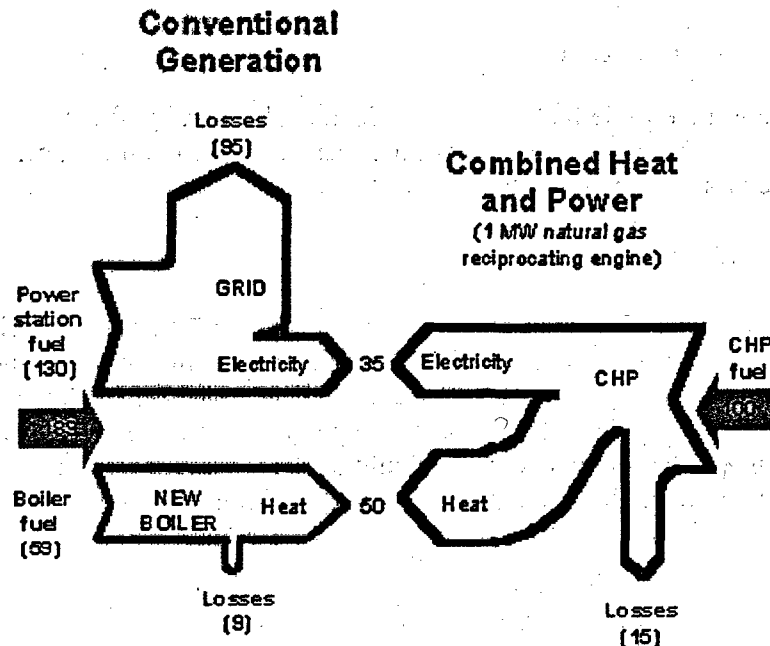


Source: Geothermal Heat Pump Consortium (EPS graphic found at <http://www.geoexchange.org/illustrations/graphics.htm>)

Combined Heat and Power

Combined heat and power, the generation of electricity and use of waste heat from the process, is not a new concept. Thomas Edison's first electrical plants were designed to take advantage of the waste heat from the generation process.

Figure 20



Source: U.S. Department of Energy CHP Systems for buildings Program website,
<http://www.bchp.org/public.basic.html>

Combined heat and power (CHP) is a term that refers to the use of so called "waste heat" from the generation of electricity.

A business using a CHP system essentially gets "more miles per gallon" and more for its money. Many businesses use both boiler system and electricity to supply the building's energy needs, with only 30 to 40 percent efficiency. When CHP is used, both heat and power needs are met with one energy supply source at up to 90 percent efficiency.

Innovations in electric power generation are helping more businesses and organizations consider CHP. Advances in microturbines and natural gas reciprocating engines have expanded CHP opportunities for smaller facilities. Thermally activated technologies have advanced to use waste heat for both heating and cooling applications such as building air conditioning or chilled water supply. While eliminating the need for traditional utility service for a location is unlikely, in some systems the electricity generated by the customer can become a value-added byproduct that can be sold back to the utility or used on site, substantially improving the economics of a CHP system.

Coal Gasification

Modern coal plants have significantly fewer emissions than older plants due to advanced technologies and more stringent emissions reduction equipment. However, even new coal-fired electric generating plants do produce emissions.

Integrated Gasification Combined Cycle (IGCC) technology has significant potential for reducing the emissions from coal fired electric generation. The unique technology is the "integrated gasification," while the "combined-cycle" portion is a conventional method of increasing efficiencies commonly used with natural gas. In coal gasification, coal is pulverized to a fine powder and then combusted with reactant gases rather than burned whole. The gasification process captures emissions before they are burned rather than filtering them afterward. The size of IGCC plants that have been tested are range from approximately:

- 100 MW for the Pinon Pine project in Nevada;
- 250 MW for the Tampa Electric project in Florida; and
- 262 MW for the Wabash River project in Indiana.

A fourth demonstration project of approximately 540 MW, is currently underway in Kentucky.

The Mesaba Coal Gasification Project

As noted in Chapter 2, an IGCC plant is currently being proposed for Minnesota's Iron Range. The size proposed for this plant is larger than the IGCC plants currently in existence. The Mesaba project is reportedly seeking to be designated the FutureGen project.

A capital construction cost comparison of electric generating technologies from the Public Utilities Commission Metropolitan Emissions Reduction Proposal briefing estimated the following capital costs:

IGCC plant: \$1.6 to \$1.8 million per megawatt (MW)
New Coal plant: \$1.5 to \$1.8 million per MW
New Natural Gas plant: \$0.7 to \$0.8 million per MW

Gasification Technology

The heart of gasification-based systems is the gasifier. A gasifier converts the coal feedstock into gaseous components by applying heat under pressure in the presence of steam. The gaseous mixture is called syngas.

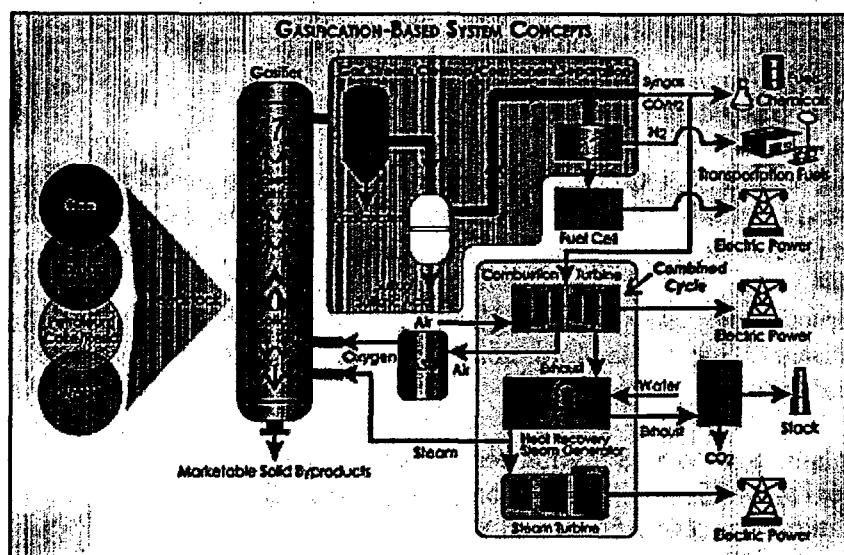
Syngas is primarily hydrogen, carbon monoxide and other gaseous constituents, the proportions of which can vary, depending on the conditions in the gasifier and the type of feedstock. The syngas is cleaned of hydrogen sulfide, ammonia and particulate matter and is burned as fuel in a

combustion turbine, much like natural gas, i.e. "integrated gasification." The combustion turbine drives an electric generator. Hot air from the combustion turbine is channeled back to the gasifier or the air separation unit, while exhaust heat from the combustion turbine is recovered and used to boil water, creating steam for a steam turbine-generator. This technology is known as "combined cycle" (see below).

The syngas can also be used as chemical "building blocks" to produce a broad range of liquid or gaseous fuels and chemicals or as a source for hydrogen that can be separated from the gas stream and used as a fuel.

Combined Cycle

Currently, only natural gas is widely used in a combined cycle power technology. The use of these two types of turbines - a combustion turbine and a steam turbine - in combination, known as a "combined cycle," is one reason why coal gasification-based power systems currently in existence can achieve higher power generation efficiencies than a conventional coal plant. Present gasification-based systems operate at efficiencies of around 45 percent. By contrast, a conventional coal-based boiler plant employs only a steam turbine-generator and is typically limited to 33-38 percent efficiencies.



Source: U.S. Department of Energy, Office of Fossil Energy

How Gasification Power Plants Work

The US Department of Energy has initiated a program called FutureGen, in which the Department is offering \$1 billion for the development and construction of a zero emissions coal gasification generation facility. In order to be emissions-free, the FutureGen facility must be able to sequester the carbon dioxide created by the combustion process. *Carbon sequestration* is a method of capturing and permanently isolating carbon dioxide (CO₂) emitted from the IGCC

process in an effort to prevent global climate change. When oxygen is used in the IGCC gasifier (rather than air), the CO₂ produced is in a concentrated gas stream. This process makes it much easier and less costly to separate and capture the CO₂. Once the CO₂ is captured, it can be sequestered - that is, prevented from escaping to the atmosphere and contributing to the "greenhouse effect."

Hydrogen & Fuels Cells

Hydrogen and the hydrogen economy have received a lot of attention recently. Hydrogen and its use in fuel cells, for example, represent a revolution in energy production and use. As discussed in more detail below, fuel cells can be used to make electricity and heat to operate our vehicles and buildings. Fuel cells use a chemical reaction rather than a combustion reaction and are more efficient than generation from combustion sources and have nearly no pollution.

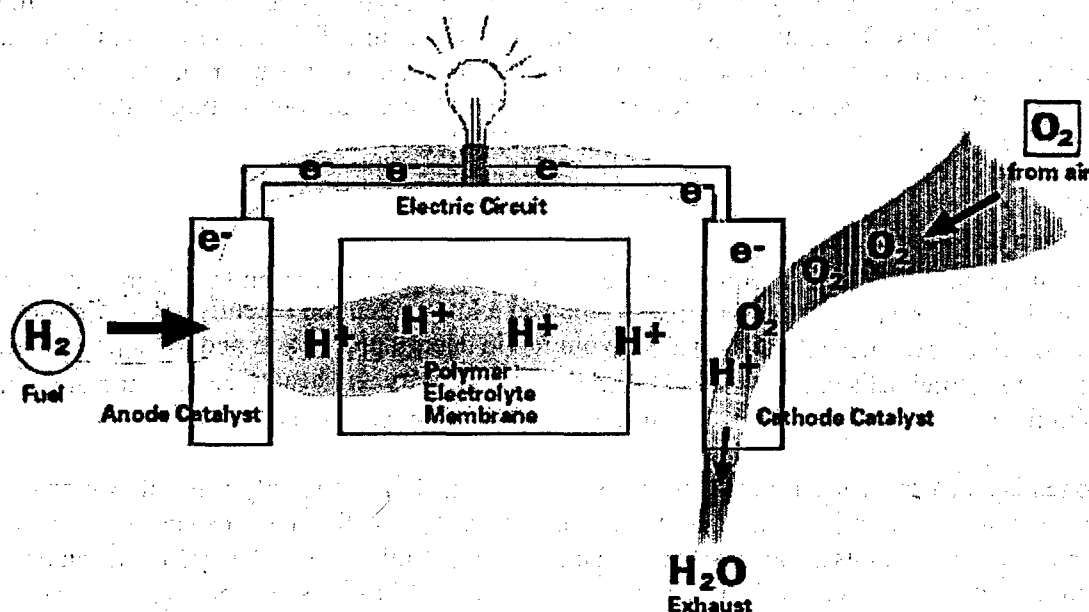
Hydrogen is an energy carrier, not an energy source. As such, it is the only concept available today that could potentially be used to "store" electricity. Many other fuels can be converted to hydrogen but hydrogen itself does not occur naturally in a usable form. The hydrogen can be derived from renewable (electrolysis using renewable energy, biomass, ethanol, algae, etc) or non-renewable sources (coal, petroleum, natural gas, methanol, propane, etc). Because hydrogen can be derived from both nonrenewable and renewable energy sources, it can be tailored to a given state's or region's strengths.

Fuel Cells

Fuel cells are an important enabling technology for the hydrogen economy and have the potential to revolutionize the way we power our nation, offering a cleaner, more-efficient alternative for heating, electricity, and transportation. Fuel cells are being developed to power passenger vehicles, commercial buildings, homes, and even small devices such as laptop computers and cell phones. The largest near-term market for fuel cells will most likely be in these small devices since the cost of electricity from batteries is very high.

A fuel cell is an electrochemical device that uses hydrogen (or a hydrogen-rich fuel such as ethanol or natural gas) and oxygen to create electricity and heat. If pure hydrogen is used as a fuel, fuel cells emit only heat and water as a byproduct. Several fuel cell types are under development, and have a variety of potential applications.

Fuel cells are classified primarily by the kind of electrolyte they employ. The electrolyte determines the kind of chemical reactions that take place in the cell, the kind of catalysts required, the temperature range in which the cell operates, the fuel required, and other factors. These characteristics, in turn, affect the applications for which these cells are most suitable. There are several types of fuel cells currently under development, each with its own advantages, limitations, and potential applications. One of the most promising types is the Polymer Electrolyte Membrane fuel cell.



Source: Fuel Cells 2000 website, <http://www.fuelcells.org/basics/how.html>

Polymer electrolyte membrane (PEM) fuel cells, also called proton exchange membrane fuel cells, deliver high power density and offer the advantages of low weight and volume, compared to other fuel cells. They need only hydrogen, oxygen from the air, and water to operate and do not require corrosive fluids like some fuel cells. They are typically fueled with pure hydrogen supplied from storage tanks or onboard reformers.

PEM fuel cells are used primarily for transportation applications and some stationary applications. Due to their fast startup time and favorable power-to-weight ratio, PEM fuel cells are particularly suitable for use in passenger vehicles, such as cars and buses.

A Flexible, Adaptable Energy System

The production of hydrogen from electricity generated by wind turbines or other renewable energy technologies or even ethanol has significant potential in Minnesota. Hydrogen production provides a level of flexibility in that the hydrogen could be used for either vehicle applications or stationary electric power. Electricity stored as hydrogen would yield a smaller amount of energy due to losses in the conversion process, but the flexibility of the fuel and the ability to deliver the energy during periods that maximize the economics could overcome some, if not all of these losses. Wind-to-hydrogen plants could serve the hydrogen needs of small communities, or they could be used to firm up wind capacity so as to relieve constraints on our electrical transmission grid.

End-Users of Hydrogen in Minnesota

Within Minnesota, Flint Hills Resources (formerly Koch Petroleum Group) and Ashland Oil may be the largest users of hydrogen, employed in the refining process and to make fertilizers, but they are also hydrogen producers. In addition, most power plants use hydrogen for cooling their electrical generation equipment, and powdered metal plants are a growing market, where hydrogen takes the place of dissociated ammonia in the metal coating process. Renewably produced hydrogen could also be used in the manufacture of anhydrous ammonia, a process that currently uses large quantities of hydrogen produced through the steam reformation of natural gas.

Laying the foundation for Hydrogen in Minnesota

Minnesota has a strong presence in the fuel cell industry, with companies such as 3M, Tescom, Entegris, Donaldson and ICM Plastics. Companies such as Praxair, Flint Hills Resources, and Marathon Ashland Petroleum have significant experience with handling hydrogen and developing fueling infrastructure. Also, Minnesota's wind and ethanol industries are or are becoming quite strong with other indigenous renewable fuels developing. Lastly, as discussed in Chapter 2, the Minnesota Legislature has provided funding sources to the University of Minnesota Initiative for Renewable Energy and Environment to support basic and applied research on hydrogen production.

Chapter Four

NATURAL GAS – A Bridge Fuel to the Future?

The recent increases in (and volatility of) natural gas prices have pushed the consumption and the availability of natural gas toward the center of the current national energy debate. Although natural gas is still considered one of the cleanest burning fuels, it can no longer be taken for granted as a low-cost, unlimited resource. Instead, natural gas may be viewed as a bridge from traditional fuels to emerging, more efficient fuels and technologies. As the future of natural gas is considered, there are issues that warrant focus. Those issues can be categorized into four general areas:

- Increasing Demand;
- Supply Availability;
- Availability of Transportation Capacity; and
- Increasing Prices and Volatility.

Each is discussed below.

INCREASING DEMAND

Natural gas consumption in the residential and commercial sectors is influenced primarily by weather. If winters are mild, weather-related consumption normally is less; if winters are severe, weather-related consumption is higher. However, natural gas consumption is also affected by the general level of economic activity, and the relative prices of natural gas and alternative fuels.²¹ Consumption of natural gas is likely to continue to increase, barring unforeseen large natural gas price increases that would make it less competitive with alternative fuels.

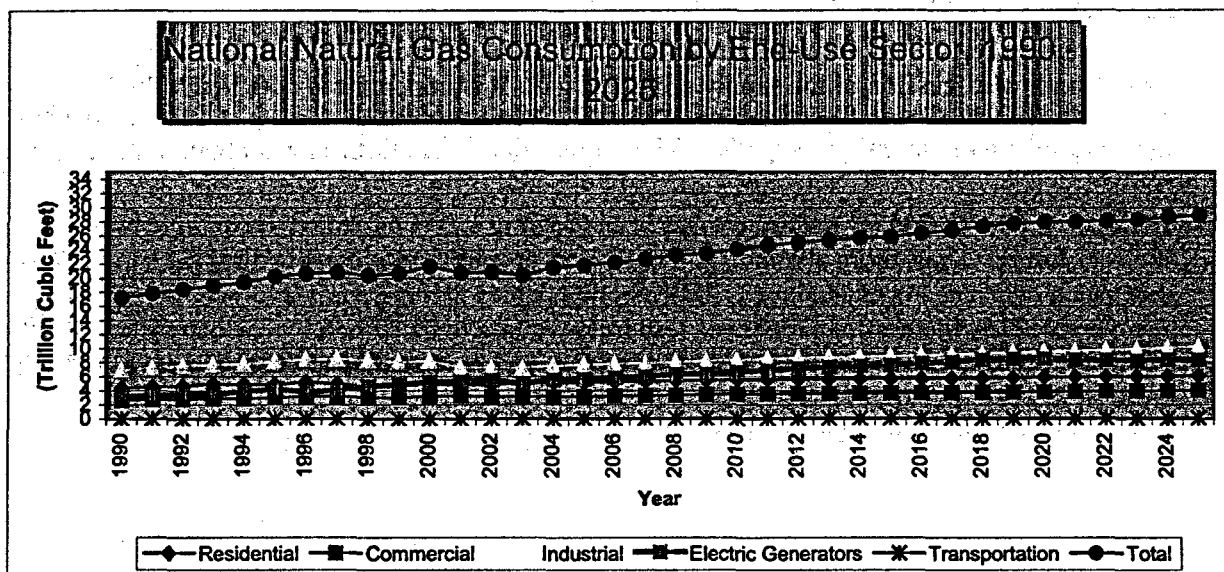
Statewide, Minnesota's demand for natural gas increased from 248,821 MMcf in 1965 to 313,435 MMcf in 2001. Residential consumption has increased approximately 44.3 percent from 87,309 MMcf in 1965 to 125,984 MMcf in 2001, while commercial consumption has increased approximately 83.5 percent from 52,121 MMcf in 1965 to 95,662 MMcf in 2001.²² Industrial consumption, which includes electric generation, and deliveries-to-transportation, account for the remaining amount of total Minnesota demand.²³

²¹ In this context, "alternative fuels" are normally considered to be other petroleum-based fuels that can be substituted in equipment, such as propane, fuel oils, and diesel fuels.

²² Source: REIS

²³ The "deliveries-to-transportation" refer to situations where larger customers purchase natural gas supplies from third-party marketers and transport it to their facilities through the local distribution companies' systems.

On a national level, demand for natural gas has been growing since the 1930s. Residential natural gas consumption has grown from 295,700 MMcf in 1930 to 4,923,151 MMcf in 2002.²⁴ Commercial consumption of natural gas has grown from 80,707 MMcf in 1930 to 3,121,595 MMcf in 2002.²⁵ In 2002, total consumption of natural gas was 22,780,710 MMcf and is expected to rise to over 35,411,745 MMcf by 2025.²⁶



Source: U.S. Energy Information Administration *Annual Energy Outlook for 2004*, Figure 85 data, pg. 89.

According to the U.S. Energy Information Administration (EIA), the largest potential near-future increase in the use of natural gas will come from electric generation. (This trend is only starting to be evident, as shown in Figure 4 of Appendix 2, which includes data through 2002.) At a national level, natural gas consumption for electricity generation is projected to increase from 5.6 trillion cubic feet (Tcf) in 2002 to 8.4 Tcf in 2025, an average annual growth rate of 1.8 percent.²⁷ New natural gas-fired peaking and intermediate²⁸ generation plants will compete with LDCs for natural gas during the traditional summer refill season, thus impacting the volatility of natural gas prices during this period.

²⁴ Source: U.S. Energy Information Administration *Annual Energy Outlook for 2004*.

²⁵ Source: U.S. Energy Information Administration *Annual Energy Outlook for 2004*.

²⁶ Source: U.S. Energy Information Administration *Annual Energy Outlook for 2004*.

²⁷ Source: U.S. Energy Information Administration *Annual Energy Outlook for 2004*, Figure 85 pg. 89.

²⁸ Unlike "baseload" plants, which operate continuously, "peaking" plants operate only during periods of high demand. "Intermediate" plants can adjust operation and output based on economic dispatch to meet high demand and/or to help run the electric system smoothly during plant outages or planned maintenance.

One way of limiting the demand for natural gas (and electricity) is to utilize energy conservation programs. With the uncertainty and volatility of natural gas prices, conservation programs are an excellent way of slowing increasing demand by reducing a customer's usage, which in turn reduces the customer's energy bill.

SUPPLY AVAILABILITY

No discussion regarding the growth in demand of natural gas would be complete without a corresponding discussion of the supply of natural gas. It is important to note that Minnesota has no native source of natural gas supplies. Therefore, Minnesota utilities must obtain natural gas predominately from the natural gas fields in Kansas, Oklahoma, Texas, and Alberta, Canada.

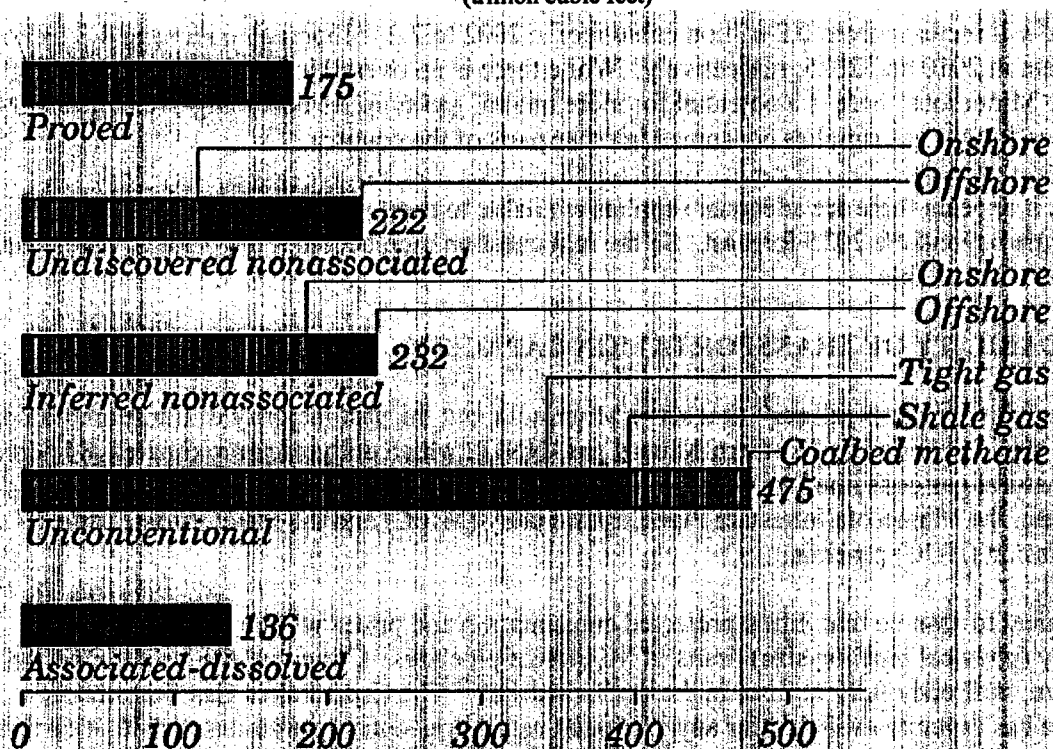
Nationally, the demand for natural gas has been growing and is projected to continue to grow for the near future. Thus, more attention is focusing on potential sources of natural gas supplies to meet such demand. As of January 1, 2002, the EIA states that there is 1,240 Tcf²⁹ of technically recoverable U.S. (domestic) natural gas resources waiting to be tapped.³⁰ The natural gas reserve additions reflect an expected increase in exploratory and developmental drilling that will result from an increase in natural gas prices and production revenues.

²⁹ EIA divides this number into two components, proved and unproved. Proved natural gas reserves (175 Tcf) are located in known and developed reservoirs, for which wells have been drilled and production rates have been demonstrated. Unproved technically recoverable resources include:

- *Undiscovered nonassociated conventional* (222 Tcf) - natural gas resources are unproved resources of natural gas, not in contact with significant quantities of crude oil in a reservoir that are estimated to exist in fields yet to be discovered, based on regional geologic formations and their propensity to hold economically producible natural gas.
- *Inferred nonassociated conventional* (232 Tcf)- natural gas reserves are gas deposits in known reserves that are considered likely to exist on the basis of a fields geology and past production but have not yet been developed through developmental drilling.
- *Unconventional* (475 Tcf)- this category is by far the largest category of unproved reserves. This gas is tight gas found in sandstone, shale and coalbed methane.
- *Associated-dissolved resources* (136 Tcf)- This includes gas in associated-dissolved crude oil reservoirs in the lower 48.

³⁰ Source: U.S. Energy Information Administration *Annual Energy Outlook for 2004*, Figure 10, pg. 33. However, table 22 on page 91 states that the technically recoverable U.S. natural gas resources as of January 1, 2002 are 1,279.5 Tcf (proved reserves of 183.5 Tcf and unproved reserves of 1,096 Tcf) –thus, this data includes Alaska.

**Technically Recoverable Lower 48 Natural
Gas Resources as of January 1, 2003
(trillion cubic feet)**



Source: U.S. Energy Information Administration Annual Energy Outlook for 2004, Figure 10, pg. 33

Currently, U.S. output is not sufficient by itself to meet U.S. natural gas demand. The nation has historically imported significant amounts of natural gas supplies from Canada. However, in 2003, the Canadian National Energy Board (NEB) reassessed and revised its earlier estimates of Canadian production. As such, EIA in its *Annual Energy Outlook for 2004* (AEO2004), has decreased its forecasted potential imports from Canada. Net imports of natural gas from Canada are projected to peak at 3.7 trillion cubic feet in 2010, then decline gradually to 2.6 trillion cubic feet in 2025. The depletion of conventional resources in the Western Sedimentary Basin is expected to reduce Canada's future production and export potential, and prospects for significant production increases in eastern offshore Canada have diminished over the past few years. There is also considerable uncertainty about the economic viability and timing of coalbed methane production in western Canada.

Two possible supply sources may be available in the near term to mitigate the decline in historic Canadian imports. The first is the construction of a pipeline to move natural gas from the MacKenzie Delta in Canada's Northwest Territories into Alberta. The second is increased use of imported liquefied natural gas (LNG). LNG is natural gas in a liquid state maintained at a temperature of -260 degrees Fahrenheit. Once the imported LNG is returned to its gaseous state it is transported through high pressure pipelines to local/regional markets. Imported LNG comes from an increased number of countries including Algeria, Malaysia, Australia, and Trinidad and

Tobago. At this time, there is only limited capability to import LNG into the United States. When planned expansions at the four existing terminals are completed and the new LNG terminals that are projected to start coming into operation in 2007, it is estimated that net LNG imports will increase from 0.2 trillion cubic feet in 2002 to 2.2 trillion cubic feet and 4.8 trillion cubic feet in 2010 and 2025, respectively. While there is no overall infrastructure to deliver LNG to Minnesota, there is a potential for more natural gas supplies becoming available as LNG displaces natural gas supplies consumed in other parts of the country.

In sum, it appears there are adequate supplies available to meet projected demand, at least for some time beyond the 2025 forecast. So the real question then becomes the price at which such supplies are available.

AVAILABILITY OF TRANSPORTATION CAPACITY

There are four major pipelines³¹ that serve Minnesota, but the vast majority of transportation of natural gas is provided by Northern Natural gas (NNG), which delivers approximately 84 percent of the natural gas consumed in Minnesota in 2002.³² There are two operational intrastate pipelines: the Minnesota Intrastate Pipeline Company (MIPC) and the Hutchinson Utilities Commission (HUC) pipeline.

It is logical to assume that future projected consumption and prices will be impacted by the capacity (physical pipeline size) limits of Minnesota pipelines. Currently, the largest pipeline, Northern, is already fully utilized in the winter season.³³ The Great Lakes Gas Transmission pipeline has capacity available for any increased natural gas consumption that would occur in the northern half of Minnesota. As for the Viking Gas Transmission pipeline, which is already operating at full capacity, any increases in year-round demand would require additional pipeline related construction. The MIPC and HUC pipelines are reported to be fully subscribed.

As with any fuel, once demand increases beyond the current available pipeline capacity, a significant new investment in infrastructure is required to expand capacity. Such infrastructure investments are expensive³⁴ and in most cases, require long-term commitments/contracts to be executed prior to construction.

Interstate pipelines are regulated by the Federal Energy Regulatory Commission (FERC). At first, that new investment would be charged only to the customers using the new pipeline capacity. Then, in order to incorporate the new investment costs into the overall rates, the pipeline company would have to file a rate case. When this step is completed, the price charged

³¹ The four pipeline systems serving Minnesota include Viking Gas Transmission, Great Lakes Gas Transmission, and Northern Border Pipeline as well as Northern Natural Gas.

³² Source: Interstate gas pipeline company information reported annually under Minnesota Rule 7610.1200. Some Companies reported their data in decatherms, which were converted to Mcf using a one-to-one ratio.

³³ The heating season is considered to be the five winter months of November, December, January, February and March.

³⁴ For example, the approximately 80 miles of intrastate pipeline installed by HUC had an initial estimated construction cost of approximately \$26 million.

to all customers reflects the increased costs.³⁵ In contrast, natural gas pipelines located wholly within the state (or Intrastate pipelines) are rate regulated by the MPUC with larger pipelines requiring a Certificate of Need prior to initial construction. The overall delivery infrastructure is aging and needs to be redeveloped and/or improved to meet energy demands into the future.

INCREASING PRICES AND PRICE VOLATILITY

The average wellhead prices for natural gas (including both spot purchases and contracts) according to the EIA shown in the table below:

Natural Gas Prices ³⁶ (2002 Dollars per Thousand Cubic Feet)						
	<u>2002</u>	<u>2010</u>	<u>2015</u>	<u>2020</u>	<u>2025</u>	<u>Annual Growth</u>
Average Wellhead Price	2.95	3.40	4.19	4.28	4.40	1.8%

As shown above, the average wellhead prices are projected to increase from \$2.95 per thousand cubic feet in 2002 to \$3.40 per thousand cubic feet in 2010. Natural gas wellhead prices are projected to be \$4.28 in 2020, when an Alaska pipeline is expected to be completed. Wellhead prices are projected to increase gradually after 2010, reaching \$4.40 per thousand cubic feet in 2025. Some of the cost drivers for the increase in natural gas prices are due to newer technologies being used to drill deeper wells and tap harder-to-extract natural gas. Additionally, the fundamental principle of supply and demand will drive prices up. As demand for natural gas increases due to increased usage, the price will increase.

One additional consequence of higher demand and tighter supplies is rapid changes (increases or decreases) in price or increased price volatility. Because natural gas is used for home heating, its consumption (and therefore, its price) is extremely weather dependent. As such, there can be periods of high price volatility during cold days or weeks followed by periods of stable prices.³⁷

One method that Local Distribution Companies (LDCs) use to combat price volatility is the use of financial tools. There are a variety of financial tools that can be used to stabilize prices for the end-use customer. One way price stabilization is achieved is by entering into financial futures contracts and options through an exchange (i.e., NYMEX). Financial tools also can involve entering into physical hedges³⁸ with suppliers and other third-parties. The purpose of these tools,

³⁵ Northern implemented a 30 percent rate increase beginning November 1, 2003 and has recently petitioned FERC for an increase of an additional 8 percent for a total potential increase of 38 percent from October 31, 2003 to November 1, 2004. The FERC allows implementation of proposed rates subject to refund per FERC's final decision.

³⁶ Source: U.S. Energy Information Administration *Annual Energy Outlook for 2004, Table A14*.

³⁷ Volatility adds to the cost of supplying natural gas. In Minnesota, natural gas utilities are allowed to pass all prudently incurred costs on to the consumer on a dollar-for-dollar basis.

³⁸ Examples of physical hedges include: (1) seasonal use of storage where supplies are purchased and injected into storage and withdrawn for use during periods of high demand or high prices; (2) fixed-price supply contracts where

whether futures contracts of physical hedges, is to obtain guaranteed supplies at a pre-set price. Thus, LDCs use these tools to mitigate price risk and volatility. Several Minnesota utilities have received Commission approval to recover the costs of such financial tools and have started using the tools in managing their gas supply portfolio.

In conclusion, the domestic demand for natural gas continues to grow and has the potential to outpace the domestic supply. Domestic supplies have relied on Canadian imports, but as Canadian imports decline, there is a need to develop an overall infrastructure to import and use LNG. The pipeline infrastructure is aging. To maintain or increase the pipeline capacity, there is a need for continual investments for improvements and expansions. As long as demand increases and supplies remain tight, the price for nature gas will be higher than in the past and will continue to be volatile. Nowadays, natural gas should be viewed as a bridge fuel while exploring and developing alternative fuel sources and technologies.

supplies are purchased over a period of time at a pre-set or fixed price for use at a later time; and (3) long-term, firm transportation contracts with pipelines where LDC's negotiate transportation charges to ensure capacity in future periods.

Chapter 5 TRANSPORTATION FUELS

OVERVIEW³⁹

Minnesotans consumed a total of 5,670 million gallons (691.5 trillion BTUs) of total petroleum products in 2002⁴⁰. Total petroleum products include: asphalt and road oil, aviation fuel, distillate fuel, jet fuel (all types), kerosene, liquid petroleum gases, lubricants, motor gasoline, and residual fuel. Motor gasoline accounted for 2.6 billion gallons of the 2002 total, an increase of 44 million over 2001 consumption. Since Minnesota has no oil reserves, Minnesota imports all of its petroleum products, valued at over \$4 billion, each year.

In 2002, Minnesotans used about 85 percent of all petroleum products for air, land, and water transportation. These products include asphalt and road oil as well as actual fuels like diesel, jet fuel, and motor gasoline. Most agricultural use of petroleum falls under the transportation category. Commercial, electric utility, industrial, and institutional space heating and processing uses accounted for about nine percent of petroleum products. About one-fourth of Minnesota households currently use either fuel oil or propane for their heating source. This use constituted about 6 percent of the total petroleum products used in 1998.

Most petroleum products enter and leave Minnesota by pipeline. Some are transported by barge, rail, ship, or truck. All but a small portion of the United States' imported Canadian crude oil and liquid petroleum gases (LPG) pass through Minnesota on their way to other parts of the Midwest, Eastern Canada, and New England.

Refined petroleum products are available in Minnesota through area refineries or via pipelines. Electric utility and other industrial customers then use barge, rail or trucks to transport the finished products to their individual locations. Smaller volume customers, such as farms, homes, and gas stations, receive their petroleum products via truck delivery.

The price of petroleum products is largely comprised of the basic cost of crude oil and assessed taxes. World political and economic market forces primarily determine the cost of crude oil. Federal and state governments assess taxes on petroleum products.

During 2004, the cost per barrel of oil has fluctuated around the \$50 per barrel mark. This translated into higher prices at the gas pump, in many cases, surpassing \$2 per gallon. However, consumption has been negligibly impacted by this increase in price.

Many factors influence the other aspects of the price of finished petroleum products. Some price changes are due to supply and demand imbalances. For example, supply shortages sometimes occur due to maintenance or damage on the pipelines or at refineries. Since each petroleum product needs to be stored individually, some supply shortages result from simple logistical

³⁹ Commerce thanks the Department of Agriculture for its review and contribution to this chapter.

⁴⁰ Further discussion and data concerning transportation fuels is found in Appendix 2.

problems associated with coordinating production and storage to meet current and future demand.

Higher than expected demand for a particular product can also create temporary shortages that lead to higher prices. Very cold weather increases the heating use of propane products and very wet or very dry weather increases the agricultural use of petroleum products.

Activity in the commodities market can further influence price changes. Spikes or sudden drops in prices are sometimes the markets' response to perceptions of future supply and demand imbalances. Thus, data trends become more important information for planning purposes than specific numbers on specific dates.

FUTURE TRENDS

Residential, commercial and industrial uses of petroleum products for non-transportation purposes has been steady or declining in the past several years and that trend is expected to continue. The transportation sector, which consumes nearly two-thirds of all petroleum products, has shown steadily increasing levels of consumption. This increase will likely continue until prices increase significantly enough to encourage consumers to consider other options.

One factor that impacts the price of petroleum products is the availability of supply. Crude oil is necessary for the production of petroleum products. The world currently uses approximately 27,010 million barrels of crude oil per year. Scientists estimate that ongoing natural processes create new crude oil at the rate of 7 million barrels per year (or .025% of total use). These numbers indicate an eventual depletion of the available crude oil, although it may be possible to find or manufacture new sources and substitutes for these products.

As with natural gas and electricity, the available infrastructure also has a large impact on petroleum prices. Currently, demand is beginning to exceed ocean-shipping capacity and is approaching the capacity of some pipelines. Furthermore, the cost of developing new crude oil wells is increasing. New wells are in less accessible locations. Higher prices for petroleum, however, allow development of lower grades of crude that were previously too costly to produce.

Three other trends may impact the price of petroleum products. First, in the 1990s, crude oil and refined petroleum product, like natural gas, became publicly traded commodities on world mercantile exchanges. During times of actual or perceived supply disruptions or shortages, prices now fluctuate more erratically. Second, nearly every major international oil company and most independent marketers are forming E-commerce sites to trade commodities independently. Their effect on energy prices and supply will depend largely on which sites survive. Third, petroleum refiners have significantly changed their operations in the 1990s. They have reduced refining costs by moving toward just-in-time production. Storage is now more in the control of independent terminal and pipeline operators.

In 2002 the United States imported over 60% of its crude oil from other countries either in the form of crude oil or refined products. U.S. crude oil imports have risen from 44 percent of new

supply in 1990 to 62 percent in 2002. U.S. finished, or refined, product imports have remained fairly steady in the 1990s at about 6 percent of total demand. Much of the crude oil that is fed into refineries in Minnesota is delivered by pipelines from Canada. However, since political pressures in all oil producing areas impact the market, the fact that Minnesota does not receive a large percentage of its crude oil feedstock from areas such as Venezuela, Nigeria, and the Middle East does not mean that Minnesotans are insulated from price fluctuations due to political and economic unrest in those areas.

RELIABILITY ISSUES

The increasing reliability issues that result from problems with the supply infrastructure will continue to be a challenge for the industry throughout the country.

Refinery Operating Practices

Inventories of petroleum products are often maintained on a “just in time” basis. That is, refineries are operated at or near the lower operational inventories for all products. This results in a market that is not as capable of adjusting to significant changes in demand. Some areas of the state are more adversely affected during these times of product shortfalls. Low inventories often causes price increases, as retailers are forced to try to curb demand in order to have sufficient product to get through these periods.

Regulation Changes Allowing Commercial Drivers' Hours of Service

The Federal Motor Carriers Safety Administration recently changed rules concerning the maximum number of hours that commercial drivers who deliver petroleum products may operate a vehicle. The change requires all drivers to account for the amount of time that they are actually waiting for product to be loaded in their vehicle towards their hours of service allotment.

During periods of high demand for all petroleum products, which includes home heating fuels such as propane and fuel oil, long truck-filling wait times may cause drivers to approach their maximum hours of service without satisfying the demand for those fuels. Fuel suppliers may choose to have additional drivers on hand to satisfy these periods of peak demand, although employing additional drivers may lead to increases in delivered fuel prices. In times of extreme hardship, Minnesota's Governor has the authority to extend drivers' allowed hours of service.

Seasonal Demand Fluctuations

September is typically seen as the end of the driving season and demand for petroleum products generally declines. Petroleum refineries tend to choose September or later winter months where there is a lower than normal demand for products as the time to schedule routine maintenance for critical equipment, known as refinery turnaround. This was especially true for refineries that served Minnesota in 2003. Several of the major refineries providing Minnesota with petroleum products underwent a maintenance “turnaround” in September 2003. Refineries normally build up supplies in advance of a turnaround in order to meet demand while the work is being done. However, the regional supply situation was somewhat tighter than years previous due to a major

fire in June 2003 at the Ponca City, OK refinery. This fire significantly limited production output from that refinery throughout the summer. Although the Ponca City refinery does not provide petroleum product for Minnesota, there was a regional ripple effect.

Scarce petroleum inventory issues introduce increased price uncertainty and less supply resilience into the market. There is less flexibility in the supply chain to buffer the market from supply disruptions such as refinery fires or even routine maintenance. Where these events used to cause regional disruptions in supply and price, they now cause upward price pressures on all areas of the country, not just those affected by infrastructure changes. These factors, combined with the ongoing political unrest in many petroleum exporting countries, underscores the importance of diversifying transportation fuels supplies in order to decrease Minnesota's dependence on factors outside of the state's control.

RENEWABLE TRANSPORTATION FUELS

Minnesota has the highest renewable fuel use per capita in the country with ethanol making up 10% of our gasoline use (260 million gallons) and biodiesel making up 2% of our diesel use beginning in mid 2005 (16 million gallons). As MTBE is phased out in other states, demand for ethanol will increase, although ethanol production capabilities are growing rapidly in other states as well. Currently there is about 3.7 billion gallons of ethanol production capacity in the United States and 0.4 billion gallons in Minnesota.

Ethanol

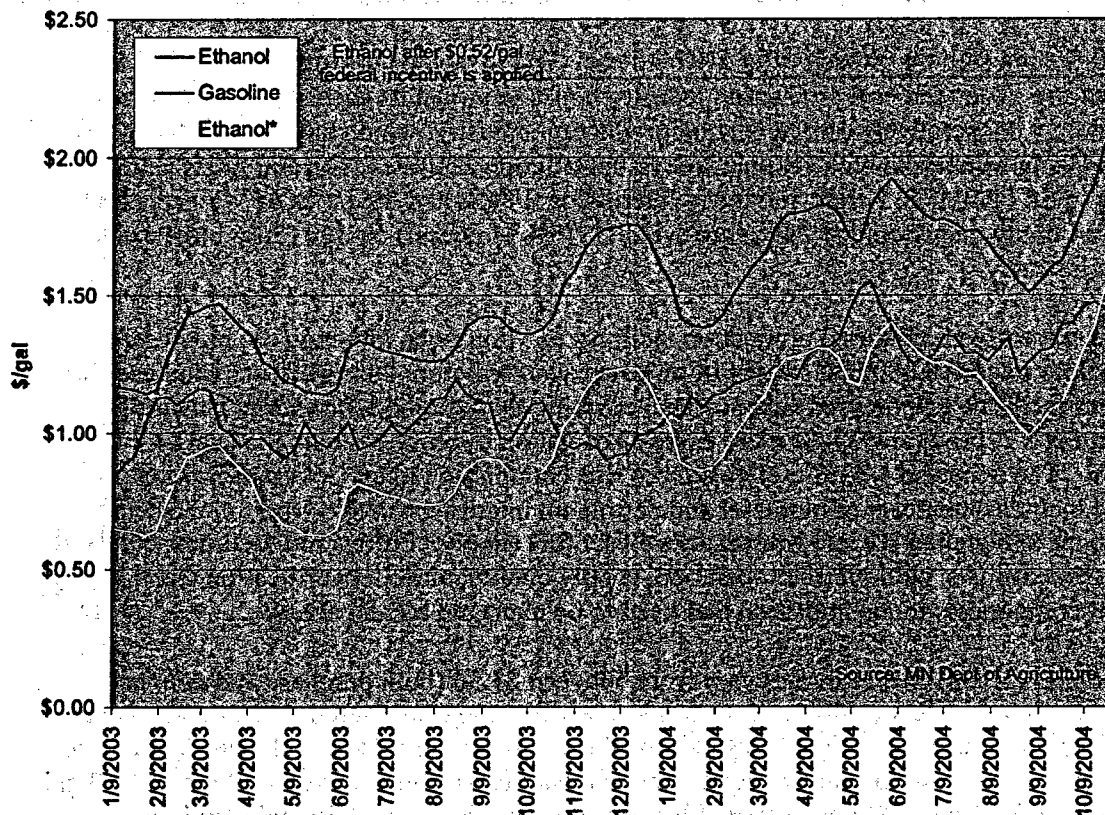
Ethanol is an alcohol fuel produced by the fermentation of organic matter, most commonly corn, but also milo, cheese whey, potato waste and brewery waste. Nearly all gasoline sold in Minnesota contains 10% ethanol to serve as an oxygenate to reduce harmful transportation air emissions. E85 fuel, a blend of 85% ethanol and 15% gasoline, requires the use of a fuel flex vehicle (FFV). FFVs are being manufactured by most of the major vehicle manufacturers. Ethanol or gasoline can be blended in any combination in an FFV.

Minnesota has the largest E85 (85% ethanol) fueling network in the world - nearly 90 stations - which makes up almost half of the stations in the United States. In 2003, over 2,000,000 gallons of E85 will be sold and there is significant room for expansion of the fueling stations and the utilization by the over 100,000 E85 vehicles in Minnesota through additional education and funding efforts. The Department is working with the American Lung Association and the Department of Administration to increase E85 usage among state fleet drivers through workshops, brochures, fuel door stickers, and fuel card data collection but it is generally considered that usage can be significantly improved. The highest selling E85 station in Minnesota, and likely the United States, is located at the Holiday Station Store in Eagan, Minnesota.

Minnesota has fourteen ethanol plants with a production capacity of 400 million gallons. Eleven of the plants are cooperatively owned by over 5,000 Minnesota farmers. It is estimated that Minnesota's plants annually contribute over \$1 billion to the state's economy.

Contrary to popular misconception, producing ethanol does not consume more energy than it yields. An energy balance of exactly one would indicate that it takes exactly as much energy to produce an energy product as is available from its use. According to a 2003 study conducted by the USDA, the energy balance of corn-based ethanol is 1.67. This means that for each unit of fossil energy used to produce corn and to process it into ethanol, 1.67 units of liquid fuel energy is produced. With today's high yielding crops and efficient plants a gallon of ethanol contains 67% more energy than it took to produce it. This study compares the energy required to produce corn and its conversion to ethanol with energy contained in the fuel grade ethanol. Early ethanol plants were inefficient and may have had a poor energy balance but today's farm and ethanol production industry have become very efficient.

Rack Prices of Ethanol and Gasoline in the Twin Cities, 2003-2004



Although the price of ethanol is influenced by the price of gasoline, it is also based on the price of corn, the price of energy inputs at the production facility, operation and maintenance costs, and demand. Ethanol facilities actually provide a hedge for ethanol cooperative farmer-owners against low-corn prices since ethanol can be sold at a higher profit. The rack price of neat ethanol (E100) averaged \$1.37/gal in 2003 and \$1.71/gal through October 2004. Ethanol also can provide a hedge against gasoline prices, once federal incentives are applied, saving consumers money most of the time.

E85 prices in 2003 ranged from \$1.08/gal to \$1.62/gal, averaging \$1.34/gal, which is \$0.18/gal or 12% less than 87 octane (E10) gasoline. However, ethanol has a lower energy content than gasoline and E85 vehicles average fuel economy is about 15% less, which varies depending on the model and driving habits. Driver's mileage can fluctuate by 10% or more based on driving habits alone - rapid starts, idling, vehicle contents, etc. It is important to note that E85 does reduce pollution on a per mile basis compared to gasoline, even with its decreased efficiency. E85 also supports economic development by partially keeping energy expenditures in Minnesota.

Biodiesel

Biodiesel is the vegetable oil equivalent of diesel fuel and can be made from soybeans or waste grease products, primarily from restaurants. It can be used as a blend of 20 percent Biodiesel with 80 percent petroleum (B20) with little or no engine modifications, or can be used as 100% biodiesel (B100) with modifications to engine valves, hoses, gaskets, and fuel filters.

Over 200 fueling stations already offer 2% biodiesel (B2) to consumers, one year ahead of the 2005 deadline. The biodiesel production industry hopes to model its success after Minnesota's predominately cooperatively owned ethanol production industry, which have helped rural communities in Minnesota with economic development opportunities. Several fleets (Eureka Recycling in St. Paul, U.S. Forest Service in International Falls and the cities of Minneapolis, Hennepin County and Brooklyn Park,) are using B5 (5% biodiesel) or B20 (20% biodiesel) blends voluntarily.

There are currently no biodiesel production facilities in Minnesota, although the biodiesel (B2) mandate does require 8,000,000 gallons of in-state capacity before taking effect. Biodiesel production facilities will be sited near soybean crushing facilities and the energy balance for production is 3.2, providing 320% more energy in a gallon of biodiesel than the energy it took to produce it. The Minnesota Biodiesel Taskforce was commissioned by Governor Pawlenty in 2003 and includes members of biodiesel and petroleum interest groups to work on the details of transitioning to blending B2 into Minnesota's diesel fuel supply. Production facilities, blending and storage terminals, cold-weather operation, supply quality, and fuel verification testing are important components to the transition that need to be managed by all parties.

Neat biodiesel (B100) cost estimates vary from between \$1.50 (bulk purchase and delivery) to \$3.00 (55-gallon drum) per gallon. The additional cost of blending B100 with petroleum diesel varies by the price of both products. For example, blending \$1.00/gal petrodiesel with \$1.50/gal B100 results in \$1.10/gal B20 or \$1.01/gal B2 (this does not include additional blending or distribution charges).

SIDEBAR: In 2004, Governor Pawlenty issued an Executive Order that aims to decrease the amount of petroleum used by the State of Minnesota fleet. The "SmartFleet" initiative aims to cut the State fleet's petroleum use 50% by 2015. The initiative also includes a proposal to move Minnesota from a 10% to 20% ethanol requirement. **END SIDEBAR**

Propane and Natural Gas

Propane and natural gas (compressed and liquefied) are also options for fueling Minnesota vehicles that feature ultra-low tailpipe emissions. Minnesota Valley Transit Authority operates three natural gas buses and Schwan's Food Services operates all of their vehicles in propane. Although having higher up-front costs, the long-term operating costs are significantly reduced.

Lower Fuel Sulfur Content

Fueling conventional vehicles with lower-sulfur gasoline further reduces air pollution emissions. Holiday Station Stores in the Twin Cities metropolitan area offers low-sulfur gasoline as their standard fuel in all gasoline grades in the Twin Cities metro area. Beginning in 2006, diesel fuel sulfur content will be significantly reduced by EPA regulations from 500 ppm to 15 ppm, resulting in significant pollution reduction benefits as well. Minnesota's adoption of a 2% blend of biodiesel will help Minnesota transition to the ultra low sulphur fuel requirements by increasing the lubricity of the fuel. There is also a federal US EPA proposal to begin reducing pollution in unregulated heavy equipment, such as those used in construction.

The sulfur content of fuel is important because pollution control equipment does not work as well using standard gasoline available in Minnesota. Low (LEV), ultra-low (ULEV), and super-ultra low (SULEV) emissions vehicles that are commonly driven on Minnesota's roads as standard equipment on many vehicles are rated using low-sulfur fuels. The sulfur reduces the efficiency of the pollution control equipment and unless a driver is consciously choosing the low-sulfur brands, pollution emissions are not as low as rated.

Hybrid Electric Vehicles

The hybrid electric vehicle market is beginning to emerge. Honda and Toyota currently offer three hybrid-electric models, with Ford beginning to start production of the first hybrid SUV. Toyota has committed to offering a hybrid-option on all of their vehicles by 2010. Hybrid vehicles offer great promise for increasing fuel economy and reducing tailpipe emissions. In 2003, the federal government offered an income tax credit of up to \$2,000/vehicle for hybrid-electric cars, which decreases by \$500/yr and would expire at the end of 2006, unless changed via federal legislation.

Hybrid vehicles are proving increasingly popular with consumers. In addition to winning the prestigious Motor Trend Car of the Year and the 2004 North American Car of the Year awards, Toyota reports that its hybrid Prius experienced the fastest sales start of any car in the company's history. (source: Alliance to Save Energy) Many of the major automobile manufacturers have launched a hybrid vehicle with plans to expand to other product lines, including SUVs and mini-vans.

Hydrogen and Fuel Cell Vehicles

Hydrogen-powered fuel cell vehicles have received a lot of attention with the announcement of President Bush's "Freedom Car" initiative. Hybrids allow greater performance with better fuel

economy and allow engines with greater horsepower to run more efficiently. This is an important option given that consumers are not significantly decreasing their purchase of SUVs and larger vehicles, even in the face of higher gasoline prices. While the U.S. Department of Energy estimates that they will make up 10% of new car sales by 2020, there are no fuel cell vehicles currently operating in Minnesota. Hybrid electric, alternative fuel, and more efficient vehicles will remain the best options for the next twenty years for the general consumer and Minnesota for reducing petroleum use, pollution emissions, and increasing in-state fuel production and economic development.

Chapter Six

OTHER KEY ISSUES AND PROGRAMS

In addition to electric reliability, renewable energy development and natural gas availability, there are a number of issues that the Department believes will be critical for policy-makers to be aware of, as they work to ensure Minnesota's energy future. Those issues include:

- Conservation
- Environmental protection
- Affordability and

CONSERVATION

Strictly defined, conserving or "saving" energy applies only to actions that cut energy use – for example, turning down a thermostat or turning off lights when they are not in use. On the other hand, "energy efficiency" focuses on the most efficient use of energy, which may or may not lower overall energy use. For example, a company might install energy efficient equipment with the goal of increasing production. The company's energy use could stay the same or even rise, but the output per unit of energy used would increase.

Other terms often included under the rubric of energy conservation refer mainly to the efficient management of energy supplies and deliveries. "Load management" describes actions that seek to shift demand for electricity away from hours of the day or seasons of the year when demand normally is highest. Late afternoon on a hot summer day is usually a peak period, and supply and delivery systems can be strained to the point of power failures or brownouts. In addition, the cost of obtaining energy is highest during these periods. By reducing strain on the system, load management helps maintain reliability and prevent costly power failure or the need to obtain expensive additional power at peak periods. An example of load management is when a company makes changes in its production schedule to use the same amount of energy, but at a different (i.e., non-peak) time of the day. This shift decreases the amount of stress on the electric system, and thereby makes it easier and less expensive to deliver energy to all customers.

"Demand Side Management," commonly referred to as DSM, covers an array of activities -- load management, conservation, and efficiency – all designed to affect the timing and amount of energy use.

In addition to traditional DSM activities, the Department has been actively engaged in market transformation projects. Market transformation is a strategy that promotes the manufacture and purchase of energy-efficient products and services. The goal of this strategy is to induce lasting structural and behavioral changes in the marketplace, resulting in increased adoption of energy-efficient technologies. According to the American Council for an Energy Efficient Economy (ACEEE), market transformation measures include low initial costs, rapid paybacks and other benefits besides energy savings.

An emerging area of energy conservation programs involves Builder Operator Certification (BOC) and commissioning and recommissioning activities. BOC provides training to builder operators to operate buildings in the most efficient manner. Commissioning involves “tuning-up” during and post-construction to ensure that all of the various systems are interfacing with each other properly. Recommissioning is a “tune-up” for buildings, which after years of use from their human occupants might not have systems that interface in the most efficient manner. These programs are proving to provide significant benefits, not only in energy efficiency and the associated reduction in energy operating costs, but also improvements in overall building occupant productivity and health.

Achieving the maximum amount of cost-effective conservation is a major policy goal of the Department, as part of an energy policy that responds to the negative impacts of increased energy use on the environment and economy. In addition to the environmental benefits of conservation, conservation can help reduce energy costs and increase the competitiveness of business. Additionally, the August 14, 2003 blackout highlights the reliability importance of conservation in reducing the strain on the electric infrastructure.

****SIDEBAR: Demand Response**

Demand response programs are a tool being used by many states to encourage energy efficiency by having fewer electrons moving through the system during peak times. A number of states have established demand response programs which look at generation from a conservation perspective. That is, instead of generating megawatts, demand response asks consumers to generate “negawatts.” On-call firm demand reduction is being bid into RFPs for peak load generation - generators are paid capacity credits each month in addition to high per kilowatt-hour rates.

For example, utilities or energy service providers in NY can get paid for curtailing electric load during peak use. There are programs for emergency (short-notice) demand response, day-ahead demand response and a reserve capacity program that contracts resources to meet system supply requirements over a certain contract period.

END SIDEBAR**

Both the federal and Minnesota state governments have acted to advance conservation, employing mandates, financial assistance, and other strategies to reach their goal. The Department of Commerce has responsibility for a number of these programs. Three such programs are discussed below.

Conservation Improvement Program

The Conservation Improvement Program (CIP), enacted by the legislature in 1982, is the primary state conservation program. It requires Minnesota’s electric and natural gas utilities to spend a percentage of their annual gross operating income on programs to encourage conservation among all their customers – residential, commercial, and industrial, with specific attention given to providing conservation opportunities for low-income residential users. This requirement amounts to something on the order of over \$75 million dollars a year being spent on conservation

in Minnesota. As a result, CIP has had a substantial impact on energy use, and its effectiveness was recognized in 2000 by the ACEEE. The Council ranked Minnesota's utility energy efficiency program among the top six in the nation, based on data collected by the Energy Information Agency.

Under CIP, investor-owned utilities (IOUs) submit their conservation projects to the Department for approval. In the four years (2000 through 2003) since the last Energy Policy and Conservation Report to the legislature, electric IOUs have spent an average of \$32.9 million a year. Gas IOUs have spent an average of \$7.8 million a year. Four-year energy savings from these programs totaled 988 million kilowatt-hours of electricity and 4.2 billion cubic feet of natural gas. The magnitude of capacity savings due to CIP is better understood by noting that Xcel Energy's programs alone have saved a total of over 2,000 megawatts – the equivalent of Xcel Energy's massive Sherco coal-fired generation facilities. CIP has also lowered the peak demand for electricity and natural gas for investor-owned utilities:

- an average of 140,000 kilowatts per year over the past four years, and
- an average of 13.9 million cubic feet of natural gas per year.

Minnesota's rural electric cooperatives and municipal utilities are also required to invest a percentage of their revenue on conservation programs and submit an annual report on the projects to the Department. The conservation programs of these utilities under CIP are reported to the Department for review and advice, but are not subject to Departmental approval.

The seven generation and transmission electric cooperatives, and their 45 distribution cooperatives, reported spending an annual average of \$23.7 million on conservation between 1999 and 2002. In the same period, Minnesota's municipal electric utilities spent an annual average of \$9 million on conservation. Education, rebates for efficient lighting and other efficiency improvements, and load management measures are among the most common types of projects, for both types of utilities.

Of Minnesota's seven municipal natural gas utilities, four met the income threshold of \$5 million that requires them to spend 0.5 percent of that revenue on conservation. Expenditures over the 1999 to 2002 period averaged \$1.4 million annually. Education, rebates, and programs for low-income customers and renters are among the most common.

The Department requires the CIP projects of investor-owned utilities to be cost-effective – that is, the cost of the project must not exceed the cost of the energy saved. Types of projects that have proved effective include:

- For residential electric consumers: discounts and rebates on efficient lighting and central air conditioning, as well as free evaluations of home energy use.
- For residential gas consumers: rebates on insulation, and efficient furnaces and water heaters.

- For commercial electric consumers: rebates on purchase of more efficient lighting and refrigeration equipment.
- For industrial electric customers: rebates on purchase of more efficient motors and industrial processes.
- For commercial and industrial gas customers: rebates for increasing insulation and purchasing more efficient space heating and cooling equipment, as well as free evaluations of energy use and ways to conserve.

As noted above, the CIP program is over 20 years old and has matured as a program. In order to ensure the program's continued success and to document the program's past accomplishments, the Department sought, and received, approval from the Legislative Audit Commission for a program evaluation by the Office of the Legislative Auditor of the CIP program, to ensure the amount of money that ratepayers are putting toward conservation projects continues to be well-spent. That audit is expected to be completed by the end of 2004.

Energy Information Center

The Energy Information Center at the Department promotes energy conservation and efficiency through almost 100,000 public contacts annually by telephone, web site, email, in classes and at presentations. The Info Center offers dozens of energy conservation publications and distributes more than 136,900 publications and CD-ROMs annually. The Info Center offers CDs for consumers, the building industry, renewable energy and commercial and industrial businesses. Info Center staff is available five days a week to answer consumer and builder questions. The Info Center distributes a quarterly electronic newsletter highlighting the Department's activities to more than 1,000 subscribers.

A recent survey concluded that people who contacted the Info Center found the information provided was easy to understand and useful – more than 50 percent surveyed implemented a change using the information they received, and many more planned to take action within the coming year. The Info Center was a sponsor of the Living Green Expo Sustainability Fair, which was attended by 5,000 people in 2002 and more than 11,000 in 2003.

Buildings, Benchmarks and Beyond (B3)

As mentioned earlier, in 2001, the Minnesota Legislature established a goal of achieving 30 percent savings in existing public buildings throughout the state. The Legislature, in setting this energy savings goal directed the Departments of Administration and Commerce to do two things:

- 1) To undertake conservation benchmarking for all public buildings. There are over 10,000 such buildings, so the work is expected to focus on creating and prioritizing a list of poorly performing buildings.

- 2) To create guidelines for designing new buildings, to ensure that the designs of new buildings are not only cost effective and energy efficient, but also beneficial to the environment and to the inhabitants of the building.

An interdisciplinary team of local and national experts has developed sustainable building guidelines for the State of Minnesota Departments of Administration and Commerce that will be used on all new state buildings.⁴¹ Benchmarking will identify the energy performance of existing public buildings in order to direct energy conservation improvements where they are most needed and most cost-beneficial.

****SIDEBAR: Federal Funds for Renewable and Energy Efficiency**

The State Energy Program (SEP) is the only federally-funded, state-based program administered by the US Department of Energy. The SEP provides resources directly to the States for allocation by them based on each State's specific needs and market environment.

The total national program was funded by Congress at \$45 million in FY2003. Minnesota received approximately \$917,000. In addition to program grants, this federal appropriation funds the Energy Information Center and staff positions in the Department.

SEP funds are used to develop and manage a variety of programs to increase energy efficiency, reduce energy use and costs, develop alternative energy and renewable energy sources and reduce reliance on non-U.S. sources of energy.

To measure the return on investment of the SEP, the DOE asked Oak Ridge National Labs to complete an evaluation. The evaluation found that each \$1 invested in SEP results in cost savings of \$7.23.

END SIDEBAR**

****SIDEBAR: Bringing Dollars to MN via Competitive Grants**

The Department has successfully brought \$1,800,000 to the State of Minnesota via competitive grants in the last two years. These grants help improve energy efficiency in key Minnesota industries in addition to promoting energy independence and clean fuels in the transportation sector. This funding is in addition to money received via the Federal State Energy Program.

In 2003 the Department was awarded over \$1,000,000 for the following:

- Boise Paper Plant, Paper Dryer Energy Efficiency Improvements, \$634,850 (State Technology Advancement Collaborative)
- Schwan's Home Service: Convert 90 Gasoline Trucks to Diesel, \$188,000 (State Energy Program Special Projects)
- Rebuild Minnesota, \$77,912 (State Energy Program Special Projects)

⁴¹ See <http://www.cbsr.umn.edu/03/index.html> for a copy of the guidelines.

- Energy Code Education and Upgrade, \$60,258 (State Energy Program Special Projects)
- Indoor Air Quality Monitoring in Federal Buildings, \$46,000 (State Energy Program Special Projects)

In 2002 the Department was awarded \$800,000 for the following:

- E85 Infrastructure Expansion, \$250,000 (State Energy Program Special Projects)
- Propane Truck Fuel Development, \$200,000 (State Energy Program Special Projects)
- Develop Energy Innovations for Mining and Forest Products, \$185,000 (State Energy Program Special Projects)
- National Energy Foundation, Energy Education in Midwest Schools, \$100,000 (State Energy Program Special Projects)
- Energy Code Technical Support and Implementation, \$65,000 (State Energy Program Special Projects)

END SIDEBAR**

ENVIRONMENTAL PROTECTION

Reliable, reasonably priced energy is necessary to sustain modern life and enable a robust economy. The generation and use of electricity, however, has negative impacts on the environment that must be managed and mitigated. Minnesotans expect a balance between mitigating the environmental impacts of electric generation and the availability of affordable, reliable electric service. The Department is constantly focused on striking the appropriate balance, striving to reduce the emissions intensity of electric generation, as well as overall emissions. That is, to reduce both the total amount of emissions from electric generation, and the emissions per kilowatt-hour consumed in Minnesota.

There are a wide variety of programs and initiatives through which the Department seeks to achieve this goal, including:

- the Renewable Energy Objective;
- the Conservation Improvement Program;
- support for legislation allowing continued operation of Xcel Energy's Prairie Island nuclear generation facility, which is a base load generation resource that emits no air pollution;

- support for Xcel Energy's contract with Manitoba Hydro for 500 megawatts of base load hydropower, another base load resource that emits no air pollution; and
- most significantly, leadership and support for the Metropolitan Emissions Reduction Project (MERP), proposed by Xcel Energy and the Izaak Walton League of America, discussed below.

MERP. Older coal-combustion electric generation facilities contribute a significant portion of the criteria pollutants produced in Minnesota. Three of these coal-fired electric facilities are situated on the banks of the Mississippi and St. Croix rivers within the Twin Cities metropolitan area. In the spring of 2002, the three facilities' owner, Xcel Energy, filed with the Commission the Metropolitan Emissions Reduction Project or MERP. This voluntary filing fulfilled a commitment made to the Izaak Walton League, as part of Xcel's merger proceeding before the Commission in 2000.

This project is one of the largest energy-related projects ever proposed in Minnesota. Xcel proposed to shut down and dismantle the two coal-fired power plants on the banks of the Mississippi River in the Twin Cities (the Riverside plant in Minneapolis and the High Bridge plant in St. Paul.) In their place, Xcel would site natural gas-fired electric generation facilities that will not only replace the power previously generated by Riverside and High Bridge but will increase the capacity by approximately 300 megawatts. MERP also includes the installation of new state-of-the-art pollution control equipment and facility refurbishment at the Allen S. King plant located on the banks of the St. Croix River south of Stillwater. The demolition and construction involved with MERP carries a price of approximately \$1 billion. The schedule for the demolition and construction for the three plants (Allen S. King, High Bridge and Riverside, in that order) calls for work to begin late 2004 or early 2005, and be completed by 2010.

This project will provide a number of benefits to the metro area and to the state.

1. Besides improving the esthetics of the riverbank in Minneapolis and St. Paul, air quality should be measurably improved in the Twin Cities, reducing emissions at the plants significantly. According to the MPCA, sulfur oxide emissions would be reduced by 95 percent, nitrogen oxide by 95 percent and particulate matters by 70 percent. Repowering the two plants with natural gas will reduce mercury emissions from those facilities to nearly zero. Health authorities have indicated that better air quality in the Twin Cities and in the State should translate into fewer illnesses such as asthma.
2. Maintaining electric generation facilities within the Twin Cities, and continuing to make use of existing electric transmission facilities, ensures that the Twin Cities and the State maintains its reliable electric system.
3. The additional 300 MW of power generated by the new natural gas-fired facilities will be needed in the coming years to meet the needs of the growing Twin Cities area.

4. The use of flexible and efficient natural gas-fired combined cycle turbines at the High Bridge and Riverside facilities will enable the further development of large-scale wind powered electric generation facilities by providing complementary backup generation resources for use at times when wind turbines are not generating electricity (a process known as “load following”).

For these benefits, Xcel ratepayers are being asked to pay a 6-8 percent increase in their electric rates. Such an increase is substantial and, in most cases, would garner opposition, especially from those groups especially sensitive to energy prices. However, MERP has met with wide and almost unanimous support. With Governor Pawlenty’s leadership, a strong and broad coalition of support was established, including representatives of the legislature, the business community, energy and environmental regulators, public health officials, citizens and environmentalists. By order dated March 8, 2004, the Commission approved the MERP project, clearing the way for the greatest single reduction in emissions in Minnesota history.

AFFORDABILITY

For many Minnesota households, energy costs place a severe and continuing stress on the family’s budget. Energy costs account for up to 13 percent of a typical low-income household budget as compared to 3 percent for other households. The inability of some households to pay their energy bill results in utilities having to focus attention and resources on bill collection, disconnection and reconnection activities. The costs of such efforts are typically borne by other ratepayers on the utility’s system.

The Department’s first line of defense against high energy costs is through its advocacy for low utility rates at the Commission. In nearly every type of proceeding at the Commission, Department analysts are working to reduce the overall costs of the provision of utility service, in order to keep rates affordable for Minnesotans. This advocacy is not only good for individual Minnesota citizens; it is also good for Minnesota’s economy.

However, for those individuals that need additional help, assistance for low-income energy consumers is available through federal programs administered by the Department of Commerce. These programs serve between a quarter and a third of the Minnesota households that are eligible for assistance.

Three Minnesota statutes specifically address low-income energy concerns. These statutes mandate programs that include an electric rate discount, conservation and energy efficiency services, and protection against utility disconnection during cold-weather months.

Low Income Home Energy Assistance Program

Minnesota’s Low Income Home Energy Assistance Program (LIHEAP) helps eligible low-income households meet their immediate winter heating needs. LIHEAP is funded by the U.S. Department of Health and Human Services. The Department contracts with 39 local nonprofit

organizations, local government organizations, and tribal organizations to provide services to the public.

Households with incomes up to 50 percent of the state median income are eligible for the program. The amount of payment allotted per household is determined by income, household size and fuel type. Households with the lowest incomes and highest bills receive the largest grants. Assistance provided to households is usually in the form of a credit with their energy vendor enabling the household to pay a portion of their heating costs. Renters and homeowners may be eligible for the program.

LIHEAP remains dependent on the federal appropriations process for its funding and the amount granted to the program varies from year to year. Although the number of eligible households has risen dramatically, the federal fuel assistance funds have not kept pace.

During the past 22 years, the number of Minnesota households that have received LIHEAP assistance range from a high of 139,573 in FY 1984 (about 21 percent of those eligible) to a low of 81,486 in FY 1998 (about 19 percent of those eligible). In FY 2003, the program served 122,609 Minnesota households with an average bill payment assistance grant of \$408 per household.

Additional money is available to households if they have an emergency situation and are in jeopardy of losing their heat. Emergency situations include:

- broken heating equipment that must be fixed or replaced
- termination of utility service
- danger of being without fuel or of having utility service terminated.

Assistance with emergency situations is available 24 hours a day, seven days a week, during the heating season. The providers also provide advocacy and referral services throughout the program year.

Reach Out for Warmth

Households that have too much income to be eligible for the LIHEAP program, but under 60 percent of the state median income, are eligible for help through the Reach Out for Warmth (ROFW) emergency fuel fund. This fund was established in 1992 by the Minnesota State Legislature. Department of Commerce staff administers the year-round fund through the same 39 local energy assistance agencies that deliver LIHEAP services. ROFW is a community-based fuel fund and is supported by individuals, businesses, churches, civic groups, school children, energy vendors, and private foundations. All funds raised locally stay in the area to help local residents and are matched with federal LIHEAP dollars.

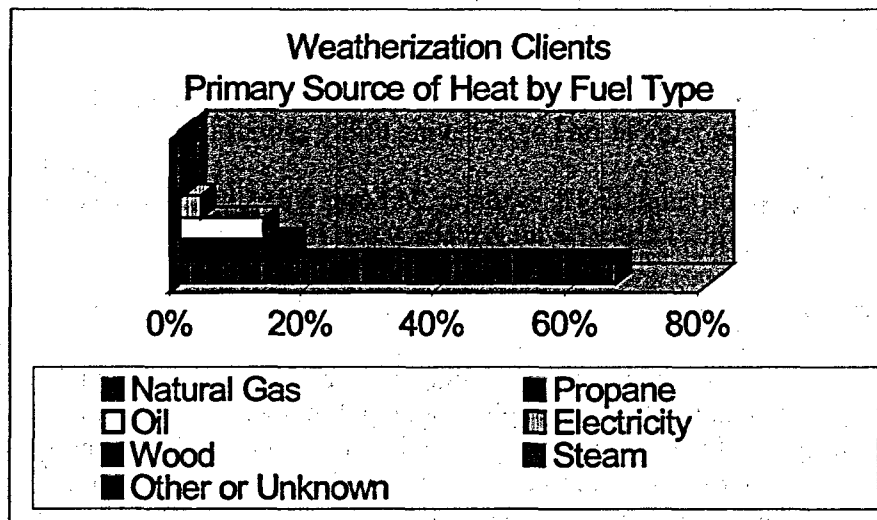
• *Minnesota Weatherization Assistance Program*

The State Energy Office administers the Weatherization Assistance Program (WAP), which uses U.S. Department of Energy funds to provide energy conservation and efficiency services to income-qualified households.

The Weatherization program offers a long-term solution to reduce the homeowner's annual heating bill by an average of 25 percent. In effect, this program reduces homeowners' reliance upon other programs, such as LIHEAP, to pay heating bills and frees up dollars in that program to assist other clients.

During FY2002, Minnesota received \$9.68 million in WAP funds from the Department of Energy, which served 3,074 households. The WAP uses the same income guidelines as LIHEAP, serving households who are at or below 50 percent of the state median income. More than half the households served have one or more members who are in a priority category (child, elderly or disabled). WAP contracts with 32 local nonprofit and government organizations to provide weatherization and conservation services. Some agencies receive additional funding from outside sources, such as CIP, to serve additional households.

The WAP is unique in that it requires an on-site visit, where the contractor can assess the client's home to identify the most necessary or helpful improvements. Correcting health and safety hazards and potentially life-threatening conditions is the first consideration in WAP activities.



The Minnesota WAP, which began in 1978, has historically been innovative in its field. It was the first WAP nationally to use blower door and infrared technology to test homes for air leakage and the first to use blown-in sidewall insulation.

Services provided by the program include:

- educating participants
- conducting energy audits to evaluate the home's energy usage
- installing exterior wall and attic insulation
- correcting air infiltration and sealing attic bypasses
- testing, repairing, or replacing home mechanical systems to ensure efficiency and safety.

Electronic Household Energy Technology Project

The Electronic Household Energy Technology (eHEAT) project is a new undertaking by the Department that will help LIHEAP and WAP service providers streamline program efficiency and increase focus on customer service. Currently the state's 40 service providers are using various software, mailing and database programs, leading to information gaps. The result of the project will be a centralized web based data and payment management software program that will streamline administrative costs and enhance program analysis. The program is expected to be operating by the end of 2004.

Minnesota Low-Income Statutes

Minn. Stat. § 216B.16, subd. 14, requires Xcel Energy to offer a 50 percent discount on the first 300 kWh of electric service to residential customers who are receiving federal energy assistance. In years past, this program provided a uniform sum to all eligible customers. In the 2004 session, the legislature authorized the modification of the program to allow for a more targeted approach.

Minn. Stat. § 216B.241, subd. 1a, established the Conservation Improvement Program (CIP). Under this program, certain natural gas and electric companies are required to make investments in conservation and energy efficiency for their residential and non-residential customers. Utilities operating these conservation programs are also required to devote a portion of their CIP spending "to programs that directly address the needs of renters and low-income persons...."

Minnesota's regulated natural gas and electric utilities have complied with the CIP statute by developing conservation projects available only to low-income residential ratepayers. In 2002, for example, low-income energy conservation spending reached nearly \$3 million for such projects as water heater replacement, home weatherization and setback thermostat installation.

Minn. Stat. § 216B.095, also known as the Cold Weather Rule, provides protection against disconnection of residential utility service during the cold weather months for any household whose income is less than 50 percent of the state median income and which pays at least 10

percent of its income toward utility bills. A utility may not disconnect a household who meets the eligibility criteria of the statute and Minnesota Rules, parts 7820.1800-7820.2300 as interpreted by the Minnesota Public Utilities Commission.

Other Programs

There are also several smaller programs, the largest of which is the Salvation Army's HeatShare program, operated at the local level by some counties, local social service providers and religious institutions. However, these programs are sporadic in their assistance and are geared almost exclusively at crisis situations.

Appendix 1

THE ENERGY SECTIONS OF THE TELECOMMUNICATIONS AND ENERGY DIVISION OF THE MINNESOTA DEPARTMENT OF COMMERCE

There are three sections within the Telecommunications and Energy Division which handle energy issues for the Department of Commerce. These units are the State Energy Office, the Energy Planning and Advocacy Unit and the Office of Energy Assistance Programs. Each of these sections is summarized below.

State Energy Office

As one of three sections in the Energy Division of the Minnesota Department of Commerce, the State Energy Office is the main state conduit for U.S. Department of Energy (DOE) funding, receiving both State Energy Program and Weatherization dollars. State energy programs are implemented through loans and grants, maximizing the benefits of energy efficiency and renewable energy through promoting energy conservation in buildings and demonstrating renewable energy technologies, with the objective of bringing them closer to market realities. Weatherization grant activities are funneled through community action agencies throughout the state, assisting low-income households weatherize their homes to use energy more efficiently and lower their energy bills for the long term. The State Energy Office also includes the Energy Information Center, which provides conservation information directly to Minnesota consumers. The Energy Information Center has operated continuously since 1974, responding to phone calls and sending brochures that provide practical advice on various energy issues. The SEO continues to promote energy conservation in all buildings through code involvement and public education.

Energy Planning and Advocacy

The Energy Planning and Advocacy unit (EPA unit) intervenes on the public's behalf in all natural-gas and electric utility matters before the Public Utilities Commission (PUC). The EPA unit's role is to ensure that energy rates are reasonable and service is reliable. The EPA unit works in energy rate cases, miscellaneous rate proposals, integrated resource planning, nuclear decommissioning and nuclear waste disposal, mergers and acquisitions, depreciation rates, capital structures, electric service territory matters, and consumer complaints. The EPA unit also works on energy conservation, both with the Commission and within the Department. The EPA unit collects data on Minnesota's energy production, use and rates, maintains historical databases, and conducts analyses of energy use in Minnesota, from production to distribution. The EPA unit also develops and advocates energy policy issues before the legislature, federal agencies, in cooperation with other state agencies, and in regional and national forums such as matters before FERC. EPA is a leader and active participant in electric transmission activities through its seat on the MISO Advisory Committee and OMS.

Office of Energy Assistance Programs

The Office of Energy Assistance Programs administers Minnesota's Low Income Home Energy Assistance Program (LIHEAP). LIHEAP helps eligible low-income households meet their immediate winter heating needs and is funded by the U.S. Department of Health and Human Services. The Department contracts with 39 local nonprofit organizations, local government organizations, and tribal organizations to provide services to the public.

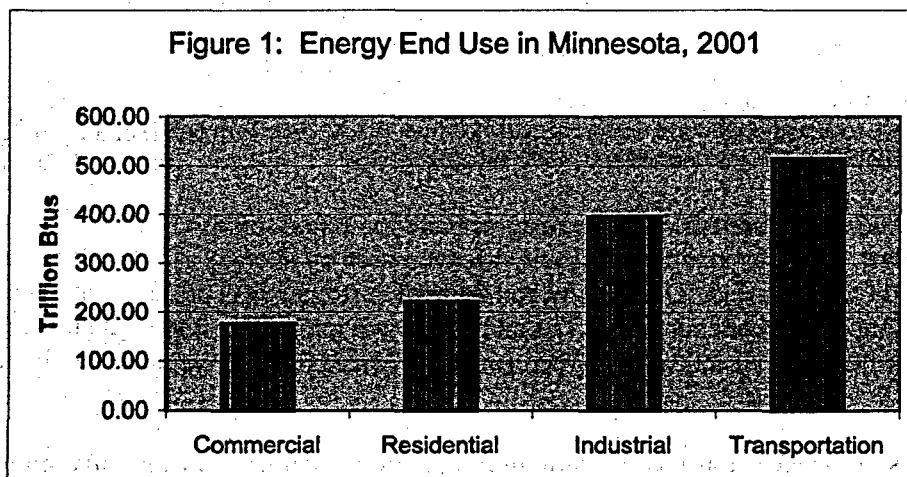
Appendix 2

MINNESOTA ENERGY INFORMATION

****Sidebar:** The data in this chapter and Appendix ___ comes primarily from two sources: data collected internally pursuant to Minn. Stat. 216C.17 through the Department of Commerce Regional Energy Information System (REIS), and data obtained through the U.S. Department of Energy's Energy Information Administration (EIA). For each graph, the sources are noted and additional information about the data and assumptions used are included in the appendix. The Department sought to provide the most current data available from different sources; hence, data references may cite differing years.******

HOW MUCH ENERGY DOES MINNESOTA USE?

Minnesotans consumed a total of 1,314.74 trillion BTUs of energy (electricity, natural gas, petroleum products, coal and biomass) in 2001.⁴² Figure 1 shows the relative amounts of energy Minnesotans use for commercial, residential, industrial and transportation purposes.⁴³



Source: REIS database and EIA.⁴⁴

The following sections further explain Minnesota energy use according to fuel type: electricity, natural gas and petroleum products.

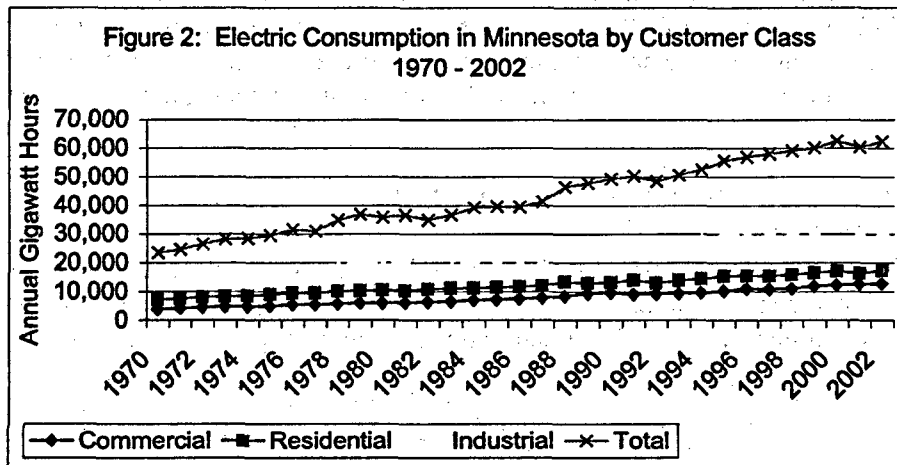
⁴² Btu (British thermal unit is the common measurement of the heat content in energy, and is approximately equivalent to the heat produced by one wooden kitchen match.

⁴³ A list of electric and natural gas utilities and other statistics may be found in the Department's Utility Data Book at <http://www.commerce.state.mn.us>.

⁴⁴ Website addresses for these and other information sources are included in Appendix 5.

Electricity

Minnesotans consumed a total 62,364 gigawatt⁴⁵ hours of electricity in 2002. Figure 2 shows total electric consumption since 1970 and breaks down that electric consumption into the residential, commercial and industrial customer classes.



Source: REIS database

Note: Data extracted from REIS and the EIA website reflects 2001 usage. Some of the petroleum, coal, biomass, solar and geothermal data were extracted from EIA's "State Energy Data 2000 Consumption" (http://www.eia.doe.gov/emeu/states/_use_multistate.html).

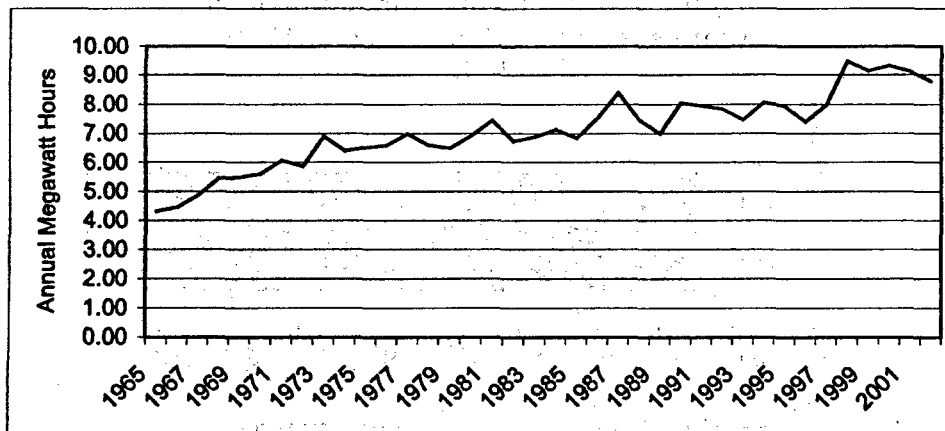
This graph illustrates Minnesota's increasing demand for electricity, both overall and in the various sectors. Total demand for electricity has increased an average of 3.1 percent annually over the 1970 – 2002 period. Demand by commercial customers has grown the most in that span, increasing 3.7 percent annually. The annual growth rates for residential and industrial customers for the same period were 2.7 percent and 3 percent respectively.

Many factors influence electricity consumption, including weather, price, population levels and the general economic climate. The data in figure 2 are not adjusted for these factors. Thus, consumption changes in the different classes can vary significantly in the short term. Industrial consumption, for example, fell by 4.8 percent in 2001, with the economic recession playing a part in that decline.

Minnesota's weather is a major factor in residential use of electricity. Figure 3 shows the electric consumption per residential customer, taking into account differences in weather from year to year. Adjusting the data to account for abnormal weather is called "weather normalization," which provides a way to look at trends in energy use. Normalization removes the effects of increased energy use in hotter summers and colder winters as well as decreased use during milder years. This figure shows a fairly steady increase in electricity used per customer from the mid-1960s to the present, with a large increase beginning in the late 1990s. These increases appear to stem from greater use of electricity for air conditioning, home computers, and various other electronic appliances.

⁴⁵ Gigawatt (GW) means one billion watts.

**Figure 3: Weather Normalized Electric Consumption Per Residential Customer
1965 - 2002**

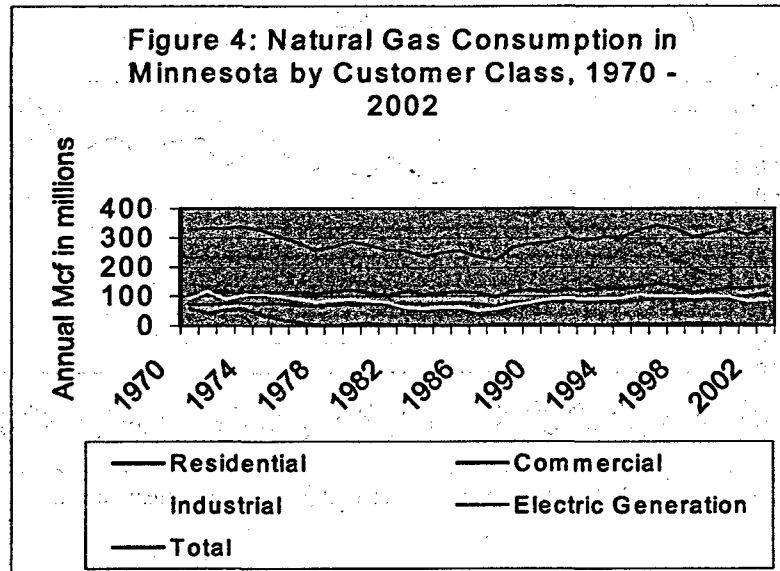


Sources: REIS database, DNR – State Climatologist at <http://www.climate.umn.edu>

Natural Gas

Minnesotans consumed a total of 269.8 Bcf (billion cubic feet) of natural gas in 2002.⁴⁶ Figure 4 shows Minnesota's natural gas consumption by residential, commercial, industrial, electric generation and transportation customers (which includes pipeline operation and, since 1990, natural gas fueled vehicles).

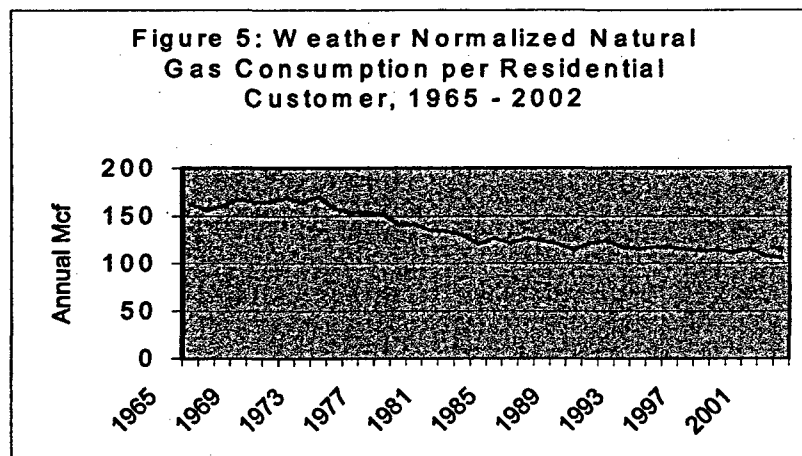
⁴⁶ Natural gas may be measured in Mcf (thousand cubic feet) or therms. (One Mcf is roughly equivalent to 1 million Btus or 1 dekatherm.)



Source: REIS database

Note: Figure 4 shows a total consumption of 333.53 Bcf in 2002. However, “deliveries to transportation,” “Company Use” and “Unaccounted For” categories account for the difference of approximately 63.73 Bcf in 2002.

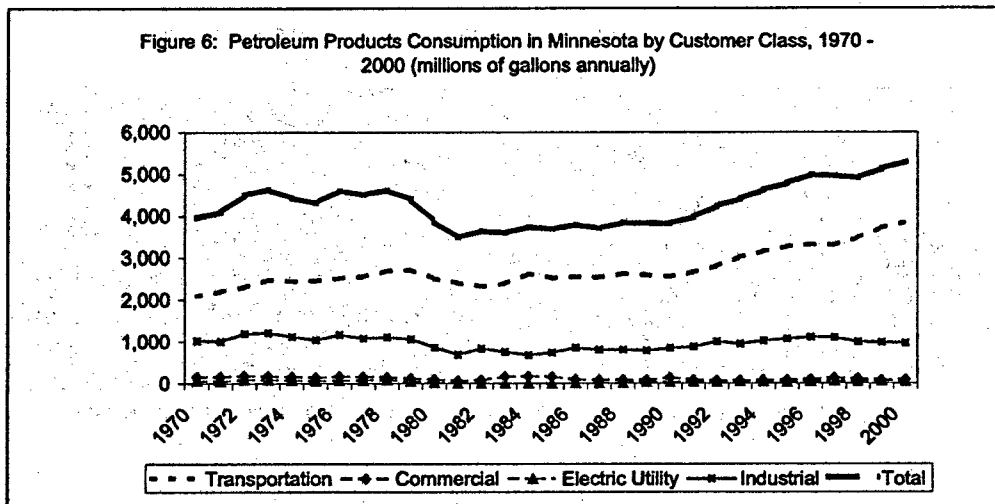
This graph shows two notable consumption trends. First, more natural gas is being used for electric generation. During the energy crisis in the middle and late 1970s, use of natural gas for electric generation declined sharply. Recently, however, natural gas has been used at significantly higher rates to generate electricity. While this upward trend is only slightly evident in this chart, (which is based on data ending in 2002), the increase will be more noticeable starting in 2003 as recently approved natural-gas facilities go on line in Minnesota. One of the basic reasons for turning to natural gas as a fuel source for electricity is that gas-fired plants have fewer harmful environmental effects than other traditional fossil fuels such as coal or fuel oil.



Sources: REIS database, DNR – State Climatologist

The second notable consumption trend is residential consumption. Residential consumers' use of natural gas has steadily decreased. Figure 5 shows natural gas use per residential customer after "normalizing" the data for weather fluctuations.

As shown in figure 5, after removing the effects of weather, residential consumption of natural gas has declined by 56.5 Mcf per year (or approximately 35 percent) over the last thirty-seven years. A major reason for this trend is the increased efficiency of household gas-fueled appliances as well as the construction of energy-efficient new housing as specified by building code requirements.



Source: EIA State Energy Data 2000 Consumption tables at http://www.eia.doc.gov/emeu/states_use_multistate.html

Petroleum

Minnesotans consumed a total of 691.5 trillion Btus (5,670 million gallons) of petroleum products in 2002.⁴⁷ Figure 6 shows the total petroleum consumption in Minnesota for the residential, commercial, industrial, transportation, and electric generation customer classes.

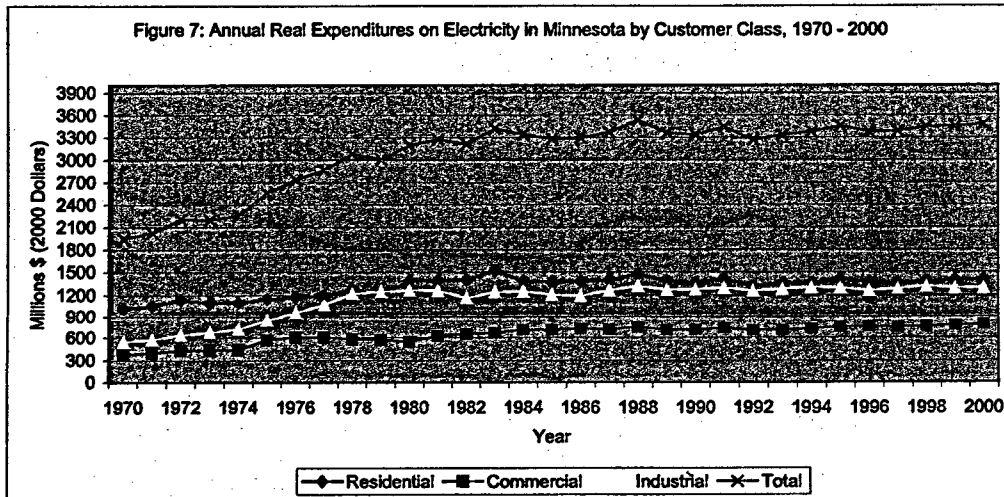
In 2002, Minnesotans used about 85 percent of all petroleum products for transportation (air, land, and water). This amount includes asphalt and road oil as well as fuels like diesel, jet fuel, and motor gasoline. Most agricultural use of petroleum is also included in the transportation category. About 9 percent of petroleum products were used for the commercial, electric utility, industrial, and institutional space heating and processing categories. With about one-fourth of Minnesota households using either fuel oil or propane for heating, residential heating use constituted about 6 percent of the total petroleum products used in 2002.

⁴⁷ Petroleum products, as used in this section, include: asphalt and road oil, aviation fuel, distillate fuel, jet fuel (all types), kerosene, liquid petroleum gases, lubricants, motor gasoline, and residual fuel.

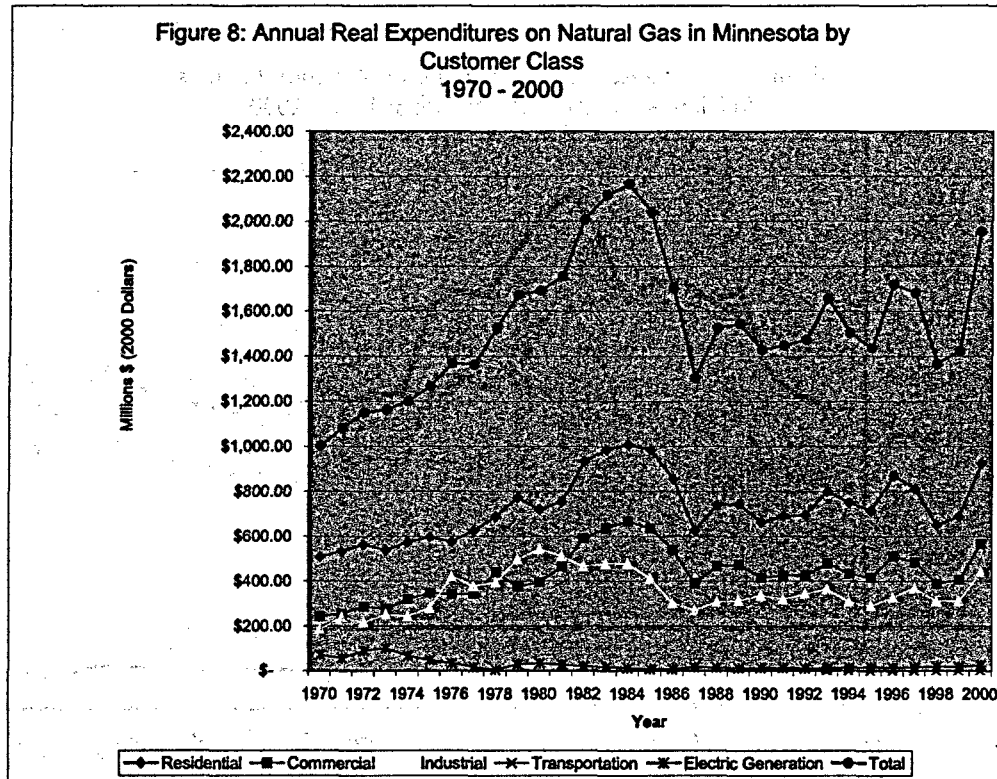
HOW MUCH DOES MINNESOTA'S ENERGY COST?

Figures 7, 8, and 9 show Minnesota's total real expenditures (adjusted for inflation) on electricity, natural gas, and petroleum. All price and expenditure data in this report has been converted to year 2000 dollar values.

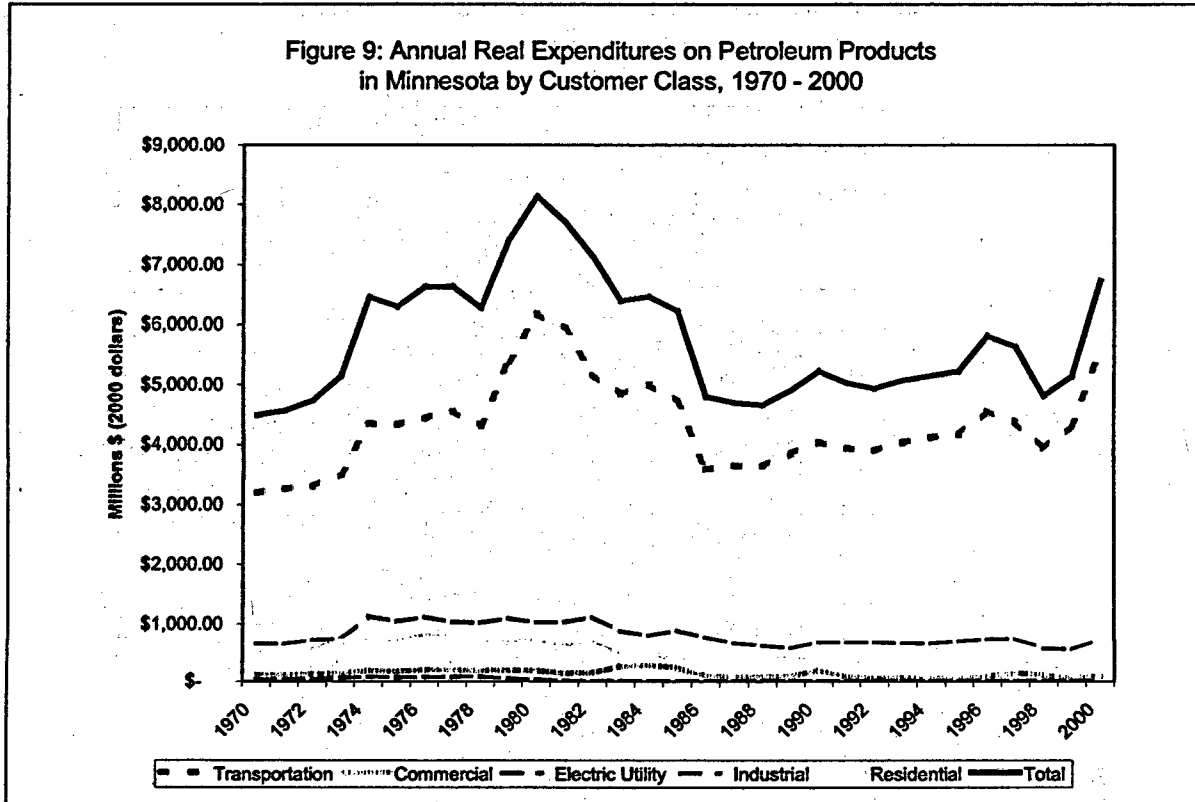
In 2000, Minnesotans spent about \$3.5 billion on electricity, \$2.0 billion on natural gas and \$6.7 billion on petroleum products.



Sources: *State Energy Price and Expenditure Report 2000*, Energy Information Administration
U.S. Department of Labor, Bureau of Labor Statistics, Series ID: CUURA211SAO, CUUSA211SAO



Sources: *State Energy Price and Expenditure Report 2000, Energy Information Administration*
U.S. Department of Labor, Bureau of Labor Statistics, Series ID: CUURA211SAO, CUUSA211SAO



Source: EIA State Energy Data 2000 Price and Expenditures tables at http://www.eia.doc.gov/emeu/states_price_multistate.html

Historically, Minnesota has enjoyed low electric prices compared with other parts of the country. Figure 10 shows the average price that residential, commercial and industrial customers paid for electricity in 2002 in Minnesota and the corresponding national average prices. This table shows that the electric rates paid by Minnesota commercial customers ranked 12th lowest nationally in 2002 (they were 19th lowest in 2000). For Minnesota industrial customers, electric rates were 18th lowest nationally (30th lowest in 2000), while the rates for Minnesota residential customers ranked 21st lowest in 2002 (same in 2000).

One of the most significant factors affecting the price of electricity is the availability of power, or generating capacity. The increasing demand for electricity has put pressure on the existing generation capacity. Utilities in Minnesota are in the process of adding more capacity to portions of the electric system. The sizes and types of new generation facilities will determine the actual affect on the relative prices of Minnesota electricity.

Figure 10: 2002 Minnesota Electric Prices Relative to Prices in Other States (¢/kWh)

	Residential Customers	Commercial Customers	Industrial Customers
Minnesota Price	7.49¢	5.88¢	4.19¢
Minnesota Rank*	21 st	12 th	18 th
Average U.S. Price	8.46¢	7.86¢	4.88¢
Highest Price	15.63¢	14.11¢	11.24¢
Lowest Price	5.65¢	5.30¢	3.09¢

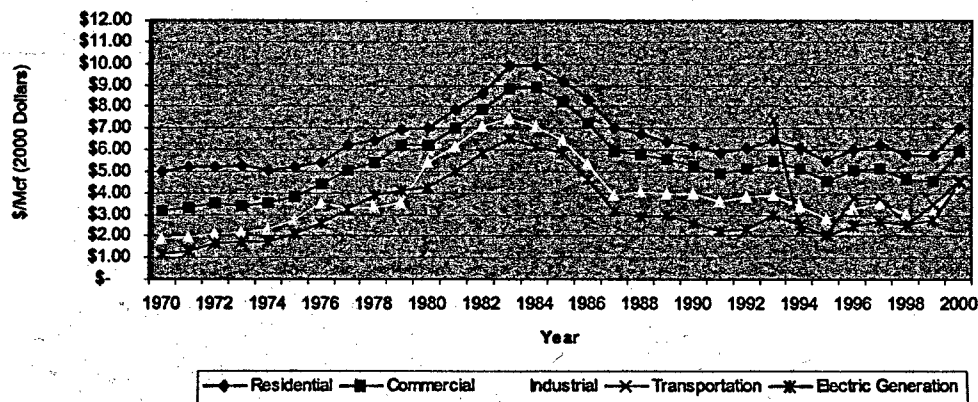
* The rank is from the lowest cost state to the highest cost state. For example, a rank of 24 means that 23 other states have lower costs.

Source: EIA-Electric Sales and Revenue 2002

Natural Gas

Figure 11 shows Minnesota's natural gas prices for the residential, commercial, industrial and electric generation customer classes.

Figure 11: Real Prices for Natural Gas in Minnesota by Customer Class, 1970 - 2000



Sources: *State Energy Price and Expenditure Report 2000*, *Energy Information Administration*
U.S. Department of Labor, Bureau of Labor Statistics, Series ID: CUURA211SAO, CUUSA211SAO

Minnesota customers have historically enjoyed very low natural gas prices compared with prices paid by consumers in other states. Figure 12 below shows this comparison for residential, commercial and industrial customers.

**Figure 12: 2002 Minnesota Natural Gas Prices Relative to Prices in Other States
(Dollars per Thousand Cubic-Feet)**

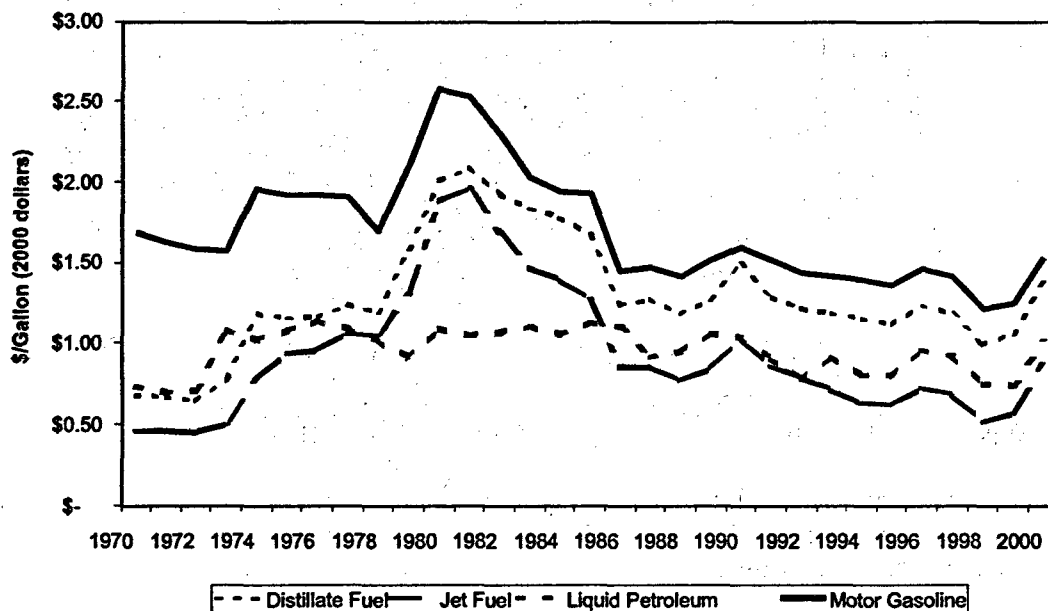
	Residential Customers	Commercial Customers	Industrial Customers
Minnesota price	\$6.41	\$5.21	\$3.95
Minnesota rank	10th	7th	8th
Average U.S. price	\$7.90	\$6.52	\$3.85
Highest price	\$23.62	\$17.74	\$10.05
Lowest Price	\$4.41	\$3.48	\$1.62

Source: EIA, Natural Gas Monthly January 2004

A major reason Minnesota enjoys comparatively lower prices is that interstate pipelines bring gas to the state from various and competing natural gas production areas in Canada and the southern U.S. Minnesota utilities have, therefore, been able to purchase gas at good prices due to competition between Canadian and U.S. natural gas production areas and relative price difference between gas producers.

Petroleum

**Figure 13 : Real Prices for Petroleum Products in
1970 - 2000**



Source: EIA, State Energy Data 2000 Price and Expenditure tables at
http://www.eia.doc.gov/emeu/states_use_multistate.html

Figure 13 shows the Minnesota prices for the most commonly used petroleum products: distillate fuel (diesel and heating fuel), jet fuel, liquid petroleum gases, and motor gasoline.

The prices that Minnesotans pay for petroleum products are largely based on the price of crude oil plus the assessed taxes. World political and economic market forces primarily determine the cost of the crude oil price. Federal and state governments assess taxes on petroleum products.

****SIDEBAR For Petroleum Price Section:**

The U.S. Department of Energy estimates that the price that consumers pay at the pump can be generally broken down as follows: 46 percent crude oil; 26 percent federal and state taxes; 19 percent refining costs; and 9 percent distribution, marketing, and retail station costs and profits. ***

The price of finished petroleum products is influenced by several factors. Sometimes price changes are due to supply and demand imbalances. For example, supply shortages can occur due to maintenance or damage on the pipelines or at refineries. Also, since each petroleum product needs to be stored separately, some supply imbalances result from simple logistical problems with coordinating production and storage to meet current and future demand.

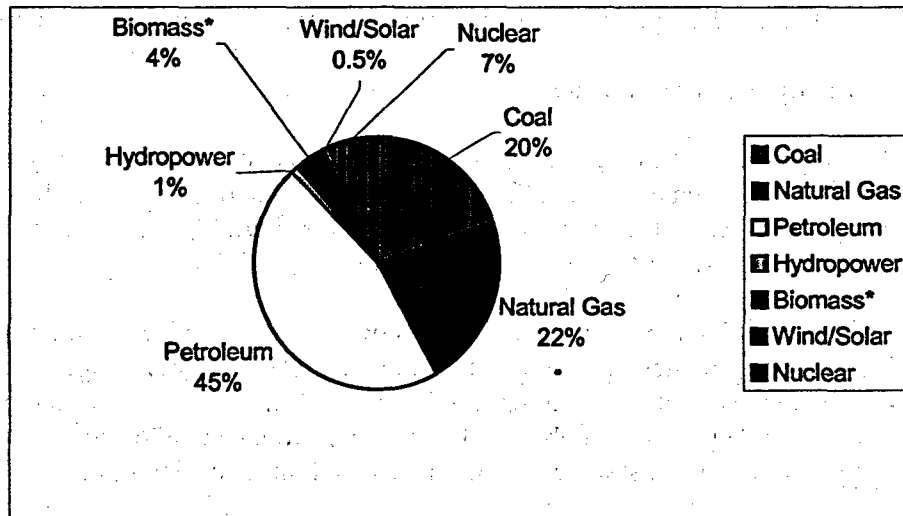
Unexpected demand for a particular product can also create temporary shortages that lead to higher prices. For instance, very cold weather increases the use of propane products for space heating and very wet or very dry weather increases or decreases the agricultural use of petroleum products.

Activity in the commodities market can further influence price. Unexpected spikes or sudden drops in prices are sometimes the markets' response to perceptions of future supply and demand imbalances. Thus, data trends typically provide more reliable information for planning than specific numbers on specific dates.

WHERE DO MINNESOTANS GET THEIR ENERGY?

In 2000, Minnesota required a total of 1,506 trillion Btus of fuel to produce all of the energy we consumed in the state. This number is greater than the total consumption figure because it also includes the losses that occur in the production and transmission of electricity. Figure 14 shows the types and relative amounts of fuel used to produce the energy consumed in Minnesota.

Figure 14: Total Inputs Used to Produce All Energy Consumed in Minnesota, 2000



Sources: REIS database, EIA

Note: Biomass includes wood and RDF (refuse-derived fuel), which is fuel generated by burning waste products.

Electricity

There are three distinct steps to providing electricity to the customer: generation, transmission, and distribution.

Step 1 Generation: Electricity is produced at generating stations or power plants that are usually located in relatively remote areas, using a variety of fuels.⁴⁸ Most generation facilities in Minnesota are owned by electric utilities with a small amount owned by independent power producers or private industrial entities. Federal regulators have taken steps to decrease price regulation and allow more competition in the wholesale market for electric generation (sales between providers), and many states have allowed generation owners other than utilities to sell power directly to consumers. In Minnesota generation remains largely state regulated and utilities are required to provide safe, reasonably priced, reliable service to customers.

Step 2 Transmission: Electric energy is transported from the generating stations to the load centers (areas where much electricity is used, like cities) via high-voltage transmission lines. The U.S. portion of the North American integrated grid of electric transmission lines is regulated by the Federal Energy Regulatory Commission (FERC), and operation of the grid is subject to the constant review of independent system operators, such as the Midwest Independent System Operator (MISO) which controls the grid in our region of the U.S. Some large industrial users receive electricity directly from transmission lines.

⁴⁸ Smaller generating facilities, sometimes referred to as "distributed generation", may be located adjacent to cities or other areas of heavier electricity use in order to better serve fluctuating electricity needs in that area.

Step 3 Distribution: Most consumers are served by lower-voltage distribution lines, which carry electricity from the transmission lines to homes and businesses.

Each electric utility in Minnesota has exclusive rights and the responsibility to serve all consumers in an established geographic area. Three types of utilities serve electric consumers in Minnesota. First, investor-owned utilities (IOUs) are rate-regulated by the state and are allowed to recover all prudently incurred costs of providing electricity to consumers. Second, distribution electric cooperative associations are member/consumer-owned and are regulated by their elected boards unless they choose to become subject to the regulation of the Minnesota Public Utilities Commission.⁴⁹ Distribution cooperatives, in turn, are served by Generation and Transmission cooperatives that procure and transmit power for their member distribution cooperatives. Third, many municipalities in Minnesota receive their electricity from municipal utilities, which are governed by city officials. Municipal utilities can either generate their own electricity or purchase it on contract through a Municipal Power Agency or other utility. Figure 15 illustrates the portion of the state each utility type serves.

Figure 15: Percentage of Customers and Load Served by Different Electric Utility Types in 2002

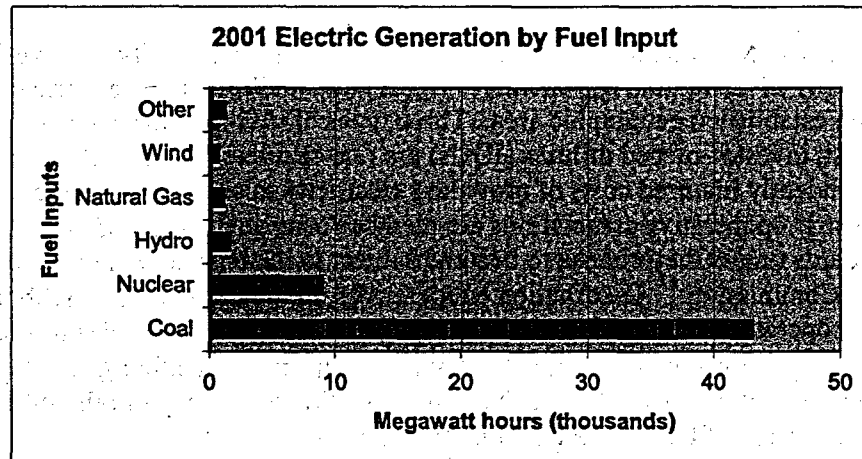
<u>Type of Entity</u>	<u># Customers</u>	<u>% Total Customers</u>	<u>Total GWh</u>	<u>% Total GWh</u>
IOU, Regulated	1,389,382	58%	41,912.3	67%
Cooperative	663,696	28%	11,662.4	19%
Municipal	329,656	14%	8,789.5	14%

Source: REIS

The electricity consumed by Minnesota customers is generated from a variety of fuels. Figure 16 shows the amount of electricity generated by source for plants in Minnesota. Information about the fuel inputs of electricity consumer in Minnesota but generated elsewhere is not included. Also, generation purchased in contracts from marketers and utilities without Minnesota service territory are not included in this data, since the fuel source is not always known in such contracts.

⁴⁹ Only one distribution electric cooperative association – Dakota Electric Association headquartered in Farmington, Minnesota – has made this election.

Figure 16



Source: REIS

Natural Gas

The natural gas industry also follows three steps in providing the product, natural gas, to the customer: production, transportation and local distribution.

Step 1: The production areas for natural gas consumed in Minnesota are in both Canada and the southern and western U.S. The production process and the wholesale price of Minnesota's natural gas supplies are completely deregulated.

Step 2: Natural gas is transported from the production areas to local distribution companies through an international grid of large pipelines. These transportation pipelines are regulated in the U.S. by the Federal Energy Regulatory Commission (FERC). The three main interstate pipelines that serve Minnesota customers are the Northern Natural Gas Company (Northern) pipeline, which provides approximately 68 percent of the total natural gas transportation capacity used by Minnesota customers; the Viking Gas Transmission Company (Viking) pipeline, which provides approximately 8 percent of the total pipeline capacity; and the Great Lakes Gas Transmission Company (Great Lakes) pipeline, which provides less than 1 percent of the natural gas pipeline capacity used in the state.⁵⁰ The remaining pipeline capacity in Minnesota is composed of three pipelines that combined represent less than 1 percent of transportation capacity and peak shaving and on-line storage facilities.⁵¹

Northern transports gas from the Hugoton basin, which is located primarily in the Kansas and Oklahoma area, as well as the Permian, Anadarko, and Gulf Coast basins, which are all located in Texas. Viking and Great Lakes pipelines have gathering facilities in the Alberta basin (in the Canadian provinces of Alberta and British Columbia). Newly FERC-approved interstate pipes

⁵⁰ Source: Department of Commerce 2002-2003 Annual Fuel Report, February 27, 2002, Table G16, Docket No. E,G999/AA-03-1264.

⁵¹ Source: The "three pipelines" include ANR Pipeline Company, Centra Pipeline and Williston Basin Interstate Pipeline.

may provide greater access to Minnesota of Rocky Mountain gas supplies. Since interstate pipeline capacity is available to all shippers on a non-discriminatory basis, prices are set by negotiations between suppliers and buyers.

Step 3: Delivery of natural gas to end-use customers is completed by the companies that build and maintain the smaller pipeline infrastructure that runs from the large interstate pipelines to the customers. These firms are called local distribution companies, or LDCs. There are six investor-owned LDCs in Minnesota that are regulated by the state. The Minnesota Department of Commerce reviews the LDCs' gas costs to ensure that they are reasonable and makes recommendations to the Minnesota Public Utilities Commission, which has the final authority to allow (or disallow) gas costs to be recovered from Minnesota ratepayers. In addition to the six regulated LDCs, there are twenty municipal LDCs that are under local control. There are also a few privately owned LDCs that do not serve sufficient numbers of customers to justify state regulation per Minn. Stat. 216B.02, subd. 4 and 216B.16, subd. 12. Figure 17 illustrates the portion of Minnesota's gas consumers served by each utility type.

Figure 17: Percentage of Customers and Volume of Gas Served by Natural Gas Utilities (2002)

Type of Entity	# Customers	Percent of Total Customers	Total Mcf	% Total Mcf
IOU, regulated	1,338,943	94	251,415,002	93.2
Municipal	73,787	5	17,694,814	6.6
Private, unregulated	5,492	1	705,682	0.2

Source: REIS database

Unlike electric companies, natural gas companies do not have assigned service territories. However, once an LDC has established the infrastructure to serve an area, in order to avoid duplication of facilities, it effectively becomes the exclusive LDC for that area. The high capital costs of developing the infrastructure to deliver natural gas to low density populations located long distances from major pipelines hinders further development.

Petroleum

The United States imports more than 60 percent of its petroleum resources, either in the form of crude oil or refined products. U.S. crude oil imports have risen from 44 percent of new supply in 1990 to 62 percent in 2002. U.S. finished, or refined, product imports have remained fairly steady in the 1990s at about 6 percent of total demand.

Minnesota has no indigenous oil reserves. All of the oil used in the state must be imported. Most petroleum products enter and leave Minnesota by pipeline. Some are transported by barge, rail, ship, or truck. Most of the United States' imported Canadian crude oil and liquid petroleum gases (LPG) pass through Minnesota on their way to other parts of the Midwest, Eastern Canada, and New England.

Minnesota customers are provided refined petroleum products through area refineries or pipelines. Electric utility and other industrial customers use barge, rail or trucks to transport the finished products from these services to their individual locations. Smaller-volume customers, such as farms, homes, and gas stations, receive their petroleum products via truck delivery.

Residential, commercial and industrial use of petroleum products for non-transportation purposes has been steady or declining in the past several years. That trend is expected to continue. The transportation sector, which accounts for nearly two-thirds of all petroleum consumption, has seen steadily increasing levels of demand.

One factor that impacts the price of petroleum products is supply. Crude oil is necessary for the production of petroleum products. The world's annual supply of crude oil depends on the interplay of many complex factors including demand, weather, politics, technology, and economics. The world currently uses approximately 27,010 million barrels of crude oil per year. Scientists estimate that ongoing natural processes create new crude oil at the rate of 7 million barrels per year. These numbers indicate an eventual depletion of the available crude oil, although it may be possible to find or manufacture new sources and substitutes for these products.

As with natural gas and electricity, the available infrastructure also has a large impact on petroleum prices. Currently, demand is beginning to exceed ocean shipping capacity and is approaching the capacity of some pipelines. Furthermore, the cost of developing new crude oil wells is increasing. New wells, for example, are in less accessible locations. Higher prices for petroleum, however, allow development of lower grades of crude that were previously too costly to exploit.

Three other trends may impact the price of petroleum products. First, in the 1990s, crude oil and refined petroleum product, like natural gas, became publicly traded commodities on world mercantile exchanges. During times of actual or perceived supply disruptions or shortages, prices now fluctuate more erratically. Second, nearly every major international oil company and most independent marketers are forming E-commerce sites to trade commodities independently. Their effect on energy prices and supply will depend largely on which sites survive. Third, petroleum refiners have significantly changed their operations in the 1990s. They have reduced refining costs by moving toward just-in-time production. Storage is now more in the control of independent terminal and pipeline operators.

Increasing Imports

In 2002 the United States met over 60 percent of its crude oil needs with imports. Much of the crude oil that is fed into refineries in Minnesota is delivered by pipelines from Canada. The fact that Minnesota does not receive a large percentage of its crude oil feedstocks from areas such as Venezuela, Nigeria, and the Middle East does not mean that Minnesotans are insulated from the political and economic unrest that has affected those areas. Events in these places affect the world market, which influences Minnesota prices.

Reliability Issues

The reliability issues that result from problems with the supply infrastructure will continue to be a challenge for the industry throughout the country.

Petroleum products suppliers often operate with only a thin margin between current demand and inventories. In other words, suppliers tend to shy away from “stockpiling” reserves of petroleum products. This results in a market that is not capable of drawing upon instantly available reserves in order to adjust to significant changes in demand.

Appendix 3

State Regulatory Programs to Promote Renewable Energy Development

<i>Statute</i>	<i>Description</i>
Renewable Development Fund	<p>Minn. Stat. § 116C.779. This statute requires Xcel Energy to transfer to a renewable development account (the “Renewable Development Fund” or RDF) \$16 million annually for each year spent fuel is stored in dry casks at the utility’s Prairie Island nuclear generation facility. Money from the fund is spent with the approval of the Public Utilities Commission, but the RDF is an account internal to Xcel Energy, not an account in the state treasury.</p> <p>Of this \$16 million, up to \$4.5 million is to be used for production incentives for small wind facilities under Minn. Stat. § 216B.41, and \$1.5 million for production incentives for other renewables.</p> <p>There is no definition for “renewables” in this statute. That definition is left to a renewable development fund board, which determines which projects get funded. The board is currently made up of two Xcel Energy representatives, one representative of environmentalists, one representative from local government, and a representative of the Mdewakanton Dakota tribal council at Prairie Island.</p>
Net Metering	<p>Minn. Stat. § 216B.164. This statute requires utilities to purchase the output of certain renewable energy facilities of 40 kilowatts or less, net of the amount of electricity used by the owner of the facility. The rate that a utility is required to pay for this net energy is the utility’s average retail rate (the amount that the utility charges retail customers for electricity).</p> <p>The statute incorporates the federal PURPA definition for qualifying facilities.</p>
State PURPA statute	<p>Minn. Stat. § 216B.164. This statute requires a distribution utility to purchase the output of certain renewable facilities of greater than 40 kilowatts at the utility’s full avoided cost of energy and capacity of the utility’s least cost renewable resource, or the bid of a competing supplier of a least cost renewable energy facility, whichever is lower. The statute incorporates the federal PURPA definition for qualifying facilities.</p>

<i>“Green Pricing” programs</i>	<p>Minn. Stat. § 216B.169. This statute requires each distribution utility to offer customers the option to purchase renewable energy. Distribution utilities are those utilities that provide electric service directly to retail customers. Rural electric cooperatives and municipal distribution utilities are examples of distribution utilities. Investor-owned utilities, such as Xcel Energy or Minnesota Power, are also included.</p> <p>This statute uses the Integrated Resource Planning statute definition of renewables.</p>
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<p><i>Renewable Energy Objectives</i></p>	<p>Minn. Stat. § 216B.1691. This statute requires each generation and transmission cooperative, municipal power agency, and investor-owned utility to make a good faith effort to get 10 percent of their power supply from renewable energy by 2015.</p> <p>The Public Utilities Commission issued an June 2004 Order detailing certain standards and criteria for evaluating a utility's performance under the REOs. The Commission will now turn its attention to developing a weighted scale of how energy produced by various eligible energy technologies shall count toward a utility's objective. In establishing this scale, the commission shall consider the attributes of various technologies and fuels, and shall establish a system that grants multiple credits toward the objectives for those technologies and fuels the commission determines is in the public interest to encourage.</p> <p>Under the REO statute, the energy generated by an eligible energy technology counts toward the REO. The statute defines "eligible energy technology" as an energy technology that:</p> <ol style="list-style-type: none">(1) generates electricity from the following renewable energy sources: solar; wind; hydroelectric with a capacity of less than 60 megawatts; hydrogen, provided that after January 1, 2010, the hydrogen must be generated from the resources listed in this clause; or biomass, which includes an energy recovery facility used to capture the heat value of mixed municipal solid waste or refuse-derived fuel from mixed municipal solid waste as a primary fuel; and(2) was not mandated by Laws 1994, chapter 641 (the 1994 Prairie Island statute), or by commission order issued pursuant to that chapter prior to August 1, 2001. <p>The 2003 legislature made the REO a requirement for Xcel, and specified that the utility must contract for or develop an additional 300 MW of wind.</p>
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<p><i>Distributed Energy Resources</i></p>	<p>Minn. Stat. § 216B.2411. This statute allows utilities to spend 5 percent of their required conservation spending under Minnesota Statutes, section 216B.241, on renewable energy projects, provided the utility is meeting their REO. Project costs may be pooled between utilities.</p> <p>This statute also has its own definition of what an eligible energy renewable energy source is, which is a bit broader than the REO definition, but narrower than the IRP definition.</p>
<p><i>Integrated Resource Planning</i></p>	<p>Minn. Stat. § 216B.2422. This statute establishes a preference for renewable energy in planning for power supply requirements. The statute prohibits the Public Utilities Commission from approving the construction of a nonrenewable energy facility unless the utility proposing the facility has demonstrated that a renewable energy facility is not in the public interest.</p> <p>It also requires a utility to use environmental cost values established by the Commission in the utility's resource plans.</p> <p>This statute has the broadest definition of what qualifies as renewable, specifying that: "Renewable energy" means electricity generated through use of any of the following resources:</p> <ul style="list-style-type: none"> (6) wind; (6) solar; (6) geothermal; (6) hydro; (5) trees or other vegetation; or (6) landfill gas.
<p><i>Wind Power Mandate</i></p>	<p>Minn. Stat. § 216B.2423. This statute requires Xcel Energy to acquire 825 megawatts of wind energy capacity.</p>
<p><i>Biomass Power Mandate</i></p>	<p>Minn. Stat. § 216B.2424. This statute requires Xcel Energy to acquire 125 megawatts of biomass energy capacity by December 1998.</p>

<i>Renewable Energy Production Incentive</i>	<p>Minn. Stat. § 216C.41. This statute provides 1.5 cents per kilowatt-hour produced by up to 200 megawatts of eligible renewable energy facilities. Eligible renewable energy facilities includes certain:</p> <ul style="list-style-type: none">• small wind energy facilities (under 2 megawatts)• on-farm anaerobic digester facilities• refurbished hydroelectric dams <p>The production incentive for the first 100 MW of capacity is paid out of the general fund by a statutory appropriation (i.e., not subject to biennial appropriation). The production incentive for the second 100 MW of capacity is paid for out of Xcel Energy's Renewable Development Fund. All of the 200 MW of capacity is fully subscribed.</p> <p>Another \$1.5 million of production incentives may be paid out of the Renewable Development Fund under this statute to eligible on-farm biogas recovery facilities for production incentives for other renewables.</p>
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Appendix 4

BLACKOUT SYMPOSIUM SUMMARY

The Office of Energy Reliability of the Minnesota Department of Commerce held a conference on November 10, 2003, to discuss the events that lead to the blackout on August 14, 2003, and reaction of Minnesota's utilities to those events. Ken Wolf, the state's Reliability Administrator and head of the Office of Energy Reliability, organized the conference.

The morning session began with an address by Nora Mead Brownell, one of the five members of the Federal Energy Regulatory Commission. Commissioner Brownell thanked the Minnesota Department of Commerce and the Minnesota Public Utilities Commission for their leadership on reliability issues, and especially for their efforts to address these issues cooperatively with stakeholders – to keep the discussion from devolving into a “industry vs. environmentalists” or “utilities vs. regulators” impasse. It is critical, said Commissioner Brownell, that the lights stay on, but it is “even more critical that we dig down deep and ask how we plan together for the future.”

Regarding the blackout itself, Ms. Brownell said that the joint U.S./Canadian investigation is continuing, and that we don't yet know what caused the blackout.⁵² She said we do know two things about the blackout. One of those is that the blackout was not caused by a single event – “complex systems have complex answers.” The other is that utility deregulation or “restructuring” was not a cause of the blackout, but being “caught in the middle of restructuring made us more vulnerable” to the cascading events that resulted in the blackout.

Commissioner Brownell made several key points:

- There has been a serious disinvestment by utilities in transmission infrastructure, partly as a result of the “financial melt-down” of the energy utility industry that followed in the wake of the Enron debacle.
- We have a integrated transmission grid, and that we are each heavily dependent on our neighboring states and utilities – the transmission system is becoming ever more regional.
- State and federal jurisdictional boundaries were developed at a time when the grid looked different. This disparity continues to lead to difficulties, but these can be overcome with cooperation and communication.
- We need mandatory reliability rules, and a regulatory entity with the authority and resources to enforce those rules. These rules are likely to be included in a federal energy bill, if Congress passes such a bill.

⁵² The “Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations,” U.S.-Canada Power System Outage Task Force, was issued on April 5, 2004, and can be accessed at <http://www.nerc.com>.

- We need to encourage deployment of new technologies, such a transmission technologies to allow the grid to be operated more efficiently, and generation technologies to allow electricity to be generated much more cleanly.
- We do need more wires – “big lines” – and that lapses in reliability of the electric system are costing the economy billions of dollars.

It is, said Commissioner Brownell, “our shared obligation” to ensure a reliable, efficient, environmentally friendly energy system for the future.

Ken Wolf gave the conference a primer on the relationships between the Federal Energy Regulatory Commission (FERC), the North American Electric Reliability Council (NERC), the Midwest Independent System Operator (MISO) and the Mid-Continent Area Power Pool (MAPP). Following Mr. Wolf’s presentation, Paul Barber gave a detailed primer on transmission system design and operation, and a moment-by-moment account of the blackout itself. Mr. Barber is a NERC consultant, and is the steering committee facilitator for the Joint U.S./Canada blackout investigation.⁵³

Jim Torgerson is the President and Chief Executive Officer of MISO, and addressed the conference as to the ISO’s efforts to enhance reliability in the region following the blackout. The electric system, Mr. Torgerson told the attendees, is not being used in the manner that it was developed. “We’re seeing flows that were not contemplated, and management of the system is much more complicated. Mr. Torgerson stressed that MISO is the reliability coordinator for the Midwest region, but is not a control area operator. As such, MISO has no ability to actually balance load and generation, but instead monitors the regional grid, and gives direction to the control area operators. Thus, enhanced modeling and monitoring systems, as well as enhanced communications systems, are vital to improving MISO’s ability to ensure reliability in the region. In addition to these, MISO is also increasing the number of security coordinators and operations engineers on its staff, and increasing the overall certification levels of its staff beyond those required by NERC standards.⁵⁴ MISO has also been moving toward assuming more operational control over the grid through the development and implementation of a new market tariff, but many concerns arose from MISO members about that tariff. As a result, MISO withdrew that tariff filing from FERC, and is working with its members on refining that initiative.⁵⁵

Conference attendees then heard from Minnesota transmission planners and operators, in a panel presentation entitled “Blackout: Can it Happen Here?” Claire Moeller, the director of Xcel Energy’s Control Center Operations talked in detail about the near-miss in 1998, when a series of

⁵³ To view the presentations given at the Symposium go to www.state.mn.us/mn/externalDocs/Commerce/Blackout_Symposium_111303040523_Blackout.ppt

⁵⁴ The current status of MISO’s reliability responses to the blackout can be reviewed at www.midwestiso.org/initiatives/reliability/index.shtml.

⁵⁵ MISO subsequently refiled the energy market tariff on March 31, 2004. In its Order on May 26, 2004, FERC moved the market start date for the Midwest ISO from December 1, 2004 to March 1, 2005. A summary of the Order can be reviewed at <http://www.ferc.gov/press-room/pr-current/05-26-04.asp>.

lightning strikes nearly brought down the electric grid for the Midwest and parts of Canada. As a result of quick action on the part of Canadian system operators, Mr. Moeller said, this event “was a footnote, rather than a headline.”

Donald Kom, executive director of the Central Minnesota Municipal Power Agency, talked about a number of frustrations with the current electric system in the region. Transmission costs for one of the cities his utility serves have more than doubled in the past few years, but transmission service to that city may in fact be worse. His utility purchases “firm” transmission service from the grid, but that service is curtailed more often than not. The transmission models that MISO uses to plan for transactions across the system show significant impacts region-wide for even very small transactions. Kom pointed out that while the electric system is complex, the solutions to these problems are not all that complicated, telling the audience that “You have to put poles in the ground, and wires in the air.”

William Kaul, vice president of transmission for Great River Energy, then addressed the significant policy changes that the industry has faced, since Congress passed the Energy Policy Act of 1992. In that legislation, Congress tackled the energy utility industry, “the last great monopoly.” These regulatory upheavals have led to the disintegration of old institutions, and the emergence of new ones.

William Head, chief operating officer of MAPPCOR (which provides professional, technical and administrative services to MAPP) cautioned that increased transmission infrastructure and better operational practices does not necessarily mean that a blackout will not happen here. He also raised a concern that the industry may be faced with a shortage of transmission engineers over the coming years.

Following that panel, Audrey Zibelman, chief executive officer of TRANSLink Development Company, talked about a number of concerns regarding the transmission system, and how an entity like TRANSLink could address some of those concerns. Ms. Zibelman reiterated a point that Commissioner Brownell made earlier in the day, that utilities are not investing in transmission infrastructure. While energy sales have increased by \$67 billion a year since 1975, transmission investments have decreased by \$103 billion a year over that time. Ms. Zibelman also emphasized another of Commissioner Brownell’s points, that the grid is regional in nature, and that policies and institutions to manage that grid have to have a regional focus. TRANSLink, as an independent transmission company approved by FERC, was designed to provide the following services to regional utilities:

- coordinated system planning
- grid investment
- consolidated system operations
- tariff administration and

Ms. Zibelman argued that having TRANSLink taking over these functions from MISO, MISO could then focus on market development and administration, regional planning oversight, and regional reliability oversight. However, she also cautioned that the future of TRANSLink is not clear, but should be made clear in the coming weeks.⁵⁶

Tom Ferguson, vice president for power delivery and transmission for Minnesota Power, was the final speaker of the day. Mr. Ferguson spoke to the conference about Minnesota's transmission planning process. Under the new state transmission planning process, each transmission owning utility in the state is required to identify and address inadequacies in the utility's transmission system, solicit public input from the public and local governments on those inadequacies, and file a plan with the Minnesota Public Utilities Commission by November 1 of each odd numbered year. The most recent plan⁵⁷ (filed on November 3, 2003) was submitted jointly by the Minnesota utilities subject to the planning requirement.

⁵⁶ On November 23, 2003 TRANSLink disbanded, citing market uncertainty to be a primary factor.

⁵⁷ A copy of this plan can be viewed or downloaded at <http://www.minnelectrans.com/>.

Appendix 5

ENERGY INFORMATION WEB RESOURCES

The following Web sites contain documents or additional information about some of the subjects and programs referenced in this report:

Minnesota Department of Commerce -- <http://www.commerce.state.mn.us/>:

- Energy Conservation and Renewable Energy Consumer Information – click on Energy Info Center
- Energy Policy Reports – click on Businesses We Regulate > Energy Utilities > Energy Utilities > Energy Policy.
- B3 Information – click on Consumer Info and Services > Buildings and Builders > B3 project guidelines.
- Low Income Energy Assistance and Weatherization Program Information – click on Heating Assistance.
- Energy Data Reports – click on Businesses We Regulate > Energy Utilities > Energy Utilities > Energy Data & Statistics

Joint Minnesota utilities transmission plan filing – <http://www.minnelectrans.com/>

Ventura Administration follow-up Energy Planning Report – <http://www.me3.org/>

Minnesota Public Utility Commission – <http://www.puc.state.mn.us>

Minnesota State Legislature: Statutes, Session Laws, and Rules –
<http://www.leg.state.mn.us/leg/statutes/asp/>

DOE Energy Efficiency and Renewable Energy Web site – <http://www.eere.energy.gov/>

DOE Energy Information Administration⁵⁸ – <http://www.eia.doe.gov/>

Clean Energy Resource Team Web site – <http://www.cleanenergyresourceteams.org/>

American Council for and Energy Efficient Economy – <http://www.aceee.org/>

ENERGY STAR Web site – <http://www.energystar.gov/>

⁵⁸ For example, Minnesota's Electricity Profile 2002 is attached from
http://www.eia.doe.gov/cneaf/electricity/st_profiles/minnesota.pdf

Appendix 6

STATE REVIEW OF PROPOSED LARGE ENERGY FACILITIES

Prepared by Staff of the Environmental Quality Board

I. Introduction

Any person proposing to construct a new large energy facility such as a power plant or a transmission line or a pipeline may be required to obtain a certificate of need from the Public Utilities Commission confirming the need for the new facility and a permit from the Environmental Quality Board identifying the site for a new power plant or a route for a new transmission line or pipeline.

Public Utilities Commission. A certificate of need for new large energy facilities has been required since 1974. Initially, the authority to issue certificates of need was vested in the Minnesota Department of Energy. In 1982, the Department of Energy was abolished and the authority to issue certificates of need was transferred to the Public Utilities Commission. Minn. Stat. § 216B.243. In the past several years the PUC has issued certificates of need for several gas-fired peaking and intermediate plants, several high voltage transmission lines, including four new lines in southwestern Minnesota designed to transport wind power off Buffalo Ridge, a large wind facility, and several pipelines.

Environmental Quality Board. The Minnesota Environmental Quality Board has had the authority since 1973, when the Power Plant Siting Act was passed, Minn. Stat. §§ 116C.51 to 116C.69, to site large electric power generating plants and to route high voltage transmission lines. The EQB has been permitting large wind energy conversion systems since 1995. Minn. Stat. §§ 116C.691 to 116C.697. The EQB has been routing intrastate natural gas and petroleum pipelines since 1987. Minn. Stat. § 116I.015.

In the past 30 years the EQB has issued permits for ten large power plants, fourteen high voltage transmission lines, ten large wind projects, and nineteen intrastate pipelines. See the EQB's webpage for a list of projects that have been permitted:

<http://www.eqb.state.mn.us/EnergyFacilities/index.html>

II. Minnesota Public Utilities Commission – Certificate of Need

A. Large Energy Facility. A certificate of need from the Public Utilities Commission is required for a “large energy facility.” Minn. Stat. § 216B.243, subd. 2. A “large energy facility” is defined in Minn. Stat. § 216B.2421, subd. 2, to include the following:

- (1) Any electric power generating plant of 50 megawatts or more
- (2) Any high voltage transmission line with a capacity of 200 kilovolts or more
- (3) Any high voltage transmission line with a capacity of 100 kilovolts or more with more than ten miles of its length in Minnesota or that crosses the state line.

- (4) Any pipeline used to transport coal crude petroleum or petroleum fuels or oil greater than six inches in diameter and having more than 50 miles of its length in Minnesota.
- (5) Any pipeline for transporting natural or synthetic gas at a pressure in excess of 200 pounds per square inch with more than 50 miles of its length in Minnesota.
- (6) Any facility capable of storing 100,000 gallons of liquefied natural gas.
- (7) Certain underground gas storage facilities.
- (8) Nuclear fuel processing or waste storage facilities.
- (9) Any facility capable of processing more than 75 tons of combustible fuels per hour.

B. Rules. Minn. Stat. § 216B.243 contains requirements for obtaining a certificate of need, and the PUC has promulgated rules describing the procedures to follow and establishing standards for issuance of certificates of need. Minn. Rules Chapter 7853 and 7849 (power plants and transmission lines) and chapter 7851 (pipelines). Other PUC rules applicable to certificate of need applications can be found in Minn. Rules chapter 7829 and 7855.

C. Application. The PUC rules establish what information must be included in an application for a certificate of need. For example, Minn. Rules parts 7849.0200 and 7851.0220. The application must be accompanied by the payment of a fee to cover the costs of processing the application. The PUC will determine whether the application is complete. An applicant may request in advance of filing the application that it not be required to submit certain information that is not pertinent to the proposed project. A person proposing to construct a new large energy facility must apply for a certificate of need before applying for a permit from the Environmental Quality Board. Minn. Stat. § 216B.243, subd. 4.

D. Environmental Review. Under rules promulgated by the Environmental Quality Board in February 2003, preparation of an Environmental Report is required as part of the certificate of need process. Minn. Rules parts 4410.7010 – 4410.7070. The EQB is the responsible governmental unit with the obligation to prepare the document. The public is afforded an opportunity to participate in the development of the scope of the Environmental Report. Minn. Rules part 4410.7030. The EQB has four months from the time a complete application is submitted to complete the Environmental Report.

E. Public Hearing. The Public Utilities Commission is required to hold a public hearing on an application for a certificate of need. Minn. Stat. § 216B.243, subd. 4. The objective of the public hearing is to obtain public opinion on the necessity of granting the certificate of need. Usually, an administrative law judge from the Office of Administrative Hearings presides at the hearing and writes a report and makes a recommendation on whether to issue the certificate of need.

F. Final Decision. Minn. Stat. § 216B.243, subd. 3 and Minn. Rules part 7849.0120 establish the standards to be applied in determining whether a certificate of need should be issued. Generally, the standard is that the applicant has established that there is a need for additional electricity and that the demand cannot be met through energy conservation and load management measures or other more prudent and feasible alternative to the proposed project. Once the PUC has determined

that there is a need for the proposed facility, questions of need, including size, type, and timing, and alternative system configurations and voltage for a proposed high voltage transmission line are final and will not be reviewed by the Environmental Quality Board. Minn. Stat. § 116C.53, subd. 2.

The PUC has six months from the time the application is submitted (or supplemented if the PUC determines the original application is incomplete) to make a final decision on the application. Minn. Stat. § 216B.243, subd. 5.

G. Alternatives to Certificate of Need. Although a decision on the need for a proposed large energy facility is required, there are other ways besides the issuance of a certificate of need in a special proceeding by which the PUC can determine that there is a need for the new facility. One way is through the certification of the need for a new high voltage transmission line in the transmission planning process that was established in 2001. Minn. Stat. § 216B.2425. Utilities are required to submit a transmission plan to the PUC in November of each odd numbered year. A utility may seek certification of the need for new lines through this process. Another way is through the resource planning process. Minn. Stat. § 216B.2422, subd. 6. Also, a certificate of need is not required for an electric power generating plant that is selected through a bidding process approved by the Commission. Minn. Stat. § 216B.2422, subd. 5.

III. Minnesota Environmental Quality Board –Site or Route Permit

A. Large Energy Facility. The Power Plant Siting Act, which establishes the authority of the Environmental Quality Board, does not use the term “large energy facility” but instead refers to “large electric power generating plants” and “high voltage transmission lines.” A “large electric power generating plant” is defined as electric power generating equipment designed for or capable of operating at a capacity of 50 megawatts or more. Minn. Stat. § 116C.52, subd. 5.

A “high voltage transmission line” is defined as a conductor of electric energy designed for and capable of operation at a nominal voltage of 100 kilovolts or more. Minn. Stat. § 116C.52, subd. 4.

A “large wind energy conversion system” is a combination of wind turbines with a wind capacity of five megawatts or more. Minn. Stat. § 116C.691, subd. 2.

A pipeline falling within the jurisdiction of the EQB is an intrastate pipeline that is designed to be operated at a pressure of more than 275 pounds per square inch if it carries natural gas and more than six inches in nominal diameter designed to transport hazardous liquids such as petroleum. Minn. Stat. § 116I.015, subd. 5.

Thus, any person proposing to construct a power plant of 50 megawatts or more, regardless of fuel type, even wind power, is required to obtain a certificate of need from the Public Utilities Commission and a permit from the Environmental Quality Board. Any person proposing to construct a transmission line of 200 kilovolts or more is required to obtain a certificate of need and a permit from the Environmental Quality Board. A person proposing to construct a transmission line of between 100 and 200 kV is required to obtain a permit from the EQB but is not required to

obtain a certificate of need from the PUC unless the line is more than ten miles in length or crosses the state border. Similarly, with pipelines, a certificate of need may be required only if the pipeline has more than 50 miles in Minnesota, but a permit from the EQB may be required regardless of length.

B. Rules. The Environmental Quality Board has promulgated rules that apply to applications for site permits and route permits. For power plants and high voltage transmission lines, the rules are found in Minn. Rules chapter 4400. The wind rules are in chapter 4401. And the pipeline rules are in chapter 4415.

For power plants and transmission lines, the Power Plant Siting Act actually establishes two different processes for considering an application for a permit. One process is referred to as the Full Process, and the other is called the Alternative Review Process. There are separate rules for each process. The Full Process is described in Minn. Rules parts 4400.1025 – 4400.1900 and the Alternative Review Process is described in parts 4400.2000 – 4400.2950. The size of the project determines which process applies. The smaller, less environmentally invasive projects, like power plants under 80 megawatts or burning natural gas and transmission lines under 200 kilovolts, are subject to the Alternative Review Process. The statute establishes what projects qualify for the alternative review. Minn. Stat. § 116C.575.

Some of the smallest projects are eligible for review by local units of government with jurisdiction over the project rather than review by the Environmental Quality Board. Minn. Stat. § 116C.576. The EQB has established the procedure that must be followed by local units of government in considering a permit for such projects. Minn. Rules part 4400.5000.

C. Application. Minn. Rules part 4400.1150 establishes the requirements for what information must be included in an application for a permit for a power plant or transmission line, regardless of the size or type of the project. An applicant for a permit for a project undergoing full review must identify both a preferred site or route and an alternative site or route. An applicant for a permit for a project eligible for alternative review is not required to propose an alternative site or route but must identify any sites or routes that were rejected and explain why. In addition, the application must be accompanied by the payment of a fee. Minn. Rules part 4400.1050. The EQB Chair will determine within ten days of submission of the application whether the application is complete. The applicant is required to notify the public that an application has been submitted and that the project has been proposed for construction.

The requirements for submitting an application for a wind project or a pipeline project are found in Minn. Rules chapters 4401 and 4415, respectively.

D. Environmental Review. Depending on the size and type of the project and whether the Full Process or the Alternative Review Process applies, the EQB prepares either an Environmental Impact Statement or an Environmental Assessment on the project. Minn. Rules parts 4400.1700 and 4400.2750. The primary difference is that an EIS requires both a draft and a final, whereas an Environmental Assessment does not undergo revision. The public can participate in the development of the scope of the environmental document at a public meeting and through submission of written comments. Id.

No separate environmental review document is prepared for proposed wind projects. Instead, the EQB Chair prepares a draft permit and provides the public with an opportunity to comment on the document at a public meeting. Minn. Rules parts 4401.0500 and 440.0550. With pipeline projects also, no discreet environmental review document is required, although the EQB holds a public meeting in each country where the pipeline will be constructed. Minn. Rules part 4415.0700.

E. Public Hearing. The EQB is required to hold a public hearing as part of the process for a permit for a power plant or transmission line. Minn. Stat. §§ 116C.57, subd. 2d, and 116C.575, subd. 6. For the larger projects, the public hearing is a contested case hearing presided over by an administrative law judge. For the smaller projects, the EQB has discretion regarding how formal a hearing to schedule. Minn. Rules part 4400.2850. In either event, the public has full opportunity to participate. With wind projects and pipeline projects, no public hearing is mandatory but the EQB could decide to hold a public hearing.

F. Final Decision. The final decision on a permit application is made by the full Environmental Quality Board. The Board takes into account a number of considerations in deciding what site to approve for a new power plant or what route to designate for a new transmission line, including the potential human and environmental impacts of the proposed project. Minn. Stat. § 116C.57, subd. 4. The Board may also impose appropriate conditions in the permit.

For wind projects, the Board determines whether the project is compatible with environmental preservation, sustainable development, and the efficient use of resources. Minn. Rules part 4401.0600, subp. 3.

The EQB has one year from the time the permit application was accepted to reach a final decision on a project undergoing review under the Full Process. Minn. Stat. § 116C.57, subd. 7. The EQB has six months to make a decision on the smaller projects under the Alternative Review Process. Minn. Stat. § 116C.575, subd. 7. For wind projects, the statutory deadline is 180 days, Minn. Stat. § 116C.694, and for pipelines, the time is nine months. Minn. Stat. § 116I.015, subd. 3(5).

III. Joint Proceedings.

A. Joint Environmental Review. The EQB rules recognize that environmental review of a proposed project can be combined to address in one document the issues necessary for the PUC to make a decision on the need and size and type of the project and the issues necessary for the EQB to designate a specific site or route for the project. Minn. Rules part 4410.7060. The matter cannot be combined, of course, unless the project proposer has identified a proposed site or route for the project at the time the certificate of need is applied for and has submitted a permit application to the EQB with the site specific data necessary for the EQB to begin its review.

B. Joint Hearing. In some instances both the Public Utilities Commission and the Environmental Quality Board could decide to hold a joint hearing. The statute allows for the two agencies to hold a joint hearing if doing so is feasible, more efficient, and may further the public interest. Minn. Stat. § 216B.243, subd. 4. The EQB rules recognize that a joint hearing may be held. Minn. Rules

parts 4400.1800, subp. 3 and 4410.7060, subp. 4. Both agencies have determined that a joint hearing on the Mankato Energy Center project, a 640 megawatt natural gas fired power plant in the Mankato, Minnesota, area is appropriate, and that hearing is scheduled for July 12, 2004.

Appendix 7

**PUBLIC UTILITIES COMMISSION RATE PLAN
Pursuant to Minn. Stat. 216C.18, subd. 1a**

Appendix 7

**PUBLIC UTILITIES COMMISSION ENERGY RATE PLAN AND POLICY
Pursuant to Minnesota Statutes, §216C.18, subd. 1a**

THE MINNESOTA PUBLIC UTILITIES COMMISSION

The Minnesota Public Utilities Commission consists of five commissioners, appointed by the Governor, for staggered, six year terms, and approximately 37 professional and administrative support staff. The Commission's primary mission is to create and maintain a regulatory environment that ensures safe, reliable, and efficient utility services at fair and reasonable rates. The Commission is structured to have a significant degree of independent decision-making autonomy and has both quasi-judicial and legislative functions.

COMMISSION ENERGY AND CONSERVATION POLICY RESPONSIBILITIES

Overview

The Commission has broad authority over natural gas and electric utility rates, service standards and practices, and resource mix. Minnesota statutes include the following direction to the Commission in carrying out its rate-making responsibilities:

- Rates shall be just and reasonable, not unreasonably preferential or discriminatory, and consistent with the financial need of public utilities to provide service.
- Rates shall be set to encourage energy conservation and the use of renewable energy.
- Utilities cannot change their general rates unless and until allowed by the Commission after notice and hearing, with some permitted exceptions. Automatic adjustment mechanisms to pass through fuel-related costs are permitted.

- Utility expenditures on cost-effective energy conservation improvements and incentive plans that further encourage conservation may be recovered through special rate mechanisms outside the rate case process.

- Costs of certain renewable energy and emission reduction projects may be recovered through special rate mechanisms outside the rate case process.

In addition to its rate setting activities, the Commission implements energy policy goals through a variety of activities that influence the mix of resources used to meet energy needs, as discussed more fully below.

Environmental Cost Values

Minnesota law requires the Commission to quantify ranges of environmental costs for each method of electricity generation and to use that information in all resource selection decisions, including resource planning, competitive bidding and certificate of need. Without the consideration of relevant environmental costs and benefits, resources may be selected that have low direct costs but relatively high external environmental costs.

The Commission adopted interim values in 1994, and a final range of values in 1997, for six types of air emissions: sulfur dioxide, particulate matter less than 10 microns in diameter, nitrogen oxides, carbon monoxide, lead, and carbon dioxide. In 2001, the Commission found that the 1997 values should be periodically updated using the Gross National Product Price Deflator Index.

Certificate of Need

Since the mid 1970s, Minnesota law has required a certificate of need be issued before large energy facilities can be constructed in this state, which include electric generating plants, high-voltage transmission lines, nuclear storage facilities, and certain pipelines, can be built in the state. The need determination process provides an important and in-depth review of the specific proposed facilities and alternatives, and is based on criteria specified in Minnesota statutes. (See Appendix 6 of this report for an overview of the Commission's certificate of need and the EQB's siting and routing processes.)

The certificate of need process applies to specific facilities and is triggered when a facility is proposed to be constructed in Minnesota. Integrated resource planning and transmission planning processes were later implemented to provide a means for longer range planning.

Integrated Resource Planning

In 1990, the Commission adopted rules requiring investor-owned electric utilities to file integrated resource plans that identify and justify the mix of supply and demand-side resource options to meet projected energy demand over the next 15 years. The Legislature has subsequently expanded the entities required to file resource plans so that four investor-owned

utilities, four generation and transmission cooperatives, and two municipal joint action agencies now file resource plans with the Commission.

Integrated resource planning is intended to broaden the focus of utility planning by placing supply and demand-side resources on an equal footing with the traditional generating facilities and allowing stakeholders to participate in long-term resource planning decisions. Benefits of a longer range planning approach include:

- identifying the need for new resources before shortages threaten the reliability of the bulk power system;
- encouraging demand-side investments, such as energy efficiency, conservation and load management, when those options are cost-effective;
- encouraging renewable generation and other alternatives to large central station generating plants when those options are more cost-effective; and
- internalizing environmental impacts and social consequences of facility construction in the resource selection process.

The Commission judges resource plans and their specific components on their ability to:

- maintain or improve system reliability;
- keep customers' bills and utility rates as low as reasonably possible;
- minimize adverse socioeconomic effects and adverse effects on the natural environment; and
- limit risk and enhance the utility's ability to respond to changing circumstances.

The resource planning process has a company-specific focus. The process is shaped by Commission rules that were developed with input from industry and public stakeholders and gear the process to feed critical information into a number of other company-specific proceedings. The Commission is interested in exploring options by which it can obtain a more state-wide perspective on resource needs and supply options. In addition, the full effects of a restructured electric industry on the resource planning and certificate of need processes are not clear and require continual evaluation.

State Transmission Planning

Legislation was passed in 2001 that requires electric utilities to submit a transmission project report to the Commission every two years. The report must: (1) list present and foreseeable future inadequacies in the transmission system in Minnesota; (2) identify alternative means of addressing each inadequacy listed; (3) identify general economic, environmental, and social issues associated with each alternative, and (4) provide a summary of public input the utilities

and associations have gathered related to the list of inadequacies and the role of local government officials and other interested persons in assisting to develop the list and analyze alternatives. The Commission has adopted rules that set out notice, content, and other procedural requirements for these filings.

Certification of transmission lines may also be obtained through this process, as an alternative to the certificate of need process. To-date, transmission line projects have gone through the certificate of need process, and no requests for certification have been made through this biennial transmission planning process.

Transmission Issues at the Regional and National Level

The traditional electric utility provides at least three services: generation, transmission, and distribution. Historically, an electric utility would serve customers by bundling these services together. The price for electricity was designed to reflect the aggregate cost of the three services. The advent of restructuring in the electric industry is changing this environment.

The Federal Energy Regulatory Commission (FERC) has taken significant actions over the last few years to foster competitive wholesale electric utility markets. A key component of FERC's strategy is the creation of regional transmission organizations (RTO) to oversee the use and development of regional transmission systems and the linkages between those systems. The FERC has approved the Midwest Independent System Operator (MISO) as the RTO for the area encompassing Minnesota, the upper Great Plains, as well as states as far east as Ohio.

State regulators, like the Minnesota Commission, are involved in MISO matters primarily through a new organization called the Organization of MISO States (OMS). OMS is comprised of the state commissions in the MISO area and is designed to monitor MISO as well as FERC activities and to protect ratepayer interests. The Minnesota Commission and Department of Commerce are active in the affairs of OMS and are striving to create an organization and process that will effectively deal with critical transmission issues facing the Upper Midwest. In addition, the Commission will intervene independently in matters before FERC when it believes issues unique to Minnesota's interests need to be represented.

Renewable Energy Objectives

Under statutes passed in 2001, the legislature established renewable energy objectives, with a goal that ten percent of the energy provided to Minnesota retail customers by 2015 be from renewable sources. In 2003, legislation required the Commission to develop criteria and standards for measuring an electric utility's good faith effort in meeting these objectives. In a June 1, 2004 order, the Commission sets forth a number of important findings needed to foster the outcomes envisioned by the statute, including:

- It determined which utilities are required to comply with the REO statutory requirements.

- It specified the kinds of technologies that may be counted in evaluating whether a good faith effort is being made.
- It provided direction on necessary notification of utility customers concerning the efforts being made by companies with an obligation to fulfill REO requirements.
- It provided specific direction on how obligated utilities can demonstrate the extent of the efforts they are making to comply with the good faith requirement.
- It asked all stakeholders to work toward the establishment of a reliable tracking system to certify, verify and implement conformance with the REOs.

On October 19, 2004, the Commission issued an order determining that all eligible generation technologies should be given a weight of one in counting toward a utility's renewable energy objectives at this time. The Commission also established a separate docket to further investigate establishing a multi-state tracking and credit trading system. In addition, the Commission has co-sponsored regional workshops exploring the creation of a renewable energy credits tracking system.

Xcel Energy - Competitive Bidding

Xcel Energy (Xcel) is required to follow a competitive bid process established by the Commission in acquiring new generation resources identified in its resource plan. This process enables identification of reliable, environmentally sound and least-cost generation sources for Xcel as it faces capacity needs. Commission review and approval is required at various steps in this process, including approval of the final contract between Xcel and the winning bidders.

The Commission has taken steps over the last several years to encourage stakeholders and Xcel to present the Commission with proposals to review and improve the competitive bidding process. The Commission expects that significant issues regarding competitive bidding will arise in conjunction with Xcel's next resource plan, scheduled to be filed on November 1, 2004.

Xcel Energy – Wind and Biomass Mandates

Legislation enacted in 1994, required Xcel to obtain at least 425 MW of wind and 125 MW. (The biomass mandate was reduced to 110 MW in 2003 legislation.) In addition, the Commission has required Xcel to construct or purchase an additional 400 MW of wind over and above the initial mandate of 425 MW, as permitted by the 1994 legislation. This capacity must be available by 2012. Legislation passed in 2003 requires Xcel to deploy an additional 300MW of wind energy by 2010.

Xcel has contracted for much of the 825 MW of wind required by the 1994 legislation, although actual production will be limited by transmission constraints and uncertainty over production tax credits, at least the shorter term. Xcel has signed contracts for the energy to fulfill the biomass mandate, but potential changes in ownership and location are delaying review of one of the agreements.

Xcel Energy - Renewable Development Fund

Under 1994 legislation, the Xcel Renewable Development Fund (RDF) was established. RDF funding was contingent on the number of nuclear spent fuel casks used by Xcel at its Prairie Island nuclear plant. The money in this fund is designated for biomass, wind and other renewable energy projects and research. The Commission is required to approve expenditures from the fund.

Legislation passed in 2003 changed the funding for the RDF to a set amount of \$16 million a year and provided further direction on how some of the monies in the fund should be used. Review of the projects selected by the RDF board as a result of the second request for proposals is in the comment stage before the Commission as of the fall of 2004.

Natural Gas Issues

Under federal law and FERC actions over the last 20 years, wholesale natural gas prices have become fully deregulated, and in recent years have fluctuated significantly, with a trend upward. At the retail level in Minnesota, larger customers have the option of purchasing their own natural gas. Whether this option, often known as unbundling, should be expanded to all customers is a subject of continuing debate.

Over the years, the Commission has reviewed and approved a number of proposals to enhance customer choice, including: clarification of transportation tariffs, a pilot aggregation service which allows marketers to combine transportation customers, a pilot fixed-price commodity tariff, and seasonal gas rates. The Commission annually reviews the purchasing practices of natural gas utilities to help assure reliability at a reasonable price. As of the fall of 2004, there are four natural gas company rate cases pending before the Commission.

FUTURE POLICY DIRECTIONS

This is a time characterized by changing market conditions, emergence of new technologies, as well as active pursuit of alternative public policy options. Achieving reliable, affordable and environmentally sound energy services requires pursuit of creative policy alternatives balanced with the proprietary interests of ratepayers and shareholders alike. The Commission will continue to implement legislative directives and to be engaged in regional and national issues that have direct bearing on Minnesota's interests.

Appendix 8

MINNESOTA STATUTES 2003, 216C.18

216C.18 State energy policy and conservation report.

Subdivision 1. Report on trends and issues. By July 1 of 1988 and every four years thereafter, the commissioner shall issue a comprehensive report designed to identify major emerging trends and issues in energy supply, consumption, conservation, and costs. The report shall include the following:

- (1) projections of the level and composition of statewide energy consumption under current government policies and an evaluation of the ability of existing and anticipated facilities to supply the necessary energy for that consumption;
- (2) projections of how the level and the composition of energy consumption would be affected by new programs or new policies;
- (3) projections of energy costs to consumers, businesses, and government;
- (4) identification and discussion of key social, economic, and environmental issues in energy;
- (5) explanations of the department's current energy programs and studies; and
- (6) recommendations.

Subd. 1a. Rate plan. The energy policy and conservation report shall include a section prepared by the Public Utilities Commission. The commission's section shall be prepared in consultation with the commissioner and shall include, but not be limited to, all of the following:

- (1) a description and analysis of the commission's rate design policy as it pertains to the goals stated in sections 216B.164, 216B.241, and 216C.05, including a description of all energy conservation improvements ordered by the commission; and
- (2) recommendations to the governor and the legislature for administrative and legislative actions to accomplish the purposes of sections 216B.164, 216B.241, and 216C.05.

Subd. 2. Draft report; public meeting. Prior to the preparation of a final report, the commissioner shall issue a draft report to the Environmental Quality Board and any person, upon request, and shall hold a public meeting. Notice of the public meeting shall be provided to each regional development commission.

Subd. 3. Final report, distribution. The commissioner shall distribute the final report to any person upon request.

HIST: 1974 c 307 s 11; 1975 c 271 s 6; Ex1979 c 2 s 19; 1981 c 356 s 138,248; 1982 c 561 s 3; 1982 c 563 s 8; 1983 c 179 s 2; 1983 c 231 s 3; 1983 c 289 s 115 subd 1; 1984 c 654 art 2 s 100; 1987 c 186 s 15; 1987 c 312 art 1 s 10 subd 1

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The Changing Structure of the Electric Power Industry 2000: An Update

October 2000

**Energy Information Administration
Office of Coal, Nuclear, Electric and Alternate Fuels
U.S. Department of Energy
Washington, DC 20585**

This report was prepared by the Energy Information Administration, the independent statistical and analytical agency within the Department of Energy. The information contained herein should not be construed as advocating or reflecting any policy position of the Department of Energy or of any other organization.

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Preface

Section 205(a)(2) of the Department of Energy Organization Act of 1977 (Public Law 95-91) requires the Administrator of the Energy Information Administration (EIA) to carry out a central, comprehensive, and unified energy data information program that will collect, evaluate, assemble, analyze, and disseminate data and information relevant to energy resources, reserves, production, demand, technology, and related economic and statistical information. To assist in meeting these responsibilities in the area of electric power, EIA has prepared this report, *The Changing Structure of the Electric Power Industry 2000: An Update*. The purpose of this report is to provide a comprehensive overview of the structure of the U.S. electric power industry, focusing on the past 10 years, with emphasis on the major changes that have occurred, their causes, and their effects. It is intended for a wide audience, including Congress, Federal and State agencies, the electric power industry, and the general public.

The legislation that created EIA vested the organization with an element of statutory independence. EIA does not take positions on policy questions. EIA's responsibility is to provide timely, high-quality information and to perform objective, credible analyses in support of deliberations by both public and private decision makers. Accordingly, this report does not purport to represent the policy positions of the U.S. Department of Energy or the Administration.

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Executive Summary

The U.S. electric power industry, the last major regulated energy industry in the United States, is changing to be more competitive. In some States, retail electricity customers can now choose their electricity company. New wholesale electricity trading markets, which were previously nonexistent, are now operating in many regions of the country. The number of independent power producers and power marketers competing in these new retail and wholesale power markets has increased substantially over the past few years. To better support a competitive industry, the power transmission system is being reorganized from a balkanized system with many transmission system operators, to one where only a few organizations operate the system. However, the introduction of these new markets has been far from seamless. California, where retail competition was introduced in 1998, has had problems recently. Electricity prices in some parts of the State have tripled and there have been supply problems as well. Although not as severe as California, New York's electricity market has had price spikes which may be attributable to problems in the market design. While some observers argue that deregulation should be scrapped, others argue that deregulation is a noble endeavor and that these problems can be solved with structural adjustments to the markets.

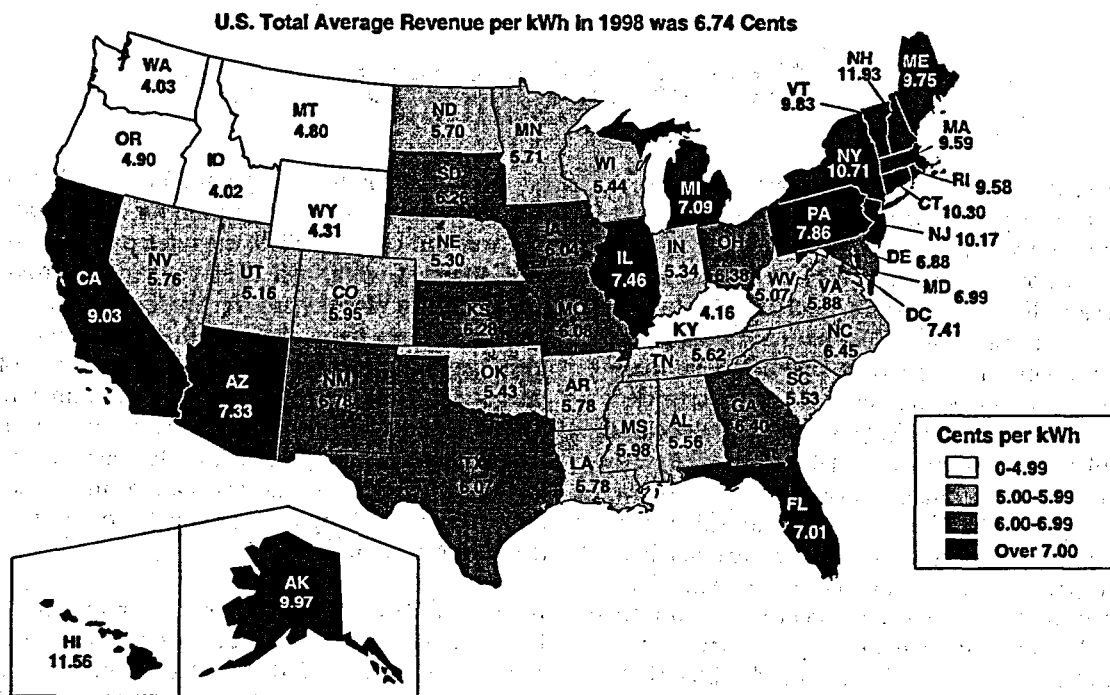
This reorganization is actually the second major structural realignment in the history of the industry. The first occurred during the late 1920s and early 1930s. However, the changes then were mandated by a Federal law that was designed to stop holding company misconduct. Today, the changes that are occurring are not driven by misconduct, but rather by economic and technological factors. In fact, three primary catalysts are driving the current movement toward a restructured electric power industry. First is a general reevaluation of regulated industries and a rethinking of how the introduction of competition might improve efficiencies. The telecommunications and banking industries have been made more competitive, and the electric power industry is being evaluated for similar efficiency gain potential. The second factor driving the restructuring debate is the wide disparity of electricity rates across the United States (Figure ES1). In 1998, consumers in New York paid more than two and one-half times the rates

that consumers in Kentucky paid for their electricity. In the western United States, the rates paid by consumers in California were well over twice the rates paid by consumers in Washington. Technological improvements in gas turbines have changed the economics of power production. No longer is it necessary to build a 1,000-megawatt generating plant to exploit economies of scale. Combined-cycle gas turbines reach maximum efficiency at 400 megawatts, while aero-derivative gas turbines can be efficient at scales as small as 10 megawatts. These improvements, involving less capital investment and less time to build capacity, are the third set of catalysts driving restructuring.

Because it provides the capability to move power over long distances, the transmission system is an integral component of the Nation's electric power industry. Through regulatory reform, the Federal Energy Regulatory Commission (FERC) has promoted the development of competitive wholesale power markets and opening the transmission system to all qualified users. Since the late 1980s, FERC has approved more than 850 applications to sell power competitively in wholesale markets. In arguably its most ambitious effort to date, in December 1999, FERC issued Order 2000 calling for electric utilities to form regional transmission organizations (RTOs) that will operate, control, and possibly own the Nation's power transmission system. The potential benefits of RTOs are the elimination of discriminatory behavior in using the transmission system, improved operating efficiency, and increased reliability of the power system.

A number of States have played an active role in promoting retail competition in the electric power industry. Relatively high-cost States have been in the forefront of enacting legislation or making rules to allow retail competition. California and the northeastern States were the first to allow retail competition and encourage consumers to shop for their power suppliers. Other States such as Kentucky and Idaho, whose rates are among the lowest in the country, are not moving as quickly. A recent report issued by Kentucky's Special Task Force on Electricity Restructuring found no compelling reason for Kentucky to move quickly to restructure its electric power industry. As of July 1, 2000,

Figure ES1. Average Revenue per Kilowatthour for All Sectors by State, 1998



kWh = Kilowatthour.

Note: The average revenue per kilowatthour of electricity sold is calculated by dividing revenue by sales. Sales in deregulated retail electricity markets are not included.

Source: Energy Information Administration, Form EIA-861, "Annual Electric Utility Report."

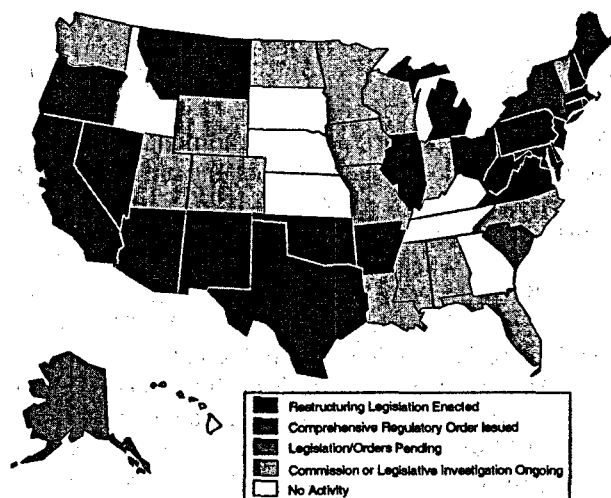
24 States and the District of Columbia had enacted legislation or passed regulatory orders to restructure the electric power industry (Figure ES2).

While most of the States have been active in restructuring their own jurisdictions, several bills designed to provide a single Federal framework for wholesale and retail competition have been introduced into the U.S. Congress. These bills address myriad restructuring issues such as reliability, reform of Federal power marketing administrations, a public benefits fund, tax issues, and renewable energy portfolio standards. Extensive hearings and debates have been held to understand the interests and concerns of all parties involved in the industry, and reaching consensus has been an imposing pursuit. The recent price spikes in California will certainly be a topic of discussion as the restructuring debate moves forward. Retail prices in San Diego have tripled in some cases over the summer of 2000 and there have been blackouts in the San Francisco Bay area. Any discussion surrounding new bills will most certainly address mitigation of these

price spikes and supply curtailments. In all likelihood, Congress will be involved in these activities for a number of months before any comprehensive restructuring legislation will be passed.

Mergers, acquisitions, and divestitures of power plants have become widespread as investor-owned utilities (IOUs) seek to improve their positions in the increasingly competitive electric power industry. Since 1992, IOUs have been involved in 35 mergers, and an additional 12 mergers are pending approval. One effect of these mergers is that the size of IOUs is increasing. In 1992, the 10 largest IOUs owned 36 percent of total IOU-held generation capacity, and the 20 largest IOUs owned 58 percent of IOU-held generation capacity. By the end of 2000, the 10 largest IOUs will own an estimated 51 percent of IOU-held generation capacity, and the 20 largest will own approximately 72 percent. While the size of the largest IOUs is increasing, because of generation divestitures, they generally own a smaller proportion of total generating capacity than in the past.

Figure ES2. Status of State Electric Utility Deregulation Activity, as of July 2000



Source: Energy Information Administration.

In addition to mergers within the electricity industry, IOUs—seeing growth opportunities in the natural gas industry—are merging with or acquiring natural gas companies, contributing to what is referred to as convergence of the two industries. In the last 3 years, 23 convergence mergers have been completed or are pending.

Influenced predominantly by State-level electricity industry restructuring programs that emphasize the unbundling of generation from transmission and distribution, and in some cases by a desire to exit the competitive power generation business, IOUs are divesting power generation assets in unprecedented numbers. Since late 1997, IOUs collectively have divested or are in the process of divesting 156.5 gigawatts of power generation capacity, representing about 22 percent of total U.S. electric utility generation capacity. Divestiture means that the IOU will either sell its generation capacity to another company or transfer the generation

capacity to an unregulated subsidiary within its own holding company structure. As a result of mergers and divestitures during the past few years, the organizational structure of the electric power industry (i.e., the numbers and roles of the industry participants) is changing. The traditional role of the electric utility as a provider of electric power is giving way to the expanding role of nonutilities as providers of electric power. An analysis of electric power data collected by the Energy Information Administration for the period 1992 through 1998 offers the following insights:

- The number of IOUs has decreased by 8 percent (261 in 1992 vs. 239 in 1998), while the number of nonutilities generating electricity has increased by 9 percent (1,792 in 1992 vs. 1,954 in 1998).
- Nonutilities are expanding and buying utility-divested generation assets, causing their net generation to increase by 42 percent (286 million megawatthours in 1992 vs. 406 million megawatthours in 1998) and their nameplate capacity to increase by 73 percent (57 thousand megawatts in 1992 vs. 98 thousand megawatts in 1998). Non-utility capacity and generation will increase even more as they acquire additional utility-divested generation assets over the next few years.
- The nonutility share of net generation rose from 9 percent (286 million megawatthours) in 1992 to 11 percent (406 million megawatthours) in 1998.
- Utilities have historically dominated the addition of new capacity. However, utilities are adding less capacity, while nonutility additions to capacity have been increasing at an average annual rate of nearly 7 percent since 1992. In 1998 alone, the nonutility share of additions to capacity was 82 percent (5,396 megawatts) with utilities adding 1,185 megawatts or 18 percent.

Since 1998, it is expected that these trends have continued.

1. Introduction

Electric power generation in the United States is changing from a regulated industry to a competitive industry. Where power generation was once dominated by vertically integrated investor-owned utilities (IOUs) that owned most of the generation capacity, transmission, and distribution facilities, the electric power industry now has many new companies that produce and market wholesale and retail electric power. These new companies are in direct competition with the traditional electric utilities. Today, vertically integrated IOUs still produce most of the country's electrical power, but that is changing.

The long-standing traditional structure of the industry was based, in part, on the economic theory that electric power production and delivery were natural monopolies, and that large centralized power plants were the most efficient and inexpensive means for producing electric power and delivering it to customers. Large power generating plants, integrated with transmission and distribution systems, achieved economies of scale and consequently lower operating costs than relatively smaller plants could realize. Because of the monopoly structure, Federal and State government regulations were developed to control operating procedures, prices, and entry to the industry in order to protect consumers from potential monopolistic abuses.

Several factors have caused this structure to shift to a more competitive marketplace. First, technological advances have altered the economics of power production. For example, new gas-fired combined cycle power plants are more efficient and less costly than older coal-fired power plants. Also, technological advances in electricity transmission equipment have made possible the economic transmission of power over long distances so that customers can now be more selective in choosing an electricity supplier. Second, between 1975 and 1985, residential electricity prices and industrial electricity prices rose 13 percent and 28 percent in real terms, respectively. These rate increases, caused primarily by increases in utility construction and fuel costs, caused Government officials to call into question the existing regulatory environment. Third, the effects of the Public Utilities Regulatory Policies Act of 1978, which encouraged the development of nonutility power producers that used renewable energy to gen-

erate power, demonstrated that traditional vertically integrated electric utilities were not the only source of reliable power.

Competition in wholesale power sales received a boost from the Energy Policy Act of 1992 (EPACT), which expanded the Federal Energy Regulatory Commission's (FERC's) authority to order vertically integrated IOUs to allow nonutility power producers access to the transmission grid to sell power in an open market. FERC's authority to order access was implemented on a case-by-case basis and proved to be slow and cumbersome. To remedy that, FERC issued Order 888 requiring all vertically integrated IOUs to file an open access transmission tariff that would provide universal access to the transmission grid to all qualified users. Order 888 was an important stimulus in the development and strengthening of competitive wholesale power markets, but discriminatory practices regarding access to the transmission grid still remained, and a more effective effort was needed. In December 1999, FERC issued Order 2000 calling for the creation of regional transmission organizations (RTOs), independent entities that will control and operate the transmission grid free of any discriminatory practices. Electric utilities are required to submit proposals to form RTOs from October 2000 through January 2001.

In addition to wholesale competition, retail competition has started in many States. For the first time in the history of the industry, retail customers in some States have been given a choice of electricity suppliers. As of July 1, 2000, 24 States and the District of Columbia had passed laws or regulatory orders to implement retail competition, and more are expected to follow. The introduction of wholesale and retail competition to the electric power industry has produced and will continue to produce significant changes to the industry. These changes are referred to collectively as restructuring.

The purpose of this report is twofold. Part I (Chapters 2 through 4) can be used as a basic reference document for information about the traditional electric power industry before restructuring started, while Part II (Chapters 5 through 9) describes the major causes and events that are changing the industry's structure from a totally regulated monopoly to one where both competition and

regulation coexist. Chapter 2 presents an overview of the industry's history from inception to approximately when deregulation and restructuring started. Chapter 3 explains the infrastructure of the industry, detailing its generating, transmitting, and distributing components. It also presents industry-wide statistics depicting how restructuring has changed the composition of the industry. For example, it illustrates the growing importance of nonutility power producers in meeting the Nation's electric power demands. Chapter 4 presents a summary of 21 Federal acts that have directly or indirectly affected the regulation, structure, and operating procedures of the electric power industry since its inception.

Chapter 5 presents a discussion of the causes leading to Federal and State deregulation of power generation and subsequently to restructuring of the electric power industry. Following this, Chapter 6 discusses numerous Federal bills, either initiated in Congress or by the Administration, designed to promote, assign responsibility, or provide guidance to continued deregulation of the industry. This chapter also discusses the debate to repeal the Public Utility Holding Company Act of 1935, and the Public Utility Regulatory Policies Act of 1978, both of which brought significant changes to the industry, but are now considered by some to be obsolete in a competitive electricity industry.

Continuing a discussion at the Federal level, Chapter 7 presents FERC's role in promoting competitive wholesale electric power markets and restructuring the management, operation, and possibly the ownership of the Nation's high voltage bulk power transmission system. Although the bulk power transmission system does not receive wide public attention, it plays a key role in the movement to a competitive industry.

Chapter 8 discusses the roles of individual States in promoting competition and restructuring at the retail level. A summary of the status of each State's restructuring activities is presented along with discussions addressing retail competition in five States. A discussion of the recent problems in the California market is included in this chapter.

Chapter 9 examines IOUs—the largest component of the electric industry in terms of power generation, value of assets, and total revenues—and how they are coping with and preparing for competition through mergers, acquisitions, and power plant divestitures. In many ways these corporate activities, which transfer and/or consolidate ownership and control of the Nation's electric power assets, represent the core of industry restructuring. Readers will also find a discussion of the role of the Federal Government in approving mergers and acquisitions, which has become more important as the number of mergers increases.

Part I:

The U.S. Electric Power Industry as a Regulated Monopoly

2. Historical Overview of the Electric Power Industry

At the beginning of the 20th century, vertically integrated¹ electric utilities produced approximately two-fifths of the Nation's electricity. At that time, many businesses (nonutilities) generated their own electricity. When utilities began to install larger and more efficient generators and more transmission lines, the associated increase in convenience and economical service prompted many industrial consumers to shift to the utilities for their electricity needs. With the introduction of the electric motor came the inevitable development and use of more home appliances. Consumption of electricity skyrocketed along with the utility share of the Nation's generation.

Utilities operated in designated exclusive franchise areas which, in the early years, were usually municipalities. Along with the service area designation came the obligation to serve all consumers within that territory. "The growth of utility service territories . . . brought State regulation of privately owned electric utilities in the early 1900s. Georgia, New York, and Wisconsin established State public service commissions in 1907, followed shortly by more than 20 other States. Basic State powers included the authority to franchise the utilities; to regulate their rates, financing, and service; and to establish utility accounting systems."²

The early structure of the electric utility industry was predicated on the concept that a central source of power supplied by efficient, low-cost utility generation, transmission, and distribution was a natural monopoly. Because monopolies in the United States were outlawed

by the Sherman Antitrust Act,³ regulation of the utilities was a necessity. In addition to its intrinsic design to protect consumers, regulation generally provided reliability and a fair rate of return to the utility. The result was traditional rate-based regulation.⁴

Electric utility holding companies⁵ were forming and expanding during the early 1900s, and by the 1920s they controlled much of the industry. By 1921, privately owned utilities were providing 94 percent of total generation, and publicly owned utilities contributed only 6 percent.⁶ At their peak in the late 1920s, the 16 largest electric power holding companies controlled more than 75 percent of all U.S. generation.⁷ Originally formed to reap the benefits (mostly of a financial nature) of centralized ownership of a multitude of subsidiaries, these unregulated holding companies were in a position to abuse their power over their subsidiaries. Sometimes, the result was increased prices paid by consumers of electricity. Because the States could not regulate an interstate holding company, it became apparent that the Federal Government would have to step in. After several large holding company systems collapsed, an investigation by the Federal Trade Commission was ordered, leading eventually to the passage of the Public Utility Holding Company Act of 1935 (PUHCA). Under the provisions of the Act, holding companies became regulated by the Securities and Exchange Commission. Under Title II of PUHCA utilities involved in interstate wholesale marketing or transmission of electric power became regulated by the Federal Power Commission (FPC).⁸

¹ A vertically integrated utility is one which engages in generation, transmission, and distribution operations.

² Energy Information Administration, *Annual Outlook for U.S. Electric Power 1985*, DOE/EIA-0474(85) (Washington, DC, August 1985), p. 3.

³ The Clayton Antitrust Act of 1914 strengthened the Sherman Antitrust Act of 1890.

⁴ This form of rate setting has been blamed by some groups for removing the incentive for utilities to achieve maximum efficiency in operations and planning, thereby exhibiting the major flaw in this type of regulation and promoting the push for its demise.

⁵ A holding company is a company that confines its activities to owning stock in and supervising management of other companies. The Securities and Exchange Commission, as administrator of the Public Utility Holding Company Act of 1935, defines a holding company as "a company which directly or indirectly owns, controls or holds 10 percent or more of the outstanding voting securities of a public utility company" (15 USC 79b, par. A (7)).

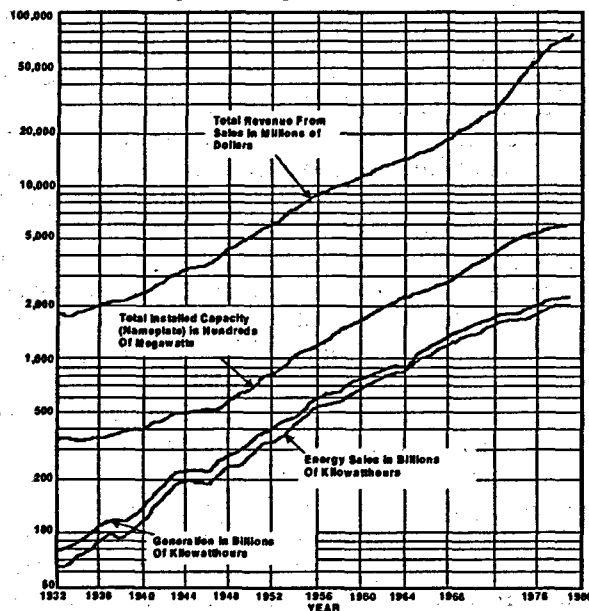
⁶ Energy Information Administration, *Annual Outlook for U.S. Electric Power 1985*, DOE/EIA-0474(85) (Washington, DC, August 1985), p. 3.

⁷ *Encyclopedia Americana*, International Edition, Vol. 22 (New York, NY: Americana Corporation, 1977), p. 769.

⁸ In October 1977, many of the regulatory powers of the FPC were transferred to the Federal Energy Regulatory Commission (FERC).

On October 29, 1929, the U.S. stock market crashed, creating losses of \$16 billion for that month—a staggering amount of money in 1929—and leading to the Great Depression. The social and economic well-being of the Nation was severely shaken, but the electric power industry was able to stay adrift of the devastation, and local operating utilities remained solvent. Figure 1 shows that, although the rate of growth in the industry did wane at times during the Depression, the U.S. electric utility industry's capacity, generation, revenues, and sales experienced a healthy growth pattern from 1932 through 1980. Table 1 shows the percentage change between various electric power industry statistics for the years 1932 and 1945, which also demonstrates the robust condition of the industry during that time.

Figure 1. Annual Statistics for the Total Electric Utility Industry, 1932-1980



Source: Electric Utility Systems Engineering Department of the General Electric Company, *Electric Utility Systems and Practices*, ed. Homer M. Rustebakke, 4th ed., Chapter 1, "The Electric Utility Industry" (New York, NY: Wiley & Sons, Inc., 1983), p. 4.

In the years immediately following the onset of the Great Depression, Congress took actions designed to alleviate some of the most acute problems, e.g., unemployment and the plight of farmers. Two of these actions directly and advantageously affected the electric power industry: the development of Federally owned power and the creation of the Rural Electrification Administration (REA). (See inset on page 7.)

⁹ For further details, refer to the subsequent section on The Public Utility Holding Company Act of 1935.

During the 1920s and the early years of the Depression, the public became disenchanted with privately owned power and began to support the idea of Government ownership of utilities, particularly hydroelectric power facilities. This disenchantment was chiefly the result of abuses heaped on utilities, and ultimately on their customers, by holding companies,⁹ causing the price of electricity to increase. Government-owned hydroelectric power facilities could produce power cheaply and sell it to publicly owned utilities for distribution. This concept was a controversial political issue at the time, with strong arguments on both sides. Many believed that private power did not employ fair operating practices and, therefore, Government-owned power was wholeheartedly supported. Others were opposed to the Government entering the electricity business because they believed that the Government was exploiting hydroelectric sites. Nevertheless, the Federal Government did become heavily involved through the construction and ownership of several massive hydroelectric facilities.

During the presidency of Franklin D. Roosevelt (1933 to 1945), a number of these facilities were built and publicly owned power took a strong hold. President Roosevelt began his New Deal campaign, which was designed to help the American public by providing jobs, and ultimately hope, during the long years of the Depression. As part of the program, he proposed that the Government build four hydropower projects and, within a year after his proposal, his administration began to implement the projects. Large Bureau of Reclamation dams began serving the western States:

- Hoover Dam began generation in 1936, followed by other large projects.
- Grand Coulee, the Nation's largest hydroelectric dam, began operation in 1941.
- The U.S. Army Corps of Engineers flood control dams provided additional low-priced power for preferred customers.

Under the Tennessee Valley Authority Act of 1933, the Federal Government supplied electric power to States, counties, municipalities, and nonprofit cooperatives, soon including those of the REA. The Bonneville Project Act of 1937 pioneered the Federal power marketing administrations. By 1940, Federal power pricing policy was set; all Federal power was marketed at the lowest possible price, while still covering costs. From 1933 to 1941, one-half of all new capacity was provided by Federal and other public power installations. By the end

Table 1. Percentage Change Between Various Electric Power Industry Statistics From the Great Depression Through World War II, 1932-1945

	1932	1945	Percent Change
Real GNP (1958 dollars in billions)	154	437	184
Energy consumption (Btu trillions)	18,022	36,030	100
Electricity production (kWh millions)	99,359	271,255	173
Real prices (1958 dollars):			
Electricity (cents/kWh)	7.08	2.89	-59
Oil (dollars per barrel)	2.16	2.04	-6
Coal (dollars per ton)	3.25	5.15	58
Percent electricity produced by:			
Privately-owned utilities	75.0	66.7	-
Publicly-(Government)owned utilities	4.9	15.3	-
Industry and transport	20.1	18.0	-
Production per kW of capacity (kilowatthours)	2,309	4,440	92
Coal equivalent per kWh produced (pounds)	1.5	1.3	-3
Return earned on average capital (percent)	6.3	6.6	5
Return earned on average equity (percent)	7.9	8.2	4
Bond yields (percent)	4.7	2.6	-45
Utility stock index (S&P electric)	16.64	14.94	-10
Industrial stock index (S&P 400)	5.37	14.72	174

Source: L. S. Hyman, *America's Electric Utilities, Past, Present and Future*, Fifth Edition, Public Utilities Reports, Inc. (Arlington, VA, August 1994), p. 113.

of 1941, public power contributed 12 percent of total utility generation, with Federal power alone contributing almost 7 percent.¹⁰ Besides electric power, these dams provided flood control, navigation, area development, and greatly needed work for the unemployed. Even during the Eisenhower Administration's policy of no

new starts, Federal power continued to grow as earlier projects came on line.

In the mid-1930s, many homes, farms, and ranches in rural areas were still without lights, indoor bathrooms, refrigerators, or running water. It was too expensive

The Rural Electrification Administration

In an effort to lessen the effects of the Depression on the American farmer, in 1936 Congress passed the Norris-Rayburn Act, the purpose of which was to ensure a 10-year integrated program for electrifying American farms. To that end, it authorized appropriations of \$410 million.¹¹ The Federal Government encouraged the growth of rural electricity service by subsidizing the formation of rural electric cooperatives. The Rural Electrification Act of 1936 established the Rural Electrification Administration (REA). Congress authorized it as an independent Federal bureau, and in 1939 it was reorganized as a division of the U.S. Department of Agriculture. The REA undertook a program to provide rural areas and towns with populations under 2,500 with inexpensive electric lighting and power. To implement those goals, the administration made long-term, self-liquidating loans to State and local governments, to farmers' cooperatives, and to nonprofit organizations; no loans were made directly to the consumers.¹² REA-backed cooperatives enjoyed Federal power preference plus lower property assessments, exemptions from Federal and State income taxes, and exemption from State and Federal Power Commission regulation.¹³

¹¹ M. L. Cooke, *Electrifying the Countryside*, <http://newdeal.feri.org/tva/cooke.htm>.

¹² Rural Electrification Administration, <http://www.infoplease.com/ce5/CE045037.html>.

¹³ The Rural Electrification Administration has been replaced by the Rural Utilities Service, whose mission is to improve the quality of life in rural America by administering its Electrification, Telecommunications, and Water and Waste Disposal Programs.

¹⁰ Edison Electric Institute, *Historical Statistics of the Electric Utility Industry Through 1970*, pp. 2, 24.

for the investor-owned utilities that served the cities to stretch their lines into the countryside, so many areas remained without access to electric power. The Federal Government encouraged the growth of rural electricity service by subsidizing the formation of rural electric cooperatives. The Rural Electrification Act of 1936 established the REA to provide loans and assistance to organizations providing electricity to rural areas and towns with populations under 2,500. REA-backed cooperatives enjoyed Federal power preferences¹¹ plus lower property assessments, exemptions from Federal and State income taxes, and exemption from State and Federal Power Commission regulation. As a result, by 1941 the proportion of electrified farm homes rose to 35 percent, more than three times that of 1932.¹²

For decades, utilities were able to meet the increasing demand for electricity at decreasing prices. Economies of scale were achieved through capacity additions, technological advances, and declining costs. Of course, the monopolistic environment in which they operated left them virtually unhindered by the worries that would have been created by competitors. This overall trend continued until the late 1960s, when the electric utility industry saw decreasing unit costs and rapid growth give way to increasing unit costs and slower growth.¹³ Over a relatively short time, a number of events took place which contributed to the unprecedented reversal in the growth and well-being of the industry: the Northeast Blackout of 1965 raised pressing concerns about reliability; the passage of the Clean Air Act of 1970 and its amendments in 1977 required utilities to reduce polluting emissions; the Oil Embargo of 1973-1974 resulted in burdensome increases in fossil-fuel prices; the accident at Three Mile Island in 1979 led to higher costs, regulatory delays, and greater uncertainty in the nuclear industry; and inflation (in general) caused interest rates to more than triple.

While the industry was attempting to recover from this onslaught of damaging events, Congress designed legislation that would reduce U.S. dependence on foreign oil, develop renewable and alternative energy

sources, sustain economic growth, and encourage the efficient use of fossil fuels. One result was the passage of the Public Utility Regulatory Policies Act of 1978 (PURPA). PURPA became a catalyst for competition in the electricity supply industry, because it allowed nonutility facilities¹⁴ that met certain ownership, operating, and efficiency criteria established by FERC to enter the wholesale market. Utilities initially did not welcome this forced competition, but some soon found that buying generation from a qualifying facility (QF) had certain advantages over adding to their own capacity, especially because of the increasing uncertainty of recovering capital costs. The growth of nonutilities was further advanced by the Energy Policy Act of 1992 (EPACT). EPACT expanded nonutility markets by creating a new category of power producers—exempt wholesale generators (EWGs)—that are exempt from PUHCA's corporate and geographic restrictions. Like QFs, EWGs are wholesale producers that do not sell electricity in the retail market and do not own transmission facilities. Moreover, unlike the nonutilities that qualified under PURPA, EWGs are not regulated and may charge market-based rates, and utilities are not required to buy their power. The growth of EWGs marked another step toward increasing the level of competition in the wholesale electricity market. (For a more detailed description of the purpose and effects of PUHCA, PURPA, and EPACT, see Chapter 4.)

Prior to passage of PURPA in 1979, the electric power industry had been relatively stable for approximately 45 years. Today, however, the industry is undergoing immense change, both structurally and operationally. Having a basic knowledge of how it was originally organized can facilitate understanding its current transitional state. A more detailed account of the industry's history is provided in Appendix A, History of the U.S. Electric Power Industry, 1882-1991. Appendix B, Historical Chronology of Energy-Related Milestones, 1800-2000, lists the major technological and institutional events in the development of the U.S. electric power industry. The following chapter describes its organizational components.

¹¹ The Federal Government moved quickly in the mid-1930s to, where opportunities appeared, produce and distribute less expensive federally produced electricity to preference customers.

¹² U.S. Bureau of the Census, Historical Statistics of the United States, *Colonial Times to 1970, Bicentennial Edition*, Part 2 (Washington, DC, 1975), p. 827.

¹³ Energy Information Administration, *Annual Outlook for U.S. Electric Power 1985*, DOE/EIA-0474(85) (Washington, DC, August 1985), p. 7.

¹⁴ A nonutility is a corporation, person, agency, authority, or other legal entity or instrumentality that owns electric generating capacity and is not an electric utility. Nonutility power producers include qualifying cogenerators, qualifying small power producers, and other nonutility generators (including independent power producers) without a designated franchise service area, and which do not file forms listed in the Code of Federal Regulations, Title 18, Part 141.

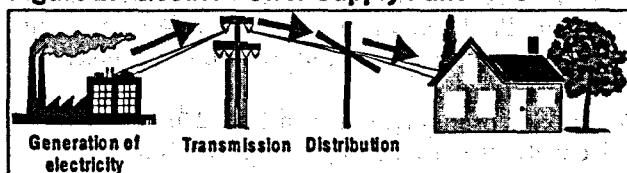
3. The U.S. Electric Power Industry Infrastructure: Functions and Components

Introduction

The transition of the U.S. electric power industry from a regulated monopoly to a deregulated industry where generators of electricity compete for customers is in full swing. Consequently, many aspects of the industry are changing, including its infrastructure. This chapter explains the functions and components (or participants) contained in the infrastructure and uses data collected by the Energy Information Administration (EIA) to reflect the changes that have taken place in the past decade or so. Shifts in the number and ownership of power production facilities, the volume of power generation and capacity, and other areas are also explained.

The fundamental structure of the industry has been based on the vertical integration of utilities, i.e., their involvement in the three functions of power supply. Those functions are *generation*, *transmission*, and *distribution* of electricity (Figure 2). Generation is defined as the production of electric energy from other energy sources. Transmission is the delivery of electric energy over high-voltage lines from the power plants to the distribution areas. Distribution includes the local system of lower voltage lines, substations, and transformers which are used to deliver the electricity to end-use consumers. Prior to detailing the components of power supply along with their characteristics, this chapter will outline the three functions of power supply.

Figure 2. Electric Power Supply Functions



¹⁵ Electric utilities are defined as either privately owned companies or publicly owned agencies that engage in the supply (including generation, transmission, and/or distribution) of electric power. Nonutilities are privately owned companies that generate power for their own use and/or for sale to utilities and others. The next section of this chapter delineates the types and characteristics of utilities and nonutilities as well as their changing roles in the supply of the Nation's electricity.

¹⁶ The demand for power varies over the day, with about 16 hours of "on-peak" time in the day and about 8 hours of "off-peak" time during the night. Demand for electric power typically reaches its highest peak on very hot or very cold days. At those times, many of the available plants in a region may need to be brought online to meet the high demand.

Generation

Generation facilities are currently owned and operated by two categories of companies—utilities and non-utilities.¹⁵ Electric power generators use a variety of prime movers and energy sources to generate electric energy. Prime movers are the engine, turbine, water wheel, or similar machines that drive an electric generator. Energy sources include combustion of fossil fuels, nuclear fission, kinetic energy in water or wind, chemical energy in a fuel cell, and sunlight. Wind, water, sunlight, geothermal energy, biomass, and waste products are renewable energy sources that are considered inexhaustible.

Generating units vary in size. Nuclear and fossil-fuel steam-electric units typically have large capacities with many over 1,000 megawatts (MW), while hydroelectric dams range from less than 1MW to thousands of MW at some of the large Federal dams. Gas turbines, combustion turbines, and combined-cycle units are typically less than 200 MW, but some are larger. Wind and solar plants are relatively small. Distributed generation, which can be installed at or near the customer's site can be quite small, such as rooftop photovoltaic arrays or fuel cells ranging from several to a few hundred kilowatts.

The generating units operated by an electric utility vary by intended usage, that is, by the three major types of load (generally categorized as base, intermediate, and peak) requirements the utility must meet.¹⁶ A base-load generating unit is normally used to satisfy all or part of the minimum or base load of the system and, as a consequence, produces electricity at an essentially constant rate and runs continuously. Base-load units are generally the largest of the three types of units, but they

cannot be brought on line or taken off line quickly. Peak-load generating units can be brought on line quickly and are used to meet requirements during the periods of greatest or peak load on the system. They are normally smaller plants using gas and combustion turbines. Intermediate-load generating units meet system requirements that are greater than base-load but less than peak load. Intermediate-load units are used during the transition between base-load and peak-load requirements.

Types of Generators

Steam Units: Steam-electric (thermal) generating units are typically the large baseload plants. Steam produced in a boiler turns a turbine to drive an electric generator (Figure 3a). Fossil fuels (coal, petroleum and petroleum products, natural gas or other gaseous fuels) and other combustible fuels, such as biomass and waste products, are burned in a boiler to produce the steam. Nuclear plants use nuclear fission as the heat source to make steam. Geothermal or solar thermal energy also produce steam. The thermal efficiency¹⁷ of fossil-fueled steam-electric plants is about 33 to 35 percent. The waste heat is emitted from the plant either directly into the atmosphere, through a cooling tower, or sent to a lake for cooling. A water pump brings the residual water from the condenser back to the boiler.

Gas Units: Gas turbines and combustion engines use the hot gas from burning fossil fuels, rather than steam, to turn a turbine that drives the generator. These plants can be brought up quickly, and so are used as peaking plants. The number of gas turbines is growing as technological advances in gas turbine design and declining gas prices have made the gas turbine competitive with the large steam-electric plants. However, thermal efficiency is slightly less than that of the large steam-electric plants (Figure 3b). The gas wastes are disposed of through an exhaust stack.

Combined-Cycle Units: Combined cycle plants first use gas turbines to generate power and then use the waste heat in a steam-electric generator to produce more electricity. Thus, combined-cycle plants make more efficient use of the heat energy in fossil fuels. New technology is improving the thermal efficiency of combined-cycle plants, with some reports of 50 to 60 percent thermal efficiency (Figure 3c).

Cogenerating Units: Cogenerators, also known as combined heat and power generators, are facilities that utilize heat for electricity generation and for another form of useful thermal energy (steam or hot water), for manufacturing processes or central heating. There are two types of cogeneration systems: bottom-cycling and top-cycling. In a bottom-cycling configuration, a manufacturing process uses high temperature steam first and a waste-heat recovery boiler recaptures the unused energy and uses it to drive a steam turbine generator to produce electricity. In one of two top-cycling configurations, a boiler produces steam to drive a turbine-generator to produce electricity, and steam leaving the turbine is used in thermal applications such as space heating or food preparation. In another top-cycling configuration, a combustion turbine or diesel engine burns fuel to spin a shaft connected to a generator to produce electricity, and the waste heat from the burning fuel is recaptured in a waste-heat recovery boiler for use in direct heating or producing steam for thermal applications (Figure 3d).

Other Units: The kinetic energy in moving water and wind is used to turn turbines at hydroelectric plants and wind facilities to produce electricity. Other types of energy conversion include photovoltaic (solar) panels that convert light energy directly to electrical energy, and fuel cells that convert chemical energy directly to electrical energy.

Energy Sources

Coal: Coal is the Nation's primary fuel for electricity generation, representing 40 percent of the capability,¹⁸ and producing over half (52 percent) of the generation (Figure 4) because coal is used as a baseload fuel.

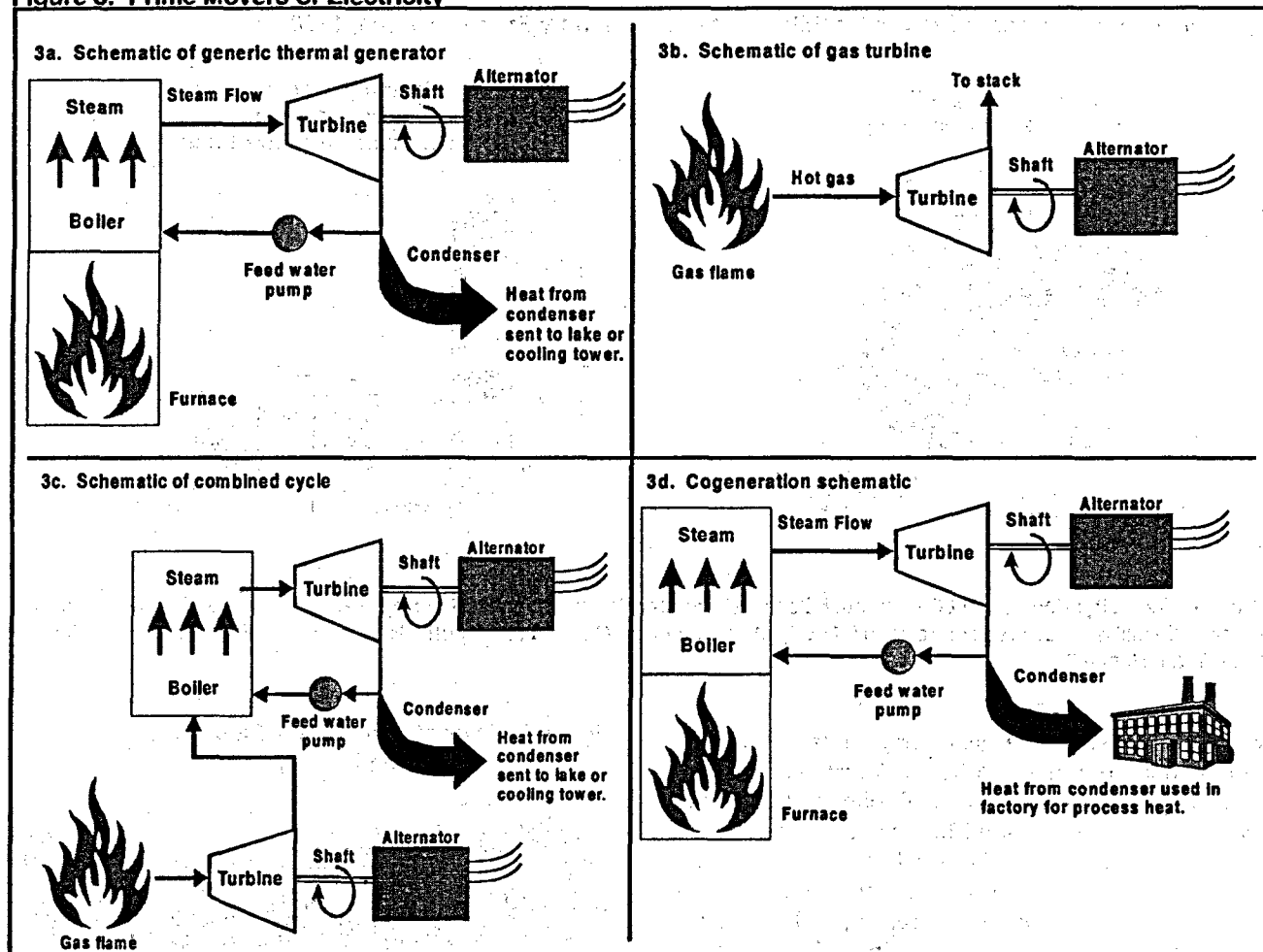
Gas and Petroleum: Gas and petroleum units, which are typically used for peak demand, make up 23 percent and 8 percent, respectively, of generating capability. In 1998, petroleum-fired generation provided 4 percent of our electricity, while gas-fired units provided 15 percent.

Coal, petroleum, and gas are considered fossil-fuels and collectively produced 71 percent of the Nation's electricity in 1998. When fossil fuels are burned in the production of electricity, a variety of gases and particulates are formed. If these gases and particulates are

¹⁷ Thermal efficiency is a measure generally expressed in Btu per kilowatthour which is computed by dividing the total Btu content of the fuel burned for electric generation by the resulting net kilowatthour generation.

¹⁸ Capability is the maximum load that a generating unit, generating station, or other electrical apparatus can carry under specified conditions for a given period of time without exceeding approved limits of temperature and stress.

Figure 3. Prime Movers of Electricity



Source: R. Baldick, "Introduction to Electric Power Systems for Legal and Regulatory Professionals," Course Materials, The University of Texas at Austin (1999).

not captured by some pollution control equipment, they are released into the atmosphere. Among the gases emitted during the burning of fossil fuels are sulfur dioxide (SO_2), nitrogen oxides (NO_x), and carbon dioxide (CO_2). Coal-fired generating units produce more SO_2 , NO_x , and CO_2 than other fossil-fuel units for two reasons. First, because coal generally contains more sulfur than other fossil fuels, it creates more SO_2 when burned. Second, there are more emissions from coal-fired plants because more coal-fired capacity than other fossil-fueled capacity is in use.

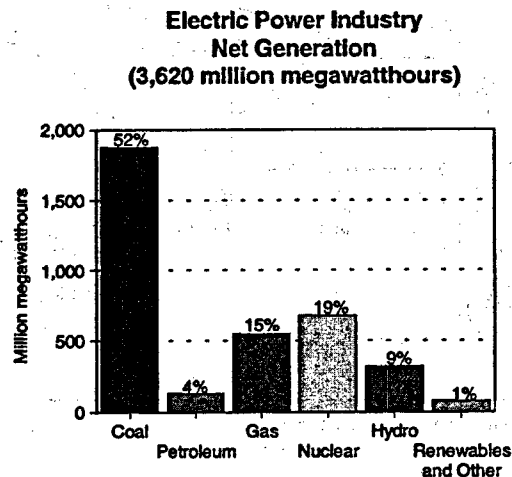
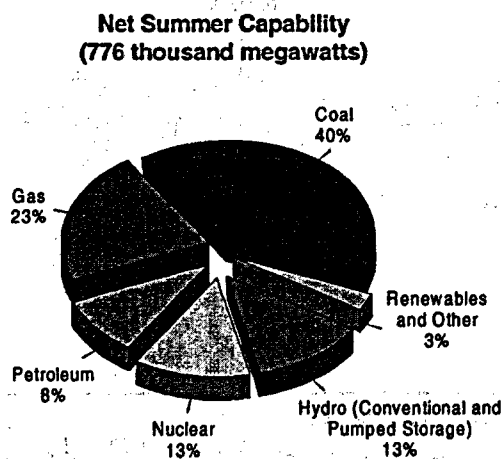
Nuclear: Nuclear power plants, which also are used as baseload plants, represented 13 percent of the generating

capability, and generated 19 percent of electricity in 1998. Nuclear plants have increased their capacity factors (the ratio of electricity actually produced to potential production if the unit runs at full power) steadily in recent years, reaching a record high of 86 percent in 1999.

Hydroelectric: Hydroelectric capability¹⁹ accounts for 13 percent of the Nation's generating capability. Precipitation patterns affect the availability of hydroelectric power, which contributed 9 percent of net generation in 1998, a relatively dry year.

¹⁹ Hydroelectric power includes pumped storage which is the generation of electric energy during peak-load periods by using water previously pumped into an elevated storage reservoir during off-peak periods when excess generating capacity is available to do so. When additional generating capacity is needed, the water can be released from the reservoir through a conduit to turbine generators located in a power plant at a lower level.

Figure 4. Electric Power Industry Capability and Generation by Energy Source, 1998



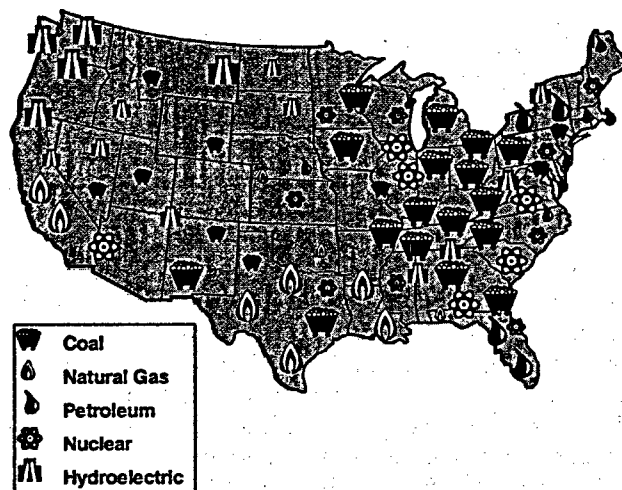
Source: Capacity: Form EIA-860A, "Annual Electric Generator Report-Utility" and Form EIA-860B, "Annual Electric Generator Report - Nonutility." Generation: Form EIA-860B, "Annual Electric Generation Report - Nonutility" and Form EIA-759, "Monthly Power Plant Report."

Renewables: Renewable generating units use energy sources that are judged to be inexhaustible including solar, wind, geothermal, municipal solid waste, and biomass fuels such as landfill methane gas, wood byproducts, and waste. (Hydroelectric power is also considered a renewable resource.) Many wind and solar plants are intermittent in nature, depending on the availability of their energy source. In 1998, renewables other than hydropower represented 3 percent of capacity and 1 percent of generation, as they are typically used only intermittently.

Regional Variation

The type of energy source used for generating electricity varies in the United States by region and is usually dictated by the availability of natural resources (Figure 5). The Pacific Northwest generates most of its power at large hydroelectric projects owned by the Federal Government. The Nation's coal-producing States and regions are the location of the majority of coal-fired plants, and consequently the source of much of the air emissions resulting from the combustion of coal. Ohio, West Virginia, Kentucky, and Tennessee are the largest users of coal for electricity generation in the Nation. Texas, Louisiana, and Oklahoma are rich in natural gas, and make use of it for electricity generation. Much of the Nation's petroleum-fired generation is concentrated in Florida and New York.

Figure 5. Energy Sources for Electricity Generation by Region



Note: The large icons on this map represent about 10 GW of capacity, not individual plants, in a regional area for each fuel source. Smaller icons represent about 5 GW capacity. Where less than 5 GW of capacity for a fuel type exists for an individual region or State, generating plants are not represented on this map.

Source: Form EIA-860A, "Annual Electric Generator Report - Utility" and Form EIA-860B, "Annual Electric Generator Report - Nonutility."

California's tight restrictions on air emissions discourage coal-fired generation. Natural gas, which burns more cleanly than coal, is used by many California plants for electricity generation. However, California utilities purchase electricity from outside of the State, some of which is generated from coal as the main fuel source. The energy source available for electricity generation is a factor in the disparity of retail prices across the Nation. For example, the Northwest enjoys the low cost of hydropower, while some Northeast States depend heavily on petroleum and nuclear power.

Regulation of Generation

The foundation for strong Federal involvement in the electricity industry was established in the early 1900s. The electric power industry became recognized as a natural monopoly due to its production of a product most efficiently provided in a specific location by one supplier. Because monopolies in the United States were outlawed by the Sherman Antitrust Act, regulation of the utilities was a necessity. Interstate wholesale markets and transmission became regulated by the Federal Power Commission. In 1997, regulatory authority was given to the Federal Energy Regulatory Commission (FERC). Today, FERC has jurisdiction over interstate movement of electricity by private utilities (investor-owned utilities), power marketers, power pools, power exchanges, and independent system operators (ISOs). FERC approves rates for wholesale sales of electricity and reviews rates set by the Federal Power Marketing Administrations (PMAs). FERC also confers Exempt Wholesale Generator status (a classification of generator created by the Energy Policy Act of 1992 (EPACT)) and certifies qualifying small power producers and cogeneration facilities under provisions of PURPA. An additional responsibility of FERC is licensing the construction and operation of hydroelectric power projects and enforcing the provisions of the licenses.

The State Public Utility Commissions (PUCs) have jurisdiction over intrastate trade of electricity. The PUCs regulate retail rates for customers, approve sites for generation facilities, and issue State environmental regulations.

The Environmental Protection Agency (EPA) is charged with implementing the provisions of Title IV of the Clean Air Act. The EPA establishes rules requiring fossil-fueled power plants to reduce the air emissions and pollutants that are a primary cause of acid rain,

sulfur dioxide, and nitrogen oxides. Carbon dioxide (CO₂) emissions are tracked, but no regulations exist at this time for CO₂ emissions.

The Nuclear Regulatory Commission licenses the construction and operation of nuclear power plants and fuel cycle facilities, inspects licensed nuclear facilities and oversees decommissioning, and enforces the provisions of nuclear licenses.

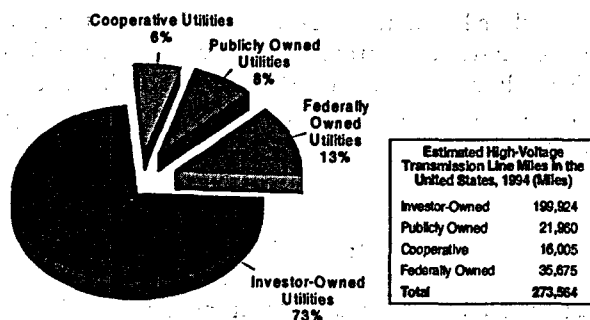
Transmission

Electric power transmission is the transportation of large blocks of power over relatively long distances from a central generating station to main substations close to major load centers or from one central station to another for load sharing. The transmission grid consists of high voltage (between 138 and 765 kilovolts) overhead and underground conducting lines made of either copper or aluminum. High-voltage transmission lines are used because they require less surface area for a given carrying power capacity, and result in less line loss. Because of resistance in the conductors, some power is "lost" as dissipated heat during transmission. At the generating station, the voltage of the three-phase alternating current output from the generator is increased to the required transmission voltage by a step-up transformer. The high-voltage alternating current is then transmitted through the transmission grid to the load center where it is again transformed (stepped down) to lower voltages required by distribution lines.

In the United States, investor-owned utilities (IOUs) own 73 percent of the transmission lines, Federally owned utilities own 13 percent, and public utilities and cooperative utilities own 14 percent (Figure 6).²⁰ Not all utilities own transmission lines (i.e., they are not vertically integrated), and no independent power producers or power marketers own transmission lines. Over the years, these transmission lines have evolved into three major networks (power grids), which also include smaller groupings or power pools. The major networks consist of extra-high-voltage connections between individual utilities designed to permit the transfer of electrical energy from one part of the network to another. These transfers are restricted, on occasion, because of a lack of contractual arrangements or because of inadequate transmission capability. The three networks are the Eastern Interconnect, the Western Interconnect, and the Texas Interconnect (Figure 7). The

²⁰ Refer to Table 2 for a definition of the types of utilities and other entities involved in electricity supply.

Figure 6. Transmission Ownership In the United States



Source: Calculations made by the Energy Information Administration, Office of Coal, Nuclear, Electric, and Alternate Fuels, from data taken from FERC Form 1, "Annual Report of Major Electric Utilities, Licensees, and Others." (Data for cooperative utilities are for 1997.)

The Texas Interconnect is not interconnected with the other two networks (except by certain direct current lines). The other two networks have limited interconnections to each other. Both the Western and the Texas Interconnect are linked with different parts of Mexico. The Eastern and Western Interconnects are completely integrated with most of Canada or have links to the Quebec Province power grid. Virtually all U.S. utilities are interconnected with at least one other utility by these three major grids. The exceptions are utilities in Alaska and Hawaii. The interconnected utilities within each power grid coordinate operations and buy and sell power among themselves.

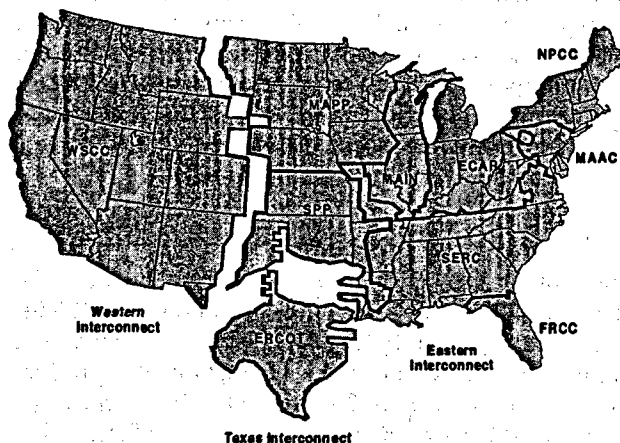
Regulation of Transmission

Under authority of the Federal Power Act of 1935, as amended, FERC exercises principal regulatory authority over the transmission system. Under this authority, FERC:

- regulates wholesale electricity rates and services for wholesale transactions
- approves sale or leasing of transmission facilities
- approves mergers and acquisitions between IOUs, and
- exercises jurisdiction over the interstate commerce of electricity.

FERC's authority covers about 73 percent of the power transmission system in the United States, while the remaining 27 percent is Federally owned, municipally owned, or owned by cooperative utilities, and is not under FERC's jurisdiction.

Figure 7. The Main Interconnections of the U.S. Electric Power Grid and the 10 North American Electric Reliability Council Regions



ECAR - East Central Area Reliability Coordination Agreement
 ERCOT - Electric Reliability Council of Texas
 FRCC - Florida Reliability Coordinating Council
 MAAC - Mid-Atlantic Area Council
 MAIN - Mid-America Interconnected Network
 MAPP - Mid-Continent Area Power Pool
 NPCC - Northeast Power Coordinating Council
 SERC - Southeastern Electric Reliability Council
 SPP - Southwest Power Pool
 WSCC - Western Systems Coordinating Council

Note: The Alaska Systems Coordinating Council (ASCC) is an affiliate NERC member.

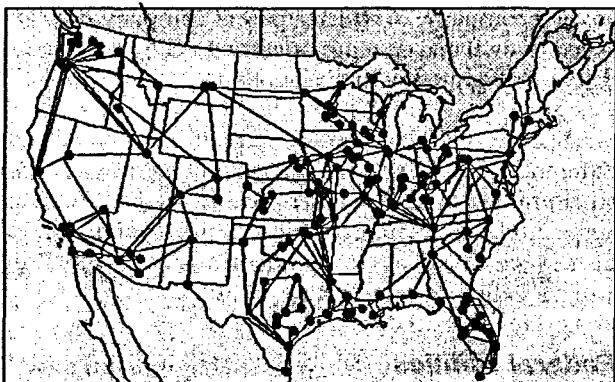
Source: North American Electric Reliability Council.

In 1965, a major blackout in the Northeastern United States precipitated the voluntary formation of the North American Electric Reliability Council (NERC). NERC is responsible for overall reliability, planning, and coordination of the electricity supply in North America. The membership of NERC is unique—as a not-for-profit corporation, NERC's owners comprise 10 Regional Councils (Figure 7). The members of these Regional Councils come from all segments of the electric industry—utilities, independent power producers, power marketers, and electricity customers. The councils cover the 48 contiguous States, part of Alaska, and portions of Canada and Mexico. The councils are responsible for overall coordination of bulk power policies that affect the reliability and adequacy of service in their areas. They also regularly exchange operating and planning information among their member utilities. However, participation in NERC is voluntary and participants in the industry are neither required to be a member nor to

follow the directions of NERC. The boundaries of the NERC regions follow the service areas of the electric utilities in the region, many of which do not follow States boundaries.

Because electric energy is instantaneously generated and consumed, the operation of an electric power system requires a coordinated balancing of generation and consumption of power. Control Area Operators (CAOs) perform this function, as well as other important tasks, that allow the interconnected electric power systems and their components to operate together both reliably and efficiently. There are approximately 150 Control Areas in the Nation (Figure 8). Most are run by the dominant large investor-owned utility in a geographic area defined by an interconnected transmission grid and power plant system. The CAOs dispatch generators from a central control center with computerized systems in such a way as to balance supply and demand and maintain the transmission system safely and reliably.

Figure 8. Electric Control Area Operators - Continental United States, 1998



Source: Energy Information Administration, Office of Coal, Nuclear, Electric and Alternate Fuels. Based on data contained in Form EIA-861, "Annual Electric Utility Report."

Distribution

Distribution is the delivery of electric power from the transmission system to the end-use consumer. The distribution systems begin at the substations, where power transmitted on high voltage transmission lines is transformed to lower voltages for delivery over low voltage lines to the consumer sites. The system ends at the consumers' meters. Distribution is considered a "natural monopoly" and is likely to remain a regulated

function because duplicate systems of lines would be impractical and costly.²¹

Distributed generation is a growing part of the restructured electric power industry. Distributed generation is defined as small generators located near or at the consumer site, within the distribution system. Distributed generators are not directly connected to the transmission grid.²² The amount of distributed generation is expected to increase in the future, with the technological and economic improvements in small generators. Fuel cells and photovoltaic systems are becoming more available as alternative or supplemental power sources.

Net metering arrangements are increasingly being offered in some States to consumers that install distributed generation units using renewable resources at their homes or businesses. The owners may use all or most of the power produced, but at times the distributed generator produces more power than the owner uses, and excess power flows out onto the distribution system. The consumer's meter "runs backwards," and "nets out" the portion of the electricity delivered to the consumer.

Regulation of Distribution and Retail Sales

The distribution of electric power is an intrastate function under the jurisdiction of State public utility commissions (PUCs). Under the traditional regulatory system, the PUCs set the retail rates for electricity, based on the cost of service, which includes the costs of distribution. Retail rates are set by the PUC in ratemaking rulings. The rates include the cost to the utility for generated and purchased power, the capital costs of power, transmission, and distribution plants, all operations and maintenance expenses, and the costs to provide programs often mandated by the PUC for consumer protections and energy efficiency, as well as taxes. As the industry restructures, in some States the PUC will eventually no longer regulate the retail rates for generated or purchased power. Retail electricity prices will be open to the market forces of competition. The PUCs will continue to regulate the rates for distribution of power to the consumer. They also have a say in the siting of distribution lines, substations, and generators. Metering and billing are under jurisdiction of the PUC and in some States are becoming competitive functions. As the industry restructures, the PUCs' responsibilities are changing. The goal of each State PUC

²¹ Competition for the distribution of electricity is being evaluated in California.

²² Distributed generators are indirectly connected to the grid through their consumers' facilities which are connected for backup purposes or to sell excess power.

remains to provide their State's consumers with reliable, reasonably and fairly priced electric power.

The Components of Electricity Supply - Utilities and Nonutilities

Introduction

This section provides a basic understanding of the infrastructure of the electric power industry, i.e., the components that carry out the generation, transmission, and distribution of electricity. The components consist of two broad categories of energy providers—utilities and nonutilities.²³ Their ownership characteristics, their current role in electricity supply, and how some roles have shifted since passage of the Energy Policy Act of 1992 (EPACT)²⁴ are explained in the following sections. In most cases, the data presented are for 1998, although in some cases, data for earlier years are compared with 1998 data to show changes.

Utilities

Electric utilities in general are defined as either privately owned companies or public agencies engaged in the generation, transmission, and/or distribution of electric power for public use. Utilities can be further classified into four subcategories based on ownership—investor-owned, Federally owned, other publicly owned, and cooperatively owned (Tables 2 and 3).

Under the traditional system, utilities are given a monopoly franchise over a specific geographic area. In return for this franchise, the electric utility is regulated by State and Federal agencies. Some electric utilities have service territories extending beyond a single county or parish. Others just serve a municipality or part of a county. Many counties in the United States are served by more than a single utility, and some parts of the country (such as Kossuth County, Iowa and Fillmore County, Minnesota) have more than 10 electric utilities operating in a county.

To move electricity among utilities, an extensive system of high-voltage transmission lines is owned and operated by the Nation's larger utilities. This transmission network permits electricity trading between utilities.

²³ Nonutilities generate but do not transmit or distribute electricity.

²⁴ As earlier stated, EPACT provided a Federal mandate to open up the national electricity transmission system to wholesale suppliers, marking the beginning of competition in the electric power industry, and was the impetus for significant structural changes. In 1996, the Federal Energy Regulatory Commission (FERC) issued its Order 888, which carried out the goal of EPACT. From the 1970s until 1992, little change had occurred in the industry, either structurally or operationally, with the exception of the creation of nonutility qualifying facilities brought about by PURPA.

Without transmission facilities, electricity could not be moved from power plants to the thousands of distribution systems serving millions of consumers of electric power.

Utilities can also be categorized in a different manner, i.e., the number of companies that generate, transmit, and/or distribute electric power. It is interesting to note that only about 27 percent of the Nation's 3,169 utilities actually generate electric power. Many electric utilities (67 percent) are exclusively distribution utilities, purchasing wholesale power from others to distribute it, over their own distribution lines, to the ultimate consumer. These are primarily the utilities owned by State and local governments and cooperatives. Conversely, all nonutilities generate power but do not own or operate transmission or distribution systems (Table 4).

Investor-Owned Utilities

Two basic organizational forms exist among investor-owned utilities (IOUs). The most prevalent is the individual corporation. Another common form is the holding company, in which a parent company is established to own one or more operating utility companies that are integrated with one another.

Most of the IOUs sell power at retail rates to several different classes of consumers and at wholesale rates to other utilities, including other investor-owned, Federal, State, and local government utilities, public utility districts, and rural electric cooperatives (Figure 9). They also have high-density service areas.

Federal Utilities

There are nine Federal electric utilities in the United States (Figure 10). They include four operating entities: the Department of Defense's U.S. Army Corps of Engineers (USACE), the Department of the Interior's U.S. Bureau of Reclamation, the Department of the Interior's U.S. Bureau of Indian Affairs (USBR), and the Department of State's International Water and Boundary Commission. These entities operate the Federal hydroelectric plants.

Also included in this category are four Federal power marketing administrations (PMAs): the Bonneville

Table 2. Major Characteristics of U.S. Electric Utilities by Type of Ownership, 1998

Ownership	Major Characteristics
<p>Investor-Owned Utilities (IOUs)</p> <p>IOUs account for about three-quarters of all utility generation and capacity. There are 239 IOUs in the United States, and they operate in all States except Nebraska. They are also referred to as privately owned utilities.</p>	<ul style="list-style-type: none"> • Earn a return for investors; either distribute their profits to stockholders as dividends or reinvest the profits. • Are granted service monopolies in specified geographic areas. • Have obligation to serve and to provide reliable electric power. • Are regulated by State and Federal governments, which in turn approve rates that allow a fair rate of return on investment. • Most are operating companies that provide basic services for generation, transmission, and distribution.
<p>Federally Owned Utilities</p> <p>There are 9 Federally owned utilities in the United States, and they operate in all areas except the Northeast, the upper Midwest, and Hawaii.</p>	<ul style="list-style-type: none"> • Power not generated for profit. • Publicly owned utilities, cooperatives, and other nonprofit entities are given preference in purchasing from them. • Primarily producers and wholesalers. • Producing agencies for some are the U.S. Army Corps of Engineers, the U.S. Bureau of Reclamation, and the International Water and Boundary Commission. • Electricity generated by these agencies is marketed by Federal power marketing administrations in the U.S. Department of Energy. • The Tennessee Valley Authority is the largest producer of electricity in this category and markets at both wholesale and retail levels.
<p>Other Publicly Owned Utilities</p> <p>Other publicly owned utilities include: Municipals Public Power Districts State Authorities Irrigation Districts Other State Organizations</p> <p>There are 2,009 in the United States.</p>	<ul style="list-style-type: none"> • Are nonprofit State and local government agencies. • Serve at cost; return excess funds to the consumers in the form of community contributions and reduced rates. • Most municipals just distribute power, although some large ones produce and transmit electricity; they are financed from municipal treasuries and revenue bonds. • Public power districts and projects are concentrated in Nebraska, Washington, Oregon, Arizona, and California; voters in a public power district elect commissioners or directors to govern the district independent of any municipal government. • Irrigation districts may have still other forms of organization (e.g., in the Salt River Project Agricultural Improvement and Power District in Arizona, votes for the Board of Directors are apportioned according to the size of landholdings). • State authorities, such as the New York Power Authority and the South Carolina Public Service Authority, are agents of their respective State governments.
<p>Cooperatively Owned Utilities</p> <p>There are 912 cooperatively owned utilities in the United States, and they operate in all States except Connecticut, Hawaii, Rhode Island, and the District of Columbia.</p>	<ul style="list-style-type: none"> • Owned by members (rural farmers and communities). • Provide service mostly to members. • Incorporated under State law and directed by an elected board of directors which, in turn, selects a manager. • The Rural Utilities Service (formerly the Rural Electrification Administration) in the U.S. Department of Agriculture was established under the Rural Electrification Act of 1936 with the purpose of extending credit to co-ops to provide electric service to small rural communities (usually fewer than 1,500 consumers) and farms where it was relatively expensive to provide service.
<p>Power Marketers</p> <p>There are 194 active power marketers in the United States.</p>	<ul style="list-style-type: none"> • Some are utility-affiliated while others are independent. • Buy and sell electricity. • Do not own or operate generation, transmission, or distribution facilities.
<p>Source: Energy Information Administration, Office of Coal, Nuclear, Electric and Alternate Fuels.</p>	

Table 3. Number of Electric Utilities by Class of Ownership and NERC Region, 1998

NERC Region ^a	Investor-Owned	Federal	State, Municipal, and Other Government	Cooperative	Total
ECAR	43	0	228	103	374
ERCOT	6	0	66	58	130
FRCC	3	0	31	12	46
MAAC	18	0	49	19	86
MAIN	17	0	131	33	181
MAPP	14	0	486	171	671
NPCC	58	0	127	10	195
SERC	20	2	352	262	636
SPP	11	0	250	86	347
WSCC	27	7	253	137	424
Subtotal NERC	217	9	1973	891	3090
Alaska ^b	19	0	36	21	76
Hawaii ^b	3	0	0	0	3
U.S. Total	239	9	2,009	912	3,169

^aNERC is the North American Electric Reliability Council, formed in 1968 by the electric utility industry to promote the reliability and adequacy of bulk power supply in the electric utility systems of North America.

^bAlaska and Hawaii are not full members of NERC.

Note: See Figure 7 for a map of NERC regions.

Source: Energy Information Administration, Form EIA-861, "Annual Electric Utility Report."

Power Administration, the Western Area Power Administration, the Southwestern Power Administration, and the Southeastern Power Administration (Figure 10). These Federal utilities exist to market and sell the power produced at Federal hydroelectric projects. They also purchase energy for resale from other electric utilities in the United States and Canada.

The ninth Federal utility is the Tennessee Valley Authority (TVA), the largest Federal power producer, which operates its own power plants and sells the power in the Tennessee Valley region in both the wholesale and retail markets. The TVA generates electricity from coal, gas, oil, and nuclear power as well as hydropower.

Of the Federal utilities, three are considered major producers of electricity: the TVA, the USACE, and the USBR. Generation by the USACE, except for the North Central Division (Saint Mary's Falls at Sault Ste. Marie, Michigan) and by the USBR, is marketed by the four PMAs.

Consumers of Federal power are usually large industrial consumers or Federal installations. Most of the remaining energy generated by non-profit Federal utilities is sold in the wholesale market to publicly owned utilities and rural cooperatives for resale at cost. These

wholesale consumers have preference claims to Federal electricity. Only the surplus remaining after meeting the energy requirements of preference consumers is sold to investor-owned utilities.

Other Publicly Owned Utilities

Publicly owned electric utilities can be categorized as generators and nongenerators. (In contrast, virtually all investor-owned electric utilities own and operate generating capacity.) Generators are those electric utilities that own and operate generating capacity to supply some or all of their customers' needs. However, some generators supplement their production by purchasing power. The nongenerators rely exclusively on power purchases. Their primary function is to distribute electricity to their consumers. The nongenerators comprise over half of the total number of publicly owned electric utilities.

Other publicly owned utilities include municipal authorities, State authorities, public power districts, irrigation districts, and other State organizations. Municipal utilities tend to be concentrated in cities where the loads are small. They exist in every State except Hawaii, but most are located in the Midwest and Southeast. State authorities are utilities that function in a manner similar to Federal utilities. They generate or purchase electricity

Table 4. Energy Supply Participants and Their Operations, 1998

Participants/Operations	Number of Companies	Percent of All Utilities
Vertically Integrated (Generate,^a Transmit,^b and Distribute^c)		
Utilities Only		
Investor Owned	140	4.4
Federal	3	0.1
Publicly Owned	132	4.2
Cooperatives	20	0.6
Total	295	9.3
Generate and Transmit Only		
Utilities Only		
Investor Owned	10	0.3
Federal	3	0.1
Publicly Owned	36	1.1
Cooperatives	40	1.3
Total	89	2.8
Transmit and Distribute Only		
Utilities Only		
Investor Owned	6	0.2
Federal	1	0.0
Publicly Owned	58	1.8
Cooperatives	74	2.3
Total	139	4.4
Generate and Distribute Only		
Utilities Only		
Investor Owned	25	0.8
Federal	2	0.1
Publicly Owned	403	12.7
Cooperatives	23	0.7
Total	453	14.3
Generate Only		
Utilities		
Investor Owned	11	0.3
Federal	0	--
Publicly Owned	12	0.4
Cooperatives	1	0.0
Total	24	0.8
Nonutilities	1,930	^d 100.0
Transmit Only		
Utilities Only		
Investor Owned	7	0.2
Federal	0	--
Publicly Owned	8	0.3
Cooperatives	19	0.6
Total	34	1.1

See notes at end of table.

Table 4. Energy Supply Participants and Their Operations, 1998 (Continued)

Participants/Operations	Number of Companies	Percent of All Utilities
Distribute Only		
Utilities Only		
Investor Owned	34	1.1
Federal	1	0.0
Publicly Owned	1,358	42.8
Cooperatives	735	23.2
Total	2,128	67.1
Other^e		
Utilities Only		
Investor Owned	6	0.2
Publicly Owned	2	0.1
Total	8	0.2
Power Marketers^f	^g 400	—

^aAn electricity generator is a facility that converts mechanical energy into electrical energy.

^bAn electricity transmitter moves or transfers electric energy over an interconnected group of lines and associated equipment between points of supply and points at which it is transformed for delivery to consumers or is delivered to other electric systems. Transmission is considered to end when the energy is transformed for distribution to the consumer.

^cAn electricity distributor delivers electric energy to an end user.

^dThis figure represents the percentage of nonutilities rather than utilities.

^e"Other" includes maintenance service companies for parent utilities that perform such functions as guard services, equipment maintenance, etc. Also, one of the publicly owned utilities in this category acts as an agent to buy and schedule power for the parent utility.

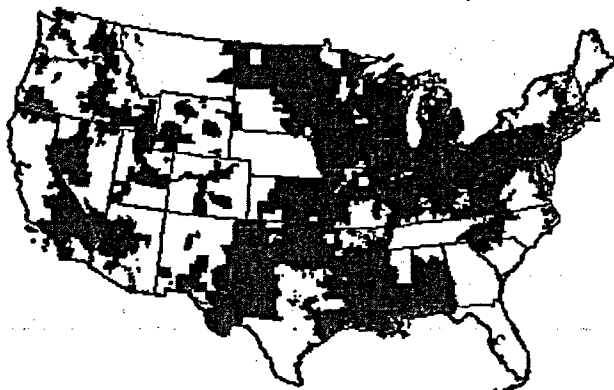
^fAn electricity power marketer buys and sells electricity but does not own or operate generation, transmission, or distribution facilities.

^gIn 1998, about 400 power marketers filed rate tariffs with FERC, of which 111 reported wholesale sales and 49 reported retail sales. Currently, over 850 power marketers have filed rate tariffs with FERC.

-- = Not applicable.

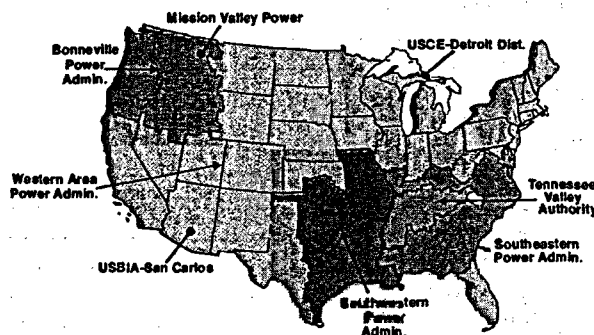
Sources: Energy Information Administration, Form EIA-861, "Annual Electric Utility Report," and Form EIA-860B, "Annual Electric Generator Report - Nonutility."

Figure 9. Service Areas of Investor-Owned Utilities, 1998



Source: Resource Data International, 1998.

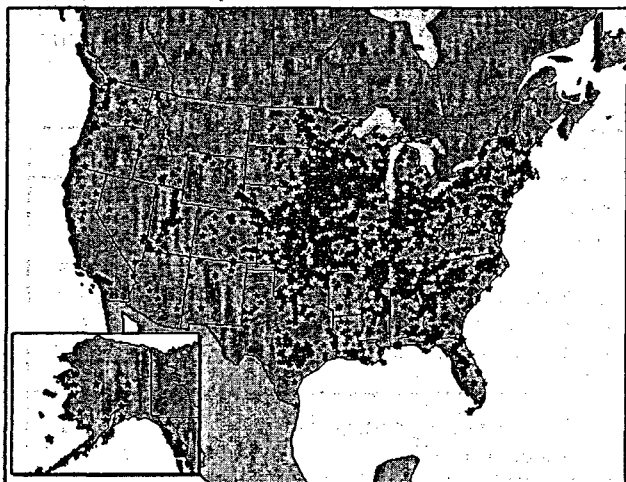
Figure 10. Service Areas of Federal Utilities, 1998



Source: EIA, Office of Coal, Nuclear, Electric and Alternate Fuels. Based on data contained in Form EIA-412, "Annual Report of Public Electric Utilities."

from other utilities and market large quantities in the wholesale market to groups of utilities within their States at lower prices than the individual utilities would otherwise pay. Large concentrations of publicly owned power districts are in the Midwest and Eastern regions of the United States (Figure 11). In general, publicly owned utilities tend to have lower costs than investor-owned utilities because they often have access to tax-free financing and do not pay certain taxes or dividends. They also tend to have high-density service areas.

Figure 11. Publicly Owned Utilities in the United States, 1998



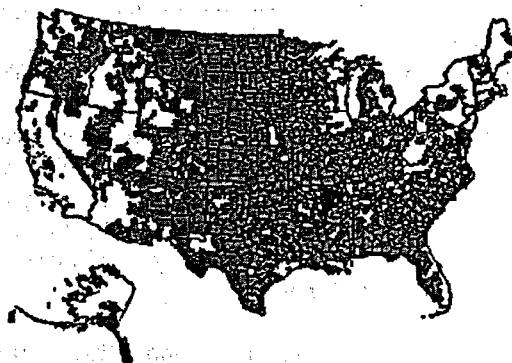
Source: EIA, Office of Coal, Nuclear, Electric and Alternative Fuels. Based on data contained in Form EIA-412, "Annual Report of Public Electric Utilities."

Rural Electric Cooperatives

Most rural electric cooperative utilities are formed and owned by groups of residents in rural areas to supply power to those areas (Figure 12). Some cooperatives may be owned by a number of other cooperatives. There are really three types of cooperatives: (1) distribution only, (2) distribution with power supply, and (3) generation and transmission. Cooperatives currently operate in 47 States, and they represent 29 percent of the total number of utilities in the country. Most distribution cooperatives resemble municipal utilities in that they often do not generate electricity, but purchase it from other utilities.

The other type (generating and transmission cooperatives) are usually referred to as "power supply cooperatives." These cooperatives are usually owned by

Figure 12. Service Areas of Cooperative Utilities, 1998



Source: National Rural Electric Cooperative Association's website at <http://www.nreca.org> (1998).

the distribution cooperatives to whom they supply wholesale power. Distribution cooperatives resemble Federal utilities, supplying electricity to other utility consumers from their generating capability.

Non-Federal Power Marketers

The introduction of the competitive wholesale market for electricity has brought about a fifth subcategory of electric utilities—power marketers. They are classified as electric utilities because they buy and sell electricity at the wholesale and retail levels. However, they do not own or operate generation, transmission, or distribution facilities, and therefore, their data (primarily electricity purchase and sales data) are not included in this chapter. Although relatively small in terms of volume of sales, the power marketers are a growing segment of the industry. Currently, over 850 power marketers have filed rate tariffs with FERC to sell electric power, but only approximately 160 were actively engaged in retail and/or wholesale sales during 1998.²⁵

Nonutilities

Nonutilities are privately owned entities that generate power for their own use and/or for sale to utilities and others. Nonutilities can be classified in two distinct ways. One approach separates nonutilities into separate categories based on their classification by FERC and the type of technology they employ: (1) cogenerators and (2) small power producers, both of which are qualifying facilities (QFs) because they meet certain criteria set

²⁵ Form EIA-861, "Annual Electric Utility Report," 1998.

forth by PURPA;²⁶ (3) exempt wholesale generators mandated by EPACT and designated by FERC, (4) cogenerators not qualified under PURPA, and (5) noncogenerators not qualified under PURPA (Table 5). As the industry furthers its transition to full retail competition in the generation portion of electricity supply, the distinctions between the nonutility subcategories are becoming less clear, and some may fade entirely within the next 10 years as a result of ongoing structural changes and the possible repeal of the Federal mandates that created them.

A second approach for classifying nonutilities is based on the major industry group into which the nonutility

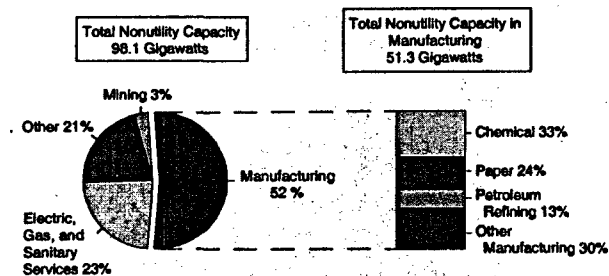
company falls. Nonutility electricity generators are found in many different industries. In 1998, most nonutility generating capacity (52 percent) was in the manufacturing sector of the economy (Figure 13). Within the manufacturing sector, the chemical industry, the paper industry, and the petroleum refining industry account for 70 percent of the electricity generated by that sector. The manufacturing processes conducted at many of these plants can utilize the thermal energy produced when cogenerating electricity. After manufacturing, the largest portion of nonutility electricity generating capacity (23 percent) can be found in the electric, gas, and sanitary services sector. The entities that make up this sector are primarily engaged in producing, transporting,

Table 5. Major Characteristics of U.S. Nonutilities by Type

Type	Major Characteristics
Cogenerators (QF) (Combined Heat and Power)	<ul style="list-style-type: none"> • Are qualified under PURPA by meeting certain ownership, operating, and efficiency criteria established by FERC. • Sequentially produce electric energy and another form of energy, such as heat or steam, using the same fuel source. • Are guaranteed that utilities will purchase their output at a price based on the utility's "avoided cost" and will provide backup service at nondiscriminatory rates.
Small Power Producers (QF)	<ul style="list-style-type: none"> • Are qualified under PURPA by meeting certain ownership, operating, and efficiency criteria, established by FERC. • Use biomass, waste, renewable resources (water, wind, solar), or geothermal as a primary energy source. • Fossil fuels can be used but renewable resources must provide at least 75 percent of the total energy input. • Are guaranteed that utilities will purchase their output at a price based on the utility's "avoided cost" and will provide backup service at nondiscriminatory rates.
Exempt Wholesale Generators	<ul style="list-style-type: none"> • Creation authorized by EPACT. • Are exempt from PUHCA's corporate and geographic restrictions. • Are wholesale producers; do not sell retail. • Do not possess significant transmission facilities. • Utilities are not required to purchase their electricity. • Are regulated but usually may charge market-based rates.
Cogenerators (Non-QF)	<ul style="list-style-type: none"> • Are not qualified under the provisions of PURPA. • Are nonutilities, utilizing a cogenerating technology, which may themselves consume part of the electricity they cogenerate.
Noncogenerators (Non-QF)	<ul style="list-style-type: none"> • Are not qualified under the provisions of PURPA. • Do not utilize a cogenerating technology.
<p>QF = Qualifying facility (under PURPA). Note: An entity can be any combination of cogenerator QF, small power producer QF, and exempt wholesale generator. Source: Energy Information Administration, <i>Electric Power Annual 1995</i>, Volume II, DOE/EIA-0348(95)/2 (Washington, DC, December 1996).</p>	

²⁶ QFs receive certain benefits under PURPA. In particular, they are guaranteed that electric utilities will purchase their output at a price based on the utility's "avoided cost."

Figure 13. Shares of Nonutility Nameplate Capacity by Major Industry Group, 1998



Note: Totals may not equal the sum of components due to independent rounding.

Source: Energy Information Administration, Form EIA-860B, "Annual Electric Generator Report - Nonutility."

and/or distributing electricity, although they may be engaged in steam, gas, water, and/or waste disposal services as a primary business. Unlike nonutilities in other sectors, these nonutilities are engaged primarily in activities similar to the generation activities carried out by electric utilities. The remaining nonutility capacity is found either in the mining industry (3 percent) or in various other industries, including agriculture, transportation, and other services (21 percent).

A Comparison of Utility and Nonutility Roles

The relative contribution of utility and nonutility components to the supply of the Nation's electricity can be understood by looking at their shares of nameplate capacity,²⁷ net generation,²⁸ additions to capacity, and number of companies (Figure 14). The number of publicly owned utilities (i.e., those owned by State and local governments) far outweighs the number of IOUs (2,009 versus 239); however, in 1998 IOUs were responsible for the lion's share of capacity (66 percent) and generation (68 percent). On the other hand, the nonutility share of capacity and generation has been relatively small, but that trend is changing. The change began with the passage of PURPA when nonutilities were promoted as energy-efficient, environment-friendly alternative sources of electricity. More recently, FERC Order 888 opened the bulk power transmission grid to suppliers other than utilities. In response, nonutilities have been

expanding their roles in wholesale power supply and are taking advantage of the divestiture activities of utilities by purchasing their generation assets. As a result, the nonutility share of total industry capacity rose from 7 percent in 1992 to 12 percent in 1998.²⁹

A yearly comparison of the above-mentioned four statistics (Figure 15) gives a clear picture of the significant shifts in ownership of electricity supply that have taken place in the relatively short period of time since passage of EPACT. A number of these shifts can be attributed to the strategic business plans companies are using to cope in a deregulated and competitive market. For instance, since 1992, the number of IOUs has decreased by 8 percent and their nameplate capacity has decreased by 5 percent (Figure 16). The decrease in the number of IOUs is a result of recent mergers between IOUs. The decrease in generation capacity is evidence of the divestiture of generation assets. On the other hand, the fact that IOU net generation has actually increased by 11 percent since 1992 can be attributed to such factors as higher demand for electricity and efficiency gains stemming from competition and mergers.

Although the number of nonutility companies decreased in 1997, the number of nonutilities grew by 9 percent during the 7-year period examined. Also, with nonutilities expanding by buying IOU generation assets and constructing new generation units, the result was an increase in nonutility nameplate capacity (up 73 percent since 1992) and generation (up 42 percent since 1992). Nonutility additions to capacity have been increasing at an average annual rate of nearly 7 percent since 1992.

Electricity Sales and Trade

Wholesale Sales and Trade

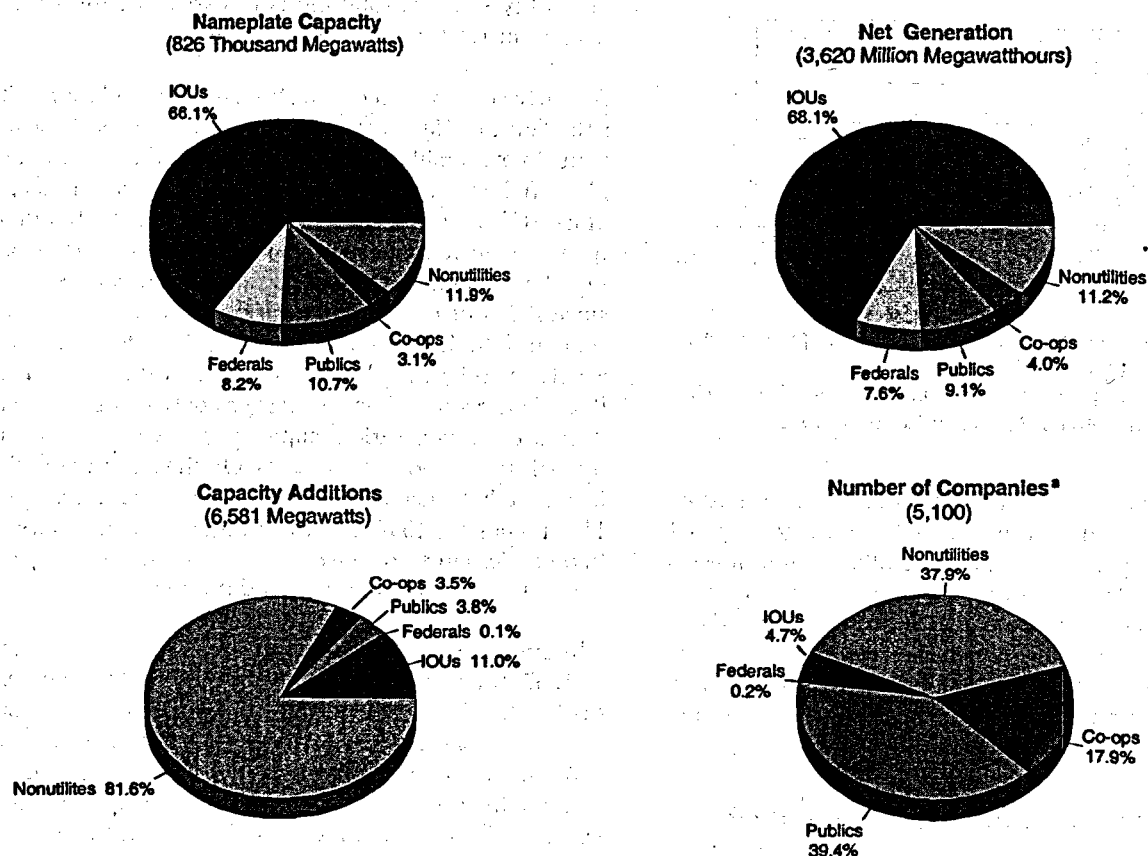
The bulk power system outlined earlier makes it possible for utilities to engage in wholesale (for resale) electric power trade. Wholesale trade has historically played an important role, allowing utilities to reduce power costs, increase power supply options, and improve reliability. In quantity, it accounts for more than one-half of electricity sales to ultimate consumers. Since 1986, the total amount of wholesale power trade (as measured by purchased power plus exchange received) among utilities and nonutilities has grown at an average annual rate

²⁷ EIA defines nameplate capacity as the maximum design production capacity specified by the manufacturer of a processing unit or the maximum amount of a product that can be produced running the manufacturing unit at full capacity.

²⁸ EIA defines net generation as gross generation minus plant use from all electric utility-owned plants.

²⁹ Energy Information Administration, *Electric Power Annual 1998, Volume I*, DOE/EIA-0348(98)/1 (Washington, DC, April 1999), p. 1.

Figure 14. Share of Utility and Nonutility Nameplate Capacity, Net Generation, Additions to Capacity, and Number of Units by Ownership Category, 1998



* Data for power marketers are not included.

Sources: Energy Information Administration, Form EIA-759, "Monthly Power Plant Report," Form EIA-860A, "Annual Electric Generator Report - Utility," Form EIA-861, "Annual Electric Utility Report," and Form EIA-860B, "Annual Electric Generator Report - Nonutility."

of 4.7 percent, which is more than the rate of growth for retail sales by utilities (3.1 percent). In the past, wholesale trade has been dominated by utility purchases from other utilities. In 1998, utilities purchased a total of 1,669 billion kilowatthours of wholesale electricity from other utilities and a smaller but increasing amount (259 billion kilowatthours) from nonutility producers (Figure 17).

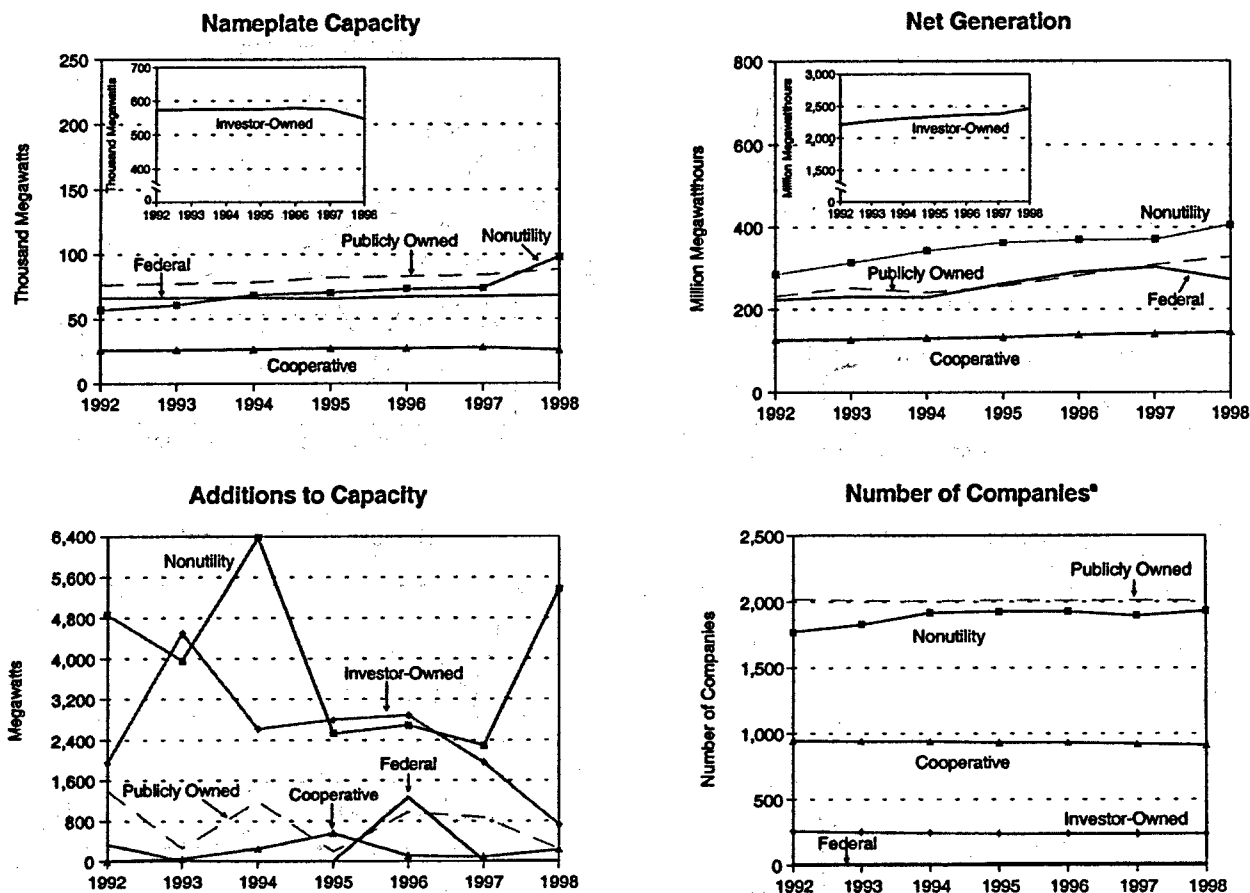
Wholesale power sales by nonutilities to utilities and wheeling (the transmission of power from one point to another via a third party) by utilities have both grown vigorously. Wholesale sales by nonutilities grew from 40 billion to 259 billion kilowatthours between 1986 and 1998, yielding an average annual growth rate of 16.8 percent. Wheeling, while not increasing as spectacularly,

grew at an annual average rate of 8.3 percent over the same period. Utility sales to ultimate consumers, wholesale sales by nonutilities, and wheeling by utilities all grew more slowly between 1990 and 1998, with annual growth rates of 2.2 percent, 12.6 percent, and 4.3 percent, respectively.

International Trade

In recent years, U.S. international trade in electricity has returned to the levels of the mid-1980s (Figure 18). U.S. trade is mostly in imports, which were more than three times the level of exports in 1998. Most imports are from Canada (99 percent of total gross imports in 1998) and the remainder is from Mexico.

Figure 15. Total Utility and Nonutility Nameplate Capacity, Net Generation, Additions to Capacity, and Number of Units by Ownership Category, 1992-1998



^a Data for power marketers are not included.

Sources: Energy Information Administration, Form EIA-759, "Monthly Power Plant Report," Form EIA-860, "Annual Electric Generator Report," Form EIA-860A, "Annual Electric Generator Report - Utility," Form EIA-861, "Annual Electric Utility Report," Form EIA 867, "Annual Nonutility Power Producer Report," and Form EIA-860B, "Annual Electric Generator Report - Nonutility."

Imported power is particularly important to the NPCC and MAPP regions of NERC,³⁰ where gross imports were 7.2 and 6.5 percent, respectively, of retail sales by utilities in these regions in 1998. In contrast, gross imports for the Nation as a whole that year were 1.2 percent of retail sales by utilities.

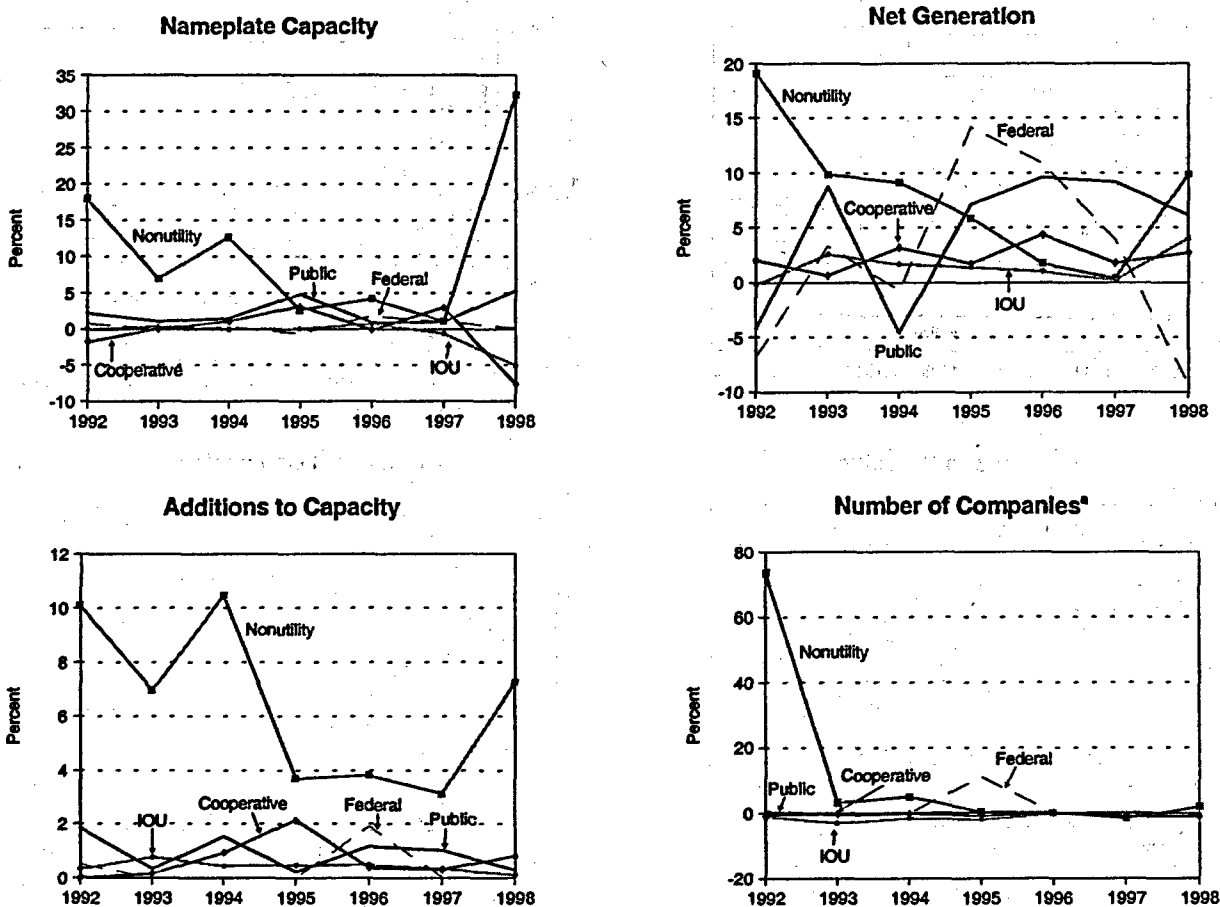
Retail Sales by Sector

Electricity is sold to four classes or sectors of retail (i.e., ultimate) consumers—residential, commercial, industrial,

and "other." The residential sector includes private households and apartment buildings where energy is consumed primarily for space heating, water heating, air conditioning, lighting, refrigeration, cooking, and clothes drying appliances. The commercial sector includes non-manufacturing business establishments such as hotels, motels, restaurants, wholesale businesses, retail stores, and health, social, and educational institutions. The industrial sector includes manufacturing, construction, mining, agriculture, fishing, and forestry establishments. The "other" sector includes public street and highway

³⁰ Refer to Figure 7 for details on NERC regions.

Figure 16. Annual Growth Rate of Utility and Nonutility Nameplate Capacity, Net Generation, Additions to Capacity, and Number of Companies, 1992-1998



^a Data for power marketers are not included.

Sources: Energy Information Administration, Form EIA-759, "Monthly Power Plant Report," Form EIA-860, "Annual Electric Generator Report," Form EIA-860A, "Annual Electric Generator Report - Utility," Form EIA-861, "Annual Electric Utility Report," Form EIA 867, "Annual Nonutility Power Producer Report," and Form EIA-860B, "Annual Electric Generator Report - Nonutility."

lighting, railroads and railways, municipalities, divisions or agencies of State and Federal Governments under special contracts or agreements, and other utility departments.³¹

Sales to the residential sector in 1998 increased 20.1 percent from the 1992 level, to 1,128 billion kilowatthours, which represented 35 percent of sales to ultimate consumers. The 1998 commercial sector retail sales increased 25 percent and the industrial sector 8 percent

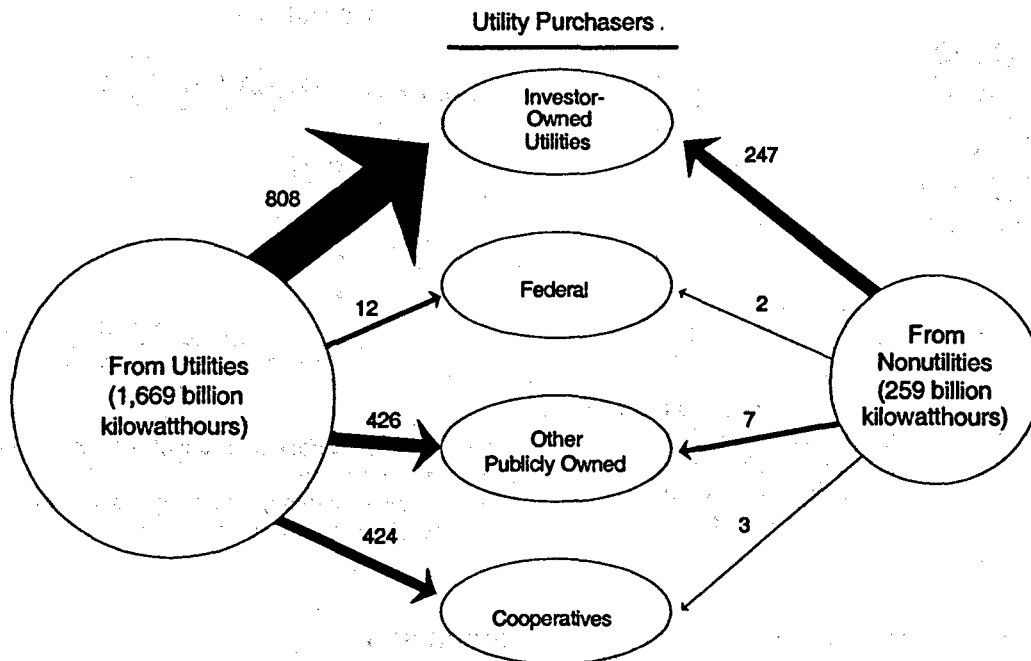
from the 1992 levels. Together, these two non-residential sectors accounted for 62 percent of 1998 retail sales. Sales to the "other" sector were 104 billion kilowatthours in 1998, an increase of 25 percent over 1992 levels (Figures 19 and 20).

Retail Sales by Ownership Category

Sales by investor-owned electric utilities in 1998 increased 15.6 percent over 1992 levels and represented

³¹ There are some exceptions to the types of customers listed in each of the four sectors. For instance, some small manufacturers are classified as commercial while some large commercial establishments are classified as industrial.

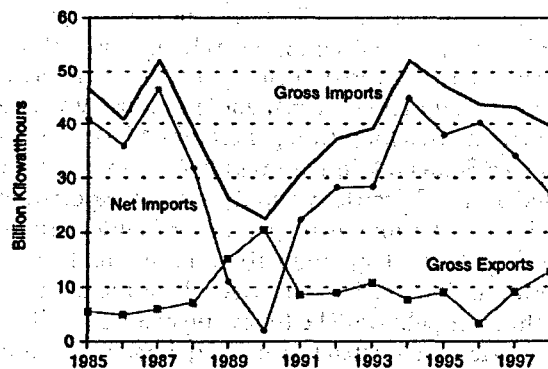
Figure 17. Electric Utility Wholesale Power Purchases by Ownership Type, 1998
(Billion Kilowatthours)



Notes: Data do not include utility purchases from power marketers. Totals may not equal sum of components due to independent rounding.

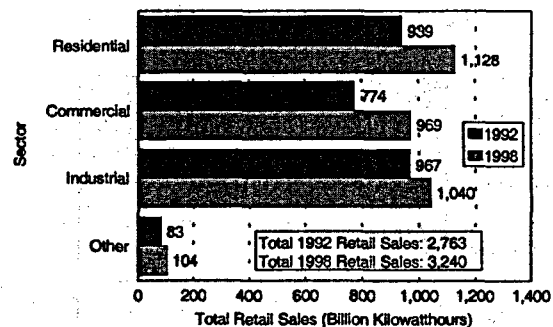
Source: Energy Information Administration, Form EIA-861, "Annual Electric Utility Report."

Figure 18. U.S. International Electricity Trade, 1985-1998



Source: 1985-1994: Energy Information Administration, *Annual Energy Review 1995*, DOE/EIA-0384(95) (Washington, DC, July 1996), Table 8.1. 1995-1998: Energy Information Administration, *Electric Power Annual 1998*, Volume II, DOE/EIA-0348(98)/2 (Washington, DC, December 1999), Tables 41-43.

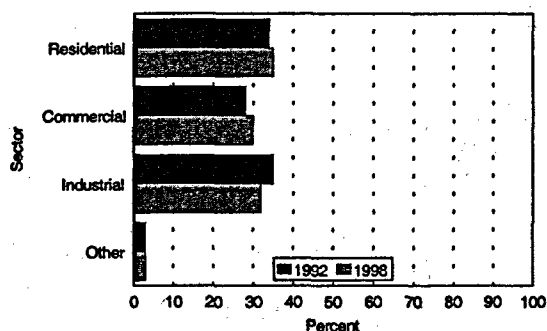
Figure 19. Sales to Ultimate Consumers by Sector, 1992 and 1998



Notes: Other includes sales for public street and highway lighting, other sales to public authorities, sales to railroads and railways, and interdepartmental sales. Totals may not equal sum of components because of independent rounding.

Source: Energy Information Administration, Form EIA-861, "Annual Electric Utility Report."

Figure 20. Share of Sales to Ultimate Consumers by Sector, 1992 and 1998

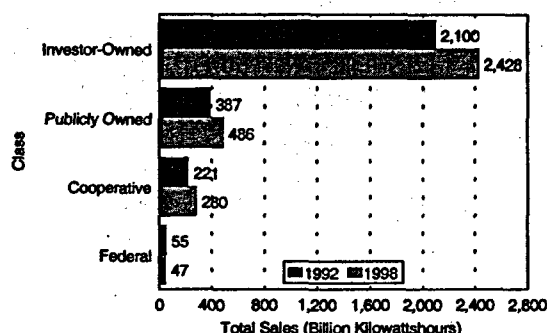


Notes: Other includes sales for public street and highway lighting, other sales to public authorities, sales to railroads and railways, and interdepartmental sales. Totals may not equal sum of components because of independent rounding.

Source: Energy Information Administration, Form EIA-861, "Annual Electric Utility Report."

74.9 percent of sales to ultimate consumers. Publicly owned utility sales increased 25.6 percent over 1992 levels and represented 15.0 percent of total sales. Cooperative utility sales increased 26.7 percent over 1992 levels and represented 8.6 percent of sales. Federal utility sales experienced a decrease of 14.5 percent from 1992 levels and represented 1.5 percent of the total retail sales in 1998 (Figures 21 and 22).

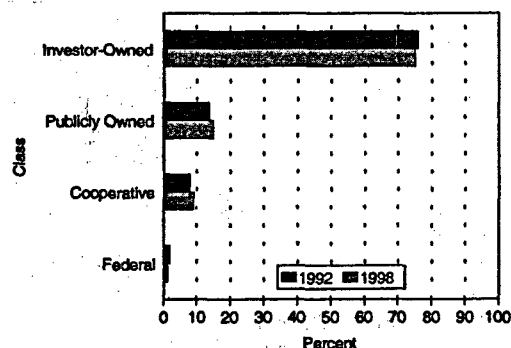
Figure 21. Sales to Ultimate Consumers by Class of Ownership, 1992 and 1998



Note: Totals may not equal sum of components because of independent rounding.

Source: Energy Information Administration, Form EIA-861, "Annual Electric Utility Report."

Figure 22. Share of Sales to Ultimate Consumers by Class of Ownership, 1992 and 1998



Note: Totals may not equal sum of components because of independent rounding.

Source: Energy Information Administration, Form EIA-861, "Annual Electric Utility Report."

Conclusion

This chapter has outlined the infrastructure of the electric power industry by defining its components and their respective roles. In addition, it has provided statistics³² to clarify the roles and has compared current data to historical data to show how the roles are changing due to the opening of competition in the industry. In addition, information was given regarding wholesale and retail sales in an effort to more thoroughly cover the roles of the components of the current electric power industry. Some roles will continue to change throughout the transition from a vertically integrated and regulated monopoly to a functionally unbundled industry with a competitive market for power generation. Market forces will replace State and Federal regulators in setting the price and terms of electricity supply and are expected to lead to lower rates for customers. The individual States are moving toward opening their retail markets to competition. Chapter 8 details the role of the States in promoting competition. The following chapter outlines the Federal legislation that has affected the structure and operating procedures of the electric power industry since the 1930s.

³² Various additional industry summary statistics are provided in Appendix D.

4. The Federal Statutory Background of the Electric Power Industry

Introduction

This chapter describes major Federal legislation that has shaped the electric power industry since the 1930s. It begins by detailing three Acts that have had the most profound effects on the industry's structure—the Public Utility Holding Company Act of 1935 (PUHCA), the Public Utility Regulatory Policies Act of 1978 (PURPA),³³ and the Energy Policy Act of 1992 (EPACT), which led to the issuance of Orders 888 and 889 by the Federal Energy Regulatory Commission (FERC). The remainder of the chapter lists and summarizes other laws which have affected the industry throughout the years. Appended to the end of the chapter is a list of major Supreme Court cases which also have had an impact.

The Public Utility Holding Company Act of 1935

The Public Utility Holding Company Act, enacted in 1935, was aimed at breaking up the unconstrained and excessively large trusts that then controlled the Nation's electric and gas distribution networks. They were accused of many abuses, including "control of an entire system by means of a small investment at the top of a pyramid of companies, sale of services to subsidiaries at excessive prices, buying and selling properties within the system at unreasonable prices, intra-system loans at unfair terms, and the wild bidding war to buy operating companies."³⁴

Although more than 100 holding companies existed before PUHCA, almost half of all electricity generated in

the United States was controlled by three huge holding companies.³⁵ The size and complexity of these huge trusts made industry regulation and oversight control by the States impossible. After the collapse of several large holding companies, the Federal Trade Commission (FTC) conducted an investigation after which it criticized the many abuses that tended to raise the cost of electricity to consumers. The Securities and Exchange Commission (SEC) also investigated and "publicly charged that the holding companies had been guilty of '... stock watering and capital inflation, manipulation of subsidies, and improper accounting practices.' The general counsel of the FTC went further, claiming that '[w]ords such as fraud, deceit, misrepresentation, dishonesty, breach of trust, and oppression are the only suitable terms to apply.'"³⁶

Under PUHCA, the SEC was charged with the administration of the Act and the regulation of the holding companies. One of the most important features of the Act was that the SEC was given the power to break up the massive interstate holding companies by requiring them to divest their holdings until each became a single consolidated system serving a circumscribed geographic area. Another feature of the law permitted holding companies to engage only in business that was essential and appropriate for the operation of a single integrated utility. This latter restriction practically eliminated the participation of nonutilities in wholesale electric power sales. The law contained a provision that all holding companies had to register with the SEC, which was authorized to supervise and regulate the holding company system. Through the registration process, the SEC decided whether the holding company would need to be regulated under or exempted from the require-

³³ PUHCA and PURPA are now being targeted for repeal due to the industry's transition to competition. Chapter 6 will address the issues and arguments associated with the call for repeal, as well as current proposals for comprehensive restructuring legislation that are before Congress.

³⁴ L. S. Hyman, *America's Electric Utilities: Past, Present and Future*, Fifth Edition (Arlington, VA: Public Utilities Reports, Inc., 1994), p. 111.

³⁵ The Securities and Exchange Commission actually noted 142 registered holding companies in 1939. Securities and Exchange Commission, *Fifth Annual Report of the Securities and Exchange Commission, Fiscal Year Ended June 30, 1939* (Washington, DC, 1940), pp. 1 and 43.

³⁶ T. J. Brennan et al., *A Shock to the System: Restructuring America's Electricity Industry* (Resources for the Future: Washington, DC, July 1996), p. 160.

Table 6. Relative Size of Registered Holding Companies as of December 31, 1998

Holding Company System	Consolidated Assets (thousand dollars)	Twelve Months' Consolidated Operating Revenues (thousand dollars)	Number of Customers	Retained Earnings ^a (thousand dollars)
Allegheny Energy, Inc. (E)	6,747,793	2,576,436	1,418,353	836,759
Alliant Energy Corp. (E) (G)	4,959,000	2,131,000	1,295,500	537,372
Ameren (E) (G)	8,847,439	3,318,208	1,479,365	1,472,200
American Electric Power Co. (E)	19,483,200	6,345,900	3,022,479	1,683,561
Central and South West Corp. (E) ...	13,744,000	5,482,000	1,752,000	1,740,000
CINergy Corp. (E) (G)	10,298,800	5,876,300	1,870,000	945,200
Columbia Energy Group (G)	6,968,700	5,731,800	2,100,000	409,544
Conectiv (E) (G)	6,100,000	3,100,000	1,049,706	276,939
Consolidated Natural Gas Co. (G) ...	6,361,900	2,760,400	1,880,000	1,591,543
Eastern Utilities Associates (E)	1,302,638	538,801	305,018	56,062
Entergy Corp. (E)	22,848,023	11,494,772	2,495,000	2,526,888
GPU Corp. (E)	16,288,109	4,248,792	2,041,000	2,230,425
National Fuel Gas Co. (G)	2,684,459	1,248,000	704,217	428,112
New Century Energies (E) (G)	7,672,000	3,610,900	2,658,000	740,677
New England Electric System (E)	5,070,535	2,420,533	1,363,000	998,912
Northeast Utilities (E)	10,387,381	3,767,714	1,729,250	560,769
PECO Energy Power Co. (E)	118,000	18,500	NA	NA
Southern Co. (E)	36,192,000	11,403,000	3,794,000	3,878,000
Unitil Corp. (E) (G)	376,855	149,639	114,500	36,401
Total	186,450,832	76,222,695	31,071,388	20,949,364

^aRetained earnings are the balance, either debit or credit, of appropriated or unappropriated earnings of an entity that are retained in the business.

E = Electric.

G = Gas.

NA = Not applicable.

Source: Securities and Exchange Commission, *Financial and Corporate Report* (Washington, DC, July 1, 1999), p. 3.

ments of the Act. The SEC also was charged with regulating the issuance and acquisition of securities by holding companies. Strict limitations on intrasystem transactions and political activities were also imposed.³⁷

The holding companies at first resisted compliance, and some challenged the constitutionality of the Act, but the Supreme Court upheld PUHCA's legality. By 1947, virtually all holding companies had undergone some type of simplification or integration, and by 1950 the utility reorganizations were virtually complete.³⁸ As of December 31, 1998, there were only 15 registered holding companies in the United States (Table 6). Additionally, there were 53 holding companies exempt

from SEC regulation by SEC order, and 112 holding companies exempt since they fell under the umbrella of PUHCA Section 3 (a) (1) and/or (2), which states:

The Commission . . . shall exempt any holding company, and every subsidiary company thereof . . . from any . . . provisions of this title . . . unless it finds the exemption detrimental to the public interest or the interest of investors or consumers if—(1) such holding company, and every subsidiary company thereof . . . are predominantly intrastate in character and carry on their business substantially in a single State in which such holding company and every such subsidiary company thereof are organized;

³⁷ For a more extensive discussion of PUHCA, see Energy Information Administration, *The Public Utility Holding Company Act of 1935: 1935-1992*, DOE/EIA-0563 (Washington, DC, January 1993), pp. 39-53.

³⁸ J. Seligman, *The Transformation of Wall Street and The History of the Securities and Exchange Commission in Modern Corporate Finance*, (Boston, MA: Houghton, Mifflin Company, 1982), p. 134.

(2) such holding company is predominantly a public utility company whose operations . . . do not extend beyond the State in which it is organized and States contiguous thereto.³⁹

Although PUHCA reform or outright repeal is being considered today because of the move to restructure (see Chapter 6), the same plea for change has been made several times over the past 20 years. In the 1970s, utilities sought relief from PUHCA constraints to diversify into nonutility lines of business as a means to improve their declining profits. In the 1980s, they sought to diversify to exploit the positive experience of independent power producers under PURPA, which eliminated PUHCA constraints on certain qualifying generating facilities. It was not until 1992 that EPACT significantly modified PUHCA by allowing both utilities and nonutilities to build, own, and operate power plants for wholesaling electricity in more than one geographic area. A more detailed discussion of the effects of PURPA and EPACT on PUHCA provisions follows.

The Public Utility Regulatory Policies Act of 1978

In October 1973, Nations of the Organization of Petroleum Exporting Countries (OPEC) imposed a ban on oil exports to the United States. Although the ban lasted only until March 1974, its effects increased public awareness of energy issues, resulted in higher energy prices, contributed to inflation, and acted as a catalyst for the proposal and adoption of the National Energy Act. This Act, which was signed into law in November 1978, comprises five different statutes: PURPA, the Energy Tax Act, the National Energy Conservation Policy Act, the Powerplant and Industrial Fuel Use Act, and the Natural Gas Policy Act. The general purpose of the National Energy Act was to ensure sustained economic growth while also permitting the economy time to make an orderly transition from the past era of inexpensive energy resources to a period of more costly energy.⁴⁰ Although it had numerous objectives, a primary goal of the National Energy Act was to reduce the Nation's dependence on foreign oil and its vulnerability to interruptions in energy supply. Another

was to develop renewable and alternative energy sources.

The most significant part of the National Energy Act of 1978 with regard to the structure of the electric power industry was PURPA, specifically, Section 2 of the Act:

The Congress finds that the protection of the public health, safety, and welfare, the preservation of national security, and the proper exercise of congressional authority under the Constitution to regulate interstate commerce require—

(1) a program providing for increased conservation of electric energy, increased efficiency in the use of facilities and resources by electric utilities, and equitable retail rates for electric consumers,

(2) a program to improve the wholesale distribution of electric energy, the reliability of electric service, the procedures concerning consideration of wholesale rate applications before the Federal Energy Regulatory Commission, and to provide other measures with respect to the regulation of the wholesale sale of electric energy,

(3) a program to provide for the expeditious development of hydroelectric power . . .⁴¹

Section 210 of PURPA requires electric utilities to interconnect with and buy whatever amount of capacity and energy is offered from any facility meeting the criteria for a qualifying facility (QF) (see inset). It further requires that the utility pay for that power at the utility's own incremental or avoided cost of production.⁴² This provision created a market in which QFs could unilaterally sell electricity to utilities. To further ease the burden on nonutility companies wishing to enter the electric generating market, Congress exempted most QFs from rate and accounting regulation by FERC under the Federal Power Act, from regulation by the SEC under PUHCA, and from State rate, financial, and organizational regulation of utilities. It also simplified contracts, streamlined the power sales process, increased financial certainty for creditors and equity sponsors, and generally eliminated several procedural and planning

³⁹ Public Utility Holding Company Act of 1935 (Public Law 74-333), Section 3.

⁴⁰ J. H. Minan and W. H. Lawrence, "Federal Tax Incentives and Solar Energy Development," *Energy Law Service*, Monograph 7F (Wilmette, IL, September 1981), p. 5.

⁴¹ Public Utility Regulatory Policies Act of 1978 (Public Law 95-617), Section 2.

⁴² The law required electric utilities to purchase electricity from qualified facilities at "a rate which [does not] exceed the incremental cost to the electric utility of alternative electric energy . . . [which the] utility would generate or purchase from another source." Public Utility Regulatory Policies Act of 1978 (Public Law 95-617), Title II, Section 210, Paragraphs (b), (2), and (d).

problems that had made entry into the electricity market prohibitive for most of the smaller energy producers.⁴³

In enacting PURPA, Congress ensured that QFs had a guaranteed market for their power at a price equal to the avoided cost of the utilities that purchased their power. This is quite different from traditional regulation, which generally sets the price of electricity on the basis of the cost (to the producer) of producing it. The QFs themselves are not subject to cost-of-service regulation, and the prices paid to them are not based on their cost of

producing the electricity. Instead, the prices they are paid reflect the avoided cost of the purchasing utility, that is, the cost the utility avoided by not producing the electricity received from the QF or purchasing it from another source. One initial interpretation of avoided cost under PURPA was the cost of additional electricity produced by the utility itself. However, under PURPA's requirements, some utilities had to purchase QF generation even though they already had sufficient supply available to meet demand, either through their own generation or through purchases from other sources.

PURPA Qualification Criteria

PURPA was designed to encourage the efficient use of fossil fuels in electric power production through cogenerators and the use of renewable resources through small power producers. There is no size limitation for an eligible solar, wind, or waste facility, as defined by section 3(17) (E) of the Federal Power Act. For a non-eligible facility, the power production capacity for which qualification is sought may not exceed 80 megawatts. (Under PURPA provisions, both cogenerators and small power producers cannot have more than 50 percent of their equity interest held by an electric utility.)^a

Cogenerators

Cogenerators are generators that sequentially or simultaneously produce electric energy and another form of energy (such as heat or steam) using the same fuel source. Cogeneration technologies are classified as "topping-cycle" and "bottoming-cycle" systems. In a typical topping-cycle system, high-temperature, high-pressure steam from a boiler is used to drive a turbine to generate electricity. The waste heat or steam exhausted from the turbine is then used as a source of heat for an industrial or commercial process. In a typical bottoming-cycle system, high-temperature thermal energy is produced first for applications such as reheat furnaces, glass kilns, or aluminum metal furnaces, and heat is then extracted from the hot exhaust stream of the primary application and used to drive a turbine. Bottoming-cycle systems are generally used in industrial processes that require very high-temperature heat.

For a nonutility to be classified as a cogenerator qualified under PURPA, it must meet certain ownership, operating, and efficiency criteria established by FERC. The operating requirements stipulate the proportion (applicable to oil-fired facilities) of output energy that must be thermal energy, and the efficiency requirements stipulate the maximum ratio of input energy to output energy.

Renewables

A renewable resource is an energy source that is regenerative or virtually inexhaustible. Renewable energy includes solar, wind, biomass, waste, geothermal, and water (hydroelectric). Solar thermal technology converts solar energy through high concentration and heat absorption into electricity or process energy. Wind generators produce mechanical energy directly through shaft power. Biomass energy is derived from hundreds of plant species, various agricultural and industrial residues, and processing wastes. Industrial wood and wood waste are the most prevalent form of biomass energy used by nonutilities. Geothermal technologies convert heat naturally present in the earth into heat energy and electricity. Hydroelectric power is derived by converting the potential energy of water to electrical energy using a hydraulic turbine connected to a generator.

For a nonutility to be classified as a small power producer under PURPA, it also must meet certain ownership and operating criteria established by FERC. In addition, renewable resources must provide at least 75 percent of the total energy input. PURPA provisions enabled nonutility renewable electricity production to grow significantly, and the industry responded by improving technologies, decreasing costs, and increasing efficiency and reliability.

^a For further information regarding criteria, refer to <http://frwebgate.access.gpo.gov>.

In the mid-1980s, several States began to review their own and others' experiences with PURPA implementation. Maine, in particular, concluded that avoided costs could be established through competitive bidding among QFs, as opposed to setting them administratively. In 1984, Central Maine Power (CMP) and the Maine Public Service Commission (PSC) became the first

to put competitive bidding into practice. CMP did this in an effort to protect itself from oversupply of electricity by QFs after the PSC had previously decided that avoided-cost rates for QFs were to be based on the cost of production of electricity by nuclear facilities. These high rates spurred a larger volume of offers than CMP needed. The switch to market-based pricing provided

⁴³ Energy Information Administration, *Renewable Energy Annual 1995*, DOE/EIA-0603(95) (Washington, DC, December 1995), p. xxvi.

a new avoided cost for purchased power from QFs that was below the initial avoided cost levels that would have prevailed in the absence of bidding.⁴⁴

The Energy Policy Act of 1992

In 1992, President George Bush signed the Energy Policy Act (EPACT). The Act substantially reformed PUHCA and made it even easier for nonutility generators to enter the wholesale market for electricity by exempting them from PUHCA constraints. The law created a new category of power producers, called exempt wholesale generators (EWGs).⁴⁵ By exempting them from PUHCA regulation, the law eliminated a major barrier for utility-affiliated and nonaffiliated power producers who want to compete to build new non-rate-based power plants. EWGs differ from PURPA QFs in two ways. First, they are not required to meet PURPA's cogeneration or renewable fuels limitations. Second, utilities are not required to purchase power from EWGs. Marketing of EWG power has come to be facilitated by transmission provisions that gave FERC the authority to order utilities to provide access to their transmission systems.

The law has been hailed by industry analysts as one of the most significant pieces of legislation in the history of the industry. In addition, the law amended the wholesale transmission provisions of the Federal Power Act. These transmission provisions have led to a nationwide open-access electric power transmission grid for wholesale transactions. (The law specifically prohibits FERC from ordering retail wheeling—the transmission of power to a final customer.) Independent power producers, publicly owned utilities, rural cooperatives, and industrial producers (i.e., anyone selling power at wholesale) gained the ability to seek from FERC orders that require transmission-owning utilities to provide transmission service at FERC-defined “just and reasonable” rates.

The language of the law concerning pricing directs FERC, when it issues a transmission order, to approve rates which permit the utility to recover “all legitimate, verifiable economic costs incurred in connection with the transmission services.” Such costs include “an appro-

priate share, if any, [of] necessary associated services, including, but not limited to, an appropriate share of any enlargement of transmission facilities.” The language also says that FERC “shall ensure, to the extent practicable,” that costs incurred by the wheeling utility are recovered from the transmission customer rather than “from a transmitting utility's existing wholesale, retail, and transmission customers.”

Probably the most salient characteristics of EPACT were the expansion of FERC's authority and the creation of EWGs that were exempt from SEC regulation. A bitter dispute was in the area of transmission access. Some nonutility groups had argued that not revising transmission-access rules would reinforce the utility monopolistic structure. The main thrust of the argument against these transmission access authority revisions was that the high level of reliability enjoyed by the Nation would be compromised.

Although regulated public utilities had no general obligation to provide access to their transmission lines before EPACT, there are several restricted exceptions to this generalization. One is the requirement, under PURPA, that utilities interconnect with and purchase power from QFs. Another is that under the Federal Power Act, as amended by PURPA, FERC had the authority to require wheeling under limited circumstances. But, in its first deliberation on this authority, FERC found that the authority was limited so that it did not allow FERC to require a utility to wheel power to its wholesale customers or to encourage competition in bulk power markets.⁴⁶ This interpretation of PURPA circumscribed the conditions under which FERC could order wheeling but FERC's interpretation was later upheld by the courts. The enactment of EPACT in 1992 broadened FERC's authority to order utilities to provide wheeling over their transmission systems to utilities and nonutilities. In addition, anti-trust laws and analyses have been used to require access to transmission and generation capacity. FERC's implementation of EPACT and open transmission access is discussed in Chapter 7.

The following table lists Federal legislation which has impacted the electric power industry since 1933.

⁴⁴ W. H. Wellford and H. E. Robertson, “Bidding for Power: The Emergence of Competitive Bidding in Electric Generation,” Working Paper No. 2, National Independent Energy Producers (March 1990), p. 3.

⁴⁵ An EWG is a corporate entity. An EWG-owned facility is called an “eligible facility.” In this report, “EWG” refers to an EWG-owned eligible facility.

⁴⁶ *Southeastern Power Administration v. Kentucky Utilities Company*, 25 FERC § 61,204 (1983).

Major Federal Legislation Affecting the Electric Power Industry

Tennessee Valley Authority Act of 1933 (Public Law 73-17)

Under this law, the Federal Government provided electric power to States, counties, municipalities, and nonprofit cooperatives. It was the steady continuation of Federal initiatives to provide navigation, flood control, strategic materials for national defense, electric power, relief of unemployment, and improvement of living conditions in rural areas. The Tennessee Valley Authority (TVA) was also authorized to generate, transmit, and sell electric power. With regard to the sale of electric power, the TVA is authorized to enter into contracts up to 20 years for sales to governmental and private entities, to construct transmission lines to areas not otherwise supplied with electricity, to establish rules and regulations for power sales and distribution, and to acquire existing electric facilities used in serving certain areas.

Public Utility Holding Company Act of 1935 (PUHCA) (Public Law 74-333)

PUHCA was enacted to remedy utility industry abuses facilitated by the holding company structure. PUHCA gave the Securities and Exchange Commission the authority to oversee utility holding companies pursuant to the extensive set of regulations provided by the Act.

Federal Power Act of 1935 (Title II of PUHCA) (Aug. 26, 1935, ch. 687, Title II, 49 Stat. 838)

This Act was passed to provide for a Federal mechanism for interstate electricity regulation.

Rural Electrification Act of 1936 (Public Law 74-605)

This Act established the Rural Electrification Administration (REA) to provide loans and assistance to organizations providing electricity to rural areas and towns with populations under 2,500. REA cooperatives are generally associations or corporations formed under State law. The predecessor to this Act was the Emergency Relief Appropriations Act of 1935, which performed the same function.

Bonneville Project Act of 1937 (Public Law 75-329)

This Act created the Bonneville Power Administration (BPA), which pioneered the Federal power marketing administrations. The BPA was accountable for the transmission and marketing of power produced at Federal dams in the Northwest. In 1953, the BPA first guaranteed the bonds of and a market for small energy facilities built and financed by public utility districts.

Reclamation Project Act of 1939 (Public Law 76-260)

This Act requires that rates for electric power generated at Federal hydroelectric projects be sufficient to recover an appropriate share of annual operation and maintenance costs and an appropriate share of construction costs, to include interest charged at a rate of not less than 3 percent.

Flood Control Act of 1944 (Public Law 78-534)

This Act formed the basis for the later creation of the Southeastern Power Administration (SEPA)^a in 1950 to sell power produced by the U.S. Army Corps of Engineers in the Southeast; and the Alaska Power Administration (APA)^b in 1967 to both operate and market power from two hydroelectric plants in Alaska: the Eklutna Project and the Snettisham Project. Although the Southwestern Power Administration's (SWPA)^c authority after World War II came from the Flood Control Act of 1944, it was established using the Executive Branch's emergency war powers authority to satisfy the growing demands from weapons development and domestic needs. This Act also demands that rates for electric power be enough to recover the cost of "producing and transmitting such electric energy."^d

Major Federal Legislation Affecting the Electric Power Industry (Continued)

<p>First Deficiency Appropriation Act of 1949 (Public Law 81-71)</p> <p>The Act authorized the Tennessee Valley Authority to construct thermal-electric power plants for commercial electricity sale.</p>
<p>Energy Supply and Environmental Coordination Act of 1974 (ESECA) (Public Law 93-319)</p> <p>This Act allowed the Federal Government to prohibit electric utilities from burning natural gas or petroleum products.</p>
<p>DOE Organization Act of 1977 (Public Law 95-91)</p> <p>In addition to forming the Department of Energy (including the Federal Energy Regulatory Commission), this Act provided authority for the establishment of the Western Area Power Administration (WAPA)⁶ and transferred power marketing responsibilities and transmission assets previously managed by the Bureau of Reclamation to WAPA. WAPA's authority was extended through the Hoover Power Plant Act of 1984. This Act also transferred the other four power marketing administrations (PMAs)—the Southeastern Power Administration, the Southwestern Power Administration, the Alaska Power Administration, and the Bonneville Power Administration—from the Department of the Interior to the Department of Energy.</p>
<p>National Energy Act of 1978 (Public Law 95-617 - 95-621)</p> <p>This Act was signed into law in November 1978 and includes five different statutes: the Public Utility Regulatory Policies Act (PURPA), the Energy Tax Act (Public Law 95-618), the National Energy Conservation Policy Act (Public Law 95-619), the Powerplant and Industrial Fuel Use Act (Public Law 95-620), and the Natural Gas Policy Act (Public Law 95-621). Passed in the wake of the oil-producing nations' ban on oil exports to the United States and retail oil price increases, its general purpose was to ensure sustained economic growth while also permitting the economy time to make an orderly transition from the past era of inexpensive energy resources to a period of more costly energy.</p>
<p>Public Utility Regulatory Policies Act of 1978 (PURPA) (Public Law 95-617)</p> <p>PURPA was passed in response to the unstable energy climate of the late 1970s. PURPA sought to promote conservation of electric energy. Additionally, PURPA created a new class of nonutility generators, small power producers, from which, along with qualified cogenerators, utilities are required to buy power. Further, PURPA gave FERC the authority to order wheeling under the FPA.</p>
<p>Energy Tax Act of 1978 (ETA) (Public Law 95-618)</p> <p>This Act, like PURPA, was passed in response to the unstable energy climate of the 1970s. The ETA encouraged conversion of boilers to coal and investment in cogeneration equipment and solar and wind technologies by allowing a tax credit on top of the investment tax credit. It was later expanded to include other renewable technologies. However, the incentives generally were curtailed as a result of tax reform legislation in the mid-1980s.</p>
<p>National Energy Conservation Policy Act of 1978 (Public Law 95-619)</p> <p>This Act required utilities to develop residential energy conservation plans to encourage slower growth of electricity demand.</p>
<p>Powerplant and Industrial Fuel Use Act of 1978 (Public Law 95-620)</p> <p>This Act succeeded the Energy Supply and Environmental Coordination Act of 1974, and extended Federal prohibition on the use of natural gas and petroleum in new electric power plants.</p>

Major Federal Legislation Affecting the Electric Power Industry (Continued)

Pacific Northwest Electric Power Planning and Conservation Act of 1980 (Public Law 96-501)

This Act created the Pacific Northwest Electric Power and Conservation Council to coordinate the conservation and resource acquisition planning of the Bonneville Power Administration (BPA). The Act also provides for BPA to purchase and exchange electric power with Northwest utilities at the "average system cost." Approval of the methodology for determining "average system cost" is required. This Act also gave the BPA the authority to plan for and acquire additional power to meet its growing load requirements.

Economic Recovery Tax Act of 1981 (Public Law 97-34)

This Act introduced a new methodology for determining allowable tax depreciation deductions. The new methodology, the *Accelerated Cost Recovery System (ACRS)*, set forth rules enabling taxpayers to claim generous depreciation deductions based on the system's permitted depreciable life, method, and salvage value assumptions. The generation, transmission, and distribution plants of regulated electric utilities were categorized as public utility property. Public utility property under ACRS was assigned relatively long depreciable lives.

Electric Consumers Protection Act of 1986 (ECPA) (Public Law 99-495)

This Act was the first significant amendment to the hydro licensing provisions of the FPA since 1935. "The amendments have made four principal changes to Part I of the FPA. First, the municipal preference on relicensing has been eliminated. Second, the importance of environmental considerations in the licensing process has been greatly increased and the role of the State and Federal fish and wildlife agencies is expanded. Third, PURPA benefits for hydroelectric projects at new dams and diversions were eliminated unless the projects satisfy stringent environmental conditions. Finally, FERC's enforcement powers have been increased substantially."

Tax Reform Act of 1986 (Public Law 99-514)

Under this Act, ACRS was replaced with the *Modified Accelerated Cost Recovery System (MACRS)*. Under MACRS, the disparity in treatment of property between regulated and nonregulated taxpayers was eliminated. The investment credit was also repealed. The investment credit of the Federal income tax law was a dollar-to-dollar offset against the taxes payable by the taxpayer. The investment credit was available for regulated and nonregulated taxpayers and was intended to encourage capital investment by the Nation's businesses. The credit continues to be of importance to regulated utilities, however, because it is generally amortized for ratemaking and financial reporting purposes over the regulatory life of the related property that gave rise to the credit.

Clean Air Act Amendments of 1990 (CAAA) (Public Law 101-549)

These Amendments established a new emissions-reduction program. The goal of the legislation was to reduce annual sulfur dioxide emissions by 10 million tons and annual nitrogen oxide emissions by 2 million tons from 1980 levels for all man-made sources. Generators of electricity will be responsible for large portions of the sulfur dioxide and nitrogen oxide reductions. The program instituted under the Clean Air Act Amendments of 1990 employs a unique, market-based approach to sulfur dioxide emission reductions, while relying on more traditional methods for nitrogen oxide reductions.

Energy Policy Act of 1992 (EPACT) (Public Law 102-486)

This Act created a new category of electricity producer, the exempt wholesale generator, which narrowed PUHCA's restrictions on the development of nonutility electricity generation. The law also authorized FERC to open up the national electricity transmission system to wholesale suppliers.

^aSEPA markets power in West Virginia, Virginia, North Carolina, South Carolina, Georgia, Florida, Alabama, Mississippi, Tennessee, and Kentucky. SEPA is unique from the other marketing authorities because it does not own any transmission lines.

^bThe APA and the TVA are the only two Federal marketing organizations that operate their own plants.

^cSWPA markets power in Arkansas, Kansas, Louisiana, Missouri, Oklahoma, and Texas.

^dEnergy Information Administration, *Financial Statistics of Major U.S. Publicly Owned Electric Utilities 1994*, DOE/EIA-0437(94)/2 (Washington, DC, December 1995), p. 458.

^eThe territory served by WAPA includes 15 Central and Western States of Arizona, California, Colorado, Iowa, Kansas, Minnesota, Montana, Nebraska, Nevada, New Mexico, North Dakota, South Dakota, Texas, Utah, and Wyoming. The WAPA's authority was lengthened through the Hoover Power Plant Act of 1984 to constrain customer utilities to address certain conservation activities and to retain a part of customers' power allocations if they did not follow.

^fD. J. Muchow and W. A. Mogel, *Energy Law and Transactions* (Matthew Bender, April 1996), p. 53-20.

Note: Although it is not a law, the Uniform Division of Income for Tax Purposes Act (UDITPA)—which provides that the sale of electricity is sourced for apportionment purposes to the ultimate destination State—has been adopted in some form by 44 States from a total of 47 States that impose a corporate income tax. Public laws before 1935 were sourced differently than those after 1935. For more information on the power marketing administrations, refer to Energy Information Administration, *Financial Statistics of Major U.S. Publicly Owned Electric Utilities 1994*, DOE/EIA-0437(94)/2 (Washington, DC, December 1995).

Source: This inset is based on information compiled by the Office of Coal, Nuclear, Electric and Alternate Fuels from various documents. These documents include *Congressional Quarterly* as well as others published by the following organizations: the Congressional Research Service, Government Institutes, Inc., the Council on Environmental Quality, the General Accounting Office, and the Federal Energy Regulatory Commission. Also refer to D. J. Muchow and W. A. Mogel, *Energy Law and Transactions* (Matthew Bender, April 1996).

In addition to the preceding statutory background regarding the electric power industry, the inset below provides a synopsis of a related subject—U.S. Supreme

Court cases and decisions that have had major impacts on the industry.

Major U.S. Supreme Court Cases Affecting the Electric Power Industry^a

Court Case	Date	Decision
Munn v. Illinois (94 U.S. 113)	1877	The Supreme Court establishes the rights of government to regulate and set rates for companies that provide vital public services in a business environment.
Smyth v. Ames (169 U.S. 466)	1898	The Supreme Court decrees just compensation on fair value. The decision in this case upheld the right of the State to regulate the prices charged to the public by a business "affected with a public interest."
Rhode Island PUC v. Attleboro (273 U.S. 83)	1927	The Supreme Court declares that selling electricity interstate cannot be regulated by a State.
Ashwander v. TVA (297 U.S. 288)	1936	The Supreme Court upholds the constitutionality of the Tennessee Valley Authority.
Electric Bond & Share v. SEC (303 U.S. 419)	1938	The Supreme Court upholds the Public Utility Holding Company Act of 1935.
Tennessee Electric Power Co. v. Tennessee Valley Authority (306 U.S. 118)	1939	The Supreme Court rules in TVA's favor, despite the claims that TVA threatened the large investments already made by privately owned utilities. This ruling resulted in TVA becoming a major electricity supplier in the region.
F.P.C. v. Hope Natural Gas (320 U.S. 591)	1944	The Supreme Court closes a longstanding dispute by allowing either original or replacement cost accounting in utility rate making, so long as just and reasonable rates result.
Otter Tail Power Co. v. United States (410 U.S. 366)	1973	The Supreme Court upholds finding that Otter Tail Power Co. violated Section 2 of the Sherman Act by refusing to sell or wheel wholesale power to proposed municipal systems.

Major U.S. Supreme Court Cases Affecting the Electric Power Industry (Continued)

Court Case	Date	Decision
FPC v. Conway Corp. (426 U.S. 271)	1976	The Supreme Court states that FERC, in setting wholesale rates, must consider allegations that the proposed rates are discriminatory and anticompetitive in effect.
FERC v. Mississippi (456 U.S. 742)	1982	The Supreme Court upholds the constitutionality of PURPA in regards to its preemptive effect on the States' authority.
American Paper Institute v. American Electric Power Service Corp. (461 U.S. 402)	1983	The Supreme Court upholds the constitutionality of FERC's cogeneration rules promoted pursuant to PURPA.
Nantahala Power & Light Co. v. Thornburg (476 U.S. 953)	1986	Among other outcomes, the Supreme Court confirms that FERC has exclusive authority over wholesale electric rates.
Mississippi Power & Light Co. v. Mississippi ^b (487 U.S. 354)	1988	The Supreme Court determines that FERC authority is controlling and that a State commission is obligated to honor a FERC order. The Court stated "FERC-mandated allocations of power are binding on States, and States must treat those allocations as fair and reasonable when determining retail rates." ^c
Duquesne Light Co. v. Barasch ^d (488 U.S. 299)	1989	"U.S. Supreme Court held that absent any showing that a State's rate-making methodology results in unreasonable rates that throw into jeopardy the financial integrity of the utilities or otherwise fail to compensate shareholders for their risks of investment, no impermissible taking exists. Further, the Constitution of the United States does not mandate any particular rate-making methodology for State regulatory commissions." ^e

^aThis inset highlights the major U.S. Supreme Court cases that affect the electric power industry, stating the final decision of the Court without discussing in detail the contents of the case.

^bThis case, Mississippi Power & Light Co. v. Mississippi, continues the holding found by the U.S. Supreme Court in the Nantahala Power & Light Co. v. Thornburg case.

^cW. F. Fox, Jr., *Regulatory Manual Series: Federal Regulation of Energy* (Shepard's/McGraw-Hill, Inc., 1993), p. 149.

^dThis case is a final construction work in progress (CWIP) case. FERC issued a CWIP rule effective July 1, 1983. This means that a utility may include, in its rate base, up to 50 percent of its CWIP costs for ongoing construction projects and for the costs of nuclear fuel in the process of fuel refinement, conversion, enrichment, and fabrication. In addition, the rule continues to permit utilities to include all CWIP costs associated with pollution control and fuel conversion facilities. See W. F. Fox, Jr., *Regulatory Manual Series: Federal Regulation of Energy* (Shepard's/McGraw-Hill, Inc., 1993), p. 150.

^eW. F. Fox, Jr., *Regulatory Manual Series: Federal Regulation of Energy* (Shepard's/McGraw-Hill, Inc., 1993), p. 153.

FERC = Federal Energy Regulatory Commission.

TVA = Tennessee Valley Authority.

PG&E = Pacific Gas & Electric Company.

PURPA = Public Utility Regulatory Policies Act.

PUC = Public Utility Commission.

Source: This inset is based on information compiled by the Office of Coal, Nuclear, Electric and Alternate Fuels from various documents from the Department of Energy Library. For more information, refer to D. J. Muchow and W. A. Mogel, *Energy Law and Transactions* (Matthew Bender, April 1996); and W. F. Fox, Jr., *Regulatory Manual Series: Federal Regulation of Energy* (Shepard's/McGraw-Hill, Inc., 1993).

Part II:

The U.S. Electric Power Industry in Transition to Competition

5. Factors Underlying the Restructuring of the Electric Power Industry

Introduction

In recent years, economists and public policy analysts have extolled the advantages of competition over regulation and have promoted the idea that free markets can drive down costs and prices by reducing inefficiencies. Competitive industries may also be more likely to spur innovations with new technologies. Recent actions with regard to electric power by legislators and regulators in the United States are evidence of the changing approach to dealing with what until recently has been a regulated monopoly. Originally, protecting consumers was a primary motivation for decisions to impose regulatory constraints on the industry. Today, legislators and regulators are making laws and rules that promote competition across the economy for the same purpose, because they believe that consumers will benefit more from an industry whose members must compete for customers than from an industry composed of regulated monopolies.

One example is the 1999 revocation of the Bank Act of 1933. Like the Public Utility Holding Company Act of 1935 mentioned in Chapter 2 and later outlined in Chapter 4, it was another piece of Depression-era legislation that was believed to have become obsolete. That law had been passed to separate commercial banking from investment banking (the underwriting of securities). Subsequent pressure from both commercial and investment bankers and from the insurance industry, promoting synergies that the Act was ostensibly constraining, led to its repeal.

The most important and controversial sections of the Telecommunications Act of 1996, and the Federal Communications Commission's regulations implementing it, concern the unbundling of the local phone company's network elements down to the level of virtual space (bandwidth) within the individual telephone line leading to a residence. The same thinking is now being applied to the electric power industry in

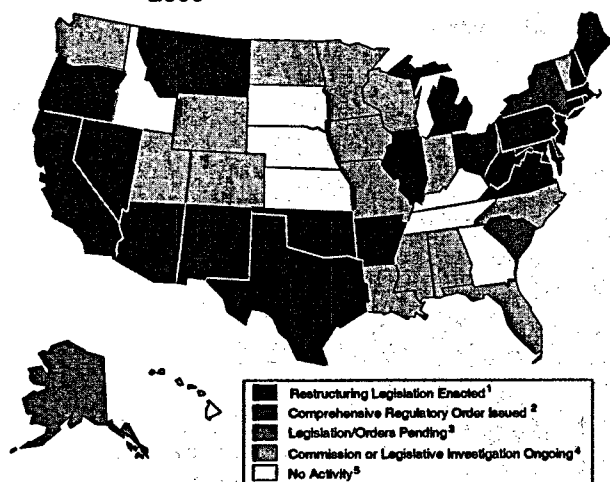
that it is now a target for unbundling along similar lines, with power generation and sales being untangled from transmission and distribution services.⁴⁷ Other examples of this changed climate can be found throughout the State and Federal levels as well as other countries around the world. In the United States, the Energy Policy Act of 1992 (EPACT) was passed by Congress to promote competition in electricity generation. The recent spate of generating asset sales (some utilities with enormous holdings of generating capacity have sold or are planning to sell their entire inventories) is at least partly a result of EPACT. In 1998, retail sales in deregulated markets occurred in 11 States.⁴⁸ With the exception of Missouri, all of these States had deregulated market sales in the industrial sector and all but Idaho, Montana, and Rhode Island had sales to commercial customers in deregulated markets. Those that did not have residential sales in deregulated markets were Idaho, Missouri, Montana, and Washington. As of July 1, 2000, 24 States and the District of Columbia had passed legislation or issued regulatory orders to restructure the electric power industries within their borders. Only eight States have taken little or no action toward restructuring (Figure 23). This changed climate and the legislative and regulatory actions that have resulted are one of the three factors underlying restructuring that are outlined in this chapter.

For most of the industry's history, consumers welcomed the protection that regulation afforded them and felt that this means of oversight assured them of fair prices for electricity. Now, however, consumers themselves are pushing for competition (to both lower prices and increase the variety of suppliers such as green power producers) and regulatory reform. The main thrust is coming from large industrial users of electricity who, in some areas of the United States, have been burdened by high electricity prices while their competitors in other areas pay far less for their electricity. These price differentials are the second factor underlying the restructuring of the industry.

⁴⁷ P. Huber, "Is a Breakup Next? Not Likely," *The Wall Street Journal* (April 4, 2000), p. A26.

⁴⁸ California, Idaho, Illinois, Missouri, Montana, New Hampshire, New York, Oregon, Pennsylvania, Rhode Island, and Washington.

Figure 23. Status of State Electric Utility Deregulation Activity, as of July 2000



¹Arizona, Arkansas, California, Connecticut, Delaware, District of Columbia, Illinois, Maine, Maryland, Massachusetts, Michigan, Montana, Nevada, New Hampshire, New Jersey, New Mexico, Ohio, Oklahoma, Oregon, Pennsylvania, Rhode Island, Texas, Virginia, and West Virginia.

²New York.

³Alaska and South Carolina.

⁴Alabama, Colorado, Florida, Indiana, Iowa, Louisiana, Minnesota, Mississippi, Missouri, North Carolina, North Dakota, Utah, Vermont, Washington, Wisconsin, and Wyoming.

⁵Georgia, Hawaii, Idaho, Kansas, Kentucky, Nebraska, South Dakota, and Tennessee

Source: Energy Information Administration, http://www.eia.doe.gov/cneaf/electricity/chg_str/regmap.html.

A third factor that has had a significant impact on restructuring is the technological innovation in the production of electricity. Nonutilities, using recently improved aero-derivative gas turbine technologies to generate electricity, can now do so cheaply enough that merchant plants are being built in many areas of the country where they are permitted.⁴⁹ Today, with one exception,⁵⁰ the capital costs and both the fixed and variable operations and maintenance costs of combined-cycle plants, and conventional and advanced combustion turbines, are lower than the traditional baseload coal and nuclear technologies.⁵¹ Also, the advanced generators are cleaner than coal plants and some are more efficient. Today's regulatory environment includes

⁴⁹ An exception is Florida, where it was ruled that merchant plants planning to sell their power outside State boundaries cannot be built in the State.

⁵⁰ Variable operations and maintenance costs at nuclear plants are less than those at combined-cycle plants.

⁵¹ Energy Information Administration, *Assumptions to the Annual Energy Outlook*, DOE/EIA-0554 (Washington DC, January 2000), Table 37, Cost and Performance Characteristics of New Central Station Electricity Generating Technologies.

⁵² The Clean Air Act Amendments of 1990 established the Environmental Protection Agency's Acid Rain Program where allowances permitting the emission of sulfur dioxide may be bought and sold on the open market. Similarly, the Amendments led to the establishment of the Ozone Transport Commission which formed a market, albeit regionally limited, for nitrogen oxide allowances.

⁵³ T.R. Kuhn, et al., "Electric Utility Deregulation Sparks Controversy," *Harvard Business Review* (May/June 1996), p. 150.

market incentives to reduce certain types of pollution.⁵² Nonutilities are also able to put advanced generators into operation quickly, sometimes as an alternative to utility capacity that is already built.

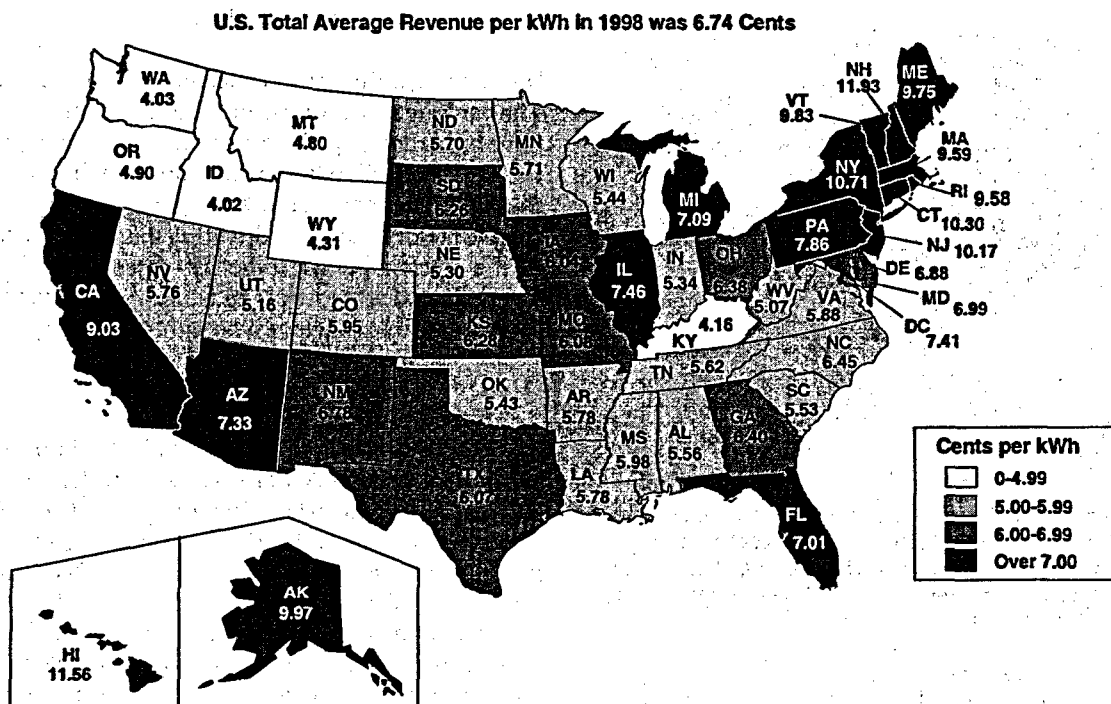
The banking industry and telecommunications industry have been discussed as points of comparison for the first factor, the changing climate of economic and regulatory thinking. The following sections analyze the more quantifiable factors that are motivating the structural changes in the electric power industry—price differences and technological advances. The analyses include EIA data to measure these factors where they are relevant.

Price Differences

While restructuring originated with the Public Utility Regulatory Policies Act of 1978, large differences in the retail prices of electricity have continued to motivate some to advocate expanded restructuring. The current structure of the electric power industry, as mentioned above, provides only a limited number of retail electricity customers—mostly in Pennsylvania, California, Massachusetts, Oregon, and Washington—with the opportunity to purchase electricity from alternative suppliers. Further restructuring of the industry holds the possibility of allowing more choice for more consumers. Many industrial companies, because they are large consumers of electricity and have a lot to gain if they can reduce their average price of electricity by choosing another provider, are especially prone to advocate further restructuring. They argue that price differentials among utilities provide an advantage to the competitor who is situated in an area with lower electricity prices, and that all consumers should have access to cheaper electricity. Some industrial consumers, who have threatened to purchase power from lower-priced providers, move the location of their companies, or generate their own electricity, often have "succeeded in wringing lower prices from their traditional electric utilities."⁵³

In the United States, the average revenue received per unit of electricity sold, i.e., the price to all retail consumers, varies substantially by State (Figure 24). In 1998, the States with average prices of more than 9.5

Figure 24. Average Revenue per Kilowatthour for All Sectors by State, 1998



kWh = Kilowatthour.

Note: The average revenue per kilowatthour of electricity sold is calculated by dividing revenue by sales. Sales in deregulated retail electricity markets are not included.

Source: Energy Information Administration, Form EIA-861, "Annual Electric Utility Report."

cents per kilowatthour were the six New England States, New York, New Jersey, Alaska, and Hawaii. Since the 1996 edition of this report, the average revenue from electricity sales to all consumers in the United States has declined from 6.9 cents per kilowatthour to 6.7 cents per kilowatthour.⁵⁴ It is not coincidental that many of the States leading the restructuring movement are among the States with high prices. They see restructuring as a means of lowering prices. In contrast, States with average prices below 6 cents per kilowatthour are still scattered throughout the country. Most have average prices for all consumers that are less than one-half those in States with the highest average revenue. These States have less incentive than the higher-cost States to restructure their electricity markets. A similar geographic pattern exists for average electricity prices received from industrial consumers, although industrial consumers yield one-third lower average revenues than all retail customers (Figure 25).⁵⁵

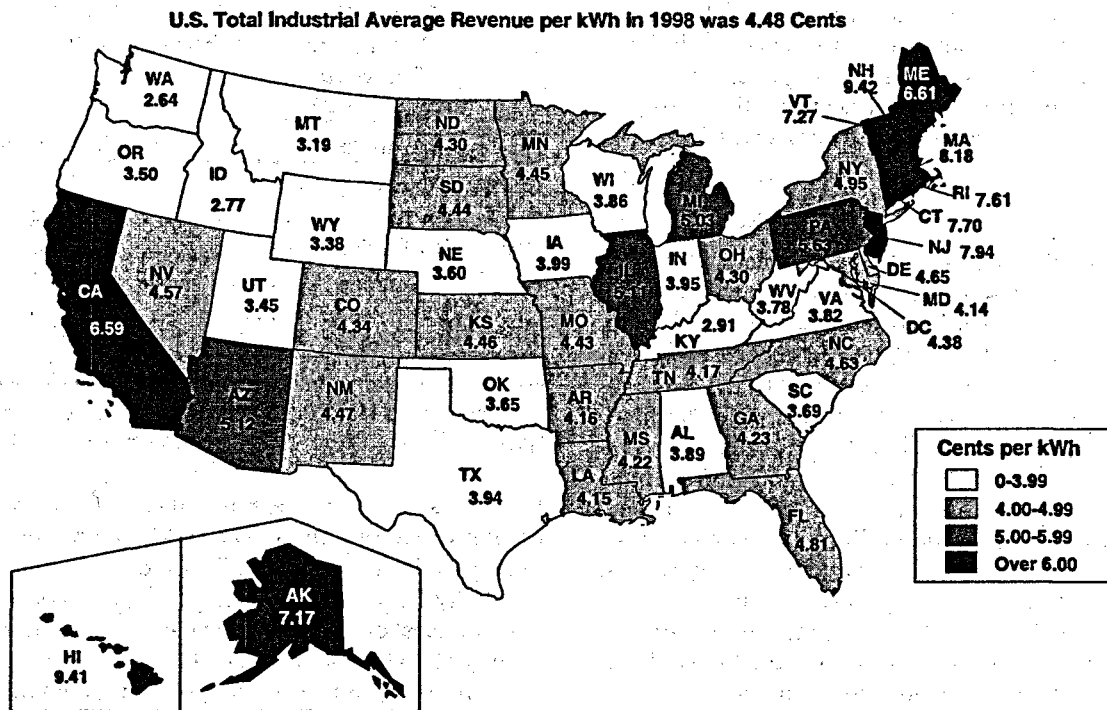
Large industrial electricity consumers typically pay less because it is less costly to service one large customer than many small ones. With this power, industrial consumers have played a substantial role in motivating the restructuring of the electric power industry. Their bargaining power is reflected in the declining trend of industrial prices relative to those paid for all consumers (Figure 26). The relative price industrial consumers paid for electricity rose from the mid-1960s until 1983, then declined from 1983 through 1997, then rose slightly in 1998, but not to the level it had been in 1996. Because real average revenues from both groups have been falling since 1983, the relatively lower revenues for industrial consumers indicate that their average price has been falling faster than the average price charged to all consumers.

Over the years, utilities have developed programs to help lower the price of electricity to the industrial sector.

⁵⁴ Both numbers are in nominal units.

⁵⁵ Because industrial consumers usually use larger amounts of electricity than other consumers, and because they usually take it at higher voltages, the cost of providing each unit of electricity to them is lower.

Figure 25. Average Revenue per Kilowatt-hour for the Industrial Sector by State, 1998

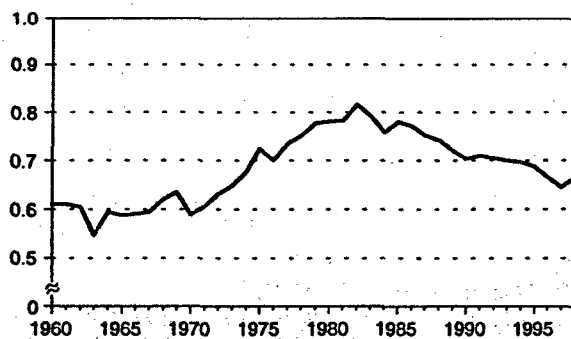


kWh = Kilowatt-hour.

Note: The average revenue per kilowatt-hour of electricity sold is calculated by dividing revenue by sales. Sales in deregulated retail electricity markets are not included.

Source: Energy Information Administration, Form EIA-861, "Annual Electric Utility Report."

Figure 26. Relative Average Revenue of Electricity Sales: Ratio of Industrial Consumers to All Consumers, 1960-1998



Source: Energy Information Administration, *Annual Energy Review 1998*, DOE/EIA-0384(98) (Washington, DC, July 1999), Table 8.13.

They traditionally have relied on alternative rate design approaches, such as interruptible service and time-of-use rates to reduce the time-variation of demand by the industrial sector. The programs also use technological approaches, such as thermal storage. A number of utilities have developed flexible custom measure programs, which allow industrial energy users and utilities to work together to identify cost-effective programs.

Technological Advances

Restructuring has been sustained primarily by technological improvements in gas turbines. "In areas with cheap... natural gas—most notably the United States—gas turbines [are] the least cost option [for new electricity generating capacity].⁵⁶ These improvements also have recast economies of scale in electric power generation technologies. No longer is it necessary to build a 1,000-megawatt generating plant to exploit economies of scale.

⁵⁶ H.R. Linden, "The Revolution Continues," *The Electricity Journal* (December 1995), p. 54.

Combined-cycle gas turbines reach maximum efficiency at 400 megawatts, while aero-derivative gas turbines can be efficient at scales as small as 10 megawatts.⁵⁷ Indeed from 1996 through 1998, gas-fired and gas- and oil-fired capacity brought on-line was almost two-thirds of the total. The average capacity of these units was 65 megawatts.⁵⁸

In its modeling of the electric power industry, the Energy Information Administration (EIA) compares the estimates of the costs of different generating technologies. In its forecasts, "it is assumed that the selection of new plants to be built is based on least cost, subject to environmental constraints."⁵⁹ The reference case forecast released by EIA in late 1999 projects that, of the 300 gigawatts of new generating capability projected to be added by electric generators between now and 2020, 90 percent will be either combined-cycle or combustion turbine technology (Table 7)⁶⁰ as nonutilities move toward less capital intensive projects.⁶¹ Both technologies are designed primarily to supply peak and intermediate capacity but combined-cycle technology can also be used to meet baseload needs. The reduction in baseload nuclear capacity also has an impact on the electricity outlook after 2010. Almost half of the new combined-cycle capacity projected over the entire forecast period is expected to be brought on line in those 10 years, due in part to nuclear retirements. Another relative advantage of combined-cycle technology as a source of baseload capacity is the shorter leadtime needed for construction.

Table 7. Total Projected Additions of Electricity Generating Capability for Electric Generators by Technology Type, 1999-2020 (Gigawatts)

Technology	Capability Additions
Coal Steam	21.1
Combined Cycle	135.2
Combustion Turbine/Diesel ...	133.8
Fuel Cells	0.1
Renewable Sources	9.7
Total	299.9

Source: Energy Information Administration, AEO2000 National Energy Modeling System run AE02K.D100199A.

Both advanced and conventional combined-cycle technologies require only 3 years while a coal or nuclear plant needs 4 years.⁶² H.R. Linden writes in *The Electricity Journal* that "under pressure of competition, the all-in cost of a combined-cycle plant has dropped to \$450 per kilowatt, less than half that of a new clean coal plant. In combined-cycle configurations, heat rates have dropped. This has made natural gas at \$2.50/million Btu competitive with coal in terms of variable cost when the much lower non-fuel operating and maintenance costs of gas are figured in."⁶³

The following chapter outlines the major issues that are framing the current debate over Federal initiatives to facilitate the industry's transition to a competitive market environment.

⁵⁷ R.E. Balzhiser, "Technology - It's Only Begun to Make a Difference," *The Electricity Journal* (May 1996).

⁵⁸ Energy Information Administration, *Inventory of Nonutility Electric Power Plants in the United States 1998*, DOE/EIA-0095(98)/2 (Washington, DC, December 1999), p. 7 and EIA, *Inventory of Electric Utility Power Plants in the United States 1999*, DOE/EIA-0095(99) (Washington, DC, November 1999), p. 11.

⁵⁹ Energy Information Administration, *Annual Energy Outlook 2000*, DOE/EIA-0383(2000) (Washington, DC, December 1999), p. 233.

⁶⁰ Energy Information Administration, AEO2000 National Energy Modeling System run AE02K.D100199A.

⁶¹ Remarks of Jay Hakes, Administrator, Energy Information Administration, North American Gas Strategies Conference (Calgary, Alberta, October 19, 1998).

⁶² Energy Information Administration, *Assumptions to the Annual Energy Outlook*, DOE/EIA-0554 (Washington DC, January 2000), Table 37, Cost and Performance Characteristics of New Central Station Electricity Generating Technologies.

⁶³ H.R. Linden, "Operational, Technological, and Economic Drivers for Convergence of the Electric Power and Gas Industries," *The Electricity Journal* (May 1997).

6. Federal Legislative Initiatives

Introduction

Even with the changes that have been spurred by the factors discussed in the previous chapter, there are still statutory and regulatory limitations at both the Federal and State levels⁶⁴ on how quickly and how far restructuring can proceed. This chapter examines the restructuring initiatives of the U.S. Congress. A number of bills were introduced in the 106th Congress as well as in the past two Congresses which dealt with the deregulation of the electricity industry. Hearings, debates, and panels were held to determine the issues that must be addressed and decided. All groups associated with the electric power industry have been given a chance to be heard. As of July 1, 2000, 18 legislative proposals dealing with the electric power industry were pending in the House of Representatives and 13 in the Senate.⁶⁵ Some of these bills addressed all of the issues surrounding the restructuring of the industry and are considered "comprehensive" legislation. Others addressed several closely related issues and still others concentrated on just one of the issues, for example bulk power reliability or tax-exempt financing by governmentally owned utilities. The latter have come to be known as "stand-alone" restructuring legislation. Stand-alone proposals receive strong support among some groups because they believe that this type of legislation can move through the legislative process quickly while others contend that this is a short-sighted and unsatisfactory "piece-meal" approach.

The Clinton Administration has been pressing Congress to reach consensus and enact comprehensive legislation without further delay.⁶⁶ The Administration has stressed

that more delays will result in a significant decrease in the reliability of the Nation's supply of power due to the ever-increasing demand for electricity coupled with the fact that needed investments in new generating capacity are being stymied due to investors' uncertainties during the industry's transition. The Administration had also made it known that, although reliability is at the forefront of the critical issues, they were not in support of a stand-alone bill that addressed reliability. However, some committee members stressed the necessity of such action if a workable comprehensive proposal could not be ironed out quickly. Consequently, the Senate Energy and Natural Resources Committee came to a decision in late June, 2000 to end their pursuit of comprehensive restructuring legislation because it was unlikely that it could be promulgated before the current Congress ends. Instead, they unanimously reported the stand-alone reliability legislation introduced by Senator Slade Gorton (R-WA).⁶⁷ This bill "... would pave the way for FERC to designate the North American Electric Reliability Organization ... as the developer and enforcer of electric reliability standards in the United States, under Federal Energy Regulatory Commission (FERC) supervision. The Committee approved the bill with an amendment that reflects industry consensus on State vs. Federal jurisdiction over reliability."⁶⁸

On the House of Representatives side, Commerce Committee members have stated that they are still hoping to move ahead with a full-committee mark-up of a comprehensive bill before the end of this year's session.⁶⁹ This bill was the only comprehensive proposal to move forward in the 106th Congress. The reason for this

⁶⁴ While each of the States have examined retail competition and most of them have taken steps toward that end, there is a consensus among many interested parties that there must be a Federally guided transition to competition to ensure reliability of the national grid.

⁶⁵ In the House of Representatives, legislation dealing with electricity deregulation is introduced and referred to the Energy and Power Subcommittee, chaired by Congressman Joe Barton (R-TX). Once this Subcommittee has marked-up a bill, it is passed on to the full committee, the Committee on Commerce, chaired by Congressman Tom Bliley (R-VA). In the Senate, legislation dealing with electricity deregulation is introduced and referred to the Subcommittee on Water and Power, chaired by Senator Slade Gorton (R-WA) then passed on to the full committee, the Energy and Natural Resources Committee, chaired by Senator Frank Murkowski (R-AK).

⁶⁶ In early 1999, the Administration submitted to Congress a comprehensive restructuring proposal entitled "The Comprehensive Electricity Competition Act." It was introduced by Senator Frank Murkowski (R-AK) on May 13, 1999. See Appendix C for a summary.

⁶⁷ Refer to Appendix C for details on S. 2071, "The Electric Reliability 2000 Act," introduced by Senator Slade Gorton (R-WA).

⁶⁸ "Senate Panel Abandons Restructuring Legislation; Approves Reliability Bill," *Public Power Daily* (June 21, 2000).

⁶⁹ This bill is H.R. 2944, "The Electricity Competition and Reliability Act of 1999," introduced by Congressman Joseph Barton (R-TX) on September 24, 1999. See Appendix C for a summary.

Major Electric Power Industry Restructuring Issues Before Congress

- Mandatory participation in a regional transmission organization (RTO)
- Bulk power reliability
- Nuclear decommissioning provisions
- Transmission expansion and construction
- Reform of the Tennessee Valley Authority and Federal power marketing administrations
- Federal authority to regulate retail sales, protect retail consumers, or regulate local grid interconnections
- Utility mergers
- Public benefits fund
- Retail net metering
- Emissions caps and standards for generators
- IRS restrictions on "private use" of municipal electric systems
- State/Federal jurisdiction clarification
- Retail sales to Federal agencies
- Retail reciprocity
- Extension of Order 888 wholesale wheeling rules to transmission by municipals, cooperatives, Federal power marketing administrations, and the Tennessee Valley Authority
- Renewable portfolio standards
- Repeal of PUHCA and Section 210 of PURPA^a

^aRepeal of PUHCA and Section 210 of PURPA are discussed in more detail later in this Chapter.

seeming lack of progress can be attributed to the fact that reaching compromise and consensus on the number of issues involved in restructuring the electric power industry is a monumental task. The inset box above lists the major issues that have been considered and debated. Underlying each of these issues are complex details which must be addressed. In addition, the pro and con arguments of a vast number of stakeholders with diverse interests have been heard and must be taken into account. The committee members themselves have been divided on various issues and must make decisions that will benefit not only the national economy and the industry, but also their varied constituencies. For instance, members who represent States or districts that already enjoy lower than average rates for electricity are concerned that certain actions, which may benefit the Nation as a whole, could result in an increase in rates for their electorate.

Major Issues Under Debate

The following paragraphs detail several of the more controversial of the issues mentioned above (reliability, regional transmission organizations, a renewable portfolio standard, and repeal of the Public Utility Holding Company Act of 1935 (PUHCA) and the Public Utility Regulatory Policies Act of 1978 (PURPA)) followed by a

synopsis of the Clinton Administration's Comprehensive Electricity Competition Plan.

Reliability

Voluntary compliance by electric utilities with procedures for ensuring the reliability of the power system, which were established by the North American Electric Reliability Council (NERC) and its member Regional Reliability Councils, has worked effectively over the past three decades. However, with the emergence of competition and the multitude of changes taking place in the industry over the past few years, industry leaders and government officials are concerned that the reliability of the system may be threatened. Many officials believe that a voluntary approach is no longer adequate, and that Federal legislation establishing mandatory reliability rules is required to ensure that competition does not compromise the reliability of the transmission system. A number of House and Senate bills contain provisions that would lead to mandatory reliability standards for electric utilities to follow.

Administration and enforcement of mandatory reliability standards is also an issue. One approach suggested in pending Federal legislation, would be to create an independent reliability organization, such as NERC, with FERC having some sort of oversight responsibility

for establishing the reliability standards. The appropriate role of the States in establishing and enforcing standards is also an issue. State regulators want to maintain some control over the quality of service received by customers in their respective States. Federal legislation dealing with reliability will have to address, in some manner, the appropriate organization structure for enforcing reliability standards, and jurisdictional authority between Federal and State regulators.

In August of 1999, Secretary of Energy Bill Richardson formed DOE's Power Outage Study Team. The Team's purpose was to study significant electric power outages and other disturbances that occurred across the Nation during the summer of 1999 and to recommend appropriate Federal actions to avoid electric power disturbances in the future. The first step was to meet with relevant utilities, independent system operators, and regulators in areas where outages and disturbances occurred. The Team's findings were published in an Interim Report issued in January 2000. Subsequently, three workshops were held to solicit recommendations from electric industry stakeholders on possible approaches to address the issues raised by the Team's findings. A Final Report was given to the Secretary on March 13, 2000, containing the Team's findings along with 12 recommendations for Federal lawmakers. Secretary Richardson stressed that "Congress must move ahead to make changes in the Federal statutory framework to provide the certainty that is needed to achieve reliable electric service in competitive wholesale and retail markets."⁷⁰

Regional Transmission Organization Issues

In December 1999, FERC released Order 2000 calling for the voluntary formation of regional transmission organizations (RTOs). FERC believes that RTOs will facilitate the continued development of competitive wholesale power markets and will lead to improvements in reliability and management of the transmission system. (Chapter 7 has a detailed discussion of Order 2000). In order for an RTO to be fully effective, all of a region's transmission system must be controlled by the RTO. Its effectiveness and the benefits cannot be achieved if portions of the transmission system are left out.

Although voluntary participation in RTOs was requested, FERC has determined that it has the authority

under Sections 205 and 206 of the Federal Power Act to order public utilities, primarily investor-owned utilities, to participate in RTOs on a case-by-case basis, if necessary, to remedy undue discrimination or anticompetitive activities of electric utilities. FERC believes that Federal legislation is needed to reinforce the Commission's authority to order public utilities to participate in an RTO, if the voluntary approach does not succeed. The above authority refers primarily to investor-owned utilities. To cover the entire transmission grid, FERC also needs similar authority with respect to municipal electric utilities, rural cooperatives, and Federally owned utilities.

Renewable Portfolio Standard

There have been a number of proposals for a renewable energy portfolio standard. Such a standard would require that any company selling electricity in a competitive market include some amount of renewable energy as part of its portfolio of generating fuels. The portfolio standard would more or less be competitively neutral, i.e., it would have to impose an equal obligation on any company selling electricity in any State.

Definitions would have to be made regarding which renewable resources were eligible. For instance, the Clinton Administration does not include hydroelectricity in the renewable portfolio section of its restructuring proposal. Purchase requirements would have to be decided upon, and the level of the standard needs to be determined. In addition, enforcement of the standard would have to be addressed as well as penalties for failure to meet the standard.

The main differences among the various renewable portfolio standards proposals are the required renewable share, the timing of the program, the definition of qualifying facilities, and whether or not there is a limit (cap) on the allowable price for renewable credits. For example, the Administration's proposed Comprehensive Electricity Competition Act, submitted to Congress on April 15, 1999, includes a Federal renewable portfolio standard that would apply to all U.S. electricity suppliers. The key provisions of the Act that pertain to a renewable portfolio standard are:

- The required renewable share of electricity sales would be set at 2.4 percent for the years 2000 to 2004, increase to 7.5 percent by 2010, and then

⁷⁰ Copies of the Report of the U.S. Department of Energy's Power Outage Study Team: Findings and Recommendations to Enhance Reliability from the Summer of 1999 are available from DOE's Office of Public Inquiries, (202) 586-5575, and on the Internet at www.policy.energy.gov/electricity/postfinal.pdf.

remain at 7.5 percent through 2015, after which it would expire (sunset).

- Qualifying renewables would include geothermal, biomass (including biomass used in coal-fired plants), solar thermal, solar photovoltaic, wind, and the portion of municipal solid waste (MSW) that consists of biomass products.
- The price for renewable credits would be capped at 1.5 cents per kilowatthour. If the market price for the credits rose above the cap, electricity retailers would be able to purchase credits from the U.S. Department of Energy (DOE) at the 1.5-cent price (with the resulting revenues deposited in a Public Benefits Fund). In that event, the qualifying renewable share actually achieved would fall below the required 7.5-percent share.⁷¹

Critics believe that a renewable portfolio standard will increase costs to consumers. They also argue that customers and the market should be able to select what types of electricity sources are used rather than be mandated to select one over another. These critics also say that promulgating a portfolio would also provide an unfair market advantage to renewable energy technologies. However, supporters argue that the portfolio standard would help diversify the Nation's energy supply and would promote environmentally-benign forms of electricity. Supporters further argue that fledgling renewable energy industries would receive a much-needed boost with an increased market demand for renewables.

Repeal of PUHCA

Although the relevancy of PUHCA's provisions are in question today due to the current transitional state of the electric power industry, there is little question that 6 decades ago PUHCA achieved what it was designed to do—break up large, powerful trusts that abused their powers over the Nation's electric and gas distribution networks. However, in today's environment of increasing electric industry competition, there are those who believe that PUHCA's regulations are antiquated and are now impeding the transition to competition. Conversely, others believe strongly that, until the industry completes the transition, PUHCA's regulations must stay in effect in order to protect consumers.

Over the years, the petition for PUHCA repeal has, for the most part, been based on two arguments—that PUHCA has already achieved its goal of restructuring in order to make holding companies manageable and regulated, and that it has been rendered obsolete because of changes that have occurred in the latter part of this century which preclude the holding company abuses of yesterday.⁷² They are as follows:

- The development of an extensive disclosure system for all publicly held companies
- The increased competence and independence of accounting firms
- The development of accounting principles and auditing standards and the means to enforce them
- The increased sophistication and integrity of securities markets and securities professionals
- The increased power and ability of State regulators.⁷³

Supporters of stand-alone PUHCA-repeal legislation believe that speedy passage is of utmost importance, given the rapidly changing makeup of the electric industry. They contend that the current PUHCA provisions prevent all companies from competing on a level playing field, which some believe is a necessity in a competitive market. Under the prevailing law, the SEC imposes the business and financial restrictions which companies feel are unfair in the current changing environment. The major restrictions include the following: prices for wholesale and retail transactions are set by FERC and State utility commissions, respectively; registered holding companies need SEC approval to own electric and gas operations; mergers and acquisitions require regulatory approval; and the types of businesses in which registered holding companies may engage are severely limited, although exempt wholesale generators (EWGs) do not have the same limitations. While other comprehensive energy legislation that has been introduced contains provisions to repeal PUHCA along with provisions aimed at addressing other restructuring issues, certain interests feel that such comprehensive proposals will take far too long to move through the system. They argue that repeal of PUHCA must be promulgated now through stand-alone legislation.

⁷¹ For information regarding EIA's examination of the potential impacts of these proposed provisions, refer to *Annual Energy Outlook 2000*, DOE/EIA-0383(2000) (Washington, DC, December 1999), p. 18.

⁷² For a discussion of these abuses, refer to Chapter 4.

⁷³ For further discussion of these changes, see Energy Information Administration, *The Public Utility Holding Company Act of 1935: 1935-1992*, DOE/EIA-0563 (Washington, DC, January 1993), p. 23.

Those who are against outright repeal of PUHCA are not arguing that the Act should remain in effect in an open market atmosphere. Rather, they believe that the time is not yet quite right for its repeal. Until the Nation has completed the transition to a fully competitive market, the safeguards that PUHCA provides are necessary. They question the wisdom of removing vital consumer protection mechanisms and leaving the door open to anticompetitive practices by monopolies which are at present aggressively taking actions, such as merging and diversifying, perhaps to increase their market dominance. Most opponents of the legislative proposals to repeal PUHCA stress that what they are against is immediate, stand-alone action. Instead, they want to see well-thought-out, comprehensive restructuring legislation that will deal with all deregulation issues, including repeal of PUHCA.

Repeal of PURPA

PURPA was born of the energy crises of the 1970s, which resulted in an intense desire by Congress to reduce the Nation's dependence on foreign oil (and fossil fuels in general) and to diversify the technologies used for electricity generation. PURPA's goal was to cultivate conservation and the efficient use of resources.⁷⁴ It was successful in that it promoted cogeneration, the use of renewable resources, and other energy-efficient technologies, and it was fortuitous in that it also introduced competition by demonstrating that the generation of electricity is not a natural monopoly. But, like PUHCA, PURPA is now being targeted for repeal due to the industry's move to competition. There are many arguments on both sides of the debate over the prudence of eliminating PURPA immediately, eventually, or not at all.

Proponents of stand-alone PURPA-repeal legislation contend that the Act's mandatory purchase obligation is grossly anticompetitive and anticonsumer—anticompetitive because the Government created an artificial market by mandating that utilities buy from QFs, and anticonsumer because numerous studies have estimated that the Act caused utilities (and ultimately, consumers) to pay billions of dollars over present market prices for power. They claim that, although the Act introduced competition, it can hardly be said that it did so in an atmosphere of free market participation, a basic tenet of economic theorists who stress that the rules and prices

must be established by the market—not by the Government. In addition they assert that, because of EPACT's creation of EWGs and its incorporation of competitive policies, PURPA's QF concept has been overtaken by events, i.e., the industry now realizes that nonutilities can cleanly and efficiently provide additional generating capacity.

Those who want PURPA eliminated now say that its mandatory purchase clause is anticompetitive and is therefore impeding the transition to competition. Furthermore, QFs have been receiving long-run avoided-cost rates that today substantially exceed current market prices. These rates were based on past forecasts of sharply rising oil and natural gas prices as well as the expectation of future increases in the demand for electricity and construction of new generating capacity. By the late 1980s and early 1990s, however, oil prices had stabilized, natural gas prices had declined, and excess generating capacity in most regions of the country allowed utilities to buy capacity and energy at much lower prices than had been forecast a decade earlier. The utilities' actual avoided costs dropped lower than in the mid-1980s and were considerably lower than the levels required by the long-term contracts imposed by some State Commissions. Many utilities contend that PURPA has caused dramatic hikes in retail electric rates, and many groups along with these utilities now believe that new regulatory action must be taken to correct past misjudgments.⁷⁵

Forecasters predict that future power generation will be dominated by natural gas. Reformers argue that, based on these forecasts, PURPA becomes irrelevant because natural gas-fired power generation is relatively inexpensive and the most environmentally benign of all the fossil fuels used in electric power generation. As mentioned earlier, some groups contend that PURPA is no longer necessary because its goals have already been achieved—i.e., cogeneration using improved turbine techniques and the use of renewable resources has not only gotten a foothold but has claimed a rather significant share of electric power production. Proponents of repeal further contend that PURPA's environmental and fuel diversification goals will be maintained by the workings of a free market while others are not so sure. Although they may agree that a free market can provide a solution to many of the industry's problems, they seriously question the wisdom

⁷⁴ For a discussion of the events that led to PURPA and how it affected the industry, refer to Chapter 4.

⁷⁵ Energy Information Administration, *Renewable Energy Annual 1995*, DOE/EIA-0603(95) (Washington, DC, December 1995), pp. xxvi-xxvii.

of relying on competition to continue the strides made in the use of renewables and cogeneration techniques. Energy conservation and diversification of generating fuels were mandated by Congress because of the growing dependence on foreign oil and the Nation's concerns about the energy crises of the 1970s. Those fears have faded with the passage of time, but it is argued that it is not out of the realm of possibilities that another crisis could occur. Indeed, some believe that it would be shortsighted and irresponsible to regard energy shortages as merely nightmares of the past and to gamble on the unlikelihood of a similar recurrence. They argue that the Nation cannot be without the ability to cope with such a situation in the future.

Even if dependence on foreign energy sources was not an issue, PURPA supporters stress that common sense dictates that energy be conserved and that electricity generation use more environmentally benign fuels in order to sustain a certain quality of life for future generations.⁷⁶ In addition, some believe that QF policy corrects a market failure—i.e., the price of fossil or nuclear energy is too low based on the costly damage it does to the environment and the fact that those who create the pollution do not pay for it. In this context, some argue that conservation, diversification of fuels, and the use of renewable resources that are not depletable and other fuels that lessen the problems of acid rain and greenhouse gases must continue to be supported.

In addition to PURPA's merits regarding the environment and fuel diversification, its supporters point out that QFs bring increased reliability while decreasing the need for large, costly plants. They contend that today's utilities have too much market power, which makes it necessary for PURPA to continue to give nonutilities a competitive advantage, and until every electricity generator is playing on a level field, PURPA's QF provisions are justified.

There are also those who believe that, while PURPA repeal might be warranted in a competitive electricity supply scenario, such a scenario has not been realized yet. Just as some PUHCA reformers are against immediate piecemeal and stand-alone action, some PURPA reformers believe that repeal should be included in a

comprehensive restructuring bill. They argue that there is no need to push a stand-alone repeal bill through Congress when there is currently other proposed electricity competition legislation that will comprehensively address the restructuring and regulatory issues that warrant legislative action, including repeal of PURPA.

The Administration's Comprehensive Electricity Competition Proposal

The Administration released its revised version of the Comprehensive Electricity Competition Plan in April 1999. The 1999 Plan closely mirrors the Administration's 1998 proposal.⁷⁷ Both are built on the premise that a competitive electric energy market will lower prices, encourage innovation, and allow customers a choice in electric energy suppliers. The Administration's Plan also aims to promote a clean environment, increase the reliability of the national power supply grid, and to aid low-income consumers, rural communities, and Indian tribes.⁷⁸

Several issues that were not adequately developed in the 1998 Plan have since been included in the 1999 Plan. These are:

- Improving prospects for competition in regions served by the Tennessee Valley Authority, the Bonneville Power Administration, and other Federal Power Marketing Administrations
- Encouraging the use of environmentally friendly and reliable technologies
- Enhancing consumer protection
- Enhancing the reliability of our electric system
- Providing support for Indian tribes and consumers in those areas
- Increasing environmental benefits
- Addressing the impact of competition on potentially affected electricity workers.

⁷⁶ This is related to the concept of "sustainable development," which refers to ways of social, economic, and political progress that meet the needs of the present without compromising the ability of future generations to meet their needs. Sustainable development points to ways that the economy can continue to develop without compromising the environment.

⁷⁷ U.S. Department of Energy, *Comprehensive Electricity Competition Plan* (Washington, DC, March 1998).

⁷⁸ Adopted from the fact sheet issued by the Department of Energy on the *Comprehensive Electricity Competition Plan* (April 15, 1999).

The Comprehensive Electricity Competition Plan:⁷⁹

- Supports customer choice through a flexible mandate that would require each utility to permit all its retail customers to purchase power from the supplier of their choice by January 1, 2003. States or unregulated utilities could opt out if they find that consumers would be better served by an alternative policy or the current monopoly system. This approach strikes a balance between the need to spur competition and the tradition of determination of retail electricity policy by States.
- Endorses the principle that utilities should be able to recover prudently incurred, legitimate, and verifiable retail stranded costs that cannot be reasonably mitigated (including assistance for displaced workers). States and non-regulated utilities would continue to determine stranded cost recovery under State laws. The Plan grants FERC "backup" authority to establish a stranded cost recovery mechanism if the State lacks the authority to provide such recovery due to constitutional constraints or jurisdictional gaps.
- Stipulates critical consumer protection initiatives by: (1) requiring all electricity suppliers to publicly disclose information on price, terms, and conditions of their offerings; the type of generation source; and generation emission characteristics; (2) granting all consumers access to competitive retail service; (3) precluding possibilities of "slamming"⁸⁰ and "cramming,"⁸¹ and (4) permitting customers to aggregate their loads.
- Repeals substantive requirements of PUHCA. Provides States and FERC with additional access to books and records of holding companies to assist regulatory authorities in guarding against inter-affiliate abuses.
- Establishes FERC's jurisdiction over mergers/consolidations of electric utility holding companies and generation-only companies, and directs FERC to examine the impact of mergers on the competitiveness of retail markets.
- Authorizes FERC to remedy market power in wholesale markets and further accords the Commission "back up" market power remedies,

including ordering divestiture of assets in cases where States lack necessary authority to remedy retail market power.

- Recommends that the Federal Power Act (FPA) be amended to require FERC to approve the formation of and oversee an organization that prescribes and enforces mandatory reliability standards.
- Creates an Electricity Outage Investigation Board to investigate major electricity outages and report its findings to the Secretary of Energy.
- Recommends that the Secretary of Energy be permitted to convene joint Federal/State meetings to consider transmission capacity additions.
- Recommends amendments to the FPA to provide FERC with the authority to require transmitting utilities to turn over the operational control of their transmission facilities to an independent regional system operator (who should also have planning and reliability responsibility).
- Secures the future of renewable generation through the establishment of a Renewable Portfolio Standard (RPS) to require that 7.5 percent of annual electricity sales be generated from non-hydroelectric renewable sources by 2010. This requirement ends in 2015. The Plan repeals the "must buy" provisions of PURPA, but preserves existing contractual obligations.
- Encourages and supports continued funding of public benefit programs by creating a \$3 billion Public Benefits Fund to provide matching funds for States for low income assistance, energy efficiency and renewables programs, consumer education, and the development and demonstration of emerging renewables technologies.
- With a view to promote renewables, recommends that consumers should be eligible for net metering with respect to very small renewable energy projects.
- Recommends that Indian tribes be assisted to participate in the new electricity markets and that an Office of Indian Energy Policy and Programs be established to evaluate various options in a changing market environment.

⁷⁹ Adopted from the fact sheet issued by the Department of Energy on the *Comprehensive Electricity Competition Plan* (April 15, 1999).

⁸⁰ Slamming is a term used to describe changing a customer's service provider without his or her permission.

⁸¹ Cramming is a term used to describe the inclusion of charges on a customer's bill for services he or she never ordered, authorized, received, or used.

- Clarifies the authority of the Environmental Protection Agency to require a cost-effective interstate trading system for nitrogen oxide pollutant reductions necessary to attain and maintain the National Ambient Air Quality Standards for ozone.
- Ensures that Federal ownership of transmission facilities does not hinder competition by modifying the governing rules of the Tennessee Valley Authority and Federal Power Marketing Administrations.
- Aims to clarify Federal and State authority in several areas. It aims to provide FERC with the authority to order retail transmission, reinforces FERC's jurisdiction over unbundled retail transmission, and extends FERC's authority over municipals and cooperatives. The Plan exempts Alaska and Hawaii from the provisions of the Comprehensive Electricity Competition Act.
- Eliminates private-use restrictions currently imposed on facilities using tax-exempt funds subject to the requirement that tax-exempt financing not be used for generation and transmission facilities in the future.

- Addresses nuclear decommissioning costs and eliminates anti-trust review by the U.S. Nuclear Regulatory Commission.

Conclusion

This chapter has examined Federal-level restructuring actions taken by the U.S. Congress. Table 8 lists the bills that have been introduced into the current Congress that deal with one or more aspects of restructuring the electric power industry.⁸² It is in chronological order (by date of introduction) and begins with the House of Representatives bills followed by the Senate bills. Appendix D provides a summary of each.⁸³ Further details about the status of the proposals and statements made by the committee chairmen, as well as the full text of the bills, can be accessed through the Library of Congress website at <http://thomas.loc.gov>. The following chapter discusses additional Federal-level initiatives—those taken by FERC concerning wholesale power markets and restructuring the U.S. transmission system. Subsequently, Chapter 8 analyzes State-level activities and Chapter 9 looks at investor-owned utility strategies, i.e., mergers, acquisitions, and divestitures.

⁸² As of May 1, 2000, three of these bills are at the forefront of Congressional attention. They are H.R. 2944 (which was the first and only proposal to move out of the Subcommittee to the full Committee), S. 1047 (the Administration's proposal), and S. 2098 (Senator Murkowski's proposal).

⁸³ Bills that are not passed during the current Congress must be reintroduced in the next Congress. Of those which are reintroduced, some will be amended while others may remain the same.

Table 8. Proposed Legislation Influencing the Restructuring of the Electric Power Industry Introduced Into the 106th Congress as of May 1, 2000

Bill	Purpose/Sponsor
<p>H.R. 341</p> <p>Environmental Priorities Act of 1999</p>	<p>Establishes a "Fund for Environmental Priorities" to be funded by a portion of the consumers' savings resulting from retail electricity choice, and for other purposes.</p> <p>Introduced by Representative Robert Andrews (D-NJ) on January 19, 1999.</p>
<p>H.R. 667</p> <p>The Power Bill</p>	<p>Clarifies State authority in matters involving retail wheeling, reciprocity, and recovery of stranded costs, eliminates mandatory purchase provisions contained within the Public Utility Regulatory Policies Act of 1978, repeals the Public Utility Holding Company Act of 1935, and for other purposes.</p> <p>Introduced by Representative Richard Burr (R-NC) on February 10, 1999.</p>
<p>H.R. 721</p> <p>Bond Fairness and Protection Act of 1999</p>	<p>Amends the Internal Revenue Code by restricting tax-exempt bond financing by public power utilities, and for other purposes.</p> <p>Introduced by Representative J.D. Hayworth (R-AZ) on February 11, 1999.</p>
<p>H.R. 971</p> <p>Electric Power Consumer Rate Relief Act of 1999</p>	<p>Amends the Public Utility Regulatory Policies Act of 1978 to allow State regulatory authorities to monitor rates charged by qualifying facilities and to determine whether the facilities meet FERC standards.</p> <p>Introduced by Representative James Walsh (R-NY) on March 3, 1999.</p>
<p>H.R. 1138</p> <p>Ratepayer Protection Act</p>	<p>Repeals Section 210 of the Public Utility Regulatory Policies Act.</p> <p>Introduced by Representative Clifford Stearns (R-FL) on March 16, 1999.</p>
<p>H.R. 1253</p> <p>A Bill to Amend the Internal Revenue Code of 1986</p>	<p>Amends the Internal Revenue Code to restrict the use of tax-exempt financing by governmentally owned electric utilities and to subject certain activities of such utilities to income tax.</p> <p>Introduced by Representative Phil English (R-PA) on March 24, 1999.</p>
<p>H.R. 1486</p> <p>Power Marketing Administration Reform Act of 1999</p>	<p>Provides for a transition to market-based rates for power sold by the Federal Power Marketing Administrations and the Tennessee Valley Authority.</p> <p>Introduced by Representative Bob Franks (R-NJ) on April 20, 1999.</p>
<p>H.R. 1587</p> <p>Electric Energy Empowerment Act of 1999</p>	<p>Amends the Federal Power Act to grant States the authority to oversee and implement restructuring of the electricity industry, repeals Section 210 of the Public Utility Regulatory Policies Act of 1978, repeals the Public Utility Holding Company Act of 1935, and for other purposes.</p> <p>Introduced by Representative Cliff Stearns (R-FL) on April 27, 1999.</p>

Table 8. Proposed Legislation Influencing the Restructuring of the Electric Power Industry Introduced into the 106th Congress as of May 1, 2000 (Continued)

Bill	Purpose/Sponsor
<p>H.R. 1828</p> <p>Comprehensive Electricity Competition Act</p>	<p>Provides a comprehensive approach to restructuring the private and public electricity industry and includes provisions to amend or repeal the Public Utility Regulatory Policies Act of 1978, the Federal Power Act, the Public Utility Holding Company Act of 1935, and for other purposes.</p> <p>Introduced by Representative Thomas Bliley (R-VA) on May 17, 1999.</p>
<p>H.R. 2050</p> <p>Electric Consumers' Power to Choose Act of 1999</p>	<p>Provides a comprehensive approach to electricity restructuring, aims to provide consumers with a reliable source of energy and a choice of electric providers, and for other purposes.</p> <p>Introduced by Representative Steve Largent (R-OK) on June 8, 1999.</p>
<p>H.R. 2363</p> <p>The Public Utility Holding Company Act of 1999</p>	<p>Repeals the Public Utility Holding Company Act of 1935 and enacts the Public Utility Holding Company Act of 1999 to provide for continuing consumer protection by facilitating Federal and State commission access to relevant books and records of all companies in a holding company system.</p> <p>Introduced by Representative W.J.(Billy) Tauzin (R-LA) on June 25, 1999.</p>
<p>H.R. 2569</p> <p>Fair Energy Competition Act of 1999</p>	<p>Directs FERC to prescribe stricter air quality regulations, establishes a National Electric System Public Benefits Board for public purpose programs funded by a capped wires charge assessed to each operator, creates a renewable energy portfolio, amends the Public Utility Regulatory Policies Act of 1978, and for other purposes.</p> <p>Introduced by Representative Frank Pallone, Jr. (D-NJ) on July 20, 1999.</p>
<p>H.R. 2602</p> <p>National Electricity Interstate Transmission Reliability Act</p>	<p>Grants FERC jurisdiction over the creation and operation of an Electric Reliability Organization (ERO) and authorizes FERC to approve and enforce reliability standards for the bulk-power system.</p> <p>Introduced by Representative Albert Wynn (D-MD) on July 22, 1999.</p>
<p>H.R. 2645</p> <p>Electricity Consumer, Worker, and Environmental Protection Act of 1999</p>	<p>Establishes consumer protection mechanisms, addresses stranded cost recovery, electric utility mergers, and standards for a renewable energy portfolio. Requires utilities to transfer certain assets to regulated counterparts or affiliates after deregulation of electricity sales.</p> <p>Introduced by Representative Dennis Kucinich (D-OH) on July 29, 1999.</p>

Table 8. Proposed Legislation Influencing the Restructuring of the Electric Power Industry Introduced into the 106th Congress as of May 1, 2000 (Continued)

Bill	Purpose/Sponsor
<p>H.R. 2756 Fair Competition in Tax-Exempt Financing Act of 1999</p>	<p>Amends the Internal Revenue Code of 1986 to prevent tax-exempt bonds from being used to finance public projects that will compete with private enterprise.</p> <p>Introduced by Representative Ralph Hall (D-TX) on September 15, 1999.</p>
<p>H.R. 2786 Interstate Transmission Act</p>	<p>Places unbundled transmission sold at retail under FERC jurisdiction and allows FERC to determine State or Federal jurisdiction for transmission and distribution facilities. Authorizes FERC to review pricing policies and activities of transmission service and allows for recovery of stranded costs.</p> <p>Introduced by Representative Thomas Sawyer (D-OH) on August 5, 1999.</p>
<p>H.R. 2944 Electricity Competition and Reliability Act of 1999</p>	<p>Provides a comprehensive approach to restructuring the electricity industry and includes provisions to amend or repeal the Public Utilities Regulatory Policies Act of 1978, the Federal Power Act, the Public Utility Holding Company Act of 1935, establish an electric reliability organization, and for other purposes.</p> <p>Introduced by Representative Joseph Barton (R-TX) on September 24, 1999.</p>
<p>H.R. 2947 Home Energy Generation Act</p>	<p>Removes barriers to net metering by amending the Federal Power Act and imposes standards for net metering and interconnection to the electric grid.</p> <p>Introduced by Representative Jay Inslee (D-WA) on September 24, 1999.</p>
<p>S.161 Power Marketing Administration Reform Act</p>	<p>Prescribes guidelines and sets operational requirements on the Federal Power Marketing Administrations and the Tennessee Valley Authority to assist as they transition to a competitive market, and prescribes specifics regarding use of revenue collected through market-based pricing.</p> <p>Introduced by Senator Daniel Moynihan (D-NY) on January 19, 1999.</p>
<p>S. 282 Transition to Competition in the Electric Industry Act</p>	<p>Repeals Section 210 of the Public Utilities Regulatory Policies Act of 1978 and allows for recovery of stranded costs.</p> <p>Introduced by Senators Connie Mack (R-FL) and Bob Graham (D-FL) on January 21, 1999.</p>
<p>S. 313 Public Utility Holding Company Act of 1999</p>	<p>Repeals the Public Utility Holding Company Act of 1935 and enacts the Public Utility Holding Company Act of 1999, and for other purposes.</p> <p>Introduced by Senator Richard Shelby (R-AL) on January 27, 1999.</p>

Table 8. Proposed Legislation Influencing the Restructuring of the Electric Power Industry Introduced into the 106th Congress as of May 1, 2000 (Continued)

Bill	Purpose/Sponsor
<p>S. 386</p> <p>Bond Fairness and Protection Act of 1999</p>	<p>Amends the Internal Revenue Code by eliminating restrictions on public power utilities which impede their ability to provide open access transmission, and restricts the ability of public power utilities to use tax-exempt financing for construction of new facilities.</p> <p>Introduced by Senator Slade Gorton (R-WA) on February 6, 1999.</p>
<p>S. 516</p> <p>Electric Utility Restructuring Empowerment and Competitiveness Act of 1999</p>	<p>Benefits consumers by promoting competition in the electric power industry, and for other purposes.</p> <p>Introduced by Senator Craig Thomas (R-WY) on March 3, 1999.</p>
<p>S. 1047</p> <p>Comprehensive Electricity Competition Act ^a</p>	<p>Provides a comprehensive approach to electricity restructuring and includes provisions to amend or repeal the Public Utilities Regulatory Policies Act of 1978, the Federal Power Act, and the Public Utility Holding Act of 1935, and for other purposes.</p> <p>Introduced by Senator Frank Murkowski (R-AK) on May 13, 1999.</p>
<p>S. 1048</p> <p>Comprehensive Electricity Competition Tax Act</p>	<p>Amends the Internal Revenue Code with respect to tax-exempt private activity bonds to declare that the determination whether any electric output facility bond issued before enactment of this Act is a private activity bond shall be made without regard to any specified permissible competitive action taken by the issuer.</p> <p>Introduced by Senator Frank H. Murkowski (R-AK) on May 13, 1999.</p>
<p>S. 1273</p> <p>Federal Power Act Amendments of 1999</p>	<p>Amends the Federal Power Act, facilitates the transition to more competitive and efficient electric power markets, and for other purposes.</p> <p>Introduced by Senator Jeffrey Bingaman (D-NM) on June 24, 1999.</p>
<p>S. 1284</p> <p>Electric Consumer Choice Act</p>	<p>Amends the Federal Power Act to include reciprocity provisions, recognizes the State's authority to regulate retail electric sales and the local distribution of electric energy, repeals the Public Utility Holding Company Act of 1935 and Section 210 of the Public Utilities Regulatory Policies Act of 1978.</p> <p>Introduced by Senator Don Nickles (R-OK) on June 24, 1999.</p>
<p>S. 1369</p> <p>Clean Energy Act of 1999</p>	<p>Enhances the benefits of the national electric system by encouraging and supporting State programs for renewable energy sources, universal electric service, energy conservation and efficiency, and for other purposes.</p> <p>Introduced by Senator James Jeffords (R-VT) on July 14, 1999.</p>
<p>S. 1949</p> <p>Clean Power Plant and Modernization Act of 1999</p>	<p>Sets emission standards for operating and future fossil fuel-fired generating plants, and for other purposes.</p> <p>Introduced by Senator Patrick Leahy (D-VT) on November 17, 1999.</p>

Table 8. Proposed Legislation Influencing the Restructuring of the Electric Power Industry Introduced Into the 106th Congress as of May 1, 2000 (Continued)

Bill	Purpose/Sponsor
S. 2071 Electric Reliability 2000 Act	Benefits electricity consumers by promoting the reliability of the bulk power system. Introduced by Senator Slade Gorton (R-WA) on February 10, 2000.
S. 2098 Electric Power Market Competition and Reliability Act	Facilitates the transition to a more competitive and efficient electric power market and ensures electric reliability. Introduced by Senator Frank Murkowski (R-AK) on February 24, 2000.
^a This is the Administration's restructuring proposal. Source: Library of Congress website at http://thomas.loc.gov/ .	

7. Wholesale Power Markets and Restructuring the U.S. Power Transmission System

Introduction

While congressional assent is necessary for many of the reforms to the electric power industry, Congress has granted the Federal Energy Regulatory Commission (FERC) authority to make regulations in a number of areas. The purpose of this chapter is twofold. First, it highlights FERC initiatives to promote competitive wholesale power markets over approximately the past 20 years, which have become progressively broader in scope in recent years. Second, it highlights FERC's initiatives in promoting an efficient and reliable power transmission system.⁸⁴ The two areas—promoting competitive wholesale power markets and an efficient power transmission system—are interrelated goals. Having fully competitive power markets depends on creating an efficient, well operating transmission system.

As mentioned in Chapter 3, the power transmission system is one of three major components of the electric power industry; the others are power generation and distribution. The transmission system provides the capability to move electrical power over long distances, producing significant benefits to electric utilities and to electricity customers. One benefit is that large efficient power plants can be built far from where the power is used, and the transmission system or systems can deliver power from those plants to many customers over a broad area at a relatively low cost. This capability was one of the reasons that utilities built large centralized power plants, which now provide most of the Nation's power generation capacity.

Another benefit of today's transmission system is that it provides wholesale electricity customers an opportunity to purchase less expensive power from alternative suppliers such as power marketers or independent power producers. This opportunity, which did not exist until the passage of the Energy Policy Act of 1992 (EPACT), and later expanded in 1996 by FERC's Order

888, is the foundation for creating competitive wholesale power markets.

As the electric power industry becomes more competitive, many of the changes taking place involve the regulation, operation, and control of the transmission system. FERC, the agency responsible for regulating interstate energy commerce and the transmission grid, is at the forefront of these changes. Its objective is to make the power generation sector more competitive by fostering wholesale power markets, and to make the Nation's transmission system more efficient.

FERC Promotes Wholesale Competition and Transmission Efficiency

FERC has long believed that competition in electric power generation could result in lower electricity prices and improved services for wholesale and retail electricity customers. Beginning approximately in the mid-1980s, FERC has issued numerous Orders, Policy Statements, or case rulings designed to promote competition in wholesale power markets and to improve operation of the transmission system. (Table 9 presents a chronological summary of these documents.) FERC's objectives center on five broad functions:

- Introducing market-based rates for wholesale power sales
- Providing nondiscriminatory access to the power transmission system
- Developing guidelines for recovery of stranded costs
- Promoting transparency of information about the bulk transmission system
- Promoting development of regional transmission organizations.

⁸⁴ The transmission system is an interconnected group of lines and equipment for the movement or transfer of electric energy between points of supply and points where it is transformed for delivery to customers or is delivered to other electric systems.

Table 9. Overview of the Federal Energy Regulatory Commission's Efforts Promoting Competition in the Electric Power Industry

Date	Description of FERC Efforts
1985-1991	Prior to the Energy Policy Act, FERC encouraged and approved the use of market-based rates representing one of FERC's initial efforts to make the industry more efficient. Between 1985 and mid-1991, FERC addressed 31 requests to sell wholesale electric power at market-based rates (Notice of Public Conference and Request for Comments on Electricity Issues, Docket No. PL91-1-000, April 1991).
July 1993	FERC issued a policy statement regarding Regional Transmission Groups (RTGs). The purpose of RTGs was to facilitate the provision of transmission services to potential users of the transmission system and to facilitate the resolution of disputes over provision of services. It was believed by FERC that RTGs would encourage negotiated agreements between transmission providers thereby avoiding the need for potentially time-consuming and expensive litigation before FERC (Policy Statement Regarding Regional Transmission Groups, RM93-3-000, July 30, 1993).
May 1994	FERC established general guidelines for comparable transmission access for third parties. Comparable access refers to the belief that owners of the transmission grid should offer third parties access to the grid on the same or comparable basis and under the same or comparable terms and conditions as the transmission owner's use of the system. Comparable access is one of the key ingredients of an open access transmission tariff specified in Order 888 (see below) (67FERC61, 168).
October 1994	FERC issued its Transmission Pricing Policy Statement. Prior to this policy statement, FERC had allowed only postage-stamp and contract path pricing of transmission services. In this policy statement, FERC recognized the need to encourage a variety of other pricing methods that may be more suitable for competitive wholesale power markets (Transmission Policy Statement, RM93-19-001, October 1994, Final Rule Order on reconsideration and clarifying the policy statement, May 22, 1995).
April 1996	FERC issued Order 888, requiring all public utilities that own, control, or operate transmission facilities to have on file an open access non-discriminatory transmission tariff. The Order also permits public utilities to seek recovery of stranded costs associated with providing open access (Order 888, Final Rule, RM95-8-000, and RM94-7-001, April 24, 1996).
April 1996	FERC issued Order 889 establishing the Open Access Same-Time Information System.
December 1996	FERC issued a Policy Statement (Order 592) amending its procedures to evaluate potential mergers between electric utilities. The procedures were designed to streamline the merger application process, and update FERC's evaluation of the merger to consider the merger's effect on competition, its effect on rates, and its effect on regulation.
January 1997 - December 1998	FERC conditionally approved five Independent System Operators (ISOs)—California ISO, ISO-New England, New York ISO, Pennsylvania, New Jersey, Maryland (PJM) ISO (official name is PJM Interconnection), and the Midwest ISO.
December 1999	FERC issued Order 2000 asking all transmission-owning utilities, including non-public utilities, to place their transmission facilities under the control of an appropriate regional transmission organization (RTO). So that utilities could comply with this request, the characteristics and minimum functions of an appropriate RTO were defined in the Order (Order 2000, Final Rule, RM99-2-000, December 20, 1999).

Introducing Market-Based Rates for Wholesale Power Sales

In a regulated environment, wholesale and retail electricity power prices are calculated based on a utility's embedded costs plus a negotiated rate of return on their investments. Because this method ensures that the utility will cover its costs of operation, this method does not have appropriate incentives to motivate a utility to fully evaluate all the risks of an investment. If a utility invests in what turns out to be an uneconomical project, it can still add the costs of the investment to the price it charges for electricity. Thus, the risks and economic consequences of a poor investment are passed to the electricity customer. Another limitation is that the cost-based pricing concept is the antithesis of the objective of promoting competitive wholesale power markets.

To overcome the limitations of cost-based pricing, in the mid-1980s FERC considered 31 applications to use market-based pricing for wholesale transactions, although only a few applications were approved. However, by the mid-1990s, FERC had approved the use of market-based rates for more than 100 power suppliers, and substantial growth in their use had begun.

Currently, 866 companies are eligible to sell wholesale power at market-based rates, including 389 independent power producers, 271 affiliated power marketers and producers, and 206 investor-owned utilities (IOUs) and other utilities (Table 10). Affiliated companies must comply with standards of conduct designed to eliminate

Table 10. Companies Eligible to Sell Wholesale Power at Market-Based Rates, as of May 1, 2000

Type of Company	Number of Companies
Independent Power Marketers ..	389
Affiliated Power Marketers	117
Affiliated Power Producers	154
Investor-Owned Utilities	99
Other Utilities	107
Total	866

Source: Federal Energy Regulatory Commission, online at www.ferc.fed.us/electric/PwrMkt/PM_LIST.htm (May 2000).

abuses and reciprocal dealing between the public utility and its affiliated power marketer.⁸⁵

The use of market-based prices started with bilateral transactions, where buyers and sellers negotiated a price. Since then, a few centralized power markets have been created where a power supplier sells through a power exchange, and wholesale electricity prices are based on the market conditions at the exchange. Centralized power markets have begun in New England; New York; Pennsylvania, New Jersey, Maryland (PJM) region; and California. More are likely to open during the coming years. Without blanket approval to sell power at market-based rates, these competitive centralized markets could not exist.

Providing Nondiscriminatory Access to the Transmission System

Historically, many vertically integrated utilities did not allow independent power suppliers to use their transmission systems. If they were ordered to provide access, the integrated utilities would favor power from their own plants over the independent supplier when the transmission lines became congested. In some instances, the utility would withhold certain types of important transmission services. These practices stymied the growth of competitive power generation markets because they limited the extent to which independent power suppliers could provide service to electricity customers.

EPACT's passage gave FERC broad authority to order transmission-owning utilities to wheel power for wholesale power transactions, and it helped to relieve some of the barriers to using the transmission system. Wheeling occurs when a transmission-owning utility allows another utility or independent power producer to move (or wheel) power over its transmission lines. Although FERC's wheeling authority facilitated creation of competitive wholesale electricity markets, wheeling requests were evaluated on a case-by-case basis, which was sometimes slow and cumbersome. Also, disparities still persisted in the comprehensiveness and quality of transmission services provided by transmission owners to other users. To address disparities in service, in 1994 FERC established a "comparability standard" stating that transmission-owning utilities should offer other transmission users access to their transmission systems

⁸⁵ D.F. Santa, "Analytical Flaws and Practical Pitfalls: Reconsidering FERC's Merchant Affiliate Rules," *The Electricity Journal*, Vol. 11, No. 9 (November 1998).

on the same basis and under the same conditions as they use the transmission systems to service their own electricity customers. FERC also applied the comparability standard case-by-case; when a utility requested approval for market-based rates or approval to merge with another utility, FERC would specify that the utility must incorporate the comparability standard into its transmission tariff as a condition for approval.

Even with more wheeling authority and implementation of the comparability standard on a case-by-case basis, open non-discriminatory transmission access still did not exist universally. In April 1996 FERC took action to correct the lack of universal access by issuing Order 888. At that time, Order 888 was considered the most far-reaching and ambitious project undertaken by FERC to eliminate deterrents to competition in the electric power industry. Order 888 had two basic goals: (1) to eliminate anti-competitive practices and undue discrimination in transmission services through a universally applied open access transmission tariff, and (2) to ensure the recovery of stranded costs a utility might accrue in the transition to competitive markets.

With respect to the first goal, FERC imposed a blanket requirement that all transmission-owning utilities under its jurisdiction must file an open access transmission tariff specifying the terms and conditions for using their transmission systems. The comparability standard was one of the required conditions of the transmission tariff. One significant advantage of a universal transmission tariff was that it eliminated FERC's time-consuming case-by-case evaluation of wheeling requests. Instead, rights, terms, and conditions to wheel power were predefined in the tariff and a company could respond immediately to opportunities in short-term markets that previously were not available to them in a timely manner. Access to the transmission system in a timely manner is essential for a competitive short-term power market to function properly.

Another equally important component of Order 888 was the requirement for transmission owners to functionally unbundle their activities. Functional unbundling required the transmission owner to take transmission service under the same tariff as other transmission users (comparability standard); to separate rates for wholesale generation, transmission, and ancillary services; and to rely on the same electronic information network that its transmission customers rely on to obtain information about prices and available capacity of the transmission system. Essentially, the idea of functional unbundling was to avoid favoritism and discriminatory practices within a vertically integrated utility by separating its

transmission services functions from other business activities in the company.

Order 888 covered other transmission tariff issues such as pricing of transmission services, the application of market-based rates for power sold from new capacity, and other items. (Table 11 provides a summary of the major provisions of Order 888 with respect to open transmission access.) Since issuance of Order 888, all utilities have filed their open access tariffs, and Order 888 is now history. In retrospect, Order 888 represented FERC's first broad sweeping effort to eliminate discriminatory and unfair practices in the management and control of the transmission system.

Developing Guidelines for Recovery of Stranded Costs

The second goal of Order 888 was to ensure that electric utilities are able to recover their sunk costs in a competitive industry. These sunk costs are called stranded costs, or transition costs, and they represent a utility's capital investments that are unrecoverable because of the transition to competition. The rationale for allowing stranded cost recovery is that utilities have invested billions of dollars in facilities under a regulatory regime that allowed cost recovery of all prudent investments. To gain support and cooperation for a successful transition to a competitive industry, and to be consistent with the past decisions, FERC believed it was critical that utilities recover these costs. At the same time, FERC recognized that recovery of stranded costs may delay some of the benefits of competitive power markets.

FERC's Order 888 spelled out under what general conditions a utility is entitled to recover its stranded costs and from whom. As far as entitlements, Order 888 specified that cost recovery at the wholesale level is limited to situations where there is a link between the use of FERC's required open access transmission tariff and the loss of wholesale power customers. FERC went further to specify that recovery of wholesale stranded costs should be assigned to the departing customer. At the retail level, FERC determined that States should have primary jurisdiction over cost recovery resulting from retail competition, although it would entertain requests to recover costs resulting from retail competition when a State does not have the authority.

FERC's concerns for the recovery of wholesale stranded costs may have been overestimated. Since Order 888 was issued, FERC has on record seven stranded costs cases. Moreover, as of April 2000, it had not received a filing for wholesale stranded cost recovery in more than a year

Table 11. Major Provisions of FERC Order 888 on Open Access

<p>Functional Unbundling</p> <p>A utility's uses of its own transmission system for the purpose of engaging in wholesale sales and purchases must be separated from other activities. Corporate unbundling is not required.</p> <ul style="list-style-type: none"> Utilities must take transmission services (including ancillary services) under the same tariff of general applicability as do others. Utilities must state separate rates for wholesale generation, transmission, and ancillary services. Utilities must rely upon the same electronic information network that its transmission customers rely upon to obtain transmission information. 	<p>Reciprocity</p> <p>Transmission customers of jurisdictional utilities who take service under the open access tariff and who own, control, or operate transmission facilities must, in turn, provide open access service to the transmitting utility. This includes municipally owned entities and RUS cooperatives.</p>
<p>Nondiscriminatory Open Access Tariff Requirement</p> <p>By July 9, 1996, jurisdictional utilities that own or control transmission must have filed a single open access tariff that offers both network, load-based services and point-to-point, contract-based services, including ancillary services, to eligible customers comparable to the service they provide themselves at the wholesale level. The rule provides a single <i>pro forma</i> tariff that sets forth minimum conditions for both network and point-to-point services and nonprice terms and conditions for providing those services and ancillary services.</p>	<p>Services to be Provided</p> <p>A public utility must offer transmission services that it is reasonably capable of providing, not just those services that it currently provides to itself and others.</p> <p>Six ancillary services must be included in the open access tariff:</p> <ol style="list-style-type: none"> 1. Scheduling, system control, and dispatch 2. Reactive supply and voltage control from generation sources 3. Regulation and frequency response 4. Energy imbalance 5. Operating reserve—spinning reserve 6. Operating reserve—supplemental reserve. <p>The transmission customer must purchase the first two services from the transmission provider.</p>
<p>Pools and Holding Companies</p> <p>Jurisdictional utilities who are members of tight or loose power pools must file either an individual <i>pro forma</i> tariff or a joint pool-wide <i>pro forma</i> tariff by July 9, 1996. They are not required to take service for pool transactions under that tariff, but are required to file a joint pool-wide tariff no later than December 31, 1996, and begin to take service under that tariff for all pool transactions by that same date. By that date, they must also restructure their ongoing operations and open membership to nonutilities.</p> <p>Public utility holding companies not subject to tight or loose pool requirements are required to file a single system-wide <i>pro forma</i> tariff permitting transmission service across the entire holding company by July 9, 1996.</p> <p>All bilateral economy energy coordination contracts executed before the effective date of this rule must be modified to require unbundling of any economy energy transaction occurring after December 31, 1996.</p>	<p>Pricing</p> <p>The rule does not prescribe rates for network, point-to-point, or ancillary services. Instead, utilities may charge current rates or apply for new transmission rates. Utilities can propose to recover opportunity costs and expansion costs. Crediting for customers' transmission facilities will be permitted on a case-by-case basis. Proposed pricing must conform with FERC's Transmission Pricing Policy Statement.</p> <p>Contract Reform</p> <p>The rule does not void any existing requirements contracts. The functional unbundling requirement applies only to transmission services under new requirements contracts, new coordination contracts, and new transactions under existing coordination contracts.</p> <p>Parties to requirements contracts executed on or before July 11, 1994, may seek modification of such contracts on a case-by-case basis, even if they contain a Mobile-Sierra clause. FERC, however, does not take contract modification lightly and parties seeking to modify contracts will have a heavy burden to demonstrate the need for it.</p>
<p>Customer Eligibility</p> <p>Any entity engaged in wholesale purchases or sales of energy or retail purchases is an eligible customer.</p>	<p>Market-Based Rates</p> <p>Utilities seeking market-based rates for sale of electricity at wholesale from new capacity are no longer required to demonstrate lack of market power in generation. New capacity is that for which construction has commenced on or after the effective date of this rule. For existing generation, FERC will continue its case-by-case approach that includes an analysis of generation market power in first- and second-tier markets.</p>
<p>Source: Adapted from "FERC Finalizes Electric Industry Restructuring Rule," <i>Public Utility Topics</i> (Philadelphia, PA: Coopers & Lybrand, LLP., June/July 1996), No. 96-2, p. 4.</p>	

and a half.⁸⁶ The overwhelming majority of stranded costs awards have been in States that have implemented retail competition. Chapter 8 contains a discussion of stranded costs resulting from States introducing retail competition.

Promoting Transparency of Information About the Bulk Power Transmission System

To follow through with non-discriminatory access to the transmission system, timely and accurate day-to-day information about transmission must be unrestricted and public to all transmission users. To implement this concept, in 1996 FERC issued Order 889 requiring all IOUs to participate in the Open Access Same-Time Information System (OASIS).

The OASIS is an interactive Internet-based database containing information on available transmission capacity, capacity reservations, ancillary services, and transmission prices. The underlying idea of the OASIS is to create an interactive computerized market for transmission-related products and services which is accessible by all qualified users of the transmission system. In that role, the OASIS facilitates the functioning of competitive power markets.

The OASIS became operational in January 1997. Currently, 23 OASIS nodes are on the Internet, and approximately 166 transmission owners participate by providing information about their transmission facilities. Initially the OASIS had operational problems traceable to a lack of common data elements and business practices. This condition made it difficult to compare data between nodes, and to conduct business over multiple nodes. Recently, OASIS developers have adopted a common set of Business Practice Standards to improve the interaction between transmissions providers and customers over the OASIS.⁸⁷ Implementation of these standards should move the OASIS further along in becoming a useful tool in support of a competitive industry.

Promoting Development of Regional Transmission Organizations

Promoting regional transmission organizations (RTOs) is the last of FERC's major objectives discussed in this

chapter. It arguably can be called FERC's most significant and, to some extent, most tumultuous activity undertaken in its effort to create a more competitive and efficient industry.

The concept of regional organizations in the electric power industry has existed for some time. Many regional entities have been created for planning, coordination, or system reliability functions. The most visible are the 10 Regional Reliability Councils that develop standards and procedures to maintain the reliability of the Nation's power system. Some industry observers have noted that perhaps there are too many regional entities, and that regional decision-making authority and responsibility sometimes becomes blurred.

RTOs refer to the idea of organizing the operation, control, and possible ownership of the transmission grid into independent companies or organizations; the process of forming RTOs is also referred to as grid regionalization.⁸⁸ Regional control of the transmission grid has many coordination and efficiency advantages over the current balkanized configuration where each vertically integrated utility operates and controls its own transmission facilities.

FERC's effort to foster grid regionalization consists of three progressively ambitious initiatives. In 1993 FERC issued a policy statement recommending that transmission owners, transmission customers, and other interested parties form regional transmission groups (RTGs) to coordinate transmission planning and expansion on a regional and inter-regional basis (Table 9). A few RTGs were established, but their role has been limited. Although effective for planning purposes, these organizations were usually not vested with appropriate decision-making authority needed to address transmission issues affecting an entire region.

In its next initiative, FERC used a stronger and more ambitious approach to grid regionalization. In Order 888, FERC encouraged the formation of independent system operators (ISOs), whereby utilities would transfer operating control of their transmission facilities to the ISO. Ownership of the facilities would remain with the utility. Utility participation in an ISO was voluntary.

⁸⁶ Personal conversation with the Federal Energy Regulatory Commission, April 3, 2000.

⁸⁷ Federal Energy Regulatory Commission, "Open Access Same-Time Information System and Standards of Conduct-Order 638," (February 25, 2000).

⁸⁸ Regional Transmission Organizations (RTOs) have also been called power pools, regional transmission groups (RTGs), and independent system operators (ISOs). They are all similar in that they represent a grouping of transmission facilities owned by different electric utilities to achieve common objectives. Their missions, scope of responsibilities, and objectives, however, were different.

By encouraging ISO formation, FERC underscored its belief in the importance of unbundling power generation and marketing from operation and control of the transmission grid. An ISO with no economic interest in marketing and selling power could administer fairly the open access transmission tariff and eliminate discriminatory practices, and at the same time achieve the efficiency benefits from regional control of the grid.⁸⁹ Since Order 888 was issued, six ISOs have been formed and five of them are now operating. (The status of these ISOs is discussed later.)

Remaining Impediments to Competitive Power Markets After Order 888

Even with five ISOs operating and open access transmission tariffs in place, the development of wholesale power markets across the nation has been slow, and obstacles to competition still remain. Three major obstacles have been mentioned. First, since Order 888 was issued the Commission has received many complaints of transmission owners discriminating against independent power companies. Further, the Commission noted that an increase in the number of market participants and transactions in wholesale markets has made discriminatory behavior with regard to transmission access more subtle and more difficult to identify.⁹⁰ Second, the Commission observed that electric utilities' implementation of functional unbundling has not produced sufficient separation between operating the transmission system and marketing and selling power, and that this lack of separation contributes to discriminatory behavior. Third, grid regionalization through ISOs has occurred in some areas of the country, but was not implemented in other areas. Although creation of an ISO was voluntary, expectations were that more regions would seek to realize the benefits of grid regionalization and would participate in forming ISOs.

In addition to these obstacles, an increase in market participants and trading over the past few years, and changes to electricity trading patterns has made system reliability more difficult to maintain which impedes creating fully competitive power markets. The North American Electric Reliability Council (NERC) reported that, "[in recent years] the adequacy of the bulk power

transmission system has been challenged to support the movement of power in unprecedented amounts and in unexpected directions."⁹¹ This view is supported by a U.S. Department of Energy Task Force noting that "there is a critical need to be sure that reliability is not taken for granted as the industry restructures, and thus does not fall through the cracks."⁹²

Not only has maintaining reliability become more difficult, other obstacles to competitive markets have emerged. Transmission congestion has increased, but current procedures for relieving congestion are antiquated and sometimes unfair. As FERC points out, "current transmission loading relief (TLR) procedures [for relieving congestion] are cumbersome, inefficient, and disruptive to power markets because they rely exclusively on physical measures of [electricity] flows with no attempt to assess the relative costs and benefits of alternative congestion management techniques." Another problem is that planning for transmission expansion is more difficult than in the past because of more uncertainty in the industry. Responsibilities for transmission expansion are not always clear, the motivation for construction of new facilities is changing, and cost recovery after construction may be more risky than in the past. Finally, the current method of transmission pricing is antiquated given the new competitive environment. In most of the United States, the transmission customer pays separate additive access charges every time the power crosses the boundary of a transmission owner. This practice is referred to as pancaked pricing, which has the effect of raising the cost of transmission and reducing the geographic size of competitive power markets.

Order 2000 and Grid Regionalization

FERC's third initiative to grid regionalization, which is currently being implemented, is perhaps its most ambitious effort. In December 1999, FERC issued Order 2000, calling for the voluntary creation of RTOs throughout the United States. FERC had noted that all of the Nation's transmission systems should be brought under regional control and perhaps regional ownership in order to eliminate the remaining discriminatory practices, meet the increasing demands placed on the

⁸⁹ The intent of FERC's functional unbundling requirement, specified in Order 888 and discussed above, was to accomplish the same thing without the need for separate organizations.

⁹⁰ Federal Energy Regulatory Commission, "Notice of Proposed Rulemaking, Regional Transmission Organization," RM99-2-000 (May 13, 1999).

⁹¹ North American Electric Reliability Council, "Reliability Assessment 1998-2007" (September 1998).

⁹² Secretary of Energy Advisory Board's (SEAB) Task Force on Electric System Reliability, "Maintaining Reliability in a Competitive U.S. Electric Industry" (September 29, 1998).

transmission system, and achieve fully competitive wholesale power markets. If FERC's implementation of Order 2000 is successful, the transmission system will go from a system owned and controlled mostly by vertically integrated electric utilities to a system owned and/or controlled by a few, but uncertain number of, unaffiliated RTOs.

With this formidable undertaking, the Commission again believes a voluntary approach will be successful because (1) many vertically integrated utilities recognize the benefits of an RTO, (2) Order 2000 provides clear rules and guidance for utilities to follow in forming an RTO, (3) to facilitate cooperation, the Commission established a collaborative process for RTO development, and (4) Order 2000 provides ratemaking incentives for companies who assume the risks of a transition to a new corporate structure. (Table 12 contains a summary of the major components of Order 2000.)

Potential Benefits of Regional Transmission Organizations Through Order 2000

By eliminating the balkanized control of the transmission grid, regionalization has the potential to increase significantly the overall operating efficiency of the industry system. Many industry analysts believe that combining the control of individual transmission systems under one regional organization with a wide regional scope can lead to improvements in transmission pricing, improved management of congestion, improved information relevant to promoting competition in power markets, better management of parallel path flow problems, improved reliability management, and as noted above, the elimination of remaining discriminatory practices concerning access to the transmission system services. The term potential is a key word because regionalized control of the Nation's transmission grid, as proposed in Order 2000, is a new and unproven concept. These potential benefits, some of which were alluded to in the above discussion, are covered below in more detail.

Eliminate remaining opportunities for discriminatory transmission practices: As organizations completely independent from power production and sales, RTOs will sever the economic incentives between power marketing and control of the transmission system. Without the economic incentive, the reasons for discriminatory practices should be eliminated. Functional unbundling required in Order 888 did not eliminate economic incentives, and was not completely effective in eliminating discriminatory practices.

Improve calculations of available transmission capacity: Available transmission capacity (ATC) is a measure of the amount of transmission capacity that is available to transmit power over the grid at a particular time. Market participants use this information to make short-term decisions to purchase or sell power. ATC is difficult to calculate due to constantly changing conditions and the complexity of the electrical network. The difficulty is compounded in a balkanized network where each utility calculates its own ATC. An RTO with regional scope will have better information on conditions of the network than an individual utility; with better information, more accurate estimates of ATC will be available to transmission users. Also, FERC has pointed out that many complaints have been filed claiming that transmission providers are calculating ATC to favor their own generators, which is a form of discrimination. An independent RTO will eliminate this behavior.

Improve management of parallel path flow and system reliability: The interconnection of the transmission grid makes management a difficult and challenging task. One of the biggest problems is managing parallel path flow (also called loop flow). Parallel path flow refers to the fact that electricity flows across an electrical path between source and destination according to the laws of physics, meaning that some power may flow over the lines of adjoining transmission systems inadvertently affecting the ability of the other region to move power. This cross-over can create compensation disputes among the affected transmission owners. It also impacts system reliability if a parallel path flow overloads a transmission line and decisions must be made to reduce (curtail) output from a particular generator or in a particular area. An RTO with access to regionwide information on transmission network conditions, with regionwide power scheduling authority, and with more efficient pricing of congestion can better manage parallel path flows and reduce the incidence of power curtailment.

Improve transmission pricing methods: Pricing of transmission services is one of the most important issues in restructuring the Nation's transmission system. Historically, FERC has based its approach to transmission prices on the rolled-in average historic costs of the transmitting utility. This method was largely developed for requirements service where the wholesale customer's load was dispersed throughout the utility's service territory and integrated generation and transmission facilities are used. The result has been a "postage stamp" rate. Postage stamp rates have important limitations, particularly in providing price signals to transmission

**Table 12. Summary of Major Provisions of the Federal Energy Regulatory Commission's Order 2000
Final Rule Establishing Regional Transmission Organizations**

Filing Requirements and Deadlines

1. Each public utility that owns, operates, or controls interstate transmission facilities (except those already participating in an approved regional transmission entity) must file by October 15, 2000, a proposal to participate in a regional transmission organization (RTO) that will be operational by December 15, 2001, or they must file, by the same date, a description of efforts to participate in an RTO, obstacles to participation, and plans and a timetable for future efforts.
2. Each public utility that is a member of an existing transmission entity that conforms with the 11 ISO principles contained in Order 888 must file by January 15, 2001, a description that explains the extent to which the transmission entity in which it participates meets the minimum characteristics and functions of an RTO, and how it proposes to modify the entity to become an RTO, or a description of efforts, obstacles, and plans to conform to an RTO's minimum characteristics and functions.
3. All RTOs will implement their minimum functions according to the following schedule:
 - Congestion management function by December 15, 2002
 - Parallel path flow coordination function by December 15, 2004
 - Transmission planning and expansion function by December 15, 2004
 - Other minimum functions will be implemented by startup.

Minimum Characteristics of a Regional Transmission Organization

1. **Independence:** The RTO must be independent of market participants. Independence can be achieved by meeting three conditions: (1) the RTO, its employees, and any non-stakeholder director must not have any financial interest in any market participants, (2) the RTO must have a decision-making process independent of control by any market participant, and (3) the RTO must have exclusive authority under Section 205 of the Federal Power Act to file changes to its transmission tariff.
2. **Scope and Regional Configuration:** The RTO's region must be of sufficient scope and configuration to perform effectively its required function and to support efficient and nondiscriminatory power markets. FERC will evaluate the configuration or boundaries of the RTO according to the extent it meets nine criteria:
 - Facilitates performing essential RTO functions
 - Encompasses one contiguous geographic area
 - Encompasses a highly interconnected portion of the grid
 - Deters the exercise of market power
 - Recognizes existing trading patterns
 - Takes into account existing regional boundaries (e.g., NERC regions)
 - Encompasses existing regional transmission entities
 - Encompasses existing control areas
 - Takes into account international boundaries.
3. **Operational Authority:** The RTO must have operational authority for all transmission facilities under its control, and it also must be the security coordinator for the region. The security coordinator ensures the real-time operating reliability of the power systems.
4. **Short-Term Reliability:** The RTO must have exclusive authority for maintaining the short-term reliability of the transmission grid under its control. Short-term is intended to include all time periods necessary for the RTO to satisfy its reliability responsibilities up to the planning horizon.

Minimum Functions of a Regional Transmission Organization

1. **Tariff Administration and Design:** The RTO will be the sole administrator of its own tariff and, therefore, it will be the sole decision-making authority on provision of transmission service including the decision to establish new interconnections.
2. **Congestion Management:** The RTO will ensure the development of market mechanisms to manage transmission congestion. These mechanisms should provide price signals to transmission customers regarding the consequences of their transmission usage decisions.

Table 12. Summary of Major Provisions of the Federal Energy Regulatory Commission's Order 2000 Final Rule Establishing Regional Transmission Organizations (Continued)

3. Parallel Path Flow: The RTO must implement procedures within 3 years of start-up to address the problems associated with interregional parallel path flow and implement procedures immediately for regional parallel path flow. Parallel path flow refers to the fact that electricity flows over transmission lines according to the laws of physics. Because of these laws, the power generated in one region may flow over the transmission lines of another region, inadvertently affecting the ability of the other region to move power.

4. Ancillary Services: The RTO must serve as the provider of last resort for all ancillary services as required in Order 888. The RTO should promote creation of competitive markets for procurement of these services.

5. Open Access Same-Time Information System (OASIS) and Capability Calculations: The RTO should act as a single OASIS node. The data elements of total transmission capability and available transmission capability, which are stored on the OASIS and used by potential transmission customers, will be calculated by the RTO, or if provided by the transmission owner, verified by the RTO.

6. Market Monitoring: The RTO will submit to FERC a market monitoring plan that (1) ensures that there is objective information about the markets, (2) contains procedures for proposing efficiency improvements, market flaws, and market power, and (3) contains procedures to evaluate the behavior of market participants.

7. Planning and Expansion: The RTO must develop a planning and expansion proposal that (1) encourages market-motivated operating and investment actions for preventing and relieving congestion, (2) accommodates efforts by State regulatory commissions to create multi-state agreements to review and approve new transmission facilities and coordinates with existing regional transmission groups, and (3) files a plan with milestones showing that the RTO will meet its planning and expansion requirements no later than 3 years after start-up.

8. Interregional Coordination: The RTO will develop mechanisms to ensure the integration of reliability practices within an interconnection and market interface practices among regions.

Open Architecture

Open architecture refers to the idea that RTOs should be designed so that improvements in their structure, operating rules, and other activities can evolve over time.

Policy for an RTO's Transmission Rates

FERC believes that effective transmission rates are essential in promoting economic efficiency in the generation and transmission sectors, and are an important factor to the success of the RTO as a stand-alone transmission business. FERC has approval responsibility for an RTO's transmission rate schedule. According to FERC policy, effective transmission rates will address the following issues:

1. Eliminate Pancake Pricing: Pancake pricing occurs when a transmission customer is charged separate access charges for each utility service territory crossed by the transmission customer's power transaction. Pancaking increases the price of electricity and it discourages competition in the generation sector. By combining transmission systems under one RTO, a wider area served by a single rate can be designed.

2. Reciprocal Waiving of Access Charges Between RTOs: FERC encourages the RTOs to waive transmission access charges for transactions that cross RTO borders. This increases the size of the competitive trading area beyond the RTO border.

3. Uniform Access Charges: FERC encouraged that an RTO establish one uniform access charge for all transmission customers. However, they recognized that this approach may result in cost shifting (i.e., low-cost transmission providers would see a rate increase, and high cost providers a rate decrease). As a temporary solution, FERC will allow a single rate, but that rate will vary based on where the customer is located.

4. Congestion Pricing: Congestion pricing is closely related to congestion management in that effective pricing of congestion problems provides the appropriate price signals to build additional transmission lines or power generation plants in order to eliminate congestion.

**Table 12. Summary of Major Provisions of the Federal Energy Regulatory Commission's Order 2000
Final Rule Establishing Regional Transmission Organizations (Continued)**

5. Service to Transmission-Ownning Utilities that do not Participate in an RTO: FERC intends to permit an RTO to propose rates, terms, and conditions of transmission service that recognize the participatory status of transmission customers. In other words, a transmission customer who is also a transmission provider in the region that chose not to join the RTO, will have a different transmission tariff than other customers.

6. Performance-Based Regulation: Performance-based regulation (PBR) represents the concept of offering financial incentives to lower rates or costs. Under PBR, good performance can be rewarded with higher profits and poor performance can be penalized in some manner. As an alternative to cost-based regulation, FERC encourages the RTO to develop PBR proposals, although submission of a proposal is voluntary.

7. Other RTO Transmission Rate Reforms: To encourage investment in transmission facilities and efficiency in operation, FERC indicated that it would consider other innovative transmission pricing proposals such as a higher return on equity than previously allowed, levelized rates, or accelerated depreciation and incremental pricing for new transmission investments.

8. Additional Ratemaking Issues: This section of Order 2000 contained a wide range of comments on ratemaking issues not specifically addressed in the notice of proposed rulemaking. These comments cover issues ranging from alternative ratemaking methods to issues dealing with how to incorporate incentives to promote environmentally benign resources.

9. Filing Procedures for Innovative Rate Proposals: FERC will evaluate innovative rate proposals based on how the proposed rate treatment would help achieve the goals of an RTO. Rate moratoria or returns on equity that do not vary according to the RTO capital structure may not be included in the RTO's rate structure after January 1, 2005.

Other Issues

In Order 2000, FERC identified nine issues, other than the ones discussed above, which may have an impact on the structure, completeness, regulation, and design of RTOs.

1. Public Power and Cooperative Participation in RTOs: FERC expects public power entities to participate in the formation of RTOs, but it is aware public power entities face several obstacles. The Internal Revenue Service Codes may prevent facilities financed by tax-exempt debt from wheeling privately owned power, or they may prevent transfer of operational control of transmission facilities financed by tax-exempt debt to a for-profit transmission company. State and local government laws may prevent public power entities from participating in RTOs. The lack of participation of public power entities may negate some of the effectiveness and expected benefits of RTOs.

2. Participation by Canadian and Mexican Entities: FERC opined that Mexican and Canadian participation in an RTO would be beneficial.

3. Existing Transmission Contracts: FERC indicated that it will examine, case-by-case, how to handle existing contractual arrangements when forming an RTO. For example, one issue may involve how to handle pancaked rates in existing contracts for others when transmission-owning utilities design a non-pancaked rate for their own transactions.

4. Power Exchanges: FERC will leave it to each region to determine a need for a power exchange, and if the RTO should operate the exchange should there be a need.

5. Effects on Retail Markets and Retail Access: FERC opined that formation of an RTO will not affect the ability of States to implement retail markets and competition. In Order 2000, FERC noted that experience with the independent system operators (ISOs) indicates that an RTO could be a benefit to States that are implementing retail competition.

6. Effects on States with Low-Cost Generation: Some States are concerned that an RTO would result in local utilities selling their low-cost power to other States. FERC asserted that an RTO will provide access to future low-cost generation plants and that new low-cost generation plants will be attracted to regions with an RTO because of dependable and nondiscriminatory access to the transmission system.

7. States' Role With Regard to RTOs: FERC believes that States have an important role to play, but they chose not to specify what role in Order 2000.

**Table 12. Summary of Major Provisions of the Federal Energy Regulatory Commission's Order 2000
Final Rule Establishing Regional Transmission Organizations (Continued)**

8. Accounting Issues: FERC will require that RTOs conform to the Uniform System of Accounts, but they also indicated that changes in the industry require them to re-examine existing accounting and related reporting requirements.

9. Market Design Lessons: FERC envisions that bid-based markets for wholesale electric power will be a central feature in many RTO proposals. Although bid-based markets for electric power do not now represent the dominant method for buying and selling electricity, this method is expected to grow. In Order 2000, FERC summarizes lessons learned from its analysis and approval of bid-based markets for four independent system operators. As these and other power markets mature, additional information on how to design and operate power markets will develop.

- **Multiple Product Markets:** Efficiency of a multi-product market operating in the same time period is maximized when arbitrage opportunities reflected in the bids are exhausted. That is, it is efficient when, after the RTO's market has cleared, no market participant would have preferred to be in another of the RTO's markets.
- **Physical Feasibility:** Transaction in the market should be physically feasible.
- **Access to Real-Time Balancing Market:** Real-time balancing refers to the moment-to-moment matching of loads and generation on a system-wide basis. A real-time balancing market should be available to all grid users for purposes of settling their individual imbalances.
- **Market Participation:** Markets are more efficient with a broad participation.
- **Demand-Side Bidding:** The current wholesale power markets do not offer customer demand-side bidding, only power suppliers bid into the markets. However, demand-side bidding, to the extent it is practical, is desirable to make electricity supply and prices more responsive to competitive markets.
- **Bidding Rules:** The market should allow generators to make bids that approximate their costs.
- **Transaction Costs and Risks:** Transaction costs should be low and participation in the market should involve no unnecessary risk.
- **Price Recalculations:** Market clearing prices should minimize electricity price recalculations.
- **Multi-Settlement Markets:** Multi-settlement markets may involve a day-ahead market and a real-time market. If the day-ahead market bids are needed for reliability, these bids need to be physically binding and may be subject to penalties for failing to adhere to the bid.
- **Preventing Abusive Market Power:** FERC highlights three items which will help to lessen the potential for market power: (1) have fewer restrictions on importing power into the region, (2) have less segmentation of geographic markets for the same product, and (3) stop allowing market participants to change bids before they complete the financial settlement. Bid changing can be used as signaling to facilitate collusive behavior.
- **Market Information and Marketing Monitoring:** Market clearing prices and quantities should be transparent so that market participants can assess the market and plan their business efficiently.
- **Prices and Cost Averaging:** Transmission and congestion prices based on average costs may distort power production, power consumption, and investment decisions. More innovative pricing methods are needed.

Collaborative Process: FERC asserted its commitment to hold regional workshops to assist in the voluntary formation of RTOs. Five workshops were held in March and April 2000.

Sources: Federal Energy Regulatory Commission, "Regional Transmission Organizations, Order No. 2000," 18 CFR Part 35 (December 20, 1999); L.S. Hyman, *What's Inside FERC's Transmission Policy: A Guide To Order 2000* (Vienna, VA: Public Utilities Reports, January 2000).

users. Such rates may not reflect the cost of scarcity when there is a bottleneck on the grid, the costs of expanding capacity to remove such a bottleneck, or the costs of transmitting power over long distances.

In addition to the potential inefficiencies, each transmission owner had its own rate structure which worked when the industry was totally regulated and wholesale electricity markets were relatively small or nonexistent and electricity trading was infrequent. Competitive wholesale power markets require more efficient and

equitable pricing methods that eliminate the possibility of pancaked pricing which can double or triple the price of the transaction, making it more difficult for electricity suppliers that have to cross multi-transmission boundaries to be cost competitive. Under Order 2000, RTOs will be required to design pricing methods that eliminate pancaked prices. Also, Order 2000 encourages RTO applicants to consider innovative transmission pricing methods such as performance-based ratemaking (PBR), or levelized rates, to replace the inefficient transmission pricing methods currently used.

Improve management of transmission congestion: Transmission congestion occurs when a transmission line reaches its transmitting capacity and additional power from a specific generator cannot be dispatched as needed. Congestion is caused by generation or power grid outages, increases in energy demand, loop flow problems, or a combination of these factors.

In the past, transmission owners had responsibility for the management of congestion on their transmission systems. Usually, adequate transmission facilities existed to support the flow of electricity within each transmission owner's system; however, when congestion occurred, the common approach was to curtail power to relieve the congestion. In a competitive environment, administrative curtailment is no longer an acceptable technique for congestion management. By not evaluating the costs of congestion, administrative curtailment provides no price signals or economic incentives to reduce congestion, and in that respect it is incompatible with competitive markets. In Order 2000, the Commission requires that an RTO develop mechanisms that measure congestion costs and that market participants are made aware of the cost consequences of their transmission usage decision. FERC leaves it up to the RTO to design a congestion pricing method to suit its needs.

Improve reliability of the transmission grid: Because an RTO typically covers a larger region, it enhances coordination among key players during system emergencies. Additionally, it can better coordinate or schedule generation and transmission outages and the sharing of ancillary services. An independent RTO can conduct more objective reliability studies of the system than others who may have vested interests in certain outcomes.

Major Issues in Forming a Regional Transmission Organization

Creating RTOs nationwide is a formidable task, and many difficult issues must be addressed. In addition to the problems unique to each region of the country, there are also generic problems applicable to all regions. Three important generic issues are the RTO's size, organizational structure, and transmission grid coverage.

Determining the appropriate size of an RTO: The Commission did not prescribe boundaries for an RTO,

but notes that a region sized appropriately will be sufficient to permit the RTO to effectively perform its required functions and to support efficient and nondiscriminatory power markets. The Commission specified regional configuration factors to evaluate the appropriateness of the proposed RTO's configuration. The region configuration should be large enough so that the RTO can make accurate and reliable ATC calculations, resolve loop flow issues internally within the region, manage congestion effectively, offer non-pancaked transmission rates, effectively operate one OASIS site, and conduct transmission planning and expansion effectively. The specific boundaries of an RTO will be evaluated using nine criteria (Table 12, Minimum Characteristic 2).

A reading of Order 2000 requirements with respect to the appropriate size of an RTO makes clear a few points. FERC does not have any apparent preconceived notion of the appropriate size of an RTO, only that determining the right size will involve evaluating many factors. One size does not fit all regions, so different configurations are likely. To maximize the benefits of an RTO, it appears that the larger the region covered by the RTO the better, to a point. Technical factors, as well as managerial, economic, and political factors need to be evaluated to determine an optimal size.

Determining the appropriate ownership structure of an RTO: One of the most important factors in determining the appropriate ownership structure for an RTO is its ability to achieve independence from market participants.⁹³ FERC commented in Order 888 that "the principle of independence is the bedrock upon which the ISO must be built and that this principle must apply to all RTOs, whether they are ISOs, transmission companies (Transcos), or variants of these two models. Order 2000 enumerates three conditions for independence: (1) the RTO's employees and any nonstakeholder directors must not have any financial interest in any market participants; (2) the RTO must have a decision-making process that is independent of control by any market participant or class of participants; and (3) the RTO must have exclusive and independent authority to file changes to its transmission tariff with the Commission under section 205 of the Federal Power Act.

The effect of ownership on an RTO's independence depends on which ownership model is used. The two basic models are the ISO model and transmission

⁹³ A definition of "market participant" was problematic, and FERC, after considering extensive comments, concluded that market participants is an entity whose economic or commercial interest is likely to be affected by an RTO's decision and actions. The Regulatory Text, Part 35, Chapter I, Title 18 CFR, 35.34(b2) contains a full definition of "market participant."

company (Transco) model. With the ISOs that are currently operating, ownership of the transmission facilities remained with the vertically integrated electric utility, but operating control of the facilities was transferred to the ISO. These ISOs operate as nonprofit and nonshare companies and their independence from market participants is established through representation and voting privileges of its governing board.

The Transco is an independent, self-sustaining, profit-making transmission company. Under this model, the Transco owns the transmission facilities and the issue of independence concerns ownership of the company itself. The Commission noted that it will permit market participants to retain limited active ownership (up to 5 percent for a single market participant and 15 percent for a class of market participants) in the RTO during a 5-year transition period. Active ownership refers to ownership of voting securities that gives the owner the ability to influence or control an RTO's operating and investment decisions. An active ownership interest will terminate after 5 years.

In Order 2000, FERC has noted its openness to consider any type of ownership and governance structure as long as the RTO's design meets the minimum characteristics requirement of Order 2000. FERC has stated that "it is important that we provide current transmission owners with flexibility in deciding how they will relinquish ownership or control of their transmission facilities to an RTO." Flexibility in ownership allows for regional differences.

Avoiding gaps in regional coverage of the transmission grid: For an RTO to realize its full potential, it must have control and authority over the entire transmission grid in the region. Gaps or breaks in continuity of coverage of the grid undermine the RTO's effectiveness and the achievement of the benefits it can provide.

Because joining an RTO is voluntary, some utilities may decide not to participate. IOUs choosing not to participate are required to file reasons and obstacles for not participating. This procedure should invoke a dialogue with FERC and provide a mechanism to overcome obstacles to participation. Because IOUs are jurisdictional utilities, FERC also has some leverage in convincing IOUs to participate.

On the other hand, federally owned and other public power and cooperative utilities are non-jurisdictional utilities; they have no filing requirements under Order 2000 and FERC has no apparent leverage in obtaining their participation. Because these utilities own approxi-

mately 30 percent of the Nation's power grid, the potential exists for substantial gaps in regional coverage. For example, in the northwest and southeast regions of the United States, federally owned utilities are major providers of electricity with substantial ownership in transmission facilities. RTO formation in those regions may be impractical without their participation.

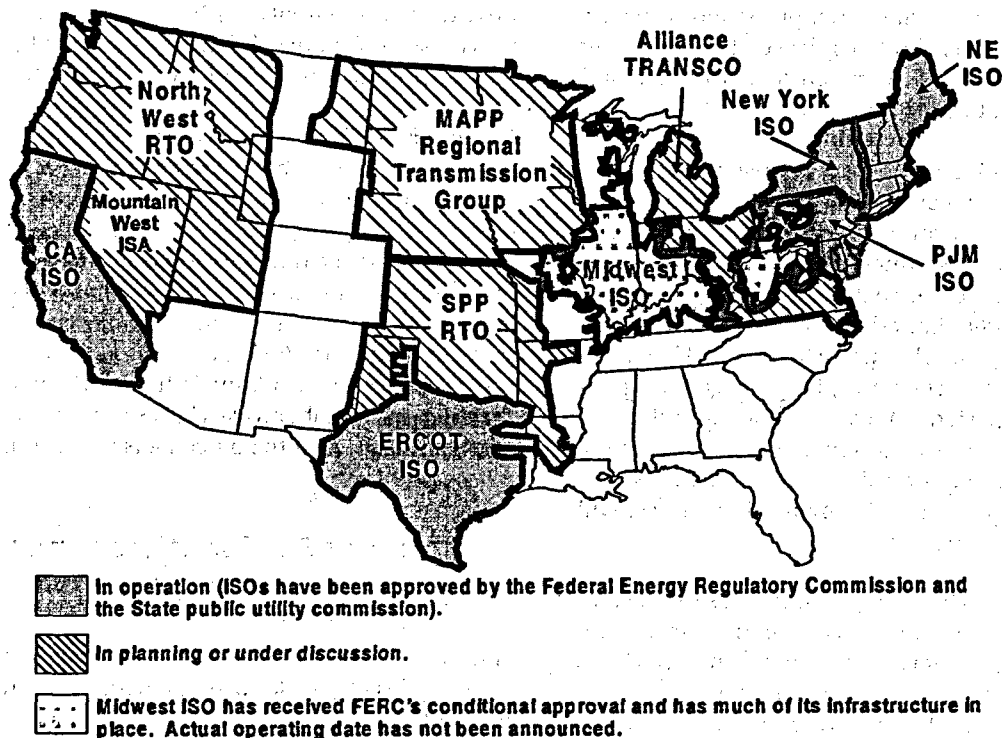
In Order 2000, FERC encourages non-jurisdictional utility participation, but also recognizes that municipally owned utilities face numerous regulatory and legal obstacles. The Internal Revenue Code has private use restrictions on the transmission facilities of municipally owned utilities financed by tax-exempt bonds. State and local government limitations, such as prohibitions on participating in stock-owning entities and other restrictions, may also impede full participation. FERC, through the collaborative process, seeks solutions to these problems, but the outcome is uncertain.

Status of Regional Transmission Organizations

Although FERC has encouraged formation of independent RTOs, development of them has been sporadic; most of the Nation's transmission grid is not under control of an independent RTO. Five ISOs have formed over the past 2 years and are now operating—California ISO; Pennsylvania, New Jersey, Maryland (PJM) ISO; ISO New England; New York ISO; and ERCOT ISO (Figure 27). The Midwest ISO has received regulatory approval and much of its operating infrastructure has been assembled; it should take operating control of the transmission grid in the near future.

Several factors have contributed to the current set of approved ISOs. PJM, New England, and New York ISOs were created from existing tight power pools. A tight power pool functions as one control area. Unlike ISOs, power pools did not have control of transmission facilities, they were not independent from transmission owners, and they did not administer a regional open access transmission tariff. According to Order 2000, "it appears that the principal motivation for these tight power pools forming ISOs was to establish a single system-wide transmission tariff as required by Order 888." In contrast, State legislation that opened California's electric industry to retail competition required the formation of the California ISO. The Public Utility Commission of Texas created the ERCOT ISO. Originally, the Midwest ISO consisted of voluntary members. Subsequent to its initial formation, electric

Figure 27. Independent System Operators and Regional Transmission Organizations in Operation or Under Discussion as of April 1, 2000



Notes: • Creation of regional transmission organizations (RTOs) is currently under rapid development. Under Order 2000, utilities not currently members of an approved ISO must submit plans to join an RTO by October 2000. Utilities that are members of an ISO must submit plans to form an RTO by January 2001. • MAPP and the Midwest ISO have reached an agreement to merge operations. Mountain West is an independent system administrator which is considered an interim organization in a broader regional transition plan.

Source: Compiled from information obtained in trade journals and websites maintained by the regional transmission organizations.

utilities in Illinois and Wisconsin have joined the Midwest ISO because of State legislation requiring either utility participation in an ISO or divestiture of their transmission assets.

A comparison of the six ISOs show many similarities, although many of the implementation details are different (Table 13). All of the ISOs are nonprofit organizations. Four of the ISOs operate as a single control area; ERCOT and the Midwest ISO have multiple control areas within their regions.

With the exception of the ERCOT ISO, all other ISOs have developed a single access charge to the ISO-controlled transmission systems, based on the costs of the transmission owner serving the customer. Access charges are used to recover the transmission owner's embedded transmission system costs, and are calculated

based on dollar per megawatt-hour of transmission system usage. Under this system, the transmission customer pays only one access charge regardless of the number of individual transmission systems crossed in the ISO-controlled grid, so pancaked charges have been eliminated. Most of the ISOs are moving toward development of one uniform access charge for the entire ISO-controlled grid.

Three of the ISOs (California, PJM, and New York) use bid prices to manage transmission congestion in their region. In general, the power generators submit voluntary bids to reduce output and relieve congestion, and the ISO uses the bids to calculate the costs (or price) of transmission congestion. The costs are assigned to the appropriate transmission user. This technique places a value on congestion and it provides a basis for economic decision-making. Managing transmission congestion

Table 13. Selected Information on Independent System Operators

	California ISO	ERCOT Texas ISO	ISO New England	MidWest ISO (MISO)	New York ISO	Pennsylvania, New Jersey, Maryland (PJM)-ISO
Operating Date	March 31, 1998	August 1996	1997	Approved 1998. Not yet operating	1999	April 1998
States Covered	California	Texas	Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, Vermont	Illinois, Indiana, Kentucky, Missouri, Ohio, Maryland, Pennsylvania, Virginia, West Virginia, Wisconsin	New York, New Jersey	Delaware, New Jersey, Maryland, Pennsylvania, Washington, DC, Virginia
Number of Transmission Owners	3	16	15	13	8	10
Type of Organization	Nonprofit	Nonprofit	Nonprofit	Nonprofit	Nonprofit	Nonprofit
Board of Directors	24 members representing 13 stakeholder classes	18 members representing 6 stakeholder classes	10 independent members	8 independent members	10 independent members	8 independent members
Control Areas	Single	Multiple	Single	Multiple	Single	Single
Transmission Rights Program	Under development	None	Under development	Undecided	Transmission congestion contracts	Fixed transmission rights
Transmission Congestion Management	Price based ^a	Priority based	Priority based	Priority based	Price based	Price based
Transmission Access Charges ^b (Method to Meet Revenue Requirements)	Charge is based on the embedded cost of the transmission owner serving the customer	System-wide (postage stamp) charge	Charge is based on the embedded cost of the transmission owner serving the customer	Charge is based on the embedded cost of the transmission owner serving the customer	Charge is based on the embedded cost of the transmission owner serving the customer	Charge is based on the embedded cost of the transmission owner serving the customer
Ancillary Services	ISO procures if not provided	ISO coordinates	ISO can provide	ISO will arrange for services	ISO can provide	ISO provides or coordinates
Transmission Planning	ISO leads coordinated process	ISO coordinates	NEPOOL has lead role	ISO develops plan with transmission owners	ISO is an active participant	ISO prepares plan
Operation of a Centralized Power Market	Separate from ISO	None	Combined with ISO	None	Combined with ISO	Combined with ISO

Table 13. Selected Information on Independent System Operators (Continued)

	California ISO	ERCOT Texas ISO	ISO New England	MidWest ISO (MISO)	New York ISO	Pennsylvania, New Jersey, Maryland (PJM)—ISO
Type of Centralized Power Markets	The California power exchange manages the day-ahead and hour-ahead markets. The ISO manages the ancillary services, real-time imbalance, and congestion markets.	None	One residual day-ahead market (only the difference between participant's energy resources and obligations can be bid); All transactions are priced at ex-post energy clearing price.	None	Day-ahead and real-time market; both ISO settled; additional bids can be submitted and non-accepted bids resubmitted (hour-ahead bids) up to 90 minutes before dispatch hour in the real-time market.	One real-time joint market for energy and reserves; generators submit hourly bids for their resources once daily; these resources are used by the ISO for energy and reserves.

^aPrice based means that the ISO calculates the costs of congestion and allocates these costs to the appropriate transmission user.

Priority based means that the ISO curtails power generation based on a predetermined curtailment plan.

^bAll of the ISOs will be phasing in one system-wide transmission access charge.

Sources: L.D. Kinsch, "Pricing the Grid: Comparing Transmission Rates of the U.S. ISO," *Public Utilities Fortnightly* (February 15, 2000). Energy Information Administration, *The Changing Structure of the Electric Power Industry: Selected Issues 1998*, DOE/EIA-0562(98) (Washington, DC, July 1998), pp. 34-35.

using energy prices is a relatively new and innovative application, and it is likely that RTOs now being formed will experiment with these new techniques.

Four of the regions—California, PJM, New York, and New England—have established centralized markets for buying and selling energy in their respective regions. In California, the California Power Exchange, which is a separate organization from the California ISO, runs their energy market. Operation of the energy markets and the ISO are combined in the other regions. These centralized markets are new, and the rules of operation will likely evolve as more operating experience is acquired.

With respect to meeting the requirements of Order 2000, ISOs have until January 1, 2001, to submit a filing to FERC specifying their plans for forming an RTO. None of the existing ISOs have announced publicly their specific compliance plans. It is unlikely that the existing organizational structure of these ISOs will satisfy all of the minimum characteristics and minimum functions required of an RTO (Table 12), so one can expect to see changes in the ISO organizational structures and functions over the coming years. Electric utilities not currently members of an ISO have to file plans to form an RTO by October 1, 2000. In some regions, progress toward compliance with Order 2000 has been made as demonstrated by the following examples.

- The most significant announcement was the planned merger between the Midwest ISO and the Mid-Continent Area Power Pool (MAPP). This arrangement has the potential of creating one RTO from east of the Rocky Mountains up to the border of the PJM ISO (Figure 27).
- The Southwest Power Pool (SPP) has filed with FERC seeking formal recognition as an ISO. It also requested that the Commission recognize that it satisfies minimum requirements for an RTO. In May 2000, FERC ruled that SPP's proposal does not have the operational authority, independence, and other requirements to qualify as an RTO.
- In June 1999, the Alliance Companies, consisting of five large IOUs located in Michigan, Ohio, and Virginia, filed with FERC an application to transfer their transmission facilities to a Transco. FERC conditionally approved the transfer of ownership and the general framework of the Transco as meeting the requirements of an ISO subject to certain revisions. In May 2000, FERC ruled that the Alliance Transco does not meet the independence requirements of an RTO.

- Recently, FERC accepted the creation of Mountain West as an Independent System Administrator (ISA) and conditionally approved the transfer of transmission facilities belonging to Nevada Power and Sierra Power to the ISA. FERC did not evaluate Mountain West under its ISO or RTO principles. Mountain West is considered an interim step in a broader regional transition plan in the western region.
- In response to FERC's Order 2000, nine transmission-owning utilities are working together to form the Northwest RTO.

Wholesale Electricity Trading Hubs and Power Exchanges

Coinciding with FERC's promotion and approvals of market-based rates for the sale of electricity, the industry has experienced a significant change in the way power is sold. Most noticeable is the emergence of centralized power markets where electricity suppliers submit bids to sell power in regional markets. The market operator evaluates the bids and selects the most economical bid to meet energy demand in the region. Four centralized power markets are now operating—California PX, New York ISO, ISO New England, and PJM-ISO (Figure 28). Of the four operating markets, the California Power Exchange may be the most active because California's three major electric utilities were until recently required by State law to sell all of their power through the exchange. Participation in the other power markets is voluntary and currently most of the power in these regions is sold through bilateral arrangements between buyer and seller. This may change as buyers and sellers gain more experience with centralized power markets.

To support bilateral power trading, numerous electricity trading hubs have emerged over the past few years. A hub is a location on the power grid representing a delivery point where power is sold and ownership changes hands. Potentially, each control area on the power grid could become a trading hub, but a few hubs account for the bulk of power trading (Figure 28). Of the 10 major trading hubs, five of them are located in the western United States, four in the midwest, and one in the east.

Part of the reason that these major trading hubs have emerged is because the New York Mercantile Exchange

(NYMEX) and the Chicago Board of Trade (CBOT) have developed and sponsored electricity futures contracts to facilitate trading at these hubs. A futures contract is a common risk management tool used in agricultural, metal, and energy commodities markets. One of the main purposes of a futures contract is to eliminate the risk of price changes. For example, a power marketer entering into a contract to sell power at a predetermined price at the California Oregon Border (COB) runs the risk that the price it must pay for electricity will increase before the power is delivered. However, the power marketer can hedge its risk by buying electricity futures that match the quantity and timing of the original power contract. NYMEX has created electricity futures contracts for the Cinergy, COB, Entergy, Palo Verde, and PJM trading hubs. CBOT has created electricity futures contracts for the Commonwealth Edison and Tennessee Valley Authority trading hubs.

Market Power in Wholesale Electricity Markets

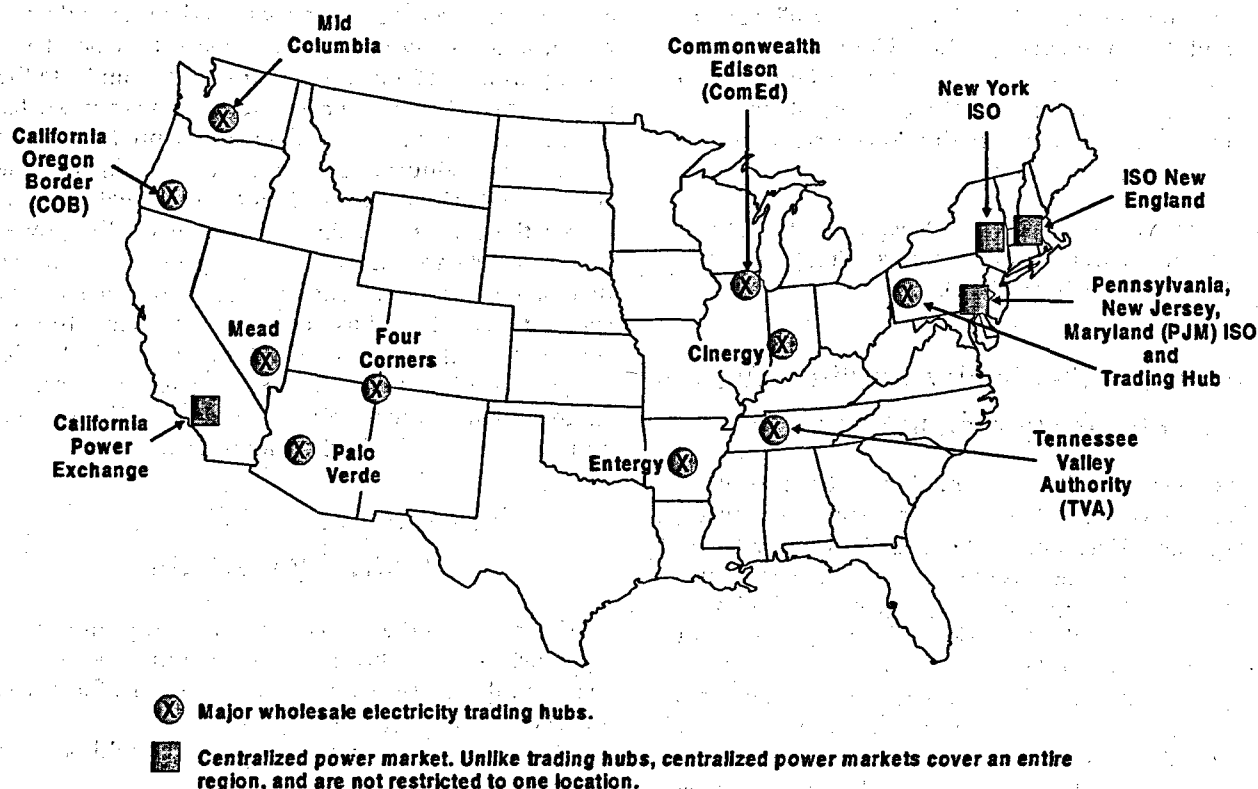
Market power is the ability of an electricity supplier to raise prices profitably above competitive levels and maintain those prices for a significant time. Electricity suppliers exercising market power force consumers to pay higher electricity prices than they would pay in a competitive market.

Market power exists in two forms—horizontal and vertical. Vertical market power may occur when a firm controls two related activities. In the electric power industry, one firm controlling both electricity generation and transmission has the potential to exercise vertical market power. Separating control of electricity generation from control of the transmission system (via ISOs and RTOs) is designed to eliminate the potential for vertical market power. Horizontal market power is more difficult to eliminate. Horizontal market power may occur when a firm controls a significant share of the market. In the electric power generation business, one firm controlling a significant share of electric generation capacity in a particular region has the potential to exercise horizontal market power.⁹⁴

FERC and State regulators are interested in seeing that market power abuses do not undermine the potential benefits of competitive markets. To meet this objective, FERC requires ISOs and RTOs to monitor bulk power markets for abuses and design flaws, and to report

⁹⁴ A detailed discussion of horizontal market power and its effects on competition can be found in a report prepared by the U.S. Department of Energy, Office of Economic, Electricity, and Natural Gas Analysis, "Horizontal Market Power in Restructured Electricity Markets," DOE/PO-0060 (Washington, DC, March 2000).

Figure 28. Major Wholesale Electricity Trading Hubs and Centralized Power Markets



Notes: Power trading also occurs at locations not indicated on the map. The New York Mercantile Exchange (NYMEX) has established electricity futures contracts for the Cinergy, COB, Entergy, Palo Verde, and PJM trading hubs. The Chicago Board of Trade has established electricity futures contracts for the ComEd and TVA trading hubs.

Source: Electric industry trade journals and Internet websites.

market anomalies to FERC and other effected regulatory authorities. This market monitoring function is critical, particularly now as new competitive bulk power markets develop across the country.

A report prepared recently by the California ISO's Department of Market Analysis demonstrates the crucial role of market monitoring.⁹⁵ The report documents that recent spikes in California's electricity prices over this summer were attributable, in part, to some electricity suppliers exercising market power. The report noted that "the presence of market power can be verified by bid prices significantly over the variable costs of many suppliers in the ISO's market."

Price spikes in wholesale power markets in California and New York have prompted FERC to conduct an

investigation of all electric bulk power markets to determine whether they are working efficiently and, if not, the causes of the problems. Their report is scheduled to be completed November 1, 2000.

Conclusion

By providing the capability to move power over long distances, the transmission system is an integral component of the Nation's electric power industry. Non-discriminatory access to the transmission system for all electricity suppliers is critical to creating competitive power markets. For more than a decade, FERC has been pushing for the development of competitive wholesale power markets and opening the transmission system to all qualified users. Since the late 1980s, FERC has

⁹⁵ California ISO, Department of Market Analysis, "Report on California Energy Market Issues and Performance: May-June 2000" (August 2000).

approved more than 850 applications from electric utilities, power marketers, and independent power producers to use market-based rates to sell power competitively in wholesale markets. In 1996, the Commission issued Order 888, which opened the transmission system to all qualified power producers and marketers. Prior to Order 888, independent power producers and power marketers had difficulty accessing the transmission grid to deliver power.

Over the past few years, FERC has also encouraged regionalization of the transmission grid whereby vertically integrated electric utilities transfer control of their transmission facilities to an independent transmission organization. Independent means generally that the transmission organization does not have an economic interest in buying or selling electricity. The independence from the electricity market helps to ensure fair and comparable access to the transmission grid. In addition, regionalization of control of the transmission grid promotes improved operating efficiency, simplified

and more efficient transmission pricing, and improved reliability.

In an ambitious move to promote regional control of the transmission system, FERC recently issued Order 2000 encouraging all electric utilities to transfer control and/or ownership of their transmission facilities to an independent RTO. Utilities that are not currently a member of an existing regional organization are required to submit plans to join an RTO by October 2000; utilities that are members of an existing regional organization are required to submit their plans to join an RTO by January 2001. It is possible that compliance with Order 2000 will reduce the ownership and control of the Nation's transmission grid to a handful of independent transmission companies over the next few years, but there is much uncertainty about the ultimate effects of Order 2000.

Both this chapter and the preceding chapter have discussed restructuring activities at the Federal level. The following chapter examines the roles of the States.

8. The Role of the States in Promoting Competition

In the years following enactment of EPACT, there has been a surge of activity in State legislatures and at utility commissions to examine various issues with respect to the electric utility industry. Critical among them has been a wide range of activities designed to promote industry competition at the retail level and to complement the wholesale wheeling and stranded cost initiatives of the Federal Energy Regulatory Commission (FERC). In 1999, customers in 12 States could actually choose their electricity supplier. In California, Rhode Island, Massachusetts, and New Jersey almost all customers had the right to choose. In Arizona, Delaware, Illinois, Michigan, Montana, New Hampshire, and New York customer choice is still being phased in. In Pennsylvania, where two-thirds of customers could choose in 1999, as of January 1, 2000, all customers can choose their electricity supplier.

Regulatory Activities

Not all State commissions have moved with the same zeal, even though most of them have under consideration the merits and implications of competition, deregulation, and electric utility industry restructuring. States with high electricity rates, such as California and those in the Northeast, have had compelling reasons to promote competition in the hope of making lower rates available to their customers in general.

As an example, the California Public Utility Commission (CPUC) directed an examination of the comprehensive set of regulatory programs to explore alternatives to what was then the current regulatory approach based on conditions and trends identified in its Decision No. 92-09-088 of September 1992.⁹⁶ The directive resulted in the submission of a staff report—generally known as the “Yellow Book”—to the CPUC in February 1993.⁹⁷

The “Yellow Book” study concluded that the State should reform its regulatory program, including a redefinition of the prevailing regulatory compact, and offered strategies to address shortcomings of its regulatory framework. Based on a comprehensive re-examination of the electric utility industry in the State and the regulatory policy under which the industry functioned, the CPUC opened rulemaking and investigative proceedings to consider its proposed restructuring policies in early 1994.⁹⁸ These initiatives, popularly known as the “Blue Book” proposals, outlined a strategy to replace the traditional cost-of-service regulatory framework with alternatives that focused on utility performance and, where possible, the discipline of the market. Subsequent regulatory and legislative activities in California will be presented in more detail as one of the five case studies that follow later in this chapter.

Other States have not moved with such enthusiasm, however. In December 1998, 23 State public utility commissions sent Congress a letter expressing concerns that issues affecting them may not be given adequate consideration in the debate about restructuring. Kentucky, whose electricity prices are the lowest east of the Rocky Mountains, is one of these States. Recently, Kentucky’s Special Task Force on Electricity Restructuring concluded that there are no compelling reasons to restructure their electric power industry.

States such as Idaho and Nebraska have taken the view that the main tenets of EPACT (as pertaining to promoting competition) are difficult for them to implement.

The Idaho Public Utilities Commission (IPUC), for example, has stated that it is not its role to actively attempt to bring about deregulation of the industry. The IPUC expressed the concern that rates in Idaho could go

⁹⁶ California Public Utility Commission, Decision 92-90-088, W4, 43, “Order Instituting Investigation on the Commission’s Own Motion to Implement the Biennial Resource Plan Update Following the California Energy Commission’s Seventh Electricity Report” (September 16, 1992).

⁹⁷ Refer to California Public Utility Commission, *California’s Electric Services Industry: Perspectives on the Past, Strategies for the Future* (San Francisco, February 1993).

⁹⁸ California Public Utility Commission, “Order Instituting Rulemaking on the Commission’s Proposed Policies Governing Restructuring California’s Electric Services Industry and Reforming Regulation and Order Instituting Investigation on the Commission’s Proposed Policies Governing Restructuring of California’s Electric Services Industry and Reforming Regulation,” Docket Nos. R.94-04-031 and L.94-04-032 (April 20, 1994).

up, and, at the same time, deregulation could result in the diminution of the quality of service enjoyed by the ratepayers in the State.⁹⁹ The Nebraska Public Power District (NPPD) maintains that applying reciprocity requirement provisions of FERC Order 888 violates Nebraska's law and its constitutional rights.¹⁰⁰ The NPPD has, however, continued to monitor the development of regional transmission organizations and independent transmission companies. NPPD has created a new position—Vice President of Transmission Services—to focus on restructuring outside its boundaries and how external activities might affect NPPD.¹⁰¹

In 1996, Idaho, Kentucky, and Nebraska ranked first, second and twelfth, respectively, in lowest average revenue per kilowatthour.¹⁰² In 1998, they ranked first, third and ninth, respectively. It is not surprising that they are not the States that are leaders in the restructuring movement.

Like California, Kentucky is one of the five States that will be examined in detail later in this chapter. The others are Massachusetts, Pennsylvania, and Texas. Massachusetts and Pennsylvania were chosen because they, like California, were among the earliest States to embrace restructuring although they have had vastly different experiences. Texas was chosen because it is a large State that is in the planning stage for instituting competition.

Legislative Activities

All State utility commissions typically enjoy broad regulatory authority to ensure that electric utilities in their jurisdictions provide fair, just, and reasonable

electricity rates to their customers. In addition, State commissions are also empowered to regulate various other aspects of power generation, transmission, and distribution at the State level. However, not all commissions may be endowed with the necessary legal authority to manage an evolving competitive market structure. Accordingly, legislation in some States is designed primarily to grant the utility regulatory agency the authority to address the restructuring issues or to consider alternative rate-making processes (incentive- or performance-based regulation). Elsewhere, State legislators show a serious interest in finding out how the State could respond to new competitive pressures emerging in the electric industry.¹⁰³ Exploratory activities may also be promoted at the behest of the State legislators in an effort to gain additional insights.¹⁰⁴ In some cases, legislative actions may become necessary to adopt decisions recommended by the commission(s) for implementation.

As of July 1, 2000, 24 States¹⁰⁵ and the District of Columbia had enacted legislation or passed regulatory orders to restructure their electric power industries. Alaska and South Carolina had legislation or regulatory orders pending. Sixteen States¹⁰⁶ still had ongoing legislative or regulatory investigations, and there were 8 States¹⁰⁷ where no restructuring activities had taken place (Figure 23).

Case Studies

This section presents the current status of restructuring in five States: California, Kentucky, Massachusetts, Pennsylvania, and Texas. California, Pennsylvania, and

⁹⁹ Idaho Public Service Commission's Order No. 26555, Case No. GNR-E-96-1, "In the Matter of the Commission's Investigating into Changes Occurring in the Electric Industry" (August 16, 1996).

¹⁰⁰ Note that Nebraska has no privately owned electric utilities. All generation, transmission, and distribution service in Nebraska is provided by public entities, municipalities, and cooperatives whose governing boards are responsible to, and serve at the voting pleasure of, rate-paying Nebraska residents.

¹⁰¹ Nebraska Public Power District, 1999 Annual Report, p. 5.

¹⁰² Energy Information Administration, *State Electricity Profiles*, DOE/EIA-0629 (Washington, DC, March 1999).

¹⁰³ On July 3, 1995, Legislative Resolve to Require a Study of Retail Competition in the Electric Industry became Maine law. This legislation directed the Maine Public Utilities Commission (MPUC) to undertake a study to develop at least two plans for an orderly transition to a competitive market. The MPUC released its draft report on July 19, 1996.

¹⁰⁴ The New Hampshire legislature, for example, passed legislation in June 1995 directing the New Hampshire Public Utility Commission (NHPUC) to establish a pilot program to examine the implications of retail competition. In its order establishing preliminary guidelines for a retail competition pilot program, the NHPUC noted that the program was not necessarily a step toward wide-scale competition but was rather a way to examine the implications of an obstacle to a competitive retail market at a time when supply shortages are not a concern. Subsequent legislation (HB-1392), enacted in May 1996, directed the NHPUC to undertake a generic proceeding to develop and establish a final order establishing a statewide electric utility restructuring plan no later than February 28, 1997.

¹⁰⁵ Arizona, Arkansas, California, Connecticut, Delaware, Illinois, Maine, Maryland, Massachusetts, Michigan, Montana, Nevada, New Hampshire, New Jersey, New Mexico, New York, Ohio, Oklahoma, Oregon, Pennsylvania, Rhode Island, Texas, Virginia, and West Virginia.

¹⁰⁶ Alabama, Colorado, Florida, Indiana, Iowa, Louisiana, Minnesota, Mississippi, Missouri, North Carolina, North Dakota, Utah, Vermont, Washington, Wisconsin, and Wyoming.

¹⁰⁷ Georgia, Hawaii, Idaho, Kansas, Kentucky, Nebraska, South Dakota, and Tennessee.

Massachusetts were chosen because they were among the first States to institute restructuring at the retail level and they did so differently. Texas has recently passed restructuring legislation and its utilities and public utility commission are planning for competition which will begin in 2002. Kentucky was chosen to serve as an example of a State that has done little to restructure; in fact, current policy is to maintain the status quo and put off restructuring until there is a compelling reason to do so.

California

In 1996, the average revenue per kilowatthour (which is used as a proxy for price) of electricity sold in California was 9.48 cents,¹⁰⁸ the tenth highest rate among the 50 States and the District of Columbia. This rate was one factor leading Governor Pete Wilson to sign Assembly Bill 1890 (AB1890) on September 23, 1996. This new law established a 4-year transition period to make the State's electric power industry competitive. To implement it, retail competition, allowing customers to choose their electricity, began on March 31, 1998. Rates were frozen at the levels in effect as of June 10, 1996, and a 10-percent rate reduction was guaranteed for residential and small commercial users.¹⁰⁹ These rates will remain frozen until March 31, 2002. As of December 31, 1999, the State has 209,752 direct access customers. This number represents 2.1 percent of the total number of eligible customers and 13.8 percent of the total load.¹¹⁰ Industrial customers, who generally use more electricity than residential customers, account for a major share of this load. These customers are currently served by 35 electric service providers registered with the CPUC.¹¹¹

AB1890 also contained provisions for the creation of an independent system operator (ISO) and a legally separate power exchange (PX) out of concern about market power issues. To ensure that utilities do not continue their traditional monopolistic advantage by controlling generation, transmission and distribution,

the ISO and PX are independent of the utilities.¹¹² The law allows for stranded cost recovery in California. Utilities may apply the difference between their actual operating costs and the frozen rate toward recovering their stranded costs. A "Competition Transition Charge" based on the sales volume appears on consumers' bills along with another charge that finances the bonds that provided the rate reduction.¹¹³ A subsequent law requires retail suppliers to disclose the sources of generation to customers; report fuel types and consumption to system operators who will make the information available to the California Energy Commission; and report emissions, purchased power, losses, and retail sales.¹¹⁴

The California ISO received FERC approval in October 1997, and became operational on March 31, 1998. The major responsibility of the ISO is to ensure fair and impartial access to the high-voltage transmission system for all generators, while maintaining reliable operation. The transmission system will continue to be owned by the investor-owned utilities (IOUs). The ISO will ensure that no particular buyer or seller of electricity can block access by others. Generators who ship electricity through the system will pay a fee to cover the system costs and to ensure reliability.¹¹⁵

The PX, regulated by FERC, also became operational on March 31, 1998. It serves as an auction market for the buying and selling of electricity. The three largest IOUs in the State—Pacific Gas & Electric (PG&E), Southern California Edison (Edison), and San Diego Gas & Electric (SDG&E)—must sell their power to the PX. If they wish to, municipalities, independent power producers, irrigation districts, and out-of-state producers may also sell power to the PX.

The PX accepts requests to buy a quantity of electricity at a given price. The PX functions like an auction to match total demand for power with generation of power. It creates a spot market where price information

¹⁰⁸ Energy Information Administration, *State Electricity Profiles*, DOE/EIA-0629 (Washington, DC, March 1999), p. 29.

¹⁰⁹ California Public Utility Commission, "Plug In, California!" <http://www.cpuc.ca.gov/divisions/csd/electric/PlainEnglish981030.htm>.

¹¹⁰ Energy Information Administration, "An Overview of the Electric Power Industry," presentation to staff of the U.S. Senate Committee on Energy and Natural Resources (March, 2000).

¹¹¹ California Public Utility Commission, http://www.cpuc.ca.gov/electric_restructuring/esp_registration/providers/esp_udc.htm.

¹¹² California Public Utility Commission, "Plug In, California!" <http://www.cpuc.ca.gov/divisions/csd/electric/PlainEnglish981030.htm>.

¹¹³ Energy Information Administration, "Status of State Electricity Industry Restructuring Activity: Stranded Costs as of May 2000," http://www.eia.doe.gov/cneaf/electricity/chg_str/tab5rev.html#CA.

¹¹⁴ California Energy Commission, "Electricity Industry Restructuring - What it is and will it affect me?," http://www.energy.ca.gov/restructuring/restructure_FAQ.html.

¹¹⁵ California Public Utility Commission, "Plug In, California!" <http://www.cpuc.ca.gov/divisions/csd/electric/PlainEnglish981030.htm>.

is publicly available. The PX then solicits bids from electricity generators and chooses the lowest bidders until it has enough supply to meet the requests to buy power. The prices change on an hourly basis.¹¹⁶

PG&E, Edison, and SDG&E were ordered to buy their power from the PX for 4 years after its inception to resell to customers who buy electricity from the utility distribution companies. They will pay a price determined by the PX based on the market demand for power. This was done to foster fair competition between utilities and other electricity suppliers.

However, in a recent development, California regulators are poised to amend the requirement that the State's IOUs buy all their power through the PX. The Automated Power Exchange of Santa Clara and other rivals have consistently opposed the mandate that the IOUs buy from the PX and they have won support from two commissioners, Josiah Neeper and Richard Bilas. They have introduced a proposal that would allow utilities to buy from any approved exchange.¹¹⁷

AB1890 established a public benefit program for low income assistance, energy efficiency, research and development programs, and programs to encourage renewables. It was anticipated that approximately \$540 million would be collected over 4 years by a non-bypassable wires charge.¹¹⁸ Approximately 30 local governments have switched to Commonwealth Energy, which is supplying geothermal energy from Lake, Sonoma, and Imperial counties. Santa Monica, in Los Angeles County, is currently the world's largest all-renewable city, but Oakland is considering making purchases that would put it in the global lead.¹¹⁹

PG&E, Edison, and SDG&E have divested a large amount of generating capacity to address concerns about market power. To date PG&E has divested itself of 7.4 gigawatts of capacity at a sale price of \$1.5 billion.

Edison has sold 10.6 gigawatts for \$1.2 billion. SDG&E has completed transactions of 2.1 gigawatts for \$475 million.¹²⁰ California has been cited as "leading the way with merchant plant proposals." The California Energy Commission approved three merchant plant proposals in 1999, has seven applications under review, and anticipates 11 more proposals.¹²¹

In June 1999, the CPUC began public hearings on opening distribution to competition. The formal opening of the proceeding in December 1998 resulted in responses from numerous stakeholders. Some have suggested waiting until competition in the generation market has matured before attempting to open distribution to competition.¹²²

The California electricity market was in turmoil during the summer months of 2000. There were periods of rolling blackouts around the San Francisco area. Prices in the San Diego region more than doubled. A scorching summer exacerbated these conditions. Some stakeholders have called to re-regulate the industry, while others have called for market reforms. In the meantime, the California ISO set price caps to contain wholesale prices over the summer. The cap was initially set at \$750 per megawatt-hour and was lowered to \$250 per megawatt-hour in August 2000.

California's high electricity prices have been linked to three causes: a deficiency of generating capacity in California; a market system that does not permit enough forward market trading as a means of managing supply and demand risk; and a system that does not allow sufficient customer response to high prices. The California ISO sees improving consumer response to increasing prices and opening the market to new electricity suppliers as fundamental solutions to the recent instability.¹²³

Government executives and agencies have offered short-term relief to high prices. On August 2, 2000 Governor

¹¹⁶ *Ibid.*

¹¹⁷ American Public Power Association, *Public Power Daily* (May 18, 2000).

¹¹⁸ Florida Public Service Commission, "Electric Restructuring Activities Update," <http://www.psc.state.fl.us/general/publications/restruc.htm>.

¹¹⁹ *The Electricity Daily*, Vol. 14, No. 98 (May 22, 2000).

¹²⁰ California Energy Commission, "Electric Generation Divestiture in California," <http://www.energy.ca.gov/electricity/divestiture.html>.

¹²¹ *The Energy Report* (Arlington, VA: Financial Times Energy, January 3, 2000), p. 5.

¹²² Energy Information Administration, "Status of State Electricity Industry Restructuring Activity as of May 2000," http://www.eia.doe.gov/cneaf/electricity/chg_str/tab5rev.html#CA.

¹²³ California Independent System Operator, *Report on California Energy Market Issues and Performance, May-June 2000* (August 10, 2000), p. 1.

Gray Davis issued three executive orders aimed at stabilizing prices, increasing supply, and reducing peak demand.¹²⁴ The Low Income Home Energy Assistance Program and the Small Business Administration released more than \$2 million in emergency funds to assist low-income households and small businesses in the San Diego area.¹²⁵

Responding to San Diego Gas & Electric's petition to reduce wholesale prices, FERC ordered a hearing on August 23, 2000 to investigate if the electricity rates are just and reasonable. Should FERC conclude that the rates were unreasonable, it could order refunds under authority granted by the Federal Power Act for sales that occurred after August 23. Subsequently, on September 21, FERC Chairman James Hoecker asked Congress for greater authority "to retroactively correct extraordinary wealth transfers" since the agency has limited authority to order refunds.¹²⁶

Texas

Much of Texas is unique in that it is not subject to the control of FERC. As stated in Chapter 3, the United States has three separate power grids connected by a few direct current tie lines: the Eastern Interconnect, the Western Interconnect, and the Texas Interconnect. Utilities within each interconnection coordinate operations and planning and buy and sell power among themselves. Because utilities in the Texas Interconnected System are not connected with other utilities outside the State and electric trade does not cross State boundaries for these utilities, FERC does not have regulatory jurisdiction over them. In 1998, Texas was near the middle of the rankings of all States and the District of Columbia with respect to electricity rates. In 1998, the average revenue per kilowatthour was 6.07 cents, which ranked as the 25th lowest in the country. With prices in the middle of the range of States, it is not surprising that Texas recently passed restructuring legislation.

In 1995, Senate Bill 373, which became the Public Utility Regulatory Act of 1995, was enacted to restructure the

wholesale electricity market in Texas consistent with FERC requirements for unbundled transmission service. The law also required the establishment of an ISO. The ISO in the Electric Reliability Council of Texas (ERCOT) differs somewhat from the other ISOs. The ERCOT ISO does not participate in generation dispatch, in power exchanges, in providing ancillary services, or in establishing prices other than determining the cost of any redispatch needed to allow transactions to occur. In 1996, the Public Utility Commission (PUC) of Texas issued rules implementing the legislation that required transmission-owning utilities in the State to provide open access to the transmission system and ancillary services. The rule also required separation of transmission, distribution, and generation costs and rates, and the establishment of the ERCOT ISO.¹²⁷

In 1999, Texas was the largest State to pass restructuring legislation. Governor George W. Bush signed Senate Bill 7 to introduce retail competition to Texas.¹²⁸ Retail choice will begin in 2002. The restructuring law freezes rates for 3 years or until 40 percent of a utility's customers have switched to an alternate provider, whichever comes first. The law is expected to give a boost to development of renewable energy sources. Utilities can recover an estimated \$9 billion in stranded costs through securitization. In response to the law, TXU and Southwestern Public Service have already put some of their power plants up for sale.¹²⁹ Electric cooperatives and municipally owned utilities are exempt from customer choice unless their governing boards decide to open their markets to competition.

As of January 10, 2000, all Texas IOUs had filed detailed plans describing how they propose to unbundle their operations.¹³⁰ As of March 31, 2000, nine utilities had turned in their transition plan proposals to the PUC.¹³¹ Utilities were required to state which aspects of their businesses would be deregulated and which portions would remain regulated. The companies were also required to describe how they would separate their businesses into a retail provider, a generation company, and a transmission and distribution utility. The electric

¹²⁴ "California Looks in Every Direction Seeking 'Fix' for Market Shock," *Electric Utility Week* (The McGraw-Hill Companies, August 7, 2000), p. 7.

¹²⁵ *The Energy Report* (Arlington, VA: Financial Times Energy, August 28, 2000), p. 1.

¹²⁶ American Public Power Association, *Public Power Daily* (September 22, 2000).

¹²⁷ Energy Information Administration, *State Electricity Profiles*, DOE/EIA-0629 (Washington, DC, March 1999), p. 263.

¹²⁸ Public Utility Commission of Texas, *Electric Competition Overview*, <http://www.puc.state.tx.us/ocp/competition/echome.cfm>.

¹²⁹ *The Energy Report* (Arlington, VA: Financial Times Energy, January 3, 2000), p. 4.

¹³⁰ *Electric Utility Week* (New York: McGraw-Hill, January 17, 2000) p. 7.

¹³¹ *Dallas Morning News* (April 1, 2000), <http://www.dallasnews.com>.

companies were required to report the fees they would charge to retail competitors using the utilities' lines.¹³² By September 2001, the PUC will begin to certify retail electricity providers. The Texas Pilot Program is scheduled to commence on June 1, 2001, and on January 1, 2002 retail choice is slated to begin with small commercial customer and residential electric rates decreasing by 6 percent. A proposal for a consumer education plan has been approved by State regulators. This marks the first step in implementing a consumer plan mandated by the restructuring law. The intent of the plan is to explain restructuring to customers and inform them of their options. Plans for northeastern Texas have been developed, and the PUC will strive to develop a plan with emphasis on non-English speaking and lower-income customers. The plan will most likely be implemented by early 2001.¹³³

The Texas approach to implementing competition has been cited as a good model for restructuring. The decision to deal with wholesale issues at the outset by leveling the playing field for equal transmission access "promises to create a strong retail market," according to one energy consultant.¹³⁴ A spokesperson for another energy company, however, believes that a serious flaw in the restructuring plan is the local control of metering and billing until 2004.¹³⁵

With regard to renewables, a new rule mandates the building of 2 gigawatts of new capacity fueled by renewable sources by 2009. Between now and 2009 the rule requires the following: 400 megawatts by 2003, an additional 450 megawatts by 2005, another 550 megawatts by 2007, and an additional 600 megawatts by 2009. January 1, 2002, will mark the beginning of a Renewable Credits Trading Program in the State, which will continue until 2019. Retailers with insufficient credits will be penalized \$50 per megawatthour or 200 percent of the average cost of traded credits of the year.¹³⁶

Massachusetts

On November 27, 1997, HB 5117, the Electric Utility Restructuring Act, was signed by Governor Paul Cellucci to restructure the industry in Massachusetts. The law basically affirmed the PUC restructuring order of 1996. The Restructuring Act mainly affects the Commonwealth's eight investor-owned distribution companies, which supply 87 percent of the electricity in Massachusetts.¹³⁷ Retail access was required by March 1998, and a simultaneous rate cut of 10 percent to be followed 18 months later by an additional 5 percent cut was made law. Municipal utilities have the option to participate.¹³⁸ Additionally, the divestiture of generation assets was encouraged.¹³⁹ In 1996, Massachusetts had the eighth highest electricity rates in the Nation, which were most certainly a consideration in enacting the legislation the following year. In 1998, the rates in the Commonwealth were the ninth highest in the country. Between 1996 and 1998, the nonutility share of capability increased from 16 percent to 67 percent as utility divestitures took place. So far, however, the number of customers that have switched is not high. A slowly increasing standard offer rate (described below) could lead to increases in customers in the future.¹⁴⁰

Three generation service options are available to consumers: (1) Standard Offer Service, provided by distribution companies; (2) Default Service, provided by distribution companies; and (3) Competitive Generation Service, provided by competitive suppliers. The price the customer pays for generation service is dependent on the type of service that the customer receives.

Standard Offer Service is a transition generation service available through 2004 to each distribution company's customers of record. The price of the Standard Offer Service is set in advance and will increase gradually. As examples, the Standard Offer Rates for the Boston

¹³² U. S. Department of Energy, Electric Utility Restructuring Weekly Update, http://www.eren.doe.gov/electricity_restructuring/weekly/apr7_00.html.

¹³³ U. S. Department of Energy, Electric Utility Restructuring Weekly Update, http://www.eren.doe.gov/electricity_restructuring/weekly/jan21_00.html.

¹³⁴ U. S. Department of Energy, Electric Utility Restructuring Weekly Update, http://www.eren.doe.gov/electricity_restructuring/weekly/feb25_00.html.

¹³⁵ *Ibid.*

¹³⁶ U. S. Department of Energy, Electric Utility Restructuring Weekly Update, http://www.eren.doe.gov/electricity_restructuring/weekly/jan7_00.html.

¹³⁷ *Foster Electric Report*, No. 176 (October 20, 1999), p. 3.

¹³⁸ States' Electric Restructuring Activities Update, Florida Public Service Commission, <http://www.psc.state.fl.us/general/publications/restruc.htm>.

¹³⁹ Energy Information Administration, "Status of State Electricity Industry Restructuring Activity as of May 2000," http://www.eia.doe.gov/cneaf/electricity/chg_str/tab5rev.html.

¹⁴⁰ *The Energy Report* (Arlington, VA: Financial Times Energy, January 3, 2000), p. 5.

Edison Company and the Cambridge Electric Light Company rose from 3.69 cents and 3.5 cents per kilowatthour to 4.5 cents and 3.8 cents per kilowatthour, respectively, from 1999 to 2000.¹⁴¹ A customer that did not select a competitive supplier as of March 1, 1998, automatically was placed on the Standard Offer Service. (Customers who move into a distribution company's service territory after March 1, 1998, are not eligible to receive the Standard Offer—these customers are placed on Default Service until they select a competitive supplier.) In general, once customers select a competitive supplier, they are no longer eligible to return to the Standard Offer Service. Exceptions include (1) low-income customers who can return at any time, (2) residential and small commercial and industrial customers who return within 120 days of deleting a supplier (This option was available only until March 1, 1999.), and (3) customers participating in a municipal aggregation program who return within 180 days of joining the program. The rates for the Standard Offer Service are regulated by the Department of Telecommunications and Energy (DTE) and were set at levels that provided a 10 percent overall bill reduction to customers receiving the Standard Offer Service. The level of the overall bill reduction for the Standard Offer customers increased to 15 percent on September 1, 1999.

Default Service is the generation service provided by distribution companies to those customers who are not receiving either Competitive Generation or Standard Offer Service. Customers who moved into a distribution company's service territory after March 1, 1998, received Default Service until they selected a competitive supplier. Prices for Default Service are regulated by the DTE and may not exceed the average market price for electricity in New England.

Competitive Generation Service will be provided by competitive suppliers and electricity brokers that have been licensed by the DTE. A competitive supplier is defined as licensed to sell electricity and related services to customers. As of May 2000, 33 authorized competitive suppliers/electricity brokers were located in Massachusetts. An electricity broker is an entity that is licensed

to facilitate or otherwise arrange for the purchase and sale of electricity and related services to customers, but is not licensed to sell electricity to customers. An applicant for a competitive supplier or electricity broker license must demonstrate, among other things, the financial and technical capability to provide the applicable services. Prices for Competitive Generation Service will be set by the competitive electricity marketplace; these prices will not be regulated by the DTE. Customers receiving generation service from a competitive supplier have two billing options: (1) complete billing, where a customer receives a single bill from the distribution company, including charges for generation service, and (2) pass-through billing, where a customer receives two bills—one from the distribution company for non-generation charges and another from the competitive supplier for generation service charges.¹⁴²

An assessment of the first year of electric utility industry restructuring in Massachusetts shows that the largest accomplishment was the mandated reduction in overall customer bills by 10 percent. However, little retail competition has resulted due to the low Standard Offer. In fact, between February and March 2000, the number of customers buying competitive power dropped by 1,100. Of the 2.5 million electric accounts in the Commonwealth, only 7,302 are buying power competitively.¹⁴³

Energy Commissioner David O'Connor has stated that the problem lies in the region's volatile wholesale power market, which has seen significant price spikes. High wholesale prices have led to high retail prices and consequently, commercial and industrial customers, whose competitive power contracts are expiring, are opting to go back to low-price utility service.¹⁴⁴

To address the problem, the DTE has proposed two market-based pricing options to remove the incentive for customers to return to default service. The first offers customers a fixed price for 6-month periods. It would be available to all customers who are already on default service when the 6-month period begins, or who moved into the service territory after the period begins. The price would be based on the average monthly wholesale

¹⁴¹ Initially the Standard Offer rates for each of the Massachusetts distribution companies approved by the Department of Telecommunications and Energy was equal to 2.8 cents per kilowatthour. The rate for each of these companies remained at 2.8 cents for the remainder of 1998, with two exceptions: (1) Boston Edison increased its Standard Offer rate to 3.2 cents on June 1, 1998, concurrent with the completion of the divestiture of its non-nuclear generating units; and (2) Massachusetts Electric Company increased its Standard Offer rate to 3.2 cents on September 1, 1998, concurrent with the completion of the divestiture of New England Power Company's non-nuclear generating units.

¹⁴² Massachusetts Department of Telecommunications and Energy, *Electric Restructuring in Massachusetts*, <http://www.magnet.state.ma.us/dpu/restruct/competition/index.htm>.

¹⁴³ *Electric Utility Week* (New York: McGraw-Hill, January 17, 2000) p. 8.

¹⁴⁴ *Ibid.*

price that each utility pays for supply. The second option would allow default service price to change monthly, based on the monthly wholesale prices that each utility pays for its default service supply. This option would be available to customers who begin receiving the service after the start of the 6-month period and who were previously receiving their electricity from a competitive supplier.¹⁴⁵

Paul Gromer, an attorney with the Boston-based Peregrine Energy Group, which represents the independent power marketers operating in the Commonwealth, states the problem lies in the fact that one default service rate exists for all customers. He argues that this creates cross-subsidization and inaccurate pricing signals. He contrasts what is happening in Massachusetts with the way Connecticut, Pennsylvania, New Jersey, California, and Maine have offered different rates for different customer classes.¹⁴⁶

Major changes are, however, taking place even though competitive supply is hardly pervasive throughout the Commonwealth. For example, utility companies made significant progress in divesting their power plants and power supply contracts. The generation portion of the electric industry is now virtually all owned by independent power producers. This extensive sale of power plants has significantly reduced the stranded cost obligations that would have been facing ratepayers. Massachusetts had awarded stranded costs if conforming utilities had demonstrated that they had divested all non-nuclear generation and attempted to mitigate all other costs. So far, approximately \$2 billion of the total \$6 billion that will eventually be paid has been transferred. Securitization then becomes permissible.¹⁴⁷ If a utility had been unwilling to divest its generation, the DTE would have determined the level of stranded costs.

ISO New England received conditional FERC approval on June 25, 1997. Utilities in all six New England States created the ISO through a voluntary agreement.¹⁴⁸ Additionally, proposed construction of more than 30 gigawatts of new power plants has been announced across the region, prompted by restructuring legislation enacted in most of the New England States. While not all

proposals will come to fruition, it is likely that the increased competition from these new plants will force some of the existing, less efficient plants into retirement. Most of the new capacity will be fueled by natural gas and other low emission fuels; therefore air pollution should be lowered and customers will have the option to buy greener power from sources close to home.

With respect to public benefit programs, distribution companies must offer low income discounts. A Renewable Energy Trust Fund was established with a fee of 0.125 cents per kilowatthour in 2000. Also, a charge of 0.33 cents per kilowatthour has been established for funding energy efficiency programs. The fee will be phased down to 0.25 cents per kilowatthour in 2002.

A renewable portfolio standard is mandated, and hydro-power is considered to be a renewable energy source. One percent of sales must be from new renewables by 2003. This rises by 0.5 percent each year until 2009 and then increases 1 percent per year thereafter until ended by the Division of Energy Resources.¹⁴⁹

Pennsylvania

In 1996, the average revenue per kilowatthour in Pennsylvania was 7.96 cents;¹⁵⁰ in 1998, it was 7.86 cents. In both years, Pennsylvania had the eleventh highest average electricity price among the 50 States and the District of Columbia. Like California and Massachusetts, Pennsylvania falls into the camp of relatively high-priced States that have been somewhat aggressive in pursuing restructuring.

In terms of numbers of customers that have switched suppliers, Pennsylvania's restructuring program is the most successful in the Nation. Governor Tom Ridge signed the Electricity Generation Customer Choice and Competition Act into law on December 3, 1996. The law basically separates the generation of electricity from the services of transmitting and distributing it. The law called for a phase-in of retail choice with one-third eligible to choose by January 1998, another third by January 1999, and the remaining third by January 2000. Therefore, all customers in Pennsylvania can now choose

¹⁴⁵ *Electric Utility Week* (New York: McGraw-Hill, January 17, 2000) p. 1.

¹⁴⁶ *Electric Utility Week* (New York: McGraw-Hill, January 17, 2000) p. 9.

¹⁴⁷ The Act authorizes the Massachusetts Industrial Finance Agency to issue "electric rate reduction revenue bonds," to finance the buy-out by electric companies of purchased power contracts with above-market rates.

¹⁴⁸ Florida Public Service Commission, "States' Electric Restructuring Activities Update," <http://www.psc.state.fl.us/general/publications/restruc.htm>.

¹⁴⁹ *Ibid.*

¹⁵⁰ Energy Information Administration, *State Electricity Profiles*, DOE/EIA-0629 (Washington, DC, March 1999), p. 234.

the generator of their electricity, but they are still required to purchase the transmission and distribution components of their electricity from the local supplier. All utilities subject to the separation requirements were required to file their restructuring plans with Pennsylvania's Public Utilities Commission (PUC) in 1997. The PUC has established industry groups to provide recommendations on areas of concern that have arisen in the restructuring process. These areas include education, information and billing, universal service, conservation, reliability, direct retail access implementation scheduling, metering competitive safeguards, interaction between suppliers and utilities, and taxes. A multimedia consumer education campaign was launched by the Pennsylvania Electric Choice Program to educate consumers about their ability to shop for a competitive supplier. Included in the campaign were television and radio advertisements as well as a four-page newspaper insert.¹⁵¹

With regard to stranded costs, the PUC is authorized to determine the level of stranded costs that each utility is permitted to recover. Cost shifting between customers as a result of stranded cost recovery is prohibited. The costs can be recovered through a non-bypassable competitive transition charge (CTC) that will be reviewed and adjusted annually for each customer who elects to receive service from an alternative generation supplier. The CTC will be collected by utilities over a maximum period of 9 years, unless the PUC approves another time frame. California, by contrast, authorized a collection period of only 4 years.

The Competition Act encourages market participants to coordinate their plans and transactions through an ISO or functional equivalent. Electric utilities are permitted to divest themselves of facilities or to reorganize their corporate structures, but unbundling of services is required. Additionally, public benefits programs are funded by an energy surcharge to provide programs for low-income assistance, energy conservation, and other public purposes at the existing funding level.¹⁵²

As a result of the new law encouraging outsiders to set up business within the Commonwealth (unlike Florida

whose Supreme Court recently reaffirmed restrictions on merchant plants), interesting developments have occurred. For example, the largest wind farm in the eastern United States is now in Pennsylvania. GreenMountain.com, which completed the eight-turbine project in April 2000, is betting that customers will pay a slight premium to switch to power that is cleaner than the traditional source of Pennsylvania's electricity—coal.¹⁵³

Today, 52 suppliers are licensed to sell their generation in the Commonwealth. A survey from the Office of Consumer Advocate reports that 408,414 (8 percent) of Pennsylvania's residential electricity customers have switched utility providers. The survey also noted that 95 percent of electricity customers are aware of their options to switch to alternative suppliers under the law. Of those who have switched, approximately 20 percent have opted for a green power choice.¹⁵⁴ In the PECO service area in southeastern Pennsylvania, 15 percent of residential customers, 30 percent of commercial customers, and 62 percent of industrial customers have switched suppliers.¹⁵⁵ Twenty-six percent of Duquesne Light's residential customers switched their supplier. Technically, with the recent completion of Duquesne Light's sales of its generating assets to Orion Power Holdings,¹⁵⁶ all customers have a new supplier of electricity. The 26-percent citation represents those customers who actively sought an alternative supplier. Duquesne Light provides service in the Greater Pittsburgh area.

One of the keys to Pennsylvania's successful transition to a competitive retail marketplace may have been its pilot program. The program provided an incentive to participate by guaranteeing a 10- to 13-percent discount off the electric distribution company charge for all classes of customers while establishing a generation credit that allowed customers to obtain electricity supply at 5 to 20 percent below the credit. "As a result, the pilot was oversubscribed and the PUC and the electric distribution companies had an opportunity to work out problems in the transition to competition," according to Sandra Barber of the National Energy Team.¹⁵⁷

¹⁵¹ U.S. Department of Energy, Electric Utility Restructuring Weekly Update (February 18, 2000), http://www.eren.doe.gov/electricity_restructuring/weekly/feb18_00.html.

¹⁵² Florida Public Service Commission, "States' Electric Restructuring Activities Update," <http://www.psc.state.fl.us/general/publications/restruc.htm>.

¹⁵³ "GreenMountain.com Makes Pitch for Clean Energy," *The Wall Street Journal* (May 1, 2000), p. A36.

¹⁵⁴ *Ibid.*

¹⁵⁵ The Pennsylvania Electric Choice Program, <http://www.electrichoice.com/public/pdf/elecchart.pdf>.

¹⁵⁶ *The Energy Report* (Arlington, VA: Financial Times Energy, May 8, 2000), p. 15.

¹⁵⁷ Anne Millen Porter, "Why Pennsylvania Might Be the Only Game in Town," *Purchasing* (July 16, 1998).

Kentucky

In December 1999, Kentucky's Special Task Force on Electricity Restructuring released its findings and recommendations. It found that "there is no compelling reason at this time for Kentucky to move quickly to restructure. Despite the prospects of Congressional legislation to mandate restructuring, actions taken by 24 States and the District of Columbia to restructure, and the fact that some of those States are geographically contiguous to Kentucky, there are obvious advantages for Kentucky adopting a wait-and-see approach to electricity restructuring. Representatives from other States that have restructured as well as experts in the field of electricity restructuring indicate that Kentucky is in a unique position because of its existing low electricity rates, which currently are the lowest east of the Rocky Mountains. Most of Kentucky's generation is coal-fired and its generators are close to coal fields which are among the cheapest fuel sources. Also, there has been relatively little construction of generating capacity recently, which has kept the Commonwealth's collective rate base low. A wait-and-see approach allows Kentucky to monitor the progress of restructuring in other States and to develop options that protect Kentucky's existing low rates for electricity."¹⁵⁸

In 1998, when the average revenue per kilowatthour in Kentucky was 4.16 cents, only Idaho and Washington had lower electricity rates. Unlike California, Massachusetts, and Pennsylvania, Kentucky has no compelling price pressure to restructure. Therefore, the Commonwealth has no retail competition and no competitive supplier activity. The only recent action of note was a Public Service Commission Order in April 1999 to reduce rates for Kentucky Utilities and Louisville Gas and Electric subsidiaries. The order calls for a \$52 million rate reduction under a performance-based rate making approach.¹⁵⁹

Because Kentucky has had no restructuring activity, no stranded cost provisions are in place.

Issues Under Consideration

The current issues faced by the States are varied based on the wide array of associated circumstances. Some areas of concern, however, are similar across State lines, for example:

- Remediating the loss of tax base for local authorities
- Generating renewable power and provisions for net metering
- Evaluating performance-based ratemaking
- Providing non-discriminatory access to all electric power suppliers
- Setting standards of conduct for suppliers and utility affiliates
- Taking environmental issues into consideration
- Ensuring reliability in supplies and designation of supplier of the last resort during transition
- Establishing consumer protection programs
- Determining the role of public power utilities in promoting competition.¹⁶⁰

The following chapter examines in more detail the role of recent mergers, acquisitions, and power plant divestitures of IOUs in restructuring the electric power industry.

¹⁵⁸ Kentucky Association of Electric Cooperatives, Inc., <http://www.kaec.org/stand/electrestructuring.htm>.

¹⁵⁹ Energy Information Administration, "Status of Electricity Industry Restructuring by State," http://www.eia.doe.gov/cneaf/electricity/chg_str/tab5rev.html.

¹⁶⁰ Energy Information Administration, *Electric Power Annual 1999, Volume I*, DOE/EIA-0348(99)/1 (Washington, DC, August 2000).

9. Mergers, Acquisitions, and Power Plant Divestitures of Investor-Owned Electric Utilities

In response to increased competition in power generation, investor-owned utilities (IOUs) have engaged in a wave of mergers and acquisitions during the past decade, resulting in some very large IOUs. In contrast, some IOUs have exited the power generation business by selling their generation assets to an independent power producer (IPP), or by transferring them to an unregulated subsidiary within their company. The purpose of these contrasting strategies is to improve and solidify a position in the new competitive industry. It is too early to determine, however, the effectiveness of these strategies on the industry and their benefits to electricity customers.

Recent mergers are classified broadly into two categories, each category representing a fundamentally different reason for merging. The first category includes mergers between IOUs or between IOUs and IPPs. These mergers are motivated by the desire to increase power generation capacity and/or transmission and distribution capacity and in general become a larger electric utility. Most utility executives take the position that to compete successfully in today's electricity market a company must be relatively large.

The second category includes mergers between electric utilities and natural gas companies. Companies entering into these types of mergers are seeking to become a regional or even a national company that produces, transports, and markets electricity and natural gas. These are called convergence mergers because they represent the increasing number of companies that own both electricity and natural gas assets and are active in both industries. Each of these categories of mergers is described followed by an examination of recent divestitures of power generation assets by IOUs.

Mergers and Acquisitions Between IOUs and IPPs

From 1992 to April 2000, 35 mergers or acquisitions have been completed between IOUs or between IOUs and

IPPs. Twelve mergers have been announced and are now pending stockholder or Federal and State government approval (Table 14).¹⁶¹ The size of IOU mergers, in terms of value of assets, is also increasing. Between 1992 and 1998, only four mergers were completed in which the combined assets of the companies in each merger were greater than \$10 billion. More recently, eight mergers completed in 1999 or 2000, or pending completion, each have combined assets greater than \$10 billion.

One of the effects of this wave of mergers is that there are fewer operating electric utilities. In 1992, 172 operating utilities owned generation capacity in the United States. By the end of 2000, the number of operating utilities owning generation capacity will decrease to an estimated 141 (Table 15). Power plant divestitures, discussed later in the chapter, have also reduced the total number of IOUs that own generation capacity.

The majority of operating electric utilities are wholly-owned subsidiaries of public utility holding companies.¹⁶² The effect of mergers on consolidation of the industry is more evident when ownership capacity is aggregated by holding companies. In 1992, there were 70 electric holding companies owning 78 percent of the IOU-held generation capacity. By the end of 2000, the number of electric holding companies will decrease to 53, and the generation capacity they own will increase to about 86 percent of the total IOU-owned capacity, primarily because of mergers and acquisitions. This statistic suggests that relatively large companies are becoming even larger.

Although many electric utilities see a need to grow through mergers, others do not. Of 82 electric utilities (53 electric utility holding companies and 29 independent electric utilities) in 2000 (Table 15), 56 (approximately 60 percent) have not been involved in a merger since 1992 and have not announced plans to merge. This suggests that even though the merger trend is strong, most IOUs believe consolidation is not necessary to

¹⁶¹ Investor-owned utility acquisitions of foreign companies or non-energy related companies are not included in this analysis.

¹⁶² In some cases a holding company will also be a subsidiary of another holding company. The number of holding companies cited in this report refers to the highest level holding company.

Table 14. Mergers and Acquisitions Between Investor-Owned Electric Utilities or Between Investor-Owned Electric Utilities and Independent Power Producers, 1992 Through April 2000

Merger Status	Company 1	Company 2	Name of Surviving Company or Name of New Company	States Served (Retail Customers)	Combined Assets (Year-of-Merger Dollars in Billions)	Comments/Status
Pending	American Electric Power Co., Inc. (a registered holding company for AEP Generating Co., Appalachian Power Co., Columbus Southern Power Co., Indiana Michigan Power Co., Kentucky Power Co., Kingsport Power Co., Ohio Power Co., and Wheeling Power Co.)	Central and South West Corp. (a registered holding company for Central Power and Light Co., Public Service Co. of Oklahoma, Southwestern Electric Power Co., and West Texas Utilities Co.)	American Electric Power Co., Inc. (Central and South West will be a wholly-owned subsidiary)	VA, WV OH, IN MI, KY TN, TX OK, LA AR	AEP: \$19.5 CSW: \$13.7 Total: \$33.2	Under regulatory review.
	Consolidated Edison, Inc. (a holding company for Consolidated Edison Co. of New York, Inc., and Orange and Rockland Utilities)	Northeast Utilities (a holding company for Connecticut Light & Power, Public Service Co. of New Hampshire, and Western Massachusetts Electric Co.)	Consolidated Edison, Inc. (Northeast Utilities will be a subsidiary)	NY, CT, MA, NH	Consolidated Edison: \$14.4 Northeast: \$10.4 Total: \$24.8	Under regulatory review. Received shareholder approval 4/14/00.
	Carolina Power & Light Co. (an operating utility)	Florida Progress Corp. (a holding company for Florida Power Corp.)	Unknown	FL, NC, SC	CP&L: \$8.3 Florida: \$6.2 Total: \$14.5	Under regulatory review.
	UtiliCorp United (a holding company)	St. Joseph Light & Power (an operating utility)	Utilicorp (St. Joseph will keep its name and become a wholly-owned subsidiary)	MO, KS CO, WV	Utilicorp: \$6.0 St. Joseph: \$0.3 Total: \$6.3	Under regulatory review.
	New Century Energies (a registered holding company for Public Service Co. of Colorado, Southwestern Public Service Co., and Cheyenne Light, Fuel, & Power)	Northern States Power (a holding company)	Xcel Energy (unknown if New Centuries and Northern States Power operate as subsidiaries)	NM, OK TX, WY AR, MI MN, SD ND, WI	New Century: \$7.7 NSP: \$7.4 Total: \$15.1	Received FERC approval. Under review by States.
	UtiliCorp United (a holding company)	Empire District Electric Co. (an operating utility)	Unknown	MO, CO KS, WV OK, AR	Utilicorp: \$6.3 Empire District: \$0.7 Total: \$7.0	Under regulatory review.
	Sierra Pacific Resources (a holding company for Sierra Pacific Power and Nevada Power)	Portland General Electric (a subsidiary of ENRON Corp.)	Sierra Pacific Resources (Portland General Electric will be a subsidiary)	NV, CA, OR	Sierra: \$4.6 Portland: \$3.2 Total: \$7.8	This acquisition was announced 11/99.
	Energy East (a holding company for New York Electric & Gas)	CMP Group (a holding company for Central Maine Power)	Energy East (CMP Group will be a wholly-owned subsidiary)	MA, MI NY, NH	Energy East: \$4.9 CMP Group: \$2.3 Total: \$7.2	Obtained FERC approval 4/10/00.

Table 14. Mergers and Acquisitions Between Investor-Owned Electric Utilities or Between Investor-Owned Electric Utilities and Independent Power Producers, 1992 Through April 2000 (Continued)

Merger Status	Company 1	Company 2	Name of Surviving Company or Name of New Company	States Served (Retail Customers)	Combined Assets (Year-of-Merger Dollars in Billions)	Comments/Status
Pending	Unicom Corporation (a holding company for Commonwealth Edison)	PECO Energy Co. (a registered holding company for Susquehanna Power Co.)	Exelon (A new holding company)	IL, PA	Unicom: \$30.2 Peco: \$12.0 Total: \$42.2	Under regulatory review.
	PowerGen plc (a foreign-owned power producer)	LG&E Energy Corp. (a holding company for Louisville Gas & Electric and Kentucky Utilities)	PowerGen (LG&E will be a wholly-owned subsidiary)	KY, VA	Not available because PowerGen is a foreign company.	This acquisition was announced in 2/00.
	Cap Rock Energy Corporation (electric cooperative)	Citizens Utilities Company (an operating utility)	Cap Rock Energy Corporation	AR, VT	Not Applicable	Cap Rock is an electric cooperative that is in the process of converting to an investor-owned utility. Cap Rock is purchasing Citizens Utilities distribution assets in Arizona and Vermont.
	Kauai Island Electric Cooperative (an electric cooperative)	Citizens Utilities Company (an operating utility)	Kauai Island Electric Cooperative	HI	Not Applicable	Citizens Utilities is selling its Hawaii Electric distribution business to Kauai Island.
Completed in 2000	Berkshire Hathaway (et. al.) (an investor group)	MidAmerican Energy Holdings Company (a holding company for MidAmerican Energy)	Berkshire Hathaway (MidAmerican will be a subsidiary)	IA, KS	Unknown	Berkshire Hathaway is an investment company. The acquisition was completed in 3/00. MidAmerican and CalEnergy merged in 1999.
	Laurel Hill Capital Partners, LLC (an investment company)	TNP Enterprises Inc. (a holding company for Texas-New Mexico Power Company)	TNP Enterprises will continue to exist	TX, NM	Unknown	This acquisition represents a change in ownership of TNP. No information was given about creating a new corporation.
	National Grid Group PLC (a foreign company)	New England Electric Systems (NEES) (a registered holding company for Granite State Electric Co., Massachusetts Electric Co., Narragansett Electric Co., and New England Power Co.)	National Grid Group (NEES will be a wholly-owned subsidiary)	VT, NH MA	Not available because National Grid Group is a foreign company.	Completed.

Table 14. Mergers and Acquisitions Between Investor-Owned Electric Utilities or Between Investor-Owned Electric Utilities and Independent Power Producers, 1992 Through April 2000 (Continued)

Merger Status	Company 1	Company 2	Name of Surviving Company or Name of New Company	States Served (Retail Customers)	Combined Assets (Year-of-Merger Dollars in Billions)	Comments/Status
Completed in 2000 (Continued)	New England Electric System (a registered holding company for Granite State Electric Co., Massachusetts Electric Co., Narragansett Electric Co., and New England Power Co.)	Eastern Utility Associates (a registered holding company for Blackstone Valley Electric Co., Newport Electric Corp., Eastern Edison Co., EUA, and Ocean State Corp.)	New England Electric System (EUA will be a wholly-owned subsidiary)	MA, RI VT, NH	NEES: \$5.3 EUA: \$1.3 Total: \$6.6	Completed.
	Allegheny Energy, Inc. (a registered holding company)	West Virginia Power (an operating utility)	Allegheny Energy (West Virginia Power will be a subsidiary)	PA, WV, OH, MD	Allegheny: \$6.7 West Virginia: \$.1 Total: \$6.8	West Virginia Power is a small electric and gas distribution company.
Completed in 1999	Nevada Power (an operating utility)	Sierra Pacific Resources (a holding company for Sierra Pacific Power Co.)	Sierra Pacific Resources (Nevada Power will be a wholly-owned subsidiary)	NV, CA	Nevada Power: \$2.6 Sierra Pacific: \$2.0 Total: \$4.6	Completed.
	AES Corporation (an independent power producer)	CILCORP (a holding company for Central Illinois Light Co.)	AES (CILCORP will be a wholly-owned subsidiary)	IL	AES: \$10.0 CILCORP: \$1.3 Total: \$11.3	Completed.
	BCE Energy (a holding company for Boston Edison)	Commonwealth Energy (a holding company for Cambridge Electric Light Co., Canal Electric Co., and Commonwealth Electric Co.)	NSTAR (a new holding company; Boston Edison and Commonwealth Energy will be subsidiaries)	MA	BCE: \$3.2 Commonwealth: \$1.5 Total: \$4.7	Completed.
	Scottish Power PLC (a foreign company)	PacifiCorp (an operating utility)	Unknown (a new holding company; PacifiCorp will be a subsidiary)	UT, OR, WY, WA, ID, MT, CA	Not available because Scottish Power is a foreign company.	Completed.
	CalEnergy Co., Inc. (an independent power producer)	MidAmerican Energy Holding Co. (a holding company for MidAmerican Energy Co.)	MidAmerican Energy Holding (CalEnergy will be a subsidiary)	IA, KS	CalEnergy: \$7.5 MidAmerican: \$4.3 Total: \$11.8	Completed.
	Consolidated Edison, Inc. (a holding company for Consolidated Edison Co. of New York, Inc.)	Orange and Rockland Utilities (an operating utility)	Consolidated Edison, Inc. (Orange and Rockland will be a wholly-owned subsidiary)	NY	ConEd: \$14.4 O&R: \$1.3 Total: \$15.7	Completed.

Table 14. Mergers and Acquisitions Between Investor-Owned Electric Utilities or Between Investor-Owned Electric Utilities and Independent Power Producers, 1992 Through April 2000 (Continued)

Merger Status	Company 1	Company 2	Name of Surviving Company or Name of New Company	States Served (Retail Customers)	Combined Assets (Year-of-Merger Dollars in Billions)	Comments/Status
Completed in 1998	Delmarva Power & Light Co. (an operating utility)	Atlantic Energy (a holding company for Atlantic City Electric Co.)	Connectiv (a new registered holding company)	MD, DE VA, NJ	Delmarva Power: \$3.0 Atlantic: \$2.7 Total: \$5.7	Completed.
	LG&E Energy (a holding company for Louisville Gas & Electric Co.)	KU Energy (a holding company for Kentucky Utilities)	LG&E Energy (KU Energy will be dissolved)	KY, VA TN	LG&E: \$3.0 KU Energy: \$1.7 Total: \$4.7	Completed.
	WPL Holding, Inc. (a holding company for Wisconsin Power & Light)	IES Industries (a holding company for IES Utilities and Interstate Power, an operating utility)	Alliant Energy (a new holding company)	WI, IA MN, IL	WPL Holding: \$1.9 IES: \$2.5 Interstate: \$0.6 Total: \$5.0	Completed.
	Wisconsin Energy (a holding company for Wisconsin Electric Power Co.)	ESELCO (a holding company for Edison Sault Electric Co.)	Wisconsin Energy Company (ESELCO will be a wholly-owned subsidiary)	WI, MI	Wisconsin: \$5.0 ESELCO: \$0.1 Total: \$5.1	Completed.
	WPS Resources (a holding company for Wisconsin Public Service Corp., Wisconsin River Power Co.)	Upper Peninsula Energy (a holding company for Upper Peninsula Power Co.)	WPS Resources (Upper Peninsula Energy will cease to exist)	WI, MI	WPS: \$1.1 Upper Peninsula: \$0.1 Total: \$1.2	Completed.
Completed in 1997	Ohio Edison Co. (an operating utility; Ohio Edison also owns Pennsylvania Power Co.)	Centerior Energy (a holding company for Cleveland Electric Illuminating Co. and Toledo Edison Co.)	FirstEnergy (a new registered holding company)	OH	Ohio Edison: \$8.9 Centerior: \$10.2 Total: \$19.1	Completed.
	Public Service Co. of Colorado (an operating utility and a holding company for Cheyenne Light, Fuel, and Power)	Southwestern Public Service Co. (an operating utility)	New Century Energies (a new registered holding company)	CO, TX NM, OK KS	PS Co. of CO: \$4.6 Southwestern: \$2.0 Total: \$6.6	Completed.
	Union Electric Co. (an operating utility)	CIPSCO (a holding company for Central Illinois Public Service Co.)	Ameren (a new registered holding company)	MO, IL	Union: \$6.8 CIPSCO: \$1.8 Total: \$8.6	Completed.
	Pacific Gas & Electric Corp. (a holding company for Pacific Gas & Electric)	U.S. Generating Co. (USGen) (an independent power producer)	Pacific Gas & Electric Corp. (USGen will be an unregulated affiliate of PG&E)	USGen has plants in numerous States	USGen: \$5.0	PG&E acquired 50 percent in USGen. At the time, USGen had ownership in 17 electric generating facilities operating in the United States.
Completed in 1996	New England Electric Systems (a registered holding company for Granite State Electric Co., Massachusetts Electric Co., Narragansett Electric Co., and New England Power Co.)	Nantucket Electric (a small electric distribution company)	New England Electric System (Nantucket Electric is a subsidiary)	VT, NH MA	NEES: \$5.1 Nantucket: \$0.1 Total: \$5.2	Completed.

Table 14. Mergers and Acquisitions Between Investor-Owned Electric Utilities or Between Investor-Owned Electric Utilities and Independent Power Producers, 1992 Through April 2000 (Continued)

Merger Status	Company 1	Company 2	Name of Surviving Company or Name of New Company	States Served (Retail Customers)	Combined Assets (Year-of-Merger Dollars in Billions)	Comments/Status
Completed in 1985	City of Groton, CT	Bozrah Light and Power	Unknown	CT	Unknown	Completed.
	Delmarva Power and Light	Conowingo Power Co.	Delmarva Power and Light	DE, MD, VA	Delmarva Power: \$2.9 Conowingo: \$0.1 Total: \$3.0	Completed.
	Midwest Resources (a holding company for Midwest Power Systems)	Iowa-Illinois Gas and Electric (an operating utility)	MidAmerican Energy (a holding company and operating utility)	IA, SD, IL	Midwest: \$2.6 Iowa: \$1.9 Total: \$4.5	Completed.
Completed in 1984	PSI Resources (an operating utility)	Cincinnati Gas & Electric (an operating utility)	CiNergy (PSI Resources and Cincinnati are wholly-owned subsidiaries)	IN, OH, KY	PSI Resources: \$2.9 Cincinnati: \$5.2 Total: \$8.1	Completed.
Completed in 1993	Citizens Utilities Co. (an operating utility)	Franklin Electric (an operating utility)	Citizens Utilities (Franklin Electric ceased to exist)	AZ, HI, VT	Citizens: \$2.6 Franklin: \$0.8 Total: \$3.4	Completed.
	IES Utilities Inc. (a holding company)	Iowa Electric Light & Power and Iowa Southern Utilities	IES Industries (IES Utilities, Iowa Electric, and Iowa Southern are subsidiaries)	IA	Total: \$1.8	Completed.
	Texas Utilities (a holding company)	Southwestern Electric Service Co. (an operating utility)	Texas Utilities (Southwestern Electric is a subsidiary)	TX	Total: \$20.9	Completed.
	Entergy Corp. (a holding company)	Gulf States Utilities (a holding company)	Entergy Corp. (Gulf States is a wholly-owned subsidiary)	AR, TN, LA, TX, MS, NY	Entergy: \$14.2 Gulf States: \$7.2 Total: \$21.4	Completed.
Completed in 1992	Connecticut Light & Power	Fletcher Electric Light Co.	Connecticut Light and Power	CT	Total: \$6.2	Completed.
	Iowa Public Service Co.	Iowa Power Co.	Midwest Power	IA, SD	Total: \$2.6	Completed.
	Kansas Power & Light	Kansas Gas & Electric	Western Resources	KS	Total: \$5.2	Completed.
	Indiana Michigan Power Co.	Michigan Power Co.	Indiana Michigan Power Co.	IN, MI	Total: \$4.3	Completed.
	Until Corp.	Fitchburg Gas & Electric	Until Corp.	NH	Total: \$0.2	Completed.
	Northeast Utilities	Public Service of New Hampshire	Northeast Utilities	NH, CT, MA	Total: \$10.6	Completed.

Table 15. Comparison of the Number of Investor-Owned Electric Utilities Owning Generation Capacity, 1992 and 2000

Company Category	1992			2000 (Estimated)		
	Number of Operating Utilities	Number of Holding Companies	Generation Capacity (Percent and Thousand Megawatts)	Number of Operating Utilities	Number of Holding Companies	Generation Capacity (Percent and Thousand Megawatts)
Utility that is a Subsidiary to a Holding Company.	113	70	(78%) 422.1	112	53	(86%) 384.5
Independent Utility	59	—	(22%) 120.3	29	—	(14%) 60.6
Total	172	70	(100%) 542.4	141	53	(100%) 445.1

*The number of utilities reported here does not match the number of utilities reported in Chapter 2 for the following reasons: (1) these data include IOUs that own power generation capacity, whereas the data reported in Chapter 2 include IOUs that operate power plants; (2) some utilities operate transmission and distribution systems only and are not included here; and (3) these data exclude Alaska and Hawaii.

Notes: • The 2000 data include the effects of pending mergers on consolidation of ownership. It is assumed that all pending mergers will be completed by 2000. • Also, the 2000 data include the effects of generation asset divestitures on consolidation of ownership. It is assumed that all divestitures where a buyer has been announced will be completed by 2000. • Holding companies were identified from the following documents: U.S. Securities and Exchange Commission Financial and Corporate Reports, "Holding Companies Registered Under the Public Utility Holding Company Act of 1935 as of October 1, 1995, as of December 1, 1996, and as of June 1, 1998," and "Holding Companies Exempt from the Public Utility Holding Company Act of 1935 Under Section 3(a) (1) and 3(a) (2) Pursuant to Rule 2 Filings or By Order as of August 1, 1995 and as of November 1, 1997."

Sources: Energy Information Administration, Forms EIA-860, "Annual Electric Generator Report;" EIA-860A, "Annual Electric Generator Report - Utility;" and EIA-861, "Annual Electric Utility Report."

remain competitive in the industry in spite of the fact that those companies choosing to merge are acquiring a larger share of the industry's assets.

The absolute number of companies provides insight into consolidation trends, but concentration of generation capacity ownership is perhaps more indicative of consolidation.¹⁶³ As a measure of consolidation of the IOU sector, concentration indicates the extent to which total capacity ownership is dispersed among companies. The data suggest that generation capacity owned by IOUs has been concentrated in the hands of a few companies, and that mergers and acquisitions are increasing the concentration of ownership within the IOU sector. In 1992, the 10 largest utilities, ranked according to generation capacity, owned 36 percent of all IOU generation capacity; by the end of 2000 the 10 largest companies' share will increase to an estimated 51 percent (Figure 29). Evidence of consolidation among the 20 largest companies is even more compelling. In 1992

the 20 largest companies owned 58 percent of total IOU generation capacity; by the end of 2000 their share is expected to increase to approximately 72 percent.

Mergers and acquisitions also cause consolidation of ownership of the Nation's transmission and distribution systems. However, the outcome of this trend is unclear because many utilities may transfer ownership of their transmission system to regional transmission organizations in compliance with the Federal Energy Regulatory Commission's (FERC's) Order 2000.

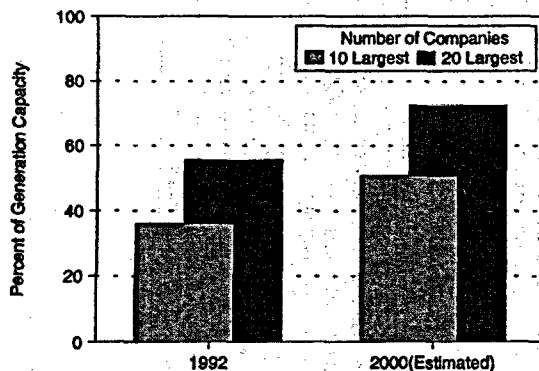
Reasons for Mergers and Acquisitions Among Electric Utilities

Most, if not all, utility executives who have directed their companies through mergers, argue that electric utilities must be relatively large to be competitive.¹⁶⁴ This position underlies most of the mergers and acquisitions recently completed between IOUs. Why does size

¹⁶³ Measures of concentration are sometimes used to identify the potential for a firm to exercise market power in a particular product market. Measuring concentration is problematic in the electric power industry due to the difficulty in defining relevant markets. In this report, measures of concentration were not developed for a particular electricity market. Instead, the term concentration is used broadly to suggest that the recent wave of mergers is responsible for the increase in size of many IOUs.

¹⁶⁴ For example, the CEO of New Century Energies, when discussing the merger between New Century Energies and Northern States Power, said "The merger provides both the combined company and its operating units with the scale necessary to remain competitive in a changing industry marketplace," Press Release, *New Century Energies* (March 1999).

Figure 29. Concentration of Ownership of Investor-Owned Utility Generating Capacity, 1992 and 2000



Notes: •The 10 largest companies are public utility holding companies that own one or more operating electric utilities. •The 2000 data assume that all pending mergers will be completed by year-end 2000. •Capacity owned by subsidiaries of IOUs was not counted when computing rankings.

Sources: Energy Information Administration, Form EIA-860, "Annual Electric Generator Report," Form EIA-860A, "Annual Electric Generator Report - Utility," and Form EIA-861, "Annual Electric Utility Report."

matter? The thinking is that larger companies are able to achieve economies of scale. By combining resources and eliminating redundant or overlapping activities, larger companies hope to benefit from increased efficiencies in procurement, production, marketing, administration, and other functional areas that smaller companies may not be able to achieve. For example, a larger company, because of a high volume of purchases, may be able to negotiate a lower price from its fuel supplier than would be available to a smaller company. Cost savings resulting from increased efficiency can be passed to the utility's customers through lower electricity rates.

Whereas utility executives argue that a merger or acquisition will improve the efficiency of the combined company, experience indicates that efficiency improvements are not guaranteed. One study reported that only 15 percent of mergers and acquisitions achieved their expected financial objectives.¹⁶⁵ Incomplete or under-developed plans to integrate the companies was noted as a major factor for not achieving the objectives.

A company's strategic objectives are also factors in the decision to merge. Does the merger complement or

enhance the strategic objectives of the company is a question asked by company executives in identifying merger partners. Strategic objectives are company specific and depend upon the merging companies' particular circumstances. Building on core competencies, securing more customers, consolidating transmission and distribution facilities, diversifying power generating capability, and acquiring additional managerial and technical expertise are mentioned often as reasons. These strategic reasons, however, relate to the desire to remain competitive in the rapidly changing electricity industry.

Convergence Mergers

Increased competition has pressured electric utilities and natural gas companies to combine operations in order to become more efficient, to diversify products, to share expertise and experience in energy markets, and to take advantage of the growing use of natural-gas-fired power plants. Combining electric utilities and natural gas companies is called convergence of the industries, and many companies that once sold only electricity or natural gas now sell both electricity and natural gas, or are involved in other aspects of both industries.

A combined electric and natural gas utility is not something new to the industry. Many IOUs sell both electricity and natural gas to retail customers. What is new about the recent wave of mergers is that many of them are between electric utilities and natural gas production, processing, or interstate pipeline companies. These types of mergers expand greatly the business opportunities for electric utilities.

From 1997 through April 2000, 23 convergence mergers involving companies with assets valued at \$0.5 billion or higher have been completed or are pending completion (Table 16).¹⁶⁶ No one knows for certain how long this trend will continue, but many industry observers agree that more convergence mergers will take place as deregulation of the electric power industry continues and electric and natural gas companies seek to diversify their businesses.

Strategic Benefits of Convergence Mergers

The natural gas industry has a relatively complicated structure that, depending on one's classification scheme, may consist of four major corporate segments (Table 17).

¹⁶⁵ J. Anderson, "Making Operational Sense of Mergers and Acquisitions," *The Electricity Journal*, Vol. 12, No. 7 (August/September 1999).

¹⁶⁶ A convergence merger is defined as a merger in which one company's primary business activity is electricity generation, transmission, and/or sales and the other company's primary business activity is natural gas production, processing, transportation, and/or sales.

Table 16. Selected Mergers and Acquisitions Involving Investor-Owned Electric Utilities and Natural Gas Companies, 1997 Through April 2000

Combined Electric Power and Natural Gas Company	Companies Merging	Type of Business	Value of Assets (Year-of-Merger Dollars in Billions)	Status	Comments
Allegheny Energy, Inc.	Allegheny Energy (Allegheny Power) Mountaineer Gas	Electric/Gas Gas	Allegheny: \$6.7 Mountain Gas: \$ 0.3 Total: \$7.0	Pending	Allegheny Energy is expanding its business in West Virginia so that it can cross-sell electricity and gas in the State.
DTE Energy	DTE Energy (Detroit Edison) MCN Energy Group (Michigan Consolidated Gas Company)	Electric Gas	DTE Energy: \$12.1 MCN Energy: \$4.4 Total: \$16.5	Pending	This merger was announced in early October 1999. DTE Energy is a holding company; its primary subsidiary is Detroit Edison, a large investor-owned electric utility. MCN Energy Group, through its subsidiary Michigan Consolidated Gas Company, is a large gas distribution company. It also has gas pipeline, processing, and marketing activities, and it has investments in electric power. The combined company will be the largest gas and electric utility in Michigan.
KeySpan Energy Corp.	KeySpan Energy Eastern Enterprises	Electric/Gas Gas	KeySpan: \$6.9 Eastern: \$1.5 Total: \$8.4	Pending	KeySpan is a diversified energy company providing electrical power and natural gas in New York. This merger expands KeySpan's natural gas customer base to New England.
NISOURCE (a new holding company will be formed)	NISOURCE (Northern Indiana Public Service) Columbia Energy Group	Electric/Gas Gas	NISOURCE: \$5.0 Columbia: \$7.0 Total: \$12.0	Pending	This merger was announced in February 2000. It will create a large integrated energy company serving nine States in the Midwest.
SCANA Corporation	SCANA Corp. (South Carolina Electric & Gas) Public Service Co. of North Carolina	Electric/Gas Gas	SCANA: \$5.3 PS of NC: \$0.7 Total: \$6.0	Pending	SCANA is the parent company of South Carolina Gas & Electric. Public Service of North Carolina, Inc. is a gas utility. This merger expands SCANA's gas distribution business and energy marketing resources.
Vectren	SigCorp Inc. (Southern Indiana Gas & Electric) Indiana Energy DPL (Natural Gas)	Electric/Gas Gas Gas	SigCorp: \$1.0 Indiana Energy: \$0.7 DPL: \$0.4 Total: \$2.1	Pending	SigCorp is a mid-size gas and electric company. Indiana Energy is a natural gas distribution and energy marketing company. Indiana Energy is purchasing DPL's natural gas distribution business. These acquisitions increase the customer base of the new combined company.
Dominion Resources	Dominion Resources (Virginia Power) Consolidated Natural Gas	Electric/Gas Gas	Dominion: \$17.5 Consolidated: \$6.4 Total: \$23.9	Completed in 2000	Dominion Resources is predominantly a power company owning regulated and unregulated power generation assets. Consolidated Natural Gas is a large producer, transporter, distributor, and retail marketer of natural gas. This merger will create one of the Nation's largest integrated electric and natural gas companies.
Dynegy	Illinova Dynegy	Electric/Gas Gas	Illinova Corp: \$6.4 Dynegy Inc: \$5.3 Total: \$11.7	Completed in 2000	Illinova is an energy service company; its primary subsidiary is Illinois Power, an electric and natural gas utility. Dynegy Inc. is a marketer of energy products and services. It grew from primarily a natural gas marketer to a full energy service marketing company.

Table 16. Selected Mergers and Acquisitions Involving Investor-Owned Electric Utilities and Natural Gas Companies, 1997 Through April 2000 (Continued)

Combined Electric Power and Natural Gas Company	Companies Merging	Type of Business	Value of Assets (Year-of-Merger Dollars in Billions)	Status	Comments
Energy East Corporation	CTG Resources, Inc. (Connecticut Natural Gas Corp.)	Gas	Energy East: \$4.9 Conn. Energy: \$0.5 CTG Resources: \$0.5 Total: \$5.9	Completed in 2000	Connecticut Natural Gas is engaged in the distribution, transportation, and sale of natural gas in Hartford and 21 other cities and towns in central Connecticut and in Greenwich, Connecticut. This represents the third acquisition by Energy East over the past few months, further strengthening its competitive position in the Northeast.
	Energy East (New York State Electric & Gas) Connecticut Energy (Southern Connecticut Gas)	Electric/Gas Gas		Completed in 2000	Energy East, the parent company of New York Electric & Gas, has chosen to focus the company on energy delivery. The merger with Connecticut Energy, the parent of Southern Connecticut Gas, a gas distribution company, increases Energy East's market share in the Northeast region.
Northeast Utilities	Northeast Utilities Yankee Energy System	Electric Gas	Northeast: \$2.2 Yankee Energy: \$0.5 Total: \$2.7	Completed in 2000	Northeast Utilities is one of New England's largest electric utility systems. Yankee Energy System, Inc. is the parent company of Yankee Gas Services Company, one of the largest natural gas distribution companies in the Northeast. Under regulatory review.
Wisconsin Energy	Wisconsin Energy Corp. Wicor (Washington Gas Co.)	Electric/Gas Gas	Wisconsin: \$5.4 Wicor: \$1.0 Total: \$6.4	Completed in 2000	Wisconsin Energy is an electricity and natural gas holding company. It owns two operating electric utilities, Wisconsin Electric and Edison Sault Electric. WICOR is a diversified holding company operating in two industries—natural gas distribution and water pump manufacturing. This merger strengthens Wisconsin Energy's gas business and helps to make it a major regional player in the evolving electricity and natural gas markets.
CMS Energy	CMS Energy (Consumer Energy) Panhandle Eastern Pipeline	Electric/Gas Gas	CMS Energy: \$11.3 Panhandle: \$2.0 Total: \$13.3	Completed in 1999	CMS is a diversified energy company having both electricity and natural gas operations. PanHandle is a natural gas pipeline company in the Midwest. Because PanHandle's pipelines connect to CMS's gas distribution and storage, this merger was a good strategic move. CMS noted that gas-fueled electricity generation continues to grow in the Midwest, and this merger improves its effort to be a major player in the gas supply market.
Duke Energy Corporation	Union Pacific Fuels	Gas	UP Fuels: \$1.4	Completed in 1999	Duke Energy Field Services, a component of Duke Energy Corporation, purchased the natural gas gathering, processing, fractionation, and liquids pipeline business of Pacific Resources (known as Union Pacific Fuels). This purchase expands Duke Energy's capability in the production of natural gas liquids and other areas in the natural gas business.
NIPSCO Industries	NIPSCO Industries (Northern Indiana Public Service) Bay State Gas	Electric Gas	NIPSCO: \$3.7 Bay State: \$0.8 Total: \$4.5	Completed in 1999	NIPSCO is a holding company for Northern Indiana Public Service, an electric and gas distribution utility. Bay State is a gas distribution utility. The merger expands NIPSCO's energy distribution market.

Table 16. Selected Mergers and Acquisitions Involving Investor-Owned Electric Utilities and Natural Gas Companies, 1997 Through April 2000 (Continued)

Combined Electric Power and Natural Gas Company	Companies Merging	Type of Business	Value of Assets (Year-of-Merger Dollars in Billions)	Status	Comments
KeySpan Energy	LILCO (Long Island Lighting Co.) Brooklyn Union Gas	Electric/Gas Gas	LILCO: \$4.2 Brooklyn Union: \$2.3 Total: \$6.5	Completed in 1998	The merger of LILCO, an electric utility, and Brooklyn Union, a gas utility, creates a regional energy distribution company serving primarily New York.
Sempra Energy	ENOVA (San Diego Gas and Electric) Pacific Enterprises (Southern California Gas)	Electric/Gas Gas	ENOVA: \$5.2 Pacific: \$5.0 Total: \$10.2	Completed in 1998	The merger of San Diego Gas & Electric, primarily an electricity distribution company, and Southern California Gas, a gas distribution company, creates one of the largest regulated energy distribution companies in the United States.
Duke Energy Corporation	Duke Power Company PanEnergy Corporation	Electric Gas	Duke Power: \$13.5 PanEnergy: \$8.6 Total: \$22.1	Completed in 1997	In June 1997, Duke Power Co., one of the Nation's leading electric utilities, and PanEnergy Corporation, a natural gas pipeline and marketing company, completed a merger creating Duke Energy Corporation. Duke Energy Corporation has an aggressive growth strategy, and its objective is to become a large diversified global energy company.
Enron	Enron Portland General Corp. (Portland General Electric)	Gas Electric	Enron: \$23.4 Portland: \$3.3 Total: \$26.7	Completed in 1997	The merger between Enron, an integrated natural gas company, and Portland General Electric was the first merger between a predominantly natural gas company and an electric utility. It marked the beginning of the convergence trend in the industry and the creation of large electricity and natural gas companies.
Pacific Gas & Electric Corporation	Pacific Gas & Electric Corp. Valero Energy Corp. (Valero Natural Gas Company)	Electric/Gas Gas	PG&E Corp: \$30.6 Valero: \$1.5 Total: \$32.1	Completed in 1997	PG&E Corporation is a large electric and natural gas company. Valero is a natural gas process and gas transportation and storage company. This acquisition increases PG&E's presence in the Texas natural gas industry.
Puget Sound Energy	Puget Sound Power & Light Co. Washington Energy Co.	Electric Gas	Puget Sound: \$3.3 Washington: \$1.0 Total: \$4.3	Completed in 1997	This merger creates one of the largest combined electric and natural gas utilities in the Northwest. The merger expands Puget Sound Power & Light into the natural gas distribution business.
Reliant (formerly Houston Industries)	Reliant NorAm Energy	Electric Gas	Reliant: \$12.3 NorAm: \$4.0 Total: \$16.3	Completed in 1997	Houston Industries is a holding company; Houston Light & Power, a vertically integrated electric company, is the principal subsidiary. NorAm Energy owns subsidiary companies engaging in wholesale electricity and gas marketing, interstate gas transmission, and retail natural gas distribution.
TXU (formerly Texas Utilities Co.)	Texas Utilities Co. ENSERCH (Lone Star Gas)	Electric/Gas Gas	Texas Utilities: \$21.4 ENSERCH: \$3.2 Total: \$24.6	Completed in 1997	Texas Utilities is a combined electric and natural gas company. It owns two electric utilities in Texas. ENSERCH is a natural gas distribution and pipeline company. It owns Lone Star Gas Company, the largest natural gas distribution company in Texas. This merger significantly expands the customer base of the new combined company.

Note: Table includes mergers or acquisitions in which each company had assets valued at \$0.5 billion or higher at the time of the merger.

Sources: Mergers and acquisitions were identified from trade journals, newspapers, and electric utility press releases found on Internet websites. Values of the companies' assets were obtained from the Securities and Exchange Commission 10-K filings.

Table 17. Overview of Strategic Benefits of a Combined Electric and Natural Gas Company

Natural Gas Corporate Segments	Description	Potential Strategic Benefits to Electric Company of Combining with Natural Gas Company
Producers	Perform gas exploration and production functions. Generally market gas at the wellhead to third parties who resell the gas.	Electric company may have direct access to natural gas to fuel power plants.
		In general, by acquiring natural gas assets, the combined company can offer a wider assortment of energy products and services.
Pipelines	Provide wholesale transportation/transmission function. Transport gas from the field to market area. Pipeline network facilities may include gathering, transmission, compressor, storage, and metering facilities.	Access to a reliable source of natural gas for existing gas-fired power plants.
		New gas-fired merchant power plants can be strategically built relative to natural gas pipelines.
		In general, by acquiring natural gas assets, the combined company can offer a wider assortment of energy products and services.
Local Distribution Companies	Provide retail sales and local transportation deliveries.	Cross-sell natural gas to retail electricity customers as a way to expand products and services.
		Help reduce unit costs by expanding overhead over larger customer base.
		Improve efficiencies of retail sales by combining billing and other administrative functions.
Marketers and Brokers	Engage in competitive wholesale gas sales and services. Buy and resell natural gas and gas management services to others on a deregulated basis.	Expand marketing effort and improve effectiveness of marketing by selling both natural gas and electricity to a common customer base.
		Apply gas company expertise and experience in gas marketing to electricity marketing.

Source: Energy Information Administration, Office of Coal, Nuclear, Electric and Alternate Fuels.

Some of the major natural gas companies are vertically integrated, having exploration and production, pipelines, local distribution, and marketing components. The majority of the companies are not vertically integrated but specialize in one or two areas. Local distribution companies (LDCs) are the largest segment of the industry, with approximately 1,400 LDCs operating in the United States. The benefits to an electric utility of a convergence merger depend on where the gas company is located in the production cycle. An analysis of the current wave of convergence mergers shows that the benefits of the merger generally fall into one or more of the following areas.

Strengthen Wholesale Marketing and Trading Operations: Deregulation of the electricity and natural gas industries has created spot markets for wholesale electricity and natural gas, as well as markets for buying, selling, and trading financial instruments for risk management. In competitive commodity markets, prices for the commodities (in this case, electricity or natural gas) are sometimes volatile. Risk management, such as buying futures contracts for electricity, helps reduce the

risk of price volatility. Many electric utilities and natural gas companies realize that there are similar and related techniques for electricity and natural gas marketing and trading in spot markets, and are merging to form larger organizations specializing in electricity and natural gas. This provides the opportunity to sell a diversified line of products to their customers, and it can help lower administrative and processing costs. It also facilitates arbitrage between electric power and natural gas prices.

One of the most frequently cited reasons for a convergence merger is the transferring of a gas company's experience in marketing and trading to an electric company that is relatively new in competitive markets and commodity trading. The gas industry has been deregulated since the 1980s, and over that time surviving gas companies have developed skills and experience in working in competitive energy markets.

Diversify Products and Expand Retail Markets: Most electric utilities believe that to remain competitive they need to offer more products and services to their retail customers. State-designed customer choice programs,

which allow retail customers to select their energy suppliers, motivate utilities to differentiate their products from their competitors' products. One strategy to accomplish this is to merge with a local gas distribution utility and offer both electricity and natural gas services to customers. The idea of one-stop shopping appeals to some customers, and combined marketing and delivery systems can also help reduce the utility's billing, metering, and other administrative costs.

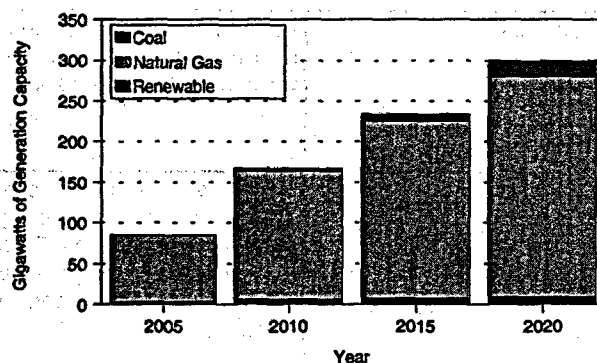
In addition to diversifying products and services, many utilities see convergence mergers as a way to increase market share, although this concept also applies to mergers involving only electric utilities. Increased market share should lower per-customer costs by spreading fixed costs over a larger customer base. Utility distribution systems have a large fixed-cost component.

Another benefit from convergence mergers is the potential for cross-selling electricity to natural gas customers and natural gas to electricity customers. The extent to which the customer base of the merging companies does not overlap represents the potential for increasing market share by cross-selling.

Expand and Strengthen Access to a Fuel Supply for Merchant Power Plants: Electric utility holding companies are merging with natural gas companies that specialize in natural gas production, processing, pipeline operation, and storage. These are called upstream and midstream functions in the natural gas industry parlance. Distribution to the ultimate customer is a downstream function. Electric utility mergers with upstream or midstream natural gas companies position the new company to benefit from the growing demand for natural gas stimulated by the projected growth in gas-fired power plants across the country.

Because of the rising demand for electricity and the retirement of older power generation units, 300 gigawatts of new generating capacity will be needed in the United States by 2020 (Figure 30). Assuming an average plant capacity of 300 megawatts, a projected 1,000 new plants will be needed to meet electricity demand and to offset plant retirements. Ninety percent of that capacity is projected to be natural-gas-fired or dual-fired gas and oil combined-cycle or combustion turbine technology. These technologies have lower capital costs and operating and maintenance costs than other technologies, and they more easily meet local and Federal Government emissions constraints, which are expected to

Figure 30. Cumulative Electricity Generation Capacity Additions Through 2020



Source: Energy Information Administration, *Annual Energy Outlook 2000*, DOE/EIA-0383 (2000) (Washington, DC, December 1999).

tighten in the future. Electric utilities that own upstream and midstream natural gas resources will be positioned to compete for customers in growing natural gas markets brought on by the increase in demand for gas-fired plants. Also, by owning upstream and midstream gas resources, a company can expand its range of products and services and build a marketing strategy focused on a customer's total energy needs.

Regulatory Review of Electric Utility Mergers and Acquisitions

Electric utility mergers or acquisitions of substantial size go through a review process involving a number of Federal and State Government agencies (Table 18). At the State level, the public utility commission or its equivalent reviews the merger for potential anti-competitive effects and potential cost savings. States may also review the merger's effect on a utility's stranded costs,¹⁶⁷ an issue brought on by industry deregulation. Because most electric utility operations cross State boundaries, it is not uncommon for multiple States to review a merger. The extent and depth of the review can vary widely between States, depending on the merger's expected impact in the State and the resources available to conduct an evaluation.

Federal review of a proposed merger may involve up to five different agencies. Either the Federal Trade Commission (FTC) or the Antitrust Division of the Department of Justice (DOJ) could conduct a review to

¹⁶⁷ In general, stranded costs are historic financial obligations of utilities incurred in the regulated market that become unrecoverable in a competitive market. Stranded costs are also known as stranded investments, stranded commitments, and transition costs.

Table 18. Government Agencies Responsible for Reviewing Mergers and Acquisitions Involving Electric Utilities

Government Agency	Authority	Type of Review
Department of Justice or Federal Trade Commission	Section 7 of the Clayton Act, Hart-Scott-Rodino Antitrust Improvements Act	Examines mergers that may substantially lessen competition or tend to create a monopoly.
Federal Energy Regulatory Commission	Federal Power Act of 1935, Department of Energy Reorganization Act of 1977, Energy Policy Act of 1992	Examines mergers and other combinations to assure markets and access to reliable service at reasonable prices.
Internal Revenue Service	16 th Amendment to U.S. Constitution (1913)	Determines amount of tax liability for combination.
Nuclear Regulatory Commission	Atomic Energy Act, Energy Reorganization Act of 1974, Energy Policy Act of 1992	Approves transfer of ownership of nuclear facilities.
Securities and Exchange Commission	Public Utility Holding Company Act of 1935 (PUHCA)	Assures compliance with PUHCA provisions and protection of shareholder interest.
State Public Utility Commission, State Attorney General Office	Various State Laws	Full review may include antitrust, market power, stranded costs, rates, and demand-side management. The State has the authority to allocate merger savings between ratepayers and shareholders.

Sources: Energy Information Administration, *Natural Gas 1998: Issues and Trends*, DOE/EIA-0560(98) (Washington, DC, June 1999), Chapter 7; and M.W. Frankena and B.M. Owen, *Electric Utility Mergers, Principles of Antitrust Analysis* (Westport, CT: Praeger Publishers, 1994).

determine whether the merger is consistent with anti-trust laws. Recently, the Antitrust Division of the DOJ, rather than the FTC, has reviewed electric utility mergers, but for most electric utility mergers the DOJ relies on FERC to take the lead in evaluating the competitive effects of the merger. The DOJ limits its role to participation as an interested party.¹⁶⁸ The Securities and Exchange Commission (SEC) can become involved in a merger or acquisition when a holding company gains control of 10 percent or more of the voting securities of another electric utility. If that is the case, the SEC reviews the merger for compliance with requirements of the Public Utilities Holding Company Act of 1935. The Nuclear Regulatory Commission (NRC) reviews a proposed merger or acquisition when it involves the transfer of a nuclear power plant operating license.

Of all Federal Government agencies involved in reviewing a proposed merger between electric utilities, FERC's review is probably the most extensive, covering the merger's potential effects on competition in the

industry, electricity rates to customers, and regulation. FERC sometimes will request merger applicants to prepare special reports showing the merger's effect on market power or the cost savings and efficiencies that are expected from the merger. These reports and other documents, such as public comments about the merger, are available on the Commission's website (www.ferc.fed.us). Depending on the level of public interest, the size of the merging companies, and the merger's potential impact on the industry, FERC may hold public hearings to obtain information and to discuss important issues associated with the merger.

Divestiture of Power Generation Assets

The previous sections discussed mergers and acquisitions and their effects on the structure of the industry. Recent divestitures of power generation assets (i.e., power plants) by a number of IOUs is another type of corporate realignment that is changing the structure of the industry. Divestiture of generation assets is defined as the sale of assets to another company, or the transfer

¹⁶⁸ M.W. Frankena and B.M. Owen, *Electric Utility Mergers, Principles of Antitrust Analysis* (Westport, CT: Praeger Publishers, 1994).

of assets from the regulated utility subsidiary to an unregulated subsidiary within the company structure.

Over the past 3 years, IOUs have divested power generation assets at unprecedented levels. From late 1997 through April 2000, 51 IOUs (32 percent of the 161 IOUs owning generation capacity) have divested or are in the process of divesting 156.5 gigawatts of power generation capacity, representing approximately 22 percent of total U.S. electric utility generation capacity (Table 19). Of the 156.5 gigawatts, 86.2 gigawatts have been sold or are pending completion of the sale, 31.9 gigawatts are up for sale, and 38.3 gigawatts will be transferred by an IOU to its nonutility subsidiary. Some industry observers have estimated that ownership may change for up to 50 percent of total U.S. generation capacity (about 364 gigawatts as of 1998) over the next 10 years. No one can predict with certainty the volume of future divestitures, but more are expected as restructuring of the electric power industry proceeds.

The idea of an electric utility divesting generation assets can be traced back to before November 1996, when FERC issued Order 888 requiring electric utilities to allow access to their transmission lines to other electricity suppliers. As discussed in Chapter 7, FERC believed that access to transmission lines was necessary in order for a competitive power generation market to develop. Some industry participants believed, however, that open access to the transmission system would not be sufficient. When transmission line capacity becomes limited due to high usage, it is argued that utilities that own the transmission lines will favor power from their own generators over a competitor's generator. Many thought the answer to this problem was for FERC to

require utilities that own both power generators and transmission lines to divest their power generation assets.

In Order 888, FERC took a less intrusive alternative to actual divestiture of generation assets by requiring functional unbundling. Functional unbundling is achieved when a company's organizational structure separates operation of and access to the transmission system from power generation. To comply with functional unbundling, electric utilities created an open access transmission tariff, established separate rates for wholesale generation, transmission, and ancillary services, and established an electronic information network that supplies information on the availability of transmission capacity to customers. All IOUs have complied with FERC's functional unbundling requirements and in some regions electric utilities have formed independent system operator (ISO) companies and turned control (but not ownership) of their transmission assets over to the ISOs. This action can be construed as a way of unbundling power generation from transmission.

Why Investor-Owned Electric Utilities Are Divesting Power Generation Assets

Even though all IOUs have functionally unbundled generation from transmission, and some have formed ISOs, many utilities have divested their power plants because of State requirements or as a result of strategic business decisions made by the utility. With regard to State requirements, States that are opening the electric market to retail competition view the separation of power generation ownership from power transmission and distribution ownership as a prerequisite for retail

Table 19. Status of Power Generation Asset Divestitures by Investor-Owned Electric Utilities, as of April 2000

Status Category	Capacity (GW)	Percent of Total	Percent of Total U.S. Generation Capacity
Sold	58.0	37	8
Pending Sale (Buyer Announced)	28.2	18	4
For Sale (No Buyer Announced)	31.9	20	4
Transferred to Unregulated Subsidiary ^a	4.1	3	1
Pending Transfer to Unregulated Subsidiary ..	34.2	22	5
Total	156.5	100	22

^aIncludes generation capacity owned by a holding company that is being transferred from its electric utility subsidiary to its nonutility subsidiary.

Note: Totals may not equal sum of individual components because of independent rounding.

Source: Energy Information Administration, Office of Coal, Nuclear, Electric and Alternate Fuels. Compiled from information in trade journals, newspapers, and Internet websites, 1998 through September 1999.

competition. Some States have passed laws requiring utilities to divest their power plants. California, Connecticut, Maine, New Hampshire, and Rhode Island are examples of States with laws explicitly requiring utilities to divest their fossil and hydroelectric generation assets and, potentially, any ownership in nuclear power generating assets.

In other States that have passed electricity industry restructuring legislation, the requirements for unbundling are not always clear and vary from State to State. In some instances, the State public utility commission (PUC) may encourage divestiture to arrive at a quantifiable level of stranded costs for purposes of recovery during the transition to competition. On the other hand, many times the PUCs are not explicit in their unbundling requirements, leaving it to the utility to propose a method that satisfies the PUC's unbundling objectives and satisfies the strategic and economic objectives of the utility. The utility prepares a company restructuring plan which may include selling its assets or, alternatively, transferring its assets to an unregulated subsidiary company. Negotiation and compromise between the PUC and the utility are part of the process of finalizing the plan. Not all States that have restructured their electricity industry require resident electric utilities to unbundle their assets.

As a business strategy, a few utilities have decided to sell their power plants, indicating that they cannot compete in a competitive power market. For example, General Public Utilities, serving customers in New Jersey and Pennsylvania, sold its fossil-fueled and hydroelectric generating assets, and will focus on running its transmission and distribution systems in a regulated environment. Potomac Electric Power Company, serving primarily Maryland and Washington, DC, announced in February 1999 that it will sell its generation business and concentrate on distribution. Both of these companies concluded that at their present level of power generation capacity, they are too small to compete effectively in a competitive power market. It is expected that more small electric utilities will either merge with other utilities or sell their power generation assets.

In a few instances, an IOU will divest power generation capacity to mitigate potential market power resulting from a merger. For example, American Electric Power Company and Central and South West Corporation have agreed, as a condition for obtaining approval of their pending merger, to divest 1,604 megawatts of generation capacity in Texas.

Five Census Divisions Accounting for Most Generation Asset Divestitures

Five census divisions—Middle Atlantic, New England, South Atlantic, East North Central, and Pacific Contiguous—account for a total of 141.3 gigawatts of the divested capacity, representing 90 percent of the 156.5 gigawatts of actual and planned divestitures in the United States as of early April 2000 (Figure 31). The majority of divestitures are concentrated in these regions because the States in these regions were among the first in the Nation to promote retail competition. With the exception of States in the South Atlantic Division, most of the States in the other four divisions passed legislation in 1996 or 1997 restructuring the electricity industry, and they have had over 2 years to implement their restructuring programs.

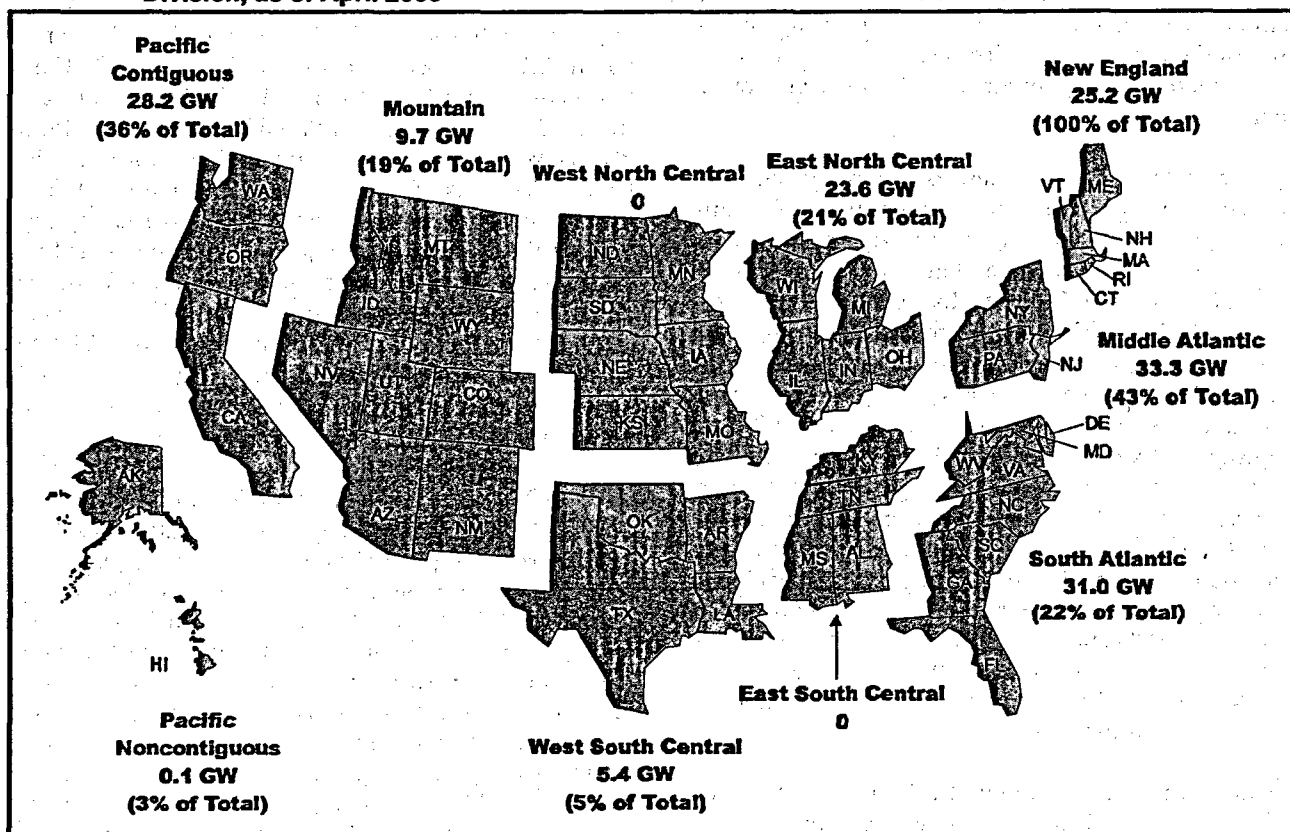
IOUs in New England have completed divesting their power plants; approximately 25.2 gigawatts have been sold, representing all of the region's generating capacity. Capacity in the region that has not been divested is owned by IPPs or municipal or Federal Government power plants. IOUs in the Middle Atlantic region, mainly in New York and Pennsylvania, have divested or are in the process of divesting more than 33 gigawatts, accounting for approximately 43 percent of the region's generating capacity. IOUs in California have divested slightly over 28 gigawatts, representing about 36 percent of the generating capacity in the Pacific Contiguous region.

Selling Generation Assets and the Approval Process

How power plants are sold is important to the owner and potential buyers. The procedure should ensure fairness to all interested buyers and ensure that the utility gets a fair market value. The most popular divestiture method is the auction. The advantages of auctions are that they have been used successfully for many years to sell products, they can be easily understood and monitored, and they can produce greater revenues than other methods, if designed properly.

Many of the IOUs divesting assets have used a two-stage auction process. In the first stage, the utility advertises the sale of the plant and bidders submit notifications of interest back to the utility. Advertising the sale of the plant can be accomplished in many ways. One way is to develop a potential buyers list and send each a notification that a power plant is for sale. In the

Figure 31. Investor-Owned Electric Utility Generation Capacity Divested or to be Divested by Census Division, as of April 2000



Note: Nationally, approximately 22 percent of total power generation capacity has been divested or will be divested.

Source: Energy Information Administration, Office of Coal, Nuclear, Electric and Alternate Fuels. Compiled from information in trade journals, newspapers, and Internet websites, 1998 through April 2000.

second stage, the utility selects a shortlist of buyers. Short-listed bidders conduct due diligence and submit their final bids. Sometimes post-bid negotiations are conducted, but they have the tendency to reduce the bid price because the bidder, knowing that negotiations will be conducted, can change the original bid price.

When the divestiture involves many plants, packaging of the plants is important. Packaging refers to the group of assets that will be sold at one auction. In many cases, bidders cannot submit a bid for just some of the assets, but must bid on all the assets in the package. Thus, it is important to combine assets in a way that will interest potential buyers.

All power plant sales must be approved by the PUC of the affected States. The PUC examines the sale's impact on the utility's customers, the environment, and other public interests, and resolves any conflicts which arise.

Ideally, contentious issues are resolved during the planning stage.

With the exception of hydroelectric power plants, the Federal Government has only a small role in IOU asset divestitures. FERC's position is that generation assets are not under its jurisdiction and its approval is not required unless the sale includes transmission assets along with generation assets.

Conclusions About Mergers, Acquisitions, and Divestitures of Generation Assets

Deregulation of the electric power industry and the ensuing competition is driving IOUs to formulate strategies that will help them to compete in the changing industry. Many times the strategy is a merger or acquisition. Recent mergers have created large vertically integrated regional electric utilities, and more are

expected as some of the pending mergers are completed. One effect of these mergers is that ownership of IOU power generation capacity is becoming more concentrated. By the end of 2000, it is expected that the 20 largest IOUs will own about 72 percent of total IOU capacity (Figure 29).

Over the past few years, IOUs have increasingly merged with natural gas production and gas pipeline companies, creating vertically integrated energy companies. These mergers are motivated primarily by the growth in gas-fired power plants and the opportunity to become a major fuel supplier to these power plants. Combined electricity and natural gas marketing and diversification of products and services are also reasons for these mergers.

Induced by State government restructuring of the electric industry and the emergence of retail competition,

many IOUs have divested their power generation assets and will focus on operating their transmission and distribution business. From 1998 through April 2000, IOUs have either divested or are in the process of divesting approximately 156.5 gigawatts of power generation capacity. Over 95 percent of this capacity has been or will be acquired by IPPs, furthering the growth of the IPP segment of the industry.

Since the early 1990s, when deregulation and restructuring of the industry began, mergers and acquisitions in the industry have accelerated. The intent of these corporate realignments is to strengthen the company's position in the competitive industry. It is not clear, however, if these strategies will benefit most companies, and if the industry and electric customers will be better off as well.

Appendix A

History of the U.S. Electric Power Industry, 1882-1991

Appendix A

History of the U.S. Electric Power Industry, 1882-1991¹⁶⁹

Beginnings: 1882-1900

The modern electric utility industry began in the 1880s. It evolved from gas and electric carbon-arc commercial and street lighting systems. Thomas Edison's Pearl Street electricity generating station, which opened September 4, 1882, in New York City, introduced the industry by featuring the four key elements of a modern electric utility system. It featured reliable central generation, efficient distribution, a successful end use (in 1882, the light bulb), and a competitive price. A model of efficiency for its time, Pearl Street used one-third the fuel of its predecessors, burning about 10 pounds of coal per kilowatthour, a "heat rate" equivalent of about 138,000 Btu per kilowatthour.¹⁷⁰ Initially the Pearl Street utility served 59 customers for about 24 cents per kilowatthour.¹⁷¹ In the late 1880s, power demand for electric motors brought the industry from mainly nighttime lighting to 24-hour service and dramatically raised electricity demand for transportation and industry needs. By the end of the 1880s, small central stations dotted many U.S. cities; each was limited to a few blocks area because of transmission inefficiencies of direct current (dc).

The hydroelectric development of Niagara Falls by George Westinghouse in 1896 inaugurated the practice of placing generating stations far from consumption centers. The Niagara plant transmitted massive amounts of power to Buffalo, New York, over 20 miles away. With Niagara, Westinghouse convincingly demonstrated both the general superiority of transmitting power with electricity rather than by mechanical means (the use of ropes, hydraulic pipes, or compressed air had also been

proposed) and the transmission superiority at that time of alternating current (ac) over direct current (dc). Niagara set a contemporary standard for generator size, and was the first large system supplying electricity from one circuit for multiple end-uses (railway, lighting, power).

Electric utilities spread rapidly in the 1890s. Municipally owned utilities predominantly supplied street lighting and trolley services and reached their peak share of total generation, about 8 percent, at the turn of the century.¹⁷² Privately owned multiservice utilities controlled the rest of the industry, aggressively competing for central city markets. Competition and technological improvements served to lower electricity prices steadily, with nominal residential prices falling to less than 17 cents per kilowatthour by the beginning of the 20th century.

Era of Private Utilities: 1901-1932

From 1901 through 1932, growing economies of scale hastened growth and consolidation in the electric utility industry, as well as the beginnings of State and Federal regulation. Larger, more efficient steam turbine-powered generators quickly replaced reciprocating steam engines; average heat rates dropped from 92,500 Btu per kilowatthour in 1902 to 20,700 Btu per kilowatthour by 1932.¹⁷³ As a direct consequence of those growing efficiencies, small private and municipal lighting and railway or power companies either merged with, purchased electricity from, or were absorbed quickly by ever-larger, more efficient private multiservice systems. Systems and cities interconnected with high voltage transmission lines. Private electric utility ownership also

¹⁶⁹The following is a historical sketch of the electric power industry from 1882 through 1991. The information for utilities from 1882 to 1984 is excerpted from Energy Information Administration (EIA), *Annual Outlook for U.S. Electric Power 1985*, DOE/EIA-0474(85) (Washington, DC, August 1985). Utility and nonutility information from 1985 to 1991 is excerpted from EIA, *The Changing Structure of the U.S. Electric Power Industry 1970-1991*, DOE/EIA-0562 (Washington, DC, March 1993).

¹⁷⁰C. E. Neil, "Entering the Seventh Decade of Electric Power, Some Highlights in the History of Electrical Development," reprinted from *Edison Electric Institute Bulletin* (September 1942), p. 6.

¹⁷¹A.J. Foster, *The Coming of the Electrical Age to the United States* (New York, NY: Arno Press, 1979), pp. 120, 123, 181.

¹⁷²Edison Electric Institute, *Historical Statistics of the Electric Utility Industry Through 1970* (New York, NY: 1973), p. 24.

¹⁷³C.E. Neil, "Entering the Seventh Decade of Electric Power," from *Edison Electric Institute Bulletin* (September 1942), p. 6.

consolidated into large utility holding companies, each "holding" controlling interest in a number of electric utilities. At their peak in the late 1920s, the 16 largest electric power holding companies controlled more than 75 percent of all U.S. generation.¹⁷⁴

The growth of utility service areas, first beyond city boundaries and then across State lines, brought State regulation of electric utilities in the early 1900s to ensure that the monopolistic utilities did not take advantage of their customers. Georgia, New York, and Wisconsin established State public service commissions in 1907, followed quickly by more than 20 other States. Basic State powers included the authority to franchise the utilities, to regulate their rates, financing, and service, and to establish utility accounting systems.

The foundations for strong Federal involvement in the electricity industry were established between 1901 and 1932, based on three factors: first, the electric power industry became recognized as a natural monopoly in interstate commerce (producing a product most efficiently provided by one supplier) subject to Federal regulation; second, the Federal Government owned most of the Nation's hydroelectric resources; and third, Federal economic development programs accelerated, including electricity generation. In 1906, Congress authorized the sale of surplus Federal power from western irrigation projects, giving sale preference to municipalities. The Federal Water Power Act of 1920 (P.L. 66-280) codified Federal powers and established the Federal Power Commission (FPC) to issue hydroelectric development licenses revokable after 50 years. In 1928, Congress authorized the Boulder Canyon Project for irrigation, flood control, and electricity production.

From 1901 to 1932, electric utility capacity and generation grew at annual average rates of about 12 percent a year, despite a 14-percent absolute drop in generation from 1929 to the Depression-era low in 1932. Both the number of municipal utilities and their share of total generation dropped steadily, as municipalities were overwhelmed by larger, more efficient private systems. By 1932 municipalities contributed only 5 percent of total generation. At the same time, State-owned utilities and Federal systems, however, grew noticeably, together contributing more than 1 percent of total generation. Private utilities provided the remaining 94 percent.¹⁷⁵ Electricity prices dropped, with nominal residential

electricity prices falling to 5.6 cents per kilowatthour in 1932, a level about one-third their price at the beginning of the century. In 1907, only 8 percent of all dwellings were using electricity; by 1932, this figure had risen to 67 percent. By 1932 considerably more than 80 percent of urban dwellings were electrified, while only 11 percent of farm dwellings had electrical service. This disparity between urban and rural service led to demands by farm interests for government help in obtaining electric power.¹⁷⁶

Emergence of Federal Power: 1933-1950

The Federal Government became a regulator of private utilities in the 1930s; it also became a major producer of electricity beginning in this period. The 1933-1950 period was also characterized by continued growth of the industry, increased consolidation and interconnection, and increasing economies of scale.

1933-1941

The Federal Government moved quickly in the mid-1930s to regulate private power and, where opportunities appeared, to produce and distribute less expensive Federally produced electricity to preference customers. Federal participation was hastened by widespread public perception of private utility abuses and national efforts to overcome the Depression.

First, the Federal Government moved to regulate private utilities. To counter utility abuses beyond State control, the Public Utility Holding Company Act of 1935 (PUHCA, P.L. 74-333) provided for the regulation of utility holding companies by the Securities and Exchange Commission (SEC). The Federal Power Act of 1935 (Title II of PUHCA) established FPC regulation of utilities involved in interstate wholesale transmission and sale of electric power.

Second, the Federal Government encouraged the growth of rural electricity service by subsidizing the formation of rural electric cooperatives. The Rural Electrification Act of 1936 (P.L. 74-605) established the Rural Electrification Administration (REA) to provide loans and assistance to organizations providing electricity to rural

¹⁷⁴Encyclopedia Americana, International Edition, Vol. 22 (New York, NY: Americana Corporation, 1977), p. 769.

¹⁷⁵Edison Electric Institute, *Historical Statistics of the Electric Utility Industry Through 1970* (New York, NY: 1973), p. 24.

¹⁷⁶U.S. Bureau of the Census, *Historical Statistics of the United States, Colonial Times to 1970, Bicentennial Edition, Part 2* (Washington, DC, 1975), p. 827.

areas and towns with populations under 2,500. REA-backed cooperatives enjoyed Federal power preferences plus lower property assessments, exemptions from Federal and State income taxes, and exemption from State and FPC regulation. As a result, by 1941 the proportion of farm homes electrified rose to 35 percent, more than three times that of 1932.¹⁷⁷

Third, in the 1930s Federal electricity generation expanded, providing less expensive electricity to municipals and cooperatives. Large Bureau of Reclamation dams began serving the western States; Hoover Dam began generation in 1936, followed by other large projects. Grand Coulee, the Nation's largest hydroelectric dam, began operation in 1941. U.S. Army Corps of Engineers flood control dams provided additional low-priced power for preference customers. Under the Tennessee Valley Authority Act of 1933 (P.L. 73-17), the Federal Government supplied electric power to States, counties, municipalities, and nonprofit cooperatives, soon including those of the REA. The Bonneville Project Act of 1937 (P.L. 75-329) pioneered the Federal power marketing administrations. By 1940, Federal power pricing policy was set; all Federal power was marketed at the lowest possible price while still covering costs. From 1933 to 1941, half of all new capacity was provided by Federal and other public power installations. By the end of 1941, public power contributed 12 percent of total utility generation, with Federal power alone contributing almost 7 percent.¹⁷⁸

During the pre-World War II years, electricity generating systems continued to grow in size and efficiency. Maximum turbine sizes and pressures doubled, and steam temperatures increased; generator cooling by pressurized hydrogen was introduced, resulting in higher generator outputs. Average heat rates dropped to 18,600 Btu per kilowatthour by 1941.¹⁷⁹ Improvements in transformers, circuit breakers, protection and reclosing devices, and transmission and distribution systems also continued, increasing both the efficiency and the reliability of electric utility systems.

Electricity prices continued to decline. Nominal residential electricity prices fell to 3.73 cents per kilowatthour in 1941, a drop of about one-third from 1932. Demand for electric power grew steadily from 1932

to 1941, with generation growth averaging over 8 percent a year, although capacity increased less than 2.5 percent per year.

1942-1950

Soaring electricity demand during World War II was met by increased use of privately owned capacity and a dramatic growth in Federal power. From 1941 to 1945, Federal capacity growth averaged 21 percent a year, and generation grew by 27 percent. By the war's end, Federal electricity generation had grown to more than 12.5 percent of U.S. generation.¹⁸⁰ Total U.S. generation grew at an annual average rate of over 7.5 percent during these war years, with capacity increasing at an annual average rate of almost 4.5 percent.

Both residential and commercial end use of electricity grew rapidly from 1941 to 1945, despite the war. Almost one-half of all farm dwellings were electrified by 1945. Growth in demand was helped by continuing technological improvements, yielding overall heat rates below 16,000 Btu per kilowatthour¹⁸¹ and residential electricity price drops averaging over 2 percent a year.

Public and Federal power continued to grow, and terms of public sale improved. Generating capacity built for defense was directed to public sale. The 1944 Pace Act (Department of Agriculture Organic Act, P.L. 78-425) extended REA indefinitely, dropped REA long-term interest rates below market rates, and authorized additional dam construction. The Flood Control Act of 1944 (P.L. 78-534) gave the Secretary of Interior jurisdiction over U.S. Army Corps of Engineers' electric power sales and extended public preference to all Corps power. The Southwestern Power Administration (SWPA) and the Southeastern Power Administration (SEPA) were established in 1943 and 1950, respectively, to market Federal power to preference customers. The First Deficiency Appropriation Act of 1949 (P.L. 81-71) in effect authorized TVA construction of thermal-electric power plants for commercial electricity sale. By 1950, Federal generation contributed over 12 percent of total U.S. generation, while cooperatives and other public power provided almost 7 percent.¹⁸² In settling the Hope Natural Gas case (Federal Power Commission vs. Hope Natural Gas Company, 1944), the Supreme Court closed

¹⁷⁷ *Ibid.*

¹⁷⁸ Edison Electric Institute, *Historical Statistics of the Electric Utility Industry Through 1970* (New York, NY: 1973), pp. 2, 24.

¹⁷⁹ C.E. Neil, "Entering the Seventh Decade of Electric Power," from *Edison Electric Institute Bulletin* (September 1942), p. 6.

¹⁸⁰ Edison Electric Institute, *Historical Statistics of the Electric Utility Industry Through 1970* (New York, NY: 1973), p. 24.

¹⁸¹ Edison Electric Institute, *EEI Pocketbook of Electric Utility Industry Statistics* (New York, NY: 1983), p. 21.

¹⁸² Edison Electric Institute, *Historical Statistics of the Electric Utility Industry Through 1970* (New York, NY: 1973), p. 24.

a longstanding dispute by allowing either original or replacement cost accounting in utility rate-making, so long as just and reasonable rates result.

Following a brief decline at war's end in 1945, overall demand for electricity continued to grow. From 1945 through 1950, generation growth averaged more than 8 percent a year and capacity over 6.5 percent. Residential electricity consumption grew most rapidly, almost 14 percent a year, and the share of farms electrified rose to almost 80 percent.¹⁸³ Growth was encouraged by continued efficiency improvements; by 1950 heat rates had fallen below 15,000 Btu per kilowatthour.¹⁸⁴ Drops in nominal residential electricity prices averaged 3 percent a year.

Utility Prosperity: 1951-1970

The era following the end of World War II through 1970 marked a time of essentially uninterrupted prosperity for the electric utility industry. Demand for electricity grew rapidly, consistently, and predictably, while electricity prices continued to fall. The arrival of commercial nuclear power held the promise of an even more prosperous future. At the same time, problems that were later to affect the industry dramatically either did not exist or were not yet serious.

The 1950s

Three major characteristics marked the electric utility industry in the 1950s: robust growth, the introduction of commercial nuclear power, and other public power expansion replacing Federal power growth.

From 1950 to 1960, generation grew by an average of over 8.5 percent a year, led by strong increases in residential electricity demand and near completion of rural electrification. Capacity grew slightly more rapidly than generation, averaging almost 9.5 percent annually. With generating efficiencies still improving, electricity prices continued to decline, as evidenced by drops in nominal residential electricity prices averaging about 1 percent a year.¹⁸⁵

Commercial nuclear power was introduced in the 1950s. The Atomic Energy Act of 1954 (P.L. 83-703) allowed private development of commercial nuclear power, and the Price-Anderson Act (P.L. 85-256) reduced private liability by guaranteeing public compensation in the event of a commercial nuclear catastrophe. The Nation's first central station commercial nuclear reactor, located in Shippingport, Pennsylvania, began operation in 1957.

Finally, during the 1950s new Federal power plant construction slowed, but the slowdown was offset by more rapid growth of other public power capacity. Both the "no new starts" policy of the Eisenhower Administration and a lack of additional major hydroelectric sites checked major new Federal development. Nevertheless, projects begun earlier continued to come on line, and Federal generation reached its highest share of total generation, more than 17 percent, in 1957. TVA added thermal capacity, by 1960 becoming predominantly a thermal rather than hydroelectric system. Non-Federal public power grew rapidly in the 1950s, led by cooperatives, power districts, and State projects. Generation from non-Federal public power plants and cooperatives increased from more than 6.5 percent of total generation in 1950 to almost 8.5 percent in 1960.¹⁸⁶

The 1960s

During the 1960s high electricity growth rates continued, paralleled by growth in nuclear power generation. During the period, however, signs of future difficulties in the electric power industry appeared, including decreasing efficiency gains, escalating costs, and environmental concerns.

Vigorous growth continued throughout the 1960s, prompted by overall economic growth, declining real energy prices, and growing consumer preference for electricity because of its convenience, versatility, and price. Generation and capacity growth averaged almost 7.5 percent a year, predominantly from increases in petroleum- and gas-fired generation. Cooperatives accelerated capacity additions, and by 1970 non-Federal public power contributed well over 10 percent of total utility generation.¹⁸⁷ Demand grew nearly 7.5 percent a year, helped by annual declines of over 1.5 percent in residential and commercial electricity prices.¹⁸⁸

¹⁸³ U.S. Bureau of the Census, *Historical Statistics of the United States* (Washington, DC, 1972), pp. 827-828.

¹⁸⁴ Derived from Edison Electric Institute, *EI Pocketbook of Electric Utility Industry Statistics* (New York, NY: 1983), p. 21.

¹⁸⁵ Edison Electric Institute, *Historical Statistics of the Electric Utility Industry Through 1970* (New York, NY: 1973), p. 23.

¹⁸⁶ Edison Electric Institute, *Historical Statistics of the Electric Utility Industry Through 1970* (New York, NY: 1973), p. 24.

¹⁸⁷ Edison Electric Institute, *Historical Statistics of the Electric Utility Industry Through 1970* (New York, NY: 1973), p. 24.

¹⁸⁸ Energy Information Administration, *Annual Energy Review 1984*, DOE/EIA-0384(84) (Washington, DC, April 1985), p. 187.

New technology introduced during this period included automated controls and computers. Technological advances during the 1960s were led by the growth of commercial nuclear power. Facing continued high demand growth and encouraged by performance of small nuclear facilities, utilities began ordering many more nuclear units of far greater size and still undemonstrated efficiency. In contrast to the 837 megawatts of new capacity ordered in the 1950s, with units averaging fewer than 150 megawatts, in the 1960s, 86,596 megawatts were ordered, averaging about 850 megawatts per unit.¹⁸⁹ Generation by nuclear power rose to over 1 percent of the U.S. total by 1970.¹⁹⁰

During the 1960s some signs of difficulties in the electric utility industry began to appear. First, environmental requirements became a noticeable component of electric utility costs. Coal-fired power plants began to experiment with emission control equipment to decrease the amount of sulfur dioxide (SO₂) emitted into the atmosphere. Tall emission stacks were introduced to disperse SO₂. Further, the National Environmental Policy Act of 1969 (NEPA, P.L. 91-190) required utilities seeking Federal permits for new power plants to prepare and defend environmental impact statements (EISs) as a part of the permit process. Second, the increasing efficiencies historically characterizing the industry flattened in the mid-1960s. From 1960 to 1970, the average size of thermal plants more than doubled. Heat rates, on the other hand, declined only a little, from about 10,800 Btu per kilowatt-hour to 10,500 Btu per kilowatt-hour.¹⁹¹ Finally a major Northeastern power blackout in 1965 raised concerns about the reliability of the huge interconnected, interdependent power networks. Response to the blackout included formation of the North American Electric Reliability Council (NERC) and its regional reliability councils to promote the reliability and adequacy of bulk power supply.

Years of Challenge: 1971-1984

The 1970s

During the 1970s, the electric utility industry moved from decreasing unit costs and rapid growth to increasing unit costs and slower growth. Among the

major factors affecting the electric utility industry during the period were general inflation, increases in fossil-fuel prices, environmental concerns, conservation, and problems in the nuclear power industry.

First, electric utilities with ambitious capital expansion programs heavily financed by borrowing were particularly affected by inflation. As technical and regulatory requirements increased construction lead times, the impact of inflation was compounded.

Second, in the 1970s all fossil-fuel prices rose sharply. Petroleum costs more than doubled in 1974 alone and increased an average of over 26 percent a year for the 1970-1980 period. Natural gas prices, accelerated by decontrol under the Natural Gas Policy Act (NGPA, P.L. 95-621), rose by over 23 percent a year, with the largest increases occurring after 1978. Coal price increases averaged almost 16 percent a year.¹⁹²

Third, during the 1970s environmental legislation increased the costs of building and operating electric utility (particularly coal-fired) power plants. The Clean Air Act of 1970 (CAA, P.L. 91-604) and its amendments in 1977 (P.L. 95-95) required utilities to reduce pollutant emissions, particularly SO₂, causing increases in capital, fuel, and operating costs. The Act also limited use of tall stacks to disperse emissions. The Federal Water Pollution Control Act of 1972 ("Clean Water Act," P.L. 92-500) limited utility waste discharges into water. In addition, the Resource Conservation and Recovery Act of 1976 (RCRA, P.L. 94-580) directed standards for disposal of both hazardous and nonhazardous utility wastes.

Finally, conservation legislation effectively barred utilities from wider use of natural gas and petroleum. The Energy Supply and Environmental Coordination Act of 1974 (ESECA, P.L. 93-319) allowed the Federal Government to prohibit electric utilities from burning natural gas or petroleum. The 1978 Powerplant and Industrial Fuel Use Act (FUA, P.L. 95-620) succeeded ESECA and extended Federal prohibition powers. The National Energy Conservation Policy Act of 1978 (NECPA, P.L. 95-619) required utilities to provide residential consumers free conservation services to encourage slower growth of electricity demand.

¹⁸⁹Energy Information Administration, *U.S. Commercial Nuclear Power Historical Perspective, Current Status, and Outlook*, DOE/EIA-0315 (Washington, DC, March 1982), p. 10.

¹⁹⁰Energy Information Administration, *Annual Energy Review 1984*, DOE/EIA-0384(84) (Washington, DC, July 1985), p. 171.

¹⁹¹Energy Information Administration, *Thermal-Electric Plant Construction Cost and Annual Production Expenses—1979*, DOE/EIA-0323(79) (Washington, DC, May 1982), p. 10.

¹⁹²Energy Information Administration, *Fuel Choice in Steam Electric Generation: A Retrospective Analysis*, EIA-MO12 (Washington, DC, October 1985), Table 2.

Expected high electricity demand growth did not materialize in the 1970s. Instead, capacity growth began to outrun increases in demand. For the first time in the history of U.S. electric power, electricity prices rose consistently, with nominal price increases averaging 11 percent a year. Consequently, demand and generation growth moderated to just over 4 percent a year. However, capacity growth continued at a rate of 6 percent a year. Slackened demand growth, coupled with completion of expensive new capacity, left utilities with excess capacity and without new revenues to pay for it. As a result, some electric utilities suffered financial setbacks and incurred declining investor confidence.

The commercial nuclear power industry expanded rapidly but also met serious reverses. From 1971 through 1974, 131 new nuclear units were ordered, at an average capacity of about 1,100 megawatts.¹⁹³ As a result, inflation, labor, and materials cost increases quickly affected construction costs of nuclear power plants, while high interest rates raised financing costs. Capital costs rose from about \$150 per kilowatt in 1971 to more than \$600 after 1976.¹⁹⁴ Utilities building commercial nuclear facilities faced financial difficulties in justifying and meeting these increased costs. Safety concerns increased. First, in February 1979 the Nuclear Regulatory Commission (NRC) shut down five operating reactors following concerns about durability during earthquakes. Then, on March 28, 1979, the Nation's most significant commercial nuclear accident occurred at the Three Mile Island Number 2 reactor near Harrisburg, Pennsylvania.

These events heightened public concerns and spurred opposition to commercial nuclear power. As a result of higher costs, slackening electricity demand growth, and public concern, demand for nuclear power plants dropped quickly in the mid- and late-1970s. After 1974, new orders plummeted and cancellations accelerated. No new reactor orders were placed after 1978. Moreover, 63 units were canceled between 1975 and 1980.¹⁹⁵

The Early 1980s

The early 1980s were marked by almost no growth in the U.S. electric utility industry. In 1982 total net generation dropped more than 2 percent, the first absolute decline since 1945. In the mid-1980s, however, the industry returned to moderate if unspectacular growth.

Cost and price increases continued to slow the growth of electric power in the early 1980s. Costs of new nuclear power plants increased to more than \$1,200 per kilowatt of capacity in the early 1980s.¹⁹⁶ High inflation ensured increases in other financial and operating costs. As a result, electricity prices rose sharply. Average end-use electricity prices (nominal) increased by almost 19 percent in 1980, 15 percent in 1981, and 12 percent in 1982. End-use electricity consumption responded to rising prices and a sluggish economy by increasing only 1 percent in 1980 and 2.5 percent in 1981. Demand then dropped almost 3 percent in 1982, because of a decline in industrial electricity use of nearly 10 percent, as part of that year's severe economic downturn.¹⁹⁷

Electricity generation increased in 1983 to a record high of 2,310 billion kilowatthours. Capacity, however, grew by little more than 1 percent over 1982, the smallest increase since 1956. Industrial electricity use grew most rapidly among end-use sectors, rebounding from its 1982 decline. The average price of electricity increased by 2.6 percent, less than the rate of inflation. In 1984, electricity posted its largest single-year increase in generation since 1976, 4.5 percent. Though not large by historic standards, the growth rate reflected a healthy economy, generally increasing preference for electricity, and a decline in electricity's price relative to other forms of energy. Capacity grew by 2.1 percent in 1984, led by coal-fired and nuclear-powered additions. Electricity prices increased at the rate of inflation, leaving real prices unchanged.

¹⁹³Energy Information Administration, *U.S. Commercial Nuclear Power Historical Perspective, Current Status, and Outlook*, DOE/EIA-0315 (Washington, DC, March 1982), p. 10.

¹⁹⁴Energy Information Administration, *Survey of Nuclear Power Plant Construction Costs 1983*, DOE/EIA-0439(83) (Washington, DC, December 1983), p. 8.

¹⁹⁵Energy Information Administration, *U.S. Commercial Nuclear Power Historical Perspective, Current Status, and Outlook*, DOE/EIA-0315 (Washington, DC, March 1982), p. 10.

¹⁹⁶Energy Information Administration, *Survey of Nuclear Power Plant Construction Costs 1984*, DOE/EIA-0439(84) (Washington, DC, November 1984), p. 15.

¹⁹⁷Energy Information Administration, *Annual Energy Review 1984*, DOE/EIA-0384(84) (Washington, DC, July 1985), pp. 179, 187.

From 1980 through 1984, net electricity generation grew an average of a mere 1.4 percent annually. End-use sales grew by only 2.1 percent a year, the slowest rate of growth since the early years of the Great Depression. Capacity, however, increased 2.3 percent a year, further raising reserves available to meet unexpected demand. Nuclear capacity additions entering commercial service, despite the absence of new orders, led the rate of new capacity growth, increasing by 6.1 percent a year. Prices rose by approximately 8 percent a year. Commercial electricity use increased more than any other end use, averaging almost 4.5 percent a year; industrial end use grew less than 1 percent a year.¹⁹⁸

Nonutility Growth: The Late 1980s¹⁹⁹

In 1970, electric utilities supplied 93 percent of the electricity generated in the United States. The balance was produced by "nonutilities"—generators of electric power that are not utilities—consisting primarily of industrial manufacturers that produced electricity for their own use. The electric utility share of electric power generation increased steadily between then and 1979, when it reached 97 percent. The trend reversed itself in the 1980s, and by 1991 the electric utility share declined to 91 percent.

Increasingly, nonutilities were generating electricity not only for their own use but also for sale to electric utilities for distribution to final consumers. In 1991, nonutilities owned about 6 percent of the electric power generating capacity and produced about 9 percent of the total electricity generated in the United States.²⁰⁰

About one-half of 1991 nonutility capacity was located in the West South Central Census Division, particularly in Texas, and the Pacific Contiguous Census Division, particularly in California. Most nonutilities in Texas, which produced 49 billion kilowatthours of electricity in 1991, were engaged in chemical manufacturing, which provides many opportunities for generating electricity along with another form of energy (such as heat or steam). In California, which produced 53 billion kilowatthours in 1991, most nonutilities were engaged primarily in electricity generation.

In 1991, nonutilities produced 49 percent of their electricity from natural-gas-fired boilers, much more than from any other single primary energy source. In contrast, utilities produced the majority of their electricity by burning coal, and their second major source of energy was nuclear power. Renewable energy sources, except for hydroelectric power, were virtually untapped by electric utilities, while renewable fuels (including wood and waste) collectively produced the second largest share (34 percent) of nonutility electricity. One reason for the difference was that the majority of nonutility capacity was in the manufacturing sector of the economy, particularly in the chemical and paper industries. Both industries produce wastes as byproducts of the manufacturing process that can be used as a source of energy to drive electricity generators. Also, paper manufacturing uses a renewable fuel (wood) as a raw material in producing paper, making wood and wood waste easily accessible to paper manufacturers as an energy source for electricity generation.

As of December 1991, the process of change in the structure of the electric power industry had not yet run its course. Major issues arose, including the effect of the changing industry structure on the reliability of electric power supply and on bulk (wholesale) power trade. Also at issue was whether the Clean Air Act Amendments of 1990 (CAAA90) would alter the course of nonutility growth.

The concern with the CAAA90 centered on whether nonutilities would be able to obtain a sufficient number of emission allowances to operate in compliance with the Amendments. Beginning in 2000 (with an incremental phase for utilities beginning in 1995), the Amendments require virtually all suppliers of wholesale electric power to obtain emission allowances for any sulfur dioxide released into the atmosphere. Utilities have been allocated most of these allowances. Nonutilities must obtain the allowances they need from utilities or from a sale or auction administered by the Federal Government.

Conclusion

This appendix has summarized the past 100 years with respect to the history of the electric power industry. The following appendix provides an interesting look at milestones in the history of the industry.

¹⁹⁸Energy Information Administration, *Annual Energy Review 1984*, DOE/EIA-0384(84) (Washington, DC, July 1985), pp. 171, 179, 181, 187.

¹⁹⁹Reprinted from *The Changing Structure of the U.S. Electric Power Industry, 1970-1991*, DOE/EIA-0562 (Washington, DC, March 1993), pp. vii-ix.

²⁰⁰Edison Electric Institute, *1991 Capacity and Generation of Non-Utility Sources of Energy* (Washington, DC, November 1992), p. 21.

Appendix C

Pending Federal Restructuring Legislation

Appendix C

Pending Federal Restructuring Legislation (As of May 1, 2000)

106th Congress House of Representatives Bills

H.R. 341

Environmental Priorities Act of 1999

Introduced on January 19, 1999 by Representative Robert Andrew (D-NJ).

- Gives the Environmental Protection Agency (EPA) the authority to establish a National Environmental Priorities Board, and requires the EPA Administrator to promulgate a final rule containing the rules and procedures of the Board. The Board is to support State environmental projects, and may include loans, loan guarantees, grants, capitalization grants, and other assistance.
- Mandates that retail electric service providers must contribute 10 percent of the total consumer savings to the Environmental Priorities Board once retail electric service choice has been established.

H.R. 667

The Power Bill

Introduced by Representative Richard Burr (R-NC) on February 10, 1999.

- Clarifies States' authority to order retail wheeling and imposes reciprocity requirements with respect to sales of electricity by out-of-state entities.
- Grants cooperatively owned sellers or distributors of electricity the right to engage in any activity or provide any service lawfully carried out by any other seller or distributor of electricity in the State.
- Authorizes a State or State regulatory authority to impose charges upon purchases of retail electric energy services, including fees: (1) to recover costs incurred by an electric utility that become unrecoverable due to the availability of retail

electric service choice; (2) to pay all reasonable costs associated with governmental requirements regarding decommissioning of nuclear generating units; and (3) to fund public benefit programs.

- Declares that, as of January 1, 1999, new electric utility contracts for purchase or sale shall no longer be subject to cost provisions of Section 210 of the Public Utility Regulatory Policies Act of 1978. Additionally, authorizes recovery of all costs associated with prior contracts involving purchases of electric energy or capacity from a cogeneration and small power production facility by electric utilities.
- Repeals the Public Utility Holding Company Act of 1935. Prescribes guidelines for Federal and State access to books and records of electric utility holding companies and their affiliates to ensure consumer rate protection.
- Requires State laws or regulations for the recovery of stranded costs to be filed with FERC as a pre-requisite to State receipt of Federal energy assistance. Precludes any modification or repeal of such laws or regulations for 7 years after such filing date.
- Instructs the Secretary of Energy to present a status report (2 years after enactment of proposed legislation) to the Congress on the extent to which State actions have removed regulatory and statutory barriers to interstate commerce in electricity.

H.R. 721

Bond Fairness and Protection Act of 1999

Introduced by Representative J.D. Hayworth (R-AZ) on February 11, 1999.

- Amends the Internal Revenue Code of 1986 (with respect to tax-exempt bond financing of certain

electric facilities) to exclude a permitted open access transaction (as defined by this Act) from the definition of private business use.

- Grants public power utilities the option of grandfathering outstanding tax-exempt debt subject to abrogating issuing tax-exempt bonds to finance new facilities in the future. Alternatively, they may continue to issue tax-exempt bonds subject to current private use limitations in the tax code.

H.R. 971

Electric Power Consumer Rate Relief Act of 1999

Introduced by Representative James Walsh (R-NY) on March 3, 1999.

- Amends the Public Utility Regulatory Policies Act of 1978 (PURPA) to provide that a State regulatory authority may ensure that rates charged by qualifying small power producers and qualifying cogenerators to purchasing utilities are (1) just and reasonable to consumers of the purchasing utility and (2) do not exceed the incremental cost to the purchasing utility of alternative electric energy and capacity at the time of delivery.
- Grants States the ability to establish programs for monitoring the operating and efficiency performance of in-state cogeneration and small power production facilities to determine whether such facilities meet FERC standards for qualifying cogenerators.
- Allows a State regulatory authority to require that any contract entered into before the enactment date of proposed legislation be amended to conform to the requirements governing rates to retail customers.

H.R. 1138

Ratepayer Protection Act

Introduced by Representative Cliff Stearns (R-FL) on March 16, 1999.

- Mandates that the Public Utility Regulatory Policies Act of 1978 (PURPA) requirement that electric utilities enter into contracts to purchase electricity from certain cogeneration and small power production facilities shall expire after January 6, 1999.
- Mandates that all power purchase contracts which were in effect up to January 6, 1999 be honored.

- Directs the Federal Energy Regulatory Commission (FERC) to ensure that utilities are not required to absorb costs associated with electric energy or capacity purchases executed prior to the enactment of proposed legislation.

H.R. 1253

A Bill to Amend the Internal Revenue Code of 1986 to Restrict the Use of Tax-Exempt Financing by Governmentally Owned Electric Utilities and to Subject Certain Activities of Such Utilities to Income Tax

Introduced by Representative Phillip English (R-PA) on March 24, 1999.

- Narrows the Internal Revenue Tax Code definition of circumstances under which governmentally owned electric utilities may finance utility facilities with tax-exempt bonds.
- Subjects utility-related income of governmental entities to Federal income tax in situations where the income is derived from sources outside their specified service area.

H.R. 1486

Power Marketing Administration Reform Act of 1999

Introduced by Representative Bob Franks (R-NJ) on April 20, 1999.

- Requires the Secretary of Energy to develop and implement procedures to ensure that the Federal Power Marketing Administrations (FPMAs) utilize the same accounting principles and requirements as the Federal Energy Regulatory Commission (FERC).
- Requires each FPMA and the Tennessee Valley Authority (TVA) to submit periodically, for FERC review, rates for the sale or disposition of Federal energy that will ensure recovery of all their costs in generating and marketing such energy.
- Prescribes rate mechanism and pricing guidelines.
- Establishes a fund within the Department of the Interior to (1) mitigate damage to environmental resources attributable to power generation and sales facilities, and (2) restore the health of such resources, including fish and wildlife. Mandates project-specific mitigation plans for each power generation project.

- Establishes a fund within the Department of Energy for renewable resources. Prescribes expenditure guidelines.
- Mandates that public bodies and cooperatives be given a preference for future power allocations or reallocations of Federal power through a right of first refusal at market prices.
- Instructs the Secretary of Energy to require each FPMA to (1) assign personnel and incur expenses solely for authorized power marketing, reclamation, and flood control activities, and not for diversification into ancillary activities; and (2) make annual public disclosures of its activities, including the full costs of power projects and marketing.
- Precludes an FPMA from entering into or renewing any power marketing contract for a term exceeding 5 years.
- Requires provision of FPMA transmission services on an open access basis, and at FERC-approved rates in the same manner as provided by any public utility under FERC jurisdiction.
- Grants FERC rate-making approval authority until a full transition is made to market-based rates, for (1) rate schedules recommended by the Secretary of Energy; and (2) rate schedules for FPMA power sales.
- Amends: (1) the Department of Energy Organization Act to reflect the changes made by this Act; and (2) specified Federal law to repeal the prohibition against the use of appropriated funds for purposes relating to the possibility of changing from an "at cost" to a "market rate" or any other noncost-based method for pricing Federal hydroelectric power.

H.R. 1587

Electric Energy Empowerment Act of 1999

Introduced by Representative Cliff Stearns (R-FL) on April 27, 1999.

- Amends the Federal Power Act (FPA) to empower the States to order electric utilities within their jurisdiction to provide nondiscriminatory open access through functionally unbundled transmission and local distribution services to retail customers

within their borders. Prescribes implementation guidelines.

- Allows States or State regulatory authorities to impose charges for recovery of stranded costs to ensure reliability and availability of electric supply, to support low-income residential programs, to retrain electric employees, to fund environmental programs, and to provide payment for reasonable costs associated with nuclear decommissioning.
- Amends FPA by placing the State in charge of regulation of bundled electric retail sales and unbundled local distribution service.
- Authorizes FERC to distinguish, after consulting with appropriate State regulatory authorities, between facilities used for transmission and delivery that are subject to FERC approval and those subject to State jurisdiction.
- Encourages creation of Independent Transmission System Operators to ensure that all sellers and buyers of electricity have access to nondiscriminatory transmission services.
- Requires public power utilities to conform to open access requirements currently applied to private power utilities.
- Repeals mandatory power purchase contract requirements set forth in the Public Utility Regulatory Policies Act of 1978 and allows for recovery of stranded costs.
- Repeals the Public Utility Holding Company Act of 1935.
- Authorizes Federal and State authorities access to books and records of all companies in a holding company system and for Federal oversight of affiliate transactions for the purpose of protecting consumers with respect to rates.
- Advocates the formation and operation of an Electric Reliability Council to ensure that competitive restructuring of the electricity industry does not lessen reliability of the electric supply. Prescribes guidelines for formation, membership, funding, and governance.

H.R. 1828

Comprehensive Electricity Competition Act

Introduced by Representative Tom Bliley (R-VA) on May 17, 1999.

- Provides a flexible mandate for States to require open access to the distribution facilities of regulated and non-regulated electric utilities. Allows State-regulated and non-regulated utilities to "opt out" of retail competition if, after a hearing before the State regulatory authority, it is determined that retail competition will have a negative impact on certain customer classes.
- Grants to any person the ability to bring an action, in the appropriate State court, against a State regulatory authority or distribution utility for failure to comply with open access requirements.
- Eliminates private use limitations on outstanding bonds for publicly owned facilities used in connection with retail competition or open access transmission. Ends the issuance of new tax-exempt bonds for generation or transmission. Continues availability of tax exempt bonds for distribution facilities under current law.
- Allows States and non-regulated utilities to determine the amount of recoverable stranded costs. Grants FERC authority to establish stranded cost recovery in the absence of State authority.
- Grants FERC authority to oversee creation of Independent Regional System Operators (IRSOs) and to compel utilities to turn over control of their transmission facilities to such organizations.
- Encourages regional agreements that facilitate coordination among States with regard to siting and planning of transmission and generation facilities; calls for FERC approval of such agreements.
- Creates a renewable portfolio system mandating that power sellers use a percentage of non-hydro electric renewable technology. Sets forth requirements of sale and purchase of renewable energy credits and stipulates use of revenue from such sales.
- Authorizes FERC, upon petition by a State, to require generators to submit a plan mitigating market power which FERC can accept or modify. Clarifies FERC merger review over generation-only companies and holding companies.
- Requires FERC to approve and oversee an organization that prescribes and enforces mandatory reliability standards.
- Clarifies the authority of the Environmental Protection Agency to require an interstate trading system for the purpose of reducing nitrogen oxide pollution.
- Creates a Public Benefits Fund for low-income assistance, energy efficiency programs, consumer education, and development of emerging technologies. Stipulates funding mechanisms and sets forth guidelines of operation.
- Repeals the Public Utility Holding Company Act of 1935 (PUHCA) 18 months after enactment of proposed legislation. Grants FERC and States access to utility books and records.
- Eliminates obligatory power purchase contracts mandated in the Public Utility Regulatory Policies Act of 1978 on the date of enactment of proposed legislation.
- Places Tennessee Valley Authority (TVA) transmission under FERC jurisdiction. Subjects power wheeled through TVA to open access requirements and allows wholesale electric power sales by TVA outside of their traditional service area. Calls for the renegotiation of long-term contracts and authorizes FERC to intervene if conflict arises. Authorizes TVA to join an Independent System Operator.
- Authorizes FERC to determine transmission rates for the Bonneville Power Administration, Western Area Power Administration, and the Southwestern Power Administration, and allows these Federal Power Administrations to impose a surcharge on sales to recover costs of environmental programs and to join IRSOs.
- Provides States that have implemented retail competition with the authority to preclude an out-of-state utility with a retail monopoly from selling within the State unless that out-of-state utility permits customer choice.
- Requires States electing retail competition to establish terms and conditions to protect consumers, including rates that are just and reasonable, measures to ensure privacy of consumer infor-

mation and that prohibit discriminatory practices by electric utilities. Allows States to impose non-bypassable fees to fund such programs. Authorizes creation of a publicly accessible database that will provide information to consumers on electric utilities which participate in retail competition.

- Amends PURPA by allowing net metering for renewable energy and granting tax credits for production of energy from renewable resources and production of energy efficient buildings.
- Grants customers the ability to acquire retail electric energy on an aggregate basis if the group of customers is served by one or more local distribution companies which sell electricity on a competitive basis.
- Authorizes the provision of grant money for assistance purposes to tribal Indians, Southeast Alaska, and rural and remote communities.
- Eliminates antitrust review by the Nuclear Regulatory Commission and amends the Internal Revenue Code relating to deductions to a qualified nuclear decommissioning fund.

H.R. 2050

Electric Consumers' Power to Choose Act of 1999

Introduced by Representative Steve Largent (R-OK) on June 8, 1999.

- Accords States a flexible mandate in terms of retail competition. States may choose to implement retail electric competition for their regulated distribution systems, or choose to opt out if retail competition would negatively impact customers. Nonregulated local distribution companies are also provided with a similar flexible mandate to establish or opt out of retail competition.
- Grandfathers State plans already underway or on the books and provides a reciprocity provision to keep out companies whose territories are not open to competition. Similar plans adopted by non-regulated local distribution companies will also be grandfathered.
- Amends tax laws to permit public power and municipal utilities to participate in open access plans without forfeiting the tax-exempt status of their outstanding bonds.

- Permits States and nonregulated utilities to bar those who have not elected retail choice from selling to electric customers in their State or utility service regions.
- Allows a group of electric customers to buy retail electricity on an aggregate basis if they are served by one or more electric utilities in consumer choice regions.
- Provides that States will have jurisdiction over disputes arising from States' or nonregulated utilities' actions in electing to move to retail competition.
- Directs the Federal Trade Commission to establish rules and penalties to protect consumers from unfair trade practices by electricity suppliers.
- Amends the Federal Power Act (FPA) to require that electric suppliers and transmitting utilities join an Electric Reliability Organization subject to FERC approval and oversight. Protects such organizations from the provisions of anti-trust laws.
- Allows small-scale power generators to interconnect with local distribution utilities to facilitate supplies that are closer to end-use requirements.
- Directs FERC to determine the exercise of market power by an electric utility and to initiate mitigation measures where necessary.
- Extends FERC's authority over transmission facilities of electric utilities to include facilities of State and municipal utilities, rural electric cooperatives, and facilities that qualify under the Public Utility Regulatory Policies Act of 1978, thus enabling the Commission to set transmission rates for all utilities in the country.
- Clarifies State and Federal authority over bundled and unbundled retail electric sales by granting FERC exclusive regulatory authority over the transmission component of an unbundled retail sale.
- Provides FERC with the authority to establish Regional Transmission Organizations (RTOs) by requiring that all transmitting utilities transfer operational control or ownership of their transmission facilities to such an organization.

- Authorizes FERC to order the BPA and the Electric Reliability Council of Texas to wheel power.
- Requires FERC to review mergers and property dispositions involving generation-only companies and holding companies.
- Encourages regional agreements that facilitate coordination among States with regard to siting and planning of transmission and generating facilities subject to approval by FERC of such agreements.
- Requires States electing retail competition to establish terms and conditions to protect consumers, including rates that are just and reasonable, measures to ensure privacy of consumer information and that prohibit discriminatory practices of electric utilities. Allows States to impose non-bypassable fees to fund such programs.
- Exempts holding companies from limitations of the Public Utility Holding Company Act of 1935 eighteen months after enactment of proposed legislation unless they provide retail service in two or more States that do not provide open access. Grants FERC and States access to utilities' books and records to assist regulatory authorities in carrying out their functional responsibilities.
- Prospectively repeals the Public Utility Regulatory Policies Act of 1978 and eliminates obligatory power purchase contracts. Allows for recovery of stranded costs with respect to purchases from outstanding contracts.
- Places TVA transmission under FERC jurisdiction. Subjects power wheeled through TVA to open access requirements and sets limitations on electric power sales by TVA. Prohibits the acquisition of new generating resources and calls for the renegotiation of long-term contracts. Repeals TVA's jurisdiction to regulate municipality or cooperative organization distributors and removes TVA's PURPA ratemaking authority. Allows for imposition of charges for the purpose of stranded cost recovery.
- Subjects BPA to relevant provisions of the FPA for purposes of BPA's transmission systems, but provides that any determination by FERC would be subject to a list of conditions, including a requirement that the rates and charges are sufficient to recover existing and future Federal

investment in the Bonneville Transmission System. Requires FERC to establish a rate recovery mechanism to meet BPA's cost recovery requirements.

- Subjects Power Marketing Administrations (PMAs) to the same accounting principles used by other public utilities and applicable antitrust laws and authorizes PMAs to participate in FERC-approved RTOs.
- Mandates a renewable portfolio generation minimum standard of 3 percent of total generation and sets forth enforcement procedures for noncompliance. Directs the Secretary of Energy to establish a program to issue, monitor the sale and exchange of, and track Renewable Energy Credits.
- Amends the Public Utility Regulatory Policies Act of 1978 by allowing net metering for renewable energy, and granting tax credits for production of energy from renewable resources and production of energy efficient buildings.

H.R. 2363

Public Utility Holding Company Act of 1999

Introduced by Representative W.J. (Billy) Tauzin (R-LA) on June 25, 1999.

- Repeals the Public Utility Holding Company Act of 1935.
- Enacts the Public Utility Holding Company Act of 1999 to support the continuing need for limited Federal and State regulation and to supplement the work of State commissions for the continued rate protection of utility customers.

H.R. 2569

Fair Energy Competition Act of 1999

Introduced by Representative Frank Pallone, Jr. (D-NJ) on July 20, 1999.

- Aims that older and more polluting power generating units internalize pollution costs on par with newer and less polluting generation units.
- Requires FERC to (1) calculate generation performance standards for nitrogen oxides, carbon dioxide, mercury, sulfate fine particulate matter, and any other significant air pollutant released in significant quantities by electric generating units from covered generating units, (2) set forth schedules of statutory tonnage caps for electric generation emissions of nitrogen oxides, carbon

dioxide, mercury, and sulfate fine particulate matter, and (3) promulgate, by rule, a national limit on total annual emissions of any other pollutant from electric generating units.

- Prescribes rules for allocation and trading of allowances and sets penalties for excess emissions.
- Mandates that, during periods when National Ambient Air Quality Standards for ozone are exceeded, certain generating units shall be required to "adjust (their) reported actual emissions."
- Amends the Federal Power Act to require the Commission to provide estimates of electricity generation from covered electric generation units with projections of demand growth for regions and time periods specified in the legislation.
- Directs the Secretary of Energy to establish a National Electric System Public Benefits Board authorized to collect wires charges to fund public purpose programs including renewable sources, universal/affordable electric service, energy conservation and efficiency programs, research and development programs, and assistance to low-income families.
- Creates a renewable energy portfolio (to become effective upon the enactment of proposed legislation) that mandates renewable electricity generation to increase from 2.5 percent in 2000 to 7.5 percent in 2010. Authorizes FERC to sell renewable energy credits (that equal the number of megawatt-hours of electricity from renewables) and to utilize proceeds to fund research and development of renewables and cleaner burning fuels.
- Amends the Public Utility Regulatory Policies Act of 1978 (PURPA) to net metering to producers of renewable electricity and sets guidelines for interconnection to the grid. Also, stipulates disclosure requirements of emissions and generation data with respect to sales of electricity to consumers.
- Eliminates obligatory power purchase contracts mandated in PURPA on the date of enactment of proposed legislation without invalidating the sanctity of existing contracts.
- Sets forth terms and conditions to protect consumers (including privacy and non-discriminatory measures) and sets penalties for violations.

H.R. 2602

National Electricity Interstate Transmission Reliability Act
Introduced by Representative Albert Wynn (D-MD) on July 22, 1999.

- Amends the Federal Power Act to accord FERC jurisdiction over an electric reliability organization (ERO), affiliated regional reliability entities, system operators, and users of the bulk-power system for enforcing compliance with respect to transmission reliability standards.
- Prescribes procedures that enable FERC to approve reliability standards (subject to the requirement that the standards are nondiscriminatory and in the public interest) for the bulk-power system and to approve an entity's application to function as an ERO contingent on its capability to meet criteria listed in the proposed legislation.
- Authorizes FERC to take disciplinary action against those violating organizational reliability standards.

H.R. 2645

Electricity Consumer, Worker, and Environmental Protection Act of 1998
Introduced by Representative Dennis Kucinich (D-OH) on July 29, 1999.

- Prescribes standards for electricity services at the State and Federal levels.
- Provides protections for electric utility workers whose companies are undergoing transfer of ownership as a result of restructuring.
- Ensures consumers' right to privacy with respect to billing, payments, usage, and dispute resolution.
- Mandates that each State create a not-for-profit membership corporation to represent and promote the interests of States' residential electricity consumers.
- Requires each provider of distribution services and supplies to submit monthly reports to monitor performance and reliability to help protect consumers.
- Establishes within the Federal Energy Regulatory Commission an office of the Consumer Council to represent energy consumers.

- Prohibits State or Federal authorities from imposing a stranded cost recovery burden on existing consumers.
- Sets limits with respect to affiliate ownership on State-regulated investor-owned utilities.
- Directs that utilities set aside adequate financial resources to meet the costs of nuclear decommissioning and waste disposal activities.
- Reinforces FERC's authority to review electric utility mergers.
- Requires the Environmental Protection Agency to promulgate regulations establishing nationwide pollution standards together with pollutant monitoring procedures.
- Establishes a National Electric Public Benefit Board to provide funds (gathered through the imposition of a wires charge) to States for low-income assistance programs.
- Establishes renewable energy portfolio standards for electricity generation to reach 8 percent in the year 2010 (increasing by 1 percent annually thereafter) by requiring the Secretary of Energy to implement the standards in accordance with the provisions of the proposed legislation.
- Amends the Public Utility Regulatory Policies Act of 1978 to provide net-metering and interconnection facilities for renewable energy, where necessary.
- Sets deadlines for States to comply with the requirements of this Act subsequent to their deregulating retail electricity sales.
- Directs States not to permit customer classes to be charged rates for transmission and distribution in excess of their proportional responsibility for providing these services.
- Requires that utilities transfer their transmission and distribution assets to regulated counterparts/affiliates after deregulation of electricity sales at the retail level. Also, provides detailed guidelines to prevent affiliate abuse and cross-subsidization.
- Limits utilities' ownership of power plants to prevent exercise of market power in electricity generation.

- Sets forth post-deregulation requirements for compliance in areas such as the provision of basic services, aggregation of customers, worker protection, and rules for electricity suppliers and distribution companies.
- Prohibits unfair business practices and stipulates norms to protect the consumers in billing, metering, and in securing credit. Remedies for violation are also provided.

H.R. 2756

Fair Competition in Tax-Exempt Financing Act of 1999

Introduced by Representative Ralph Hall (D-TX) on August 5, 1999.

- Amends the Internal Revenue Code of 1986 by eliminating the issuance of tax-exempt bonds to finance public projects to prevent governmental entities from using tax-exempt financing to engage in unfair competition against private sector facilities.

H.R. 2786

Interstate Transmission Act

Introduced by Representative Thomas Sawyer (D-OH) on August 5, 1999.

- Expands the definition of interstate commerce in electricity to include unbundled transmission of electricity sold at the retail level under FERC's jurisdiction (in addition to transmission at the wholesale level) and directs FERC to determine which facilities used in interstate commerce will be subject to FERC's jurisdiction and which facilities will be subject to the State's jurisdiction.
- Authorizes FERC to permit a transmitting utility to recover all costs incurred in connection with the transmission and associated services including the costs of expansion of transmission networks.
- Directs FERC to establish just and non-discriminatory rates that promote efficient transmission and network expansion to avoid cost shifting among customer classes.
- Directs FERC to promote and approve the voluntary formation of regional transmission organizations.
- Entrusts FERC with the responsibility to ensure that transmitting utilities and their customers comply with reliability standards adopted by electric reliability organizations.

H.R. 2944

Electricity Competition and Reliability Act

Introduced by Representative Joseph Barton (R-TX) on September 24, 1999.

- Gives priority to State laws that are passed up to 3 years after enactment of proposed legislation that address concerns proffered by proposed legislation.
- Amends the Federal Power Act (FPA) to clarify States' authority to require retail competition and to clarify State and Federal jurisdiction. Gives States the authority to impose fees to fund public purpose programs.
- Amends the FPA to require open access for all transmitting utilities and to provide transmission service at nondiscriminatory prices. Grants FERC authority over the transmission systems at the State, municipal and rural cooperative level, and allows FERC to review transmission rates.
- Grants FERC the power to determine which transmission facilities compose the bulk power system (and fall under FERC's jurisdiction) and which are exempt from FERC regulations.
- Allows FERC to recover wholesale stranded costs where necessary.
- Amends the FPA to permit FERC to order domestic transmission service to be used for a foreign country.
- Encourages the formation of RTOs. Provides standards that RTOs must meet and authorizes FERC to approve RTOs. Allows Federal transmitting utilities to participate in RTOs with Congressional consent. Protects RTOs formed prior to enactment of legislation from mandatory modifications directed by FERC.
- Amends the FPA to grant Congressional consent to regional transmission siting to ameliorate problems encountered by States in planning for future transmission. Authorizes FERC to review compacts to protect the public's interest.
- Authorizes FERC to order a transmitting utility to expand its transmission facilities (if it would not unreasonably harm the services provided by the utility), but retains State and local authority over transmission siting.
- Amends the FPA by allowing transmission utilities to recover costs incurred to encourage additional investment in transmission. Directs FERC to approve transmission rates that are high enough to ensure the expansion of transmission networks.
- Directs FERC to encourage transmission pricing policies that encourage RTO formation, reduce pancaking of rates, minimize cost shifting among customer classes, encourage reliability of the transmission system, and encourage investment in the transmission system. Authorizes FERC to approve transmission rates and requires FERC to submit a report to Congress on these issues.
- Amends the FPA to allow FERC to impose civil penalties for non-compliance with FPA regulations. Permits Federal agencies to file complaints with FERC and seek rehearing of FERC orders.
- Amends the FPA to allow FERC jurisdiction over an ERO, affiliated regional reliability entities, and bulk power system users and operators to ensure reliability. Calls for FERC review of ERO standards and provides guidelines for the ERO's operation.
- Provides consumer protection measures that address information disclosure issues, consumer privacy practices, unfair trade practices, and express the consensus that electric services should be universal and affordable.
- Expands FERC merger review authority to include all electric utilities and transmitting utilities. Eliminates antitrust review by the Nuclear Regulatory Commission for production facilities.
- Repeals the Public Utility Holding Company Act of 1935. Allows FERC and the State access to records of holding and associate companies to identify costs and to protect utility consumers' rates.
- Prospectively repeals the Public Utility Regulatory Policies Act of 1978 and allows for cost recovery of purchases made prior to enactment of proposed legislation.
- Allows retail customers to designate an entity to aggregate purchases of electric energy.
- Amends the FPA to require local distribution companies to interconnect distributed generation facilities with the local distribution facilities.

Grants FERC the ability to order interconnection and establish safety standards.

- Prohibits TVA from selling electric power at the retail level with certain exceptions. Allows TVA to only sell excess electric power and limits TVA's contract offerings to new customers. Places TVA under the same standards for wholesale sales in interstate commerce as public utilities. Authorizes TVA to build or acquire additional generation facilities, if needed, and directs TVA to renegotiate existing all-requirements power contracts. Allows stranded cost recovery by TVA.
- Provides that FERC determine transmission rates, terms, and conditions to assure BPA adequately recovers costs, protects customers from cost shifting, and provides transmission access.
- Grants FERC statutory authority to approve and modify Power Marketing Administration (PMA) wholesale rates to guarantee full cost recovery. Applies provisions of the FPA to the transmission of electric energy by PMAs, and subjects PMAs to antitrust laws
- Reauthorizes and expands the Renewable Energy Production Incentive program established by the Energy Policy Act of 1992. Requires retail electric suppliers to provide net metering services. Maintains States' authority to set Renewable Energy Portfolio standards.
- Directs the Department of Energy to present a report to Congress on interstate commerce in electric energy and identify regulatory and statutory barriers. Directs FERC to study State regulation of transmission sales and report the results to Congress.

H.R. 2947

Home Energy Generation Act

Introduced by Representative Jay Inslee (D-WA) on September 24, 1999.

- Amends the Federal Power Act to allow for net metering. Requires retail electric suppliers to make electric energy meters available (if necessary) to consumers who have installed an energy generating unit capable of net metering.
- Protects against discrepancies in rates and contract terms between net metering customers and customers who do not participate in net metering.

- Attributes energy generated through net metering that is entitled to receive credits under a Federal minimum energy portfolio to the retail electric supplier and allows the retail supplier to count these credits towards requirements for renewable resources.
- Prescribes guidelines and procedures for the calculation of net metering and for the purposes of monitoring, billing, and providing consumer protection.
- Places limits on the amount of allowable net metering that a local distribution company retail electric supplier is required to provide.
- Calls for open public documentation of total generating capacity, type of unit, and energy source(s) of consumer-owned generating units.
- Provides consumer protection measures and sets performance and safety standards for use in net-metering and interconnection to the electrical grid.

106th Congress Senate Bills

S. 161

Power Marketing Administration Reform Act of 1999

Introduced by Senator Daniel Moynihan (D-NY) on January 19, 1999.

- Directs the Secretary of Energy to develop and implement cost accounting procedures to ensure that the Federal Power Marketing Administrations (FPMAs) and TVA use the same accounting principles and requirements that FERC applies to the electric operations of public electric utilities.
- Mandates that the FPMAs and TVA implement rate-adjusting procedures to allow for full cost recovery of power they sell while transitioning to market-based rates set by an open market.
- Requires FPMAs and TVA to develop and submit to FERC, once every 5 years, proposed rates that ensure recovery of all costs of generation and marketing of power (including fish and wildlife related costs) for approval and/or modification.
- Empowers the Secretary of Energy to establish procedures enabling FPMAs and the TVA to implement market-based pricing 2 years after the enactment of legislation using bid and auction procedures.

- Prescribes specifics regarding use of revenue collected through market-based pricing including, among others, environmental mitigation and restoration, renewable resource development, and utilization of potential surpluses to reduce the budgetary deficit.
- Precludes an FPMA or TVA from entering into or renewing any power marketing contract for a term exceeding 5 years from the date of enactment of proposed legislation.
- Directs that FPMAs and the TVA provide transmission service on an open access basis at just and reasonable rates approved by FERC.

S. 282

Transition to Competition in the Electric Industry Act
Jointly introduced by Senators Connie Mack (R-FL) and Bob Graham (D-FL) on January 21, 1999.

- Prospectively repeals mandatory power purchase requirements (from cogenerators and small power producers) by the electric utilities as required by Section 210 of the Public Utility Regulatory Policies Act of 1978.
- Ensures recovery of power purchase contract costs incurred by electric utilities prior to the enactment of proposed legislation.

S. 313

Public Utility Holding Company Act of 1999
Introduced by Senator Richard Shelby (R-AL) on January 27, 1999.

- Repeals the Public Utility Holding Company Act (PURPA) of 1935.
- Ensures rate protection of utility customers by empowering State and Federal regulatory authorities with tools which permit access to the books and records of holding companies for the purpose of jurisdictional rate-setting activities.
- Grants the Federal Energy Regulatory Commission additional enforcement authority under the Federal Power Act to permit implementation of provisions of proposed legislation.

S. 386

Bond Fairness and Protection Act of 1999
Introduced by Senator Slade Gorton (R-WA) on February 6, 1999.

- Amends the Internal Revenue Code by eliminating restrictions placed on public utilities which prevent the reciprocal provision of open access transmission and ancillary services required by FERC Order 888.
- Grants public power utilities the option of grandfathering outstanding tax-exempt debt subject to abrogating issuing tax-exempt bonds in the future to finance new facilities. Alternatively, they may continue to issue tax-exempt bonds subject to current private use limitations in the tax code.

S. 516

Electric Utility Restructuring Empowerment and Competitiveness Act of 1999

Introduced by Senator Craig Thomas (R-WY) on March 3, 1999.

- Empowers States to regulate intrastate retail electric supply or distribution service, establish and enforce reliability standards, determine just and reasonable fees where appropriate, and to enforce open transmission and provision of universal service.
- Grants FERC jurisdiction over wholesale electricity transmission services, but removes sales of wholesale electricity from the scope of FERC regulation.
- Amends PURPA to exempt electric utilities from obligatory contracts with cogenerating facilities or small power producers.
- Repeals PUHCA.
- Allows FERC and the States access to and disclosure of holding company management and affiliate rate recovery records. Authorizes appropriations and calls on FERC to promulgate final rules of exemption from PUHCA.

S. 1047

Comprehensive Electricity Competition Act
Introduced by Senator Frank Murkowski (R-AK) on May 13, 1999.

- Amends PURPA to require each distribution utility to permit all of its retail customers to purchase power from the supplier of their choice by January 1, 2003, but provides a flexible mandate for States to require open access to the distribution facilities of regulated and non-regulated electric utilities. Allows State-regulated and non-regulated

utilities to "opt out" of retail competition if, after a hearing before the State regulatory authority, it is determined that retail competition will have a negative impact on certain customer classes.

- Allows States and non-regulated utilities to determine the amount of recoverable stranded costs. Grants FERC authority to establish stranded cost recovery in the absence of State authority.
- Amends PURPA to permit a State that has chosen to implement retail competition to prohibit a distribution utility that is not under the rate-making authority of the State and that has not elected to institute retail competition from selling electricity to the consumers of the State that has chosen retail competition. Grants non-regulated utilities similar requirements of reciprocity.
- Allows electricity customers and entities acting on their behalf to acquire retail electric energy on an aggregate basis if they are served by one or more distribution utilities for which a notice of retail competition has been filed.
- Requires States electing retail competition to establish terms and conditions to protect consumers, including rates that are just and reasonable, measures to ensure privacy of consumer information and that prohibit discriminatory practices by electric utilities. Allows States to impose non-bypassable fees to fund such programs. Authorizes the creation of a publicly accessible database that will provide consumers information on electric utilities that participate in retail competition.
- Clarifies State and Federal authority over retail transmission services. Expands FERC's jurisdiction to include authority over unbundled retail transmission and municipal and publicly owned utilities and cooperatives. Reinforces FERC's authority to require public utilities to provide open access transmission services and permit recovery of stranded costs.
- Grants FERC authority to oversee creation of IRSOs and to compel utilities to turn over control of their transmission facilities to such organizations.
- Creates a Public Benefits Fund for low-income assistance, energy efficiency programs, consumer education, and development of emerging technologies. Stipulates funding mechanisms and sets forth guidelines for operation.

- Creates a renewable portfolio system mandating that sellers use, as a generation source, a percentage of non-hydro electric renewable technology. Sets forth requirements of sale and purchase of renewable energy credits and stipulates use of revenue from such sales.
- Amends PURPA by allowing net metering for renewable energy, and granting tax credits for production of energy from renewable resources and production of energy efficient buildings.
- Eliminates obligatory power purchase contracts mandated in the Public Utility Holding Company Act of 1935 (PUHCA) on the date of enactment of proposed legislation.
- Amends PURPA to require a distribution utility to allow a heat and power or a distributed power facility to interconnect with it if the facility is located within the distribution utility's service territory and complies with rules issued by the Secretary of Energy and related safety and power quality standards.
- Authorizes the provision of grant money for assistance purposes to tribal Indians, Southeast Alaska, and rural and remote communities.
- Repeals PUHCA 18 months after enactment of proposed legislation. Grants FERC and States access to utilities' books and records.
- Authorizes FERC, upon petition by a State, to require generators to submit a plan mitigating market power that FERC can accept or modify. Clarifies FERC merger review over generation-only companies and holding companies.
- Allows FERC to approve and oversee an ERO to prescribe and enforce mandatory reliability standards.
- Clarifies the authority of the Environmental Protection Agency to require a nitrogen oxide (NO_x) allowance cap and trading program in all States in which a NO_x emission source is located.
- Places TVA transmission under FERC jurisdiction. Subjects power wheeled through TVA to open access requirements and allows wholesale electric power sales by TVA outside of their traditional service area. Calls for the renegotiation of long-term contracts and authorizes FERC to intervene

if conflict arises. Authorizes TVA to join an Independent System Operator.

- Authorizes FERC to determine transmission rates for the BPA, Western Area Power Administration (WAPA), and the Southwestern Power Administration (SWPA) and allows these Federal Power Administrations to impose a surcharge on sales to recover costs of environmental programs and to join IRSOs.
- Eliminates antitrust review by the Nuclear Regulatory Commission and amends the Internal Revenue Code relating to deductions to a qualified nuclear decommissioning fund.

S. 1048

Comprehensive Electricity Competition Tax Act

Introduced by Senator Frank Murkowski (R-AK) on May 13, 1999.

- Amends the Internal Revenue Code with respect to tax-exempt private activity bonds to declare that the determination whether any electric output facility bond issued before enactment of this Act (pre-effective date electric output facility bond) is a private activity bond shall be made without regard to any specified permissible competitive action taken by the issuer. Requires such a bond not to be a private activity bond or industrial development bond as of the date of enactment of this Act. Makes this Act inapplicable to any qualified refunding bond meeting certain criteria which is issued to refund a pre-effective date electric output facility bond if the net proceeds of the refunding bond are used within 90 days of issuance to redeem the refunded bond.
- Qualifies for tax exemption private activity bonds for electric output facilities issued after enactment of this Act, excluding any part of an issue for distribution property that operates at 69 kilovolts or less.
- Modifies special rules for nuclear decommissioning costs to eliminate cost-of-service as the maximum which a taxpayer may pay into a Nuclear Decommissioning Fund.
- Includes any distributed power property within 15-year depreciation property.
- Establishes an 8-percent investment credit for combined heat and power (CHP) systems property

placed in service in calendar years 2000 through 2002. Precludes any carryback of the energy credit prior to the effective date of this Act, except for solar and geothermal energy property.

S. 1273

Federal Power Act Amendments of 1999

Introduced by Senator Jeffrey Bingaman (D-NM) on June 24, 1999.

- Expands the jurisdiction of FERC to order retail wheeling to facilitate transition to competition in power generation.
- Preserves authority of States (and of their regulatory commissions) to require that jurisdictional utilities provide unbundled local distribution service on a nondiscriminatory basis to customers within the State.
- Sustains States' authority to impose charges on retail electricity distribution and power generation.
- Directs FERC to establish and enforce reliability standards for transmission purposes and grants FERC the authority to set up the required infrastructure.
- Empowers FERC to order a transmitting utility to enlarge, extend, or improve its transmission facilities.
- Authorizes FERC to order the formation of regional transmission systems and regional independent system operators to ensure nondiscriminatory transmission availability within a region by securing the participation of all transmitting utilities within regions so formed.
- Protects existing wholesale power purchase contracts and preempts any State action that would bar recovery of associated costs by electric utilities.

S. 1284

Electric Consumer Choice Act

Introduced by Senator Don Nickles (R-OK) on June 24, 1999.

- Amends the Federal Power Act to ensure that no State may establish, maintain, or enforce on behalf of any electric utility an exclusive right to sell electric energy or otherwise unduly discriminate against any consumer who seeks to purchase electric energy in interstate commerce from any supplier.

- Stipulates that no electricity suppliers shall be denied access to transmission and local distribution facilities or be precluded from participating in retail sales on grounds that such denial may be permissible under existing State laws.
- Authorizes the State to prohibit retail electric sales by an electric utility or its affiliates if the utility or affiliates fail to comply with State requirements of reciprocity.
- Repeals the Public Utility Holding Company Act of 1935 from the date of enactment of proposed legislation.
- Prospectively repeals mandatory power purchase provisions required by the Public Utility Regulatory Policies Act of 1978.
- Recognizes the authority of a State to regulate retail sales and local distribution of electric energy.

S. 1369

Clean Energy Act of 1999

Introduced by Senator James Jeffords (R-VT) on July 14, 1999.

- Directs EPA to promulgate final regulations that establish a schedule of limits on the quantity of each pollutant that all covered generation facilities, (i.e., all non-nuclear facilities with a nameplate capacity of 15 megawatts or greater that use a combustion device to generate power) in the aggregate, shall be permitted to emit in each calendar year beginning in 2002.
- Sets maximum limits for nationwide emissions of carbon dioxide, mercury, nitrogen oxide, and sulfur dioxide for the calendar year 2005 and each year thereafter.
- Requires that EPA perform an annual determination of generation performance standards for carbon dioxide, mercury, nitrogen oxide, and sulfur dioxide emissions per megawatthour of electric production by covered generation facilities.
- Establishes guidelines for earning emission credits for covered generation facilities and prescribes penalties for noncompliance with the emission credit system.
- Prohibits a generating plant from emitting specified pollutants if the EPA determines, upon

review, that an emissions rate of specified pollutants in excess of the generation performance standard can be reasonably anticipated to cause or contribute to significant adverse local impacts. Establishes civil penalties for noncompliance.

- Directs the Secretary of Energy to establish a National Electric System Public Benefits Board to fund States for supporting renewable energy sources, universal electric service, energy conservation, and other public purposes. Prescribes funding for the Board by establishing a non-bypassable wires charge of up to 2 mills per kilowatthour.
- Establishes Renewable Energy Portfolio Standards and prescribes minimum requirements for electricity generation from renewable sources to gradually increase from 2.5 percent in 2000 to 20 percent in 2020 (as a share of total electric sales).
- Requires FERC to establish standards and procedures for issuing renewable energy credits to facilities generating electricity from renewable sources.
- Amends PURPA to repeal its mandatory power purchase provisions, but retains the validity of contracts entered under such provisions prior to the enactment of proposed legislation.
- Requires electric companies to allow a retail electric customer to interconnect and employ a net metering system. Sets procedures and guidelines for net metering, and sets safety and performance standards.
- Directs the Secretary of Energy to establish a system of disclosure that enables retail consumers to knowledgeably compare retail electric services offerings, including comparisons based on generation source portfolios, emissions data, and price terms.

S. 1949

Clean Power Plant and Modernization Act of 1999

Introduced by Senator Patrick Leahy (D-VT) on November 17, 1999.

- Sets combustion heat rate efficiency levels for operational and future fossil fuel-fired generating plants, and requires each generating unit to obtain a permit.

- Directs the Department of Energy (DOE) and EPA to promulgate methods of measuring compliance levels. Allows EPA to grant waivers for heat rate efficiency standards.
- Requires all fossil fuel-fired generating units to comply with the air emissions standards put forth in the Clean Air Act not later than 10 years after the date of enactment of proposed legislation. Sets emission rates for certain particulates and requires each generating unit to obtain a permit within the same timeframe. Requires the DOE and EPA to promulgate methods for determining compliance.
- Directs the Administrator of EPA to promulgate fuel sampling and monitoring techniques, reporting requirements, and disposal procedures for certain pollutants.
- Amends the Internal Revenue Code of 1986 by (1) extending Renewable Energy Production Credits, (2) imposing a tax on fossil fuel-fired generating units, (3) reviewing and adjusting tax rates on a biannual basis, and (4) creating a Clean Air Trust Fund.
- Provides grants to publicly owned generating units that make capital expenditures for compliance purposes.
- Grants monies to fund research and development programs focused on generating electric power from renewable resources, clean coal technologies, gas turbine technologies, and combined heat and power technologies.
- Requires DOE, the Federal Energy Regulatory Commission, and the EPA to submit a report to Congress within 2 years of enactment of proposed legislation to evaluate the implementation of proposed legislation.
- Provides dislocation and worker adjustment funds for coal industry workers who are terminated from employment and communities that are adversely affected due to downsizing of the coal industry.
- Appropriates money for the development and implementation of carbon sequestration strategies.
- Provides that FERC shall have jurisdiction over the electric reliability organization, all affiliated regional reliability entities, all system operators, and all bulk power system users.
- Allows any person, including the North American Electric Reliability Council and its member Regional Reliability Councils, to submit to FERC, before designation of an electric reliability organization, any reliability standard, guidance, practice, or amendment to a reliability standard, guidance, or practice that the person proposes to be made mandatory and enforceable.
- Directs FERC to (1) propose regulations specifying procedures and requirements for an entity to apply for designation as the electric reliability organization not later than 90 days after the date of enactment, (2) provide notice and opportunity for comment on the proposed regulations, and (3) promulgate final regulations not later than 180 days after the date of enactment.
- Mandates that the electric reliability organization submit to FERC (1) proposals for any new or modified organization standards, and (2) any proposed change in a procedure, governance, or funding provision relating to delegated functions.
- Requires the electric reliability organization, at the request of an entity, to enter into an agreement with the entity for the delegation of authority to implement and enforce compliance with organization standards in a specified geographic area if the electric reliability organization finds that the entity satisfies certain requirements and the delegation would promote the effective and efficient implementation and administration of bulk power system reliability.
- Requires each system operator to be a member of the electric reliability organization and any affiliated regional reliability entity operating under an agreement applicable to the region in which the system operator operates, or is responsible for the operation of, a transmission facility.
- Allows the electric reliability organization to impose a penalty, limitation on activities, functions, or operations, or other disciplinary action against a bulk-power system user if the electric reliability organization, after notice and an opportunity for interested parties to be heard, issues a finding in

S. 2071

Electric Reliability 2000 Act

Introduced by Senator Slade Gorton (R-WA) on February 10, 2000.

writing that the bulk power system user has violated an organization standard.

- Directs the electric reliability organization to conduct periodic assessments of the reliability and adequacy of the interconnected bulk power system and report annually to the Secretary of Energy and the Commission its findings and recommendations for monitoring or improving system reliability and adequacy.
- Prescribes all appropriate steps that the electric reliability organization shall take to gain recognition in Canada and Mexico.

S. 2098

Electric Power Market Competition and Reliability Act

Introduced by Senator Frank Murkowski (R-AK) on February 24, 2000.

Title I: Amendments to the Federal Power Act

- Amends the Federal Power Act to (1) place within the ambit of Federal regulation unbundled interstate transmission of electric energy sold at retail, and (2) place within the jurisdiction of the State within which the energy is consumed the bundled retail sale of electric energy, unbundled local distribution service, and unbundled retail sale of electric energy and attendant facilities.

Title II: Repeal of PURPA Mandatory Purchase Requirement

- Directs that, with respect to new contracts, no electric utility shall be required to enter into a new contract or obligation to purchase or sell electricity or capacity under the Public Utility Regulatory Policies Act of 1978.
- Preserves existing contract rights and remedies under such Act.

Title III: Electric Reliability

- Amends the Federal Power Act to provide for the establishment and enforcement of mandatory reliability standards to ensure the reliable operation of the bulk power system.
- Grants FERC jurisdiction over (1) the Electric Reliability Organization, (2) all affiliated regional

reliability entities (entities to which authority has been delegated to enforce compliance with reliability standards), (3) all system operators and all users of the bulk power system for purposes of approving and enforcing compliance with standards in the United States.

- Provides that, before establishment of the Electric Reliability Organization, any person (including the North American Electric Reliability Council and its member Regional Reliability Councils) shall file a proposed reliability standard, guidance, or practice which, subject to FERC approval, shall be mandatory and enforceable.

Title IV: Repeal of the Public Utility Holding Company Act of 1935 and Enactment of the Public Utility Holding Company Act of 1999

- Repeals the Public Utility Holding Company Act of 1935 effective 1 year after enactment of this title.
- Prescribes procedural guidelines for (1) FERC access to records of a public utility or natural gas holding company, and (2) State access to records of a public utility in a holding company system.
- Instructs FERC to promulgate a final rule to exempt for such Federal access requirements any holding company with respect to one or more (1) qualifying facilities under PURPA, (2) exempt wholesale generators, or (3) foreign utility companies.
- Retains the jurisdiction of FERC and State commissions to determine whether a public utility company or natural gas company may recover in rates any costs of affiliate transactions; grants FERC certain FPA enforcement powers; and transfers from the Securities and Exchange Commission to FERC all books and records that relate primarily to the functions vested in FERC by this Act.

Title V: Nuclear Decommissioning

- Permits a nuclear power facility licensee to petition the Nuclear Regulatory Commission for a determination of whether (1) adequate amounts are deposited in its nuclear decommissioning trust fund, and (2) future funding for any nuclear power plant is assured for any nuclear power plant owned in whole or in part by such licensee.

Appendix D

Electric Power Industry Statistics

Appendix D

Electric Power Industry Statistics

The Energy Information Administration (EIA) collects and disseminates electric power industry statistics, and a summary of those statistics is provided in Table D1. The following publications contain additional industry data relevant to this report and are available from EIA's website at <http://www.eia.doe.gov>. The reports are also available in hardcopy by contacting the National Energy Information Center via telephone at 202-586-8800 or via Internet at infoctr@eia.doe.gov. Previous analysis reports dealing with the restructuring of the electric power industry are also attainable.

Carbon Dioxide Emissions from the Generation of Electric Power in the United States

This report summarizes carbon dioxide emissions produced by electricity generation in the United States.

Electric Power Annual, Volume I

This publication contains data on net generation; fossil fuel consumption, stocks, receipts, and cost; generating unit capability; retail sales of electricity and associated revenue; and the average revenue per kilowatthour of electricity sold.

Electric Power Annual, Volume II

This publication presents an overview of the electric power industry in the United States and a summary of industry statistics at national, regional, and State levels.

Electric Power Monthly

This report provides monthly statistics at the State, Census division, and national levels for net generation, fossil fuel consumption and stocks, quantity and quality of fossil fuels, cost of fossil fuels, electricity sales, revenue, and average revenue per kilowatthour of electricity sold.

Electric Sales and Revenue

This publication provides information on electricity sales, associated revenue, average revenue per kilowatt-hour sold, and number of consumers throughout the United States. Data are presented at the national, Census division, State, and electric utility levels.

Electric Trade in the United States

This report presents information on bulk power transactions by investor-owned utilities, Federal and other publicly owned utilities, and cooperative utilities.

Financial Statistics of Major U.S. Investor-Owned Electric Utilities

This publication presents summary and detailed financial accounting data on investor-owned electric utilities.

Financial Statistics of Major U.S. Publicly Owned Electric Utilities

This report presents summary financial data for the past 5 years and detailed current financial data on major publicly owned electric utilities.

Inventory of Electric Utility Power Plants in the United States

This report provides annual statistics on generating units operated by electric utilities in the United States. The publication also presents a 5-year outlook for generating unit additions and retirements.

Inventory of Nonutility Power Plants in the United States

This publication summarizes U.S. nonutility data with detailed information on existing and planned net summer capability, nameplate capacity, energy source and prime mover, as well as information on facility owner and facility locations.

The Restructuring of the Electric Power Industry - A Capsule of Issues and Events

This brochure offers an overview of electric power industry restructuring, including the major changes that have already occurred, their causes, and current events.

State Electricity Profiles

This report is designed to profile each State and the District of Columbia regarding not only their current restructuring activities but also their electricity generation and concomitant statistics. Included are data

on a number of subject areas, including generating capability, generation, revenues, fuel use, capacity factor of nuclear plants, retail sales, and pollutant emissions.

U.S. Electric Utility Demand-Side Management

This publication presents comprehensive information on electric power industry demand-side management (DSM) activities in the United States at the national, regional, and utility levels.

Table D1. Electric Power Industry Summary Statistics for the United States, 1998

Item	1998
Electric Power Industry¹	
Generating Capability (megawatts) ²	775,885
Net Generation (million kilowatthours)	3,617,873
Emissions (thousand short tons) ³	
Sulfur Dioxide (SO ₂)	13,083
Nitrogen Oxides (NO _x)	7,902
Carbon Dioxide (CO ₂) ⁴	2,455,267
Electric Utilities	
Generating Capability (megawatts) ^{2,5,9}	686,692
Coal	299,739
Petroleum	62,959
Gas	125,386
Hydroelectric Pumped Storage	18,898
Nuclear	97,070
Waste Heat	4,818
Hydroelectric (conventional)	75,525
Other Renewable	
Geothermal	1,550
Biomass ⁶	504
Wind	9
Photovoltaic	5
Net Generation (million kilowatthours)	3,212,171
Coal	1,807,480
Petroleum ⁷	110,158
Gas	309,222
Nuclear	673,702
Hydroelectric Pumped Storage ⁸	-4,441
Hydroelectric (conventional)	308,844
Other Renewable	
Geothermal	5,176
Biomass ⁶	2,024
Wind	3
Photovoltaic	3
Consumption	
Coal (million short tons)	911
Petroleum (million barrels) ¹⁰	179
Gas (billion cubic feet)	3,258
Stocks (Year End)	
Coal (million short tons)	121
Petroleum (million barrels) ¹¹	54
Receipts	
Coal (million short tons)	929
Petroleum (million barrels) ¹²	165
Gas (billion cubic feet) ¹³	2,924
Cost (cents per million Btu)¹⁴	
Coal	125.2
Petroleum ¹⁵	213.6
Gas	238.1
Sales To Ultimate Consumers (million kilowatthours)	3,239,818
Residential	1,127,735
Commercial	968,528
Industrial	1,040,038
Other ¹⁶	103,518
Revenue From Ultimate Consumers (million dollars)	218,346
Residential	93,164
Commercial	71,769
Industrial	46,550
Other ¹⁶	6,863

See footnotes at end of table.

Table D1. Electric Power Industry Summary Statistics for the United States, 1998
(Continued)

Item	1998
Average Revenue per Kilowatthour (cents)	6.74
Residential	8.26
Commercial	7.41
Industrial	4.48
Other ¹⁶	6.63
Net Electric Plant Inc Fuel (million dollars)	
Major Investor Owned	333,006
Major Publicly Owned Generator/Nongenerator	69,725
Emissions (thousand short tons)¹⁷	
Sulfur Dioxide (SO ₂)	12,432
Nitrogen Oxides (NO _x)	7,221
Carbon Dioxide (CO ₂)	2,209,286
Noncoincident Summer Peak Load (megawatts)	669,069
DSM Actual Peak Load Reductions (megawatts)	27,231
DSM Energy Savings (million kilowatthours)	49,187
Nonutility Power Producers	
Installed Capacity (megawatts)	98,065
Coal ¹⁸	13,712
Petroleum Only ¹⁹	2,629
Gas Only ²⁰	37,530
Petroleum/Natural Gas (combined)	23,105
Nuclear	--
Hydroelectric (conventional)	4,136
Other Renewable	
Geothermal	1,449
Biomass ⁶	10,374
Wind	1,689
Solar Thermal	385
Photovoltaic	--
Other ²¹	3,075
Gross Generation (million kilowatthours)	421,364
Coal ¹⁸	70,369
Petroleum ¹⁹	17,533
Gas ²⁰	247,613
Nuclear	--
Hydroelectric (conventional)	14,633
Other Renewable	
Geothermal	9,882
Biomass ⁶	53,682
Wind	3,015
Solar Thermal	887
Photovoltaic	--
Other ²¹	3,750
Consumption²²	
Coal (Thousand short tons)	56,850
Petroleum (Thousand barrels) ²³	58,745
Natural Gas (Million cubic feet)	2,666,430
Other Gas (Million cubic feet) ²⁴	881,017
Supply and Disposition (million kilowatthours)	
Gross Generation	421,364
Receipts ²⁵	90,675
Deliveries ²⁶	275,260
Facility Use	236,770
Emissions (thousand short tons)²⁷	
Sulfur Dioxide (SO ₂)	651
Nitrogen Oxides (NO _x)	681
Carbon Dioxide (CO ₂)	245,981

¹ Electric utility and nonutility values (capability versus capacity, net versus gross generation, total emissions versus emissions for the production of electricity) may not be summed directly.

² Data are based on the initial commercial operation year for the generator.

³ In 1997, the useful utility thermal output produced additional emissions of 192 thousand short tons of sulfur dioxide, 66 thousand short tons of nitrogen oxides, and 18,159 thousand short tons of carbon dioxide. In 1998, the useful utility thermal output produced additional emissions of 231 thousand short tons of sulfur dioxide, 91 thousand short tons of nitrogen oxides, and 29,267 thousand short tons of carbon dioxide. In 1997, the useful nonutility thermal output produced additional emissions of 775 thousand short tons of sulfur dioxide, 473 thousand short tons of nitrogen oxides, and 143,824 thousand short tons of carbon dioxide. In 1998, the useful nonutility thermal output produced additional emissions of 756 thousand short tons of sulfur dioxide, 493 thousand short tons of nitrogen oxides, and 185,084 thousand short tons of carbon dioxide.

⁴ The report, *Carbon Dioxide Emissions from the Generation of Electric Power in the United States*, presented carbon dioxide emissions of 2,359,853 thousand short tons in 1997 and 2,447,457 thousand short tons in 1998. The nonutility data were revised since the October 15, 1999 release of that report.

Table D1. Electric Power Industry Summary Statistics for the United States, 1998
(Continued)

Item	1998
⁵ Net summer capability based on primary energy source. Waste gases and waste steam are included in the original primary energy source (i.e., coal, petroleum, or gas). Historical data have been revised to reflect this change.	
⁶ Includes wood, wood waste, peat, wood liquors, railroad ties, pitch, wood sludge, municipal solid waste, agricultural byproducts, straw, tires, landfill gases, and fish oils.	
⁷ Includes petroleum coke.	
⁸ Represents total pumped storage facility production minus energy used for pumping. Negative generation denotes that electric power consumed for plant use exceeds gross generation.	
⁹ Includes 216 megawatts multi-fueled capacity and 13 megawatts fueled by hot nitrogen.	
¹⁰ Does not include petroleum coke consumption of 1,400 thousand short tons in 1997 and 1,769 thousand short tons in 1998.	
¹¹ Does not include petroleum coke stocks of 469 thousand short tons at year end 1997 and 559 thousand short tons at year end 1998.	
¹² Does not include petroleum coke receipts of 2,192 thousand short tons in 1997 and 3,217 thousand short tons in 1998.	
¹³ Includes small amounts of coke-oven, refinery, blast furnace, and landfill gas.	
¹⁴ Average cost of fuel delivered to electric generating plants with a total steam-electric nameplate capacity of 50 or more megawatts; average cost values are weighted by Btu.	
¹⁵ Does not include petroleum coke cost of \$1.2 cents per million Btu in 1997 and 71.2 cents per million Btu in 1998.	
¹⁶ Includes public street and highway lighting, other sales to public authorities, sales to railroads and railways, and interdepartmental sales.	
¹⁷ Includes only those power plants with a fossil-fueled steam-electric nameplate capacity (existing or planned) of 10 or more megawatts. As of 1998, emission factors for the calculation of carbon dioxide emissions have been changed. Historical data were revised to reflect that change.	
¹⁸ Includes coal, anthracite culm, coke breeze, fine coal, waste coal, bituminous gob, and lignite waste.	
¹⁹ Includes petroleum, petroleum coke, diesel, kerosene, liquid butane, liquid propane, oil waste, and tar oil.	
²⁰ Includes natural gas, waste heat, waste gas, butane, methane, propane, and other gas.	
²¹ Includes hydrogen, sulfur, batteries, chemicals, and purchased steam.	
²² Includes all combustible fuels burned at generating facilities (not just for the production of electricity).	
²³ Does not include petroleum coke consumption of 4,364 thousand short tons for 1997 and 4,470 thousand short tons for 1998.	
²⁴ Includes butane, methane, propane, digester gas, and other gas.	
²⁵ Includes purchases, interchanges, and exchanges of electric energy with utilities and other nonutilities.	
²⁶ Includes sales, interchanges, and exchanges of electric energy with utilities and other nonutilities. The disparity in these data and data reported on other EIA surveys occurs due to differences in the respondent universe. The Form EIA-860B and the Form EIA-867 are filed by nonutilities reporting the energy delivered, while other data sources are filed by electric utilities reporting energy received. Differences in terminology and accounting procedures contribute to the disparity. In addition, since the frame for the Form EIA-860B and the Form EIA-867 is derived from utility surveys, the Form EIA-860B and the Form EIA-867 universes lag 1 year.	
²⁷ In 1998, emission factors for the calculation of carbon dioxide and the reductions from nitrogen oxides and sulfur dioxide have been changed. Historical data were revised to reflect that change.	
R = Revised data.	
Notes: • Data previously published have been reclassified by energy source and have been changed to reflect these changes. • Data for nonutility power producers and emissions are preliminary for 1998; other data in this table are final. • Totals may not equal sum of components because of independent rounding. • Percent change is calculated before rounding.	
Sources: Energy Information Administration, Form EIA-412, "Annual Report of Public Electric Utilities"; Form EIA-759, "Monthly Power Plant Report"; Form EIA-860, "Annual Electric Generator Report" for 1997; Form EIA-860A, "Annual Electric Generator Report - Utility" for 1998; Form EIA-861, "Annual Electric Utility Report"; Form EIA-767, "Steam-Electric Plant Operation and Design Report"; Form EIA-860B, "Annual Electric Generator Report- Nonutility" for 1998 and Form EIA-867, "Annual Nonutility Power Producer Report" for 1997; Federal Energy Regulatory Commission (FERC) Form 1, "Annual Report of Major Electric Utilities, Licensees, and Others" as edited by Navigant Consulting, Inc.; FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants"; Form EIA-411, "Coordinated Bulk Power Supply Programs"; Department of Energy, Office of Emergency Policy, Form OE-411, "Coordinated Bulk Power Supply Program."	

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Table 80. Renewable Energy Generation by Fuel Mid-Continent Area Power Pool

	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Electric Power Sector 1/													
Generating Capacity (gigawatts)													
Conventional Hydropower	2.90	2.90	2.90	2.90	2.90	2.90	2.90	2.90	2.90	2.90	2.90	2.90	2.90
Geothermal 2/	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Municipal Solid Waste 3/	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.12
Wood and Other Biomass 4/	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16
Solar Thermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Solar Photovoltaic 5/	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Wind	0.85	1.09	1.12	1.62	1.64	1.65	1.67	1.69	1.71	1.71	1.71	1.71	1.71
Total	4.02	4.26	4.29	4.79	4.81	4.83	4.84	4.86	4.88	4.88	4.88	4.88	4.88
Electricity Generation (billion kilowatt-hours)													
Conventional Hydropower	10.01	9.71	11.42	12.88	13.41	13.41	13.41	13.41	13.41	13.41	13.41	13.41	13.41
Geothermal 2/	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Municipal Solid Waste 3/	0.95	0.93	0.73	0.73	0.73	0.73	0.73	0.73	0.73	0.73	0.73	0.73	0.76
Wood and Other Biomass 4/	0.03	0.04	0.70	0.70	0.70	0.70	0.70	0.75	0.75	0.77	0.78	0.80	0.78
Solar Thermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Solar Photovoltaic 5/	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Wind	1.85	1.99	2.93	4.50	4.55	4.61	4.67	4.73	4.79	4.80	4.80	4.80	4.80
Total	12.83	12.67	15.78	18.81	19.39	19.45	19.51	19.62	19.68	19.71	19.72	19.75	19.75
Energy Consumption (quadrillion Btu)													
Conventional Hydropower	0.10	0.10	0.12	0.13	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14
Geothermal 2/	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Municipal Solid Waste 3/	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Wood and Other Biomass 4/	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Solar Thermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Solar Photovoltaic 5/	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Wind	0.02	0.02	0.03	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
Total	0.14	0.13	0.17	0.20	0.20	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21
End-Use Generators 6/													
Generating Capacity (gigawatts)													
Conventional Hydropower 7/	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Geothermal 2/	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Municipal Solid Waste	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Wood and Other Biomass 4/	0.12	0.12	0.13	0.14	0.14	0.14	0.15	0.15	0.15	0.15	0.16	0.16	0.16
Solar Photovoltaic 5/	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Total	0.16	0.16	0.17	0.18	0.18	0.18	0.19	0.20	0.20	0.20	0.21	0.21	0.21
Electricity Generation (billion kilowatt-hours)													
Conventional Hydropower 7/	0.09	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14
Geothermal 2/	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Municipal Solid Waste	0.04	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
Wood and Other Biomass 4/	0.71	0.67	0.71	0.75	0.76	0.77	0.79	0.81	0.82	0.83	0.84	0.85	0.87
Solar Photovoltaic 5/	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.02	0.02	0.02	0.02	0.02	0.02
Total	0.84	0.86	0.91	0.95	0.96	0.98	1.00	1.02	1.04	1.05	1.06	1.07	1.08
Energy Consumption (quadrillion Btu)													
Conventional Hydropower 7/	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Table 80. Renewable Energy Generation by Fuel Mid-Continent Area Power Pool

	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Geothermal 2/	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Municipal Solid Waste	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Wood and Other Biomass 4/	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Solar Photovoltaic 5/	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.02	0.02	0.02

Table 80. Renewable Energy Generation by Fuel Mid-Continent Area Power Pool

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2003-2025
Electric Power Sector 1/												
Generating Capacity (gigawatts)												
Conventional Hydropower	2.90	2.90	2.90	2.90	2.90	2.90	2.90	2.90	2.90	2.90	2.90	0.0%
Geothermal 2/	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	N/A
Municipal Solid Waste 3/	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.1%
Wood and Other Biomass 4/	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.0%
Solar Thermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	N/A
Solar Photovoltaic 5/	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	N/A
Wind	1.71	1.71	1.71	1.71	1.71	1.71	1.71	1.74	1.79	1.81	1.81	2.3%
Total	4.88	4.88	4.88	4.88	4.88	4.88	4.88	4.92	4.96	4.98	4.98	0.7%
Electricity Generation (billion kilowatthours)												
Conventional Hydropower	13.41	13.41	13.41	13.41	13.41	13.41	13.41	13.41	13.41	13.41	13.41	1.5%
Geothermal 2/	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	N/A
Municipal Solid Waste 3/	0.76	0.76	0.76	0.76	0.76	0.76	0.76	0.76	0.76	0.76	0.76	-0.9%
Wood and Other Biomass 4/	0.72	0.72	0.72	0.72	0.71	0.71	0.70	0.70	0.70	0.70	0.70	13.7%
Solar Thermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	N/A
Solar Photovoltaic 5/	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	N/A
Wind	4.80	4.80	4.80	4.80	4.80	4.80	4.80	4.93	5.09	5.15	5.15	4.4%
Total	19.69	19.69	19.69	19.69	19.68	19.68	19.67	19.80	19.96	20.02	20.02	2.1%
Energy Consumption (quadrillion Btu)												
Conventional Hydropower	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	1.5%
Geothermal 2/	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	N/A
Municipal Solid Waste 3/	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	-0.9%
Wood and Other Biomass 4/	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	15.6%
Solar Thermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	N/A
Solar Photovoltaic 5/	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	N/A
Wind	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	4.4%
Total	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	2.1%
End-Use Generators 6/												
Generating Capacity (gigawatts)												
Conventional Hydropower 7/	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.0%
Geothermal 2/	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	N/A
Municipal Solid Waste	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.0%
Wood and Other Biomass 4/	0.16	0.16	0.17	0.17	0.18	0.18	0.19	0.19	0.19	0.20	0.20	2.3%
Solar Photovoltaic 5/	0.01	0.01	0.02	0.02	0.02	0.02	0.03	0.03	0.04	0.05	0.05	17.0%
Total	0.21	0.22	0.22	0.23	0.24	0.24	0.25	0.26	0.27	0.28	0.29	2.7%
Electricity Generation (billion kilowatthours)												
Conventional Hydropower 7/	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.0%
Geothermal 2/	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	N/A
Municipal Solid Waste	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.8%
Wood and Other Biomass 4/	0.88	0.89	0.90	0.93	0.95	0.97	0.99	1.00	1.02	1.04	1.05	2.1%
Solar Photovoltaic 5/	0.02	0.02	0.03	0.03	0.04	0.04	0.05	0.06	0.07	0.08	0.09	16.9%
Total	1.10	1.11	1.13	1.15	1.18	1.21	1.23	1.26	1.28	1.31	1.34	2.0%
Energy Consumption (quadrillion Btu)												
Conventional Hydropower 7/	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.0%

Table 80. Renewable Energy Generation by Fuel Mid-Continent Area Power Pool

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2003- 2025
Geothermal 2/	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	N/A
Municipal Solid Waste	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.0%
Wood and Other Biomass 4/	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.02	1.8%
Solar Photovoltaic 5/	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	N/A
Total	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	1.5%

Table 60. Renewable Energy Generation by Fuel Mid-Continent Area Power Pool

1/ Includes electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.

2/ Includes hydrothermal resources only (hot water and steam).

3/ Includes landfill gas.

4/ Includes projections for energy crops after 2010.

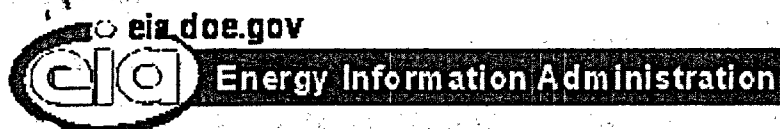
5/ Does not include off-grid photovoltaics (PV). Based on annual PV shipments from 1989 through 2002, EIA estimates that as much as 134 megawatts of remote electricity generation PV applications (i.e., off-grid power systems) were in service in 2002, plus an additional 362 megawatts in communications, transportation, and assorted other non-grid-connected, specialized applications. See Annual Energy Review 2003, Table 10.6 (annual PV shipments 1989-2002). The approach used to develop the estimate, based on shipment data, provides an upper estimate of the size of the PV stock, including both grid-based and off-grid PV. It will overestimate the size of the stock, because shipments include a substantial number of units that are exported, and each year some of the PV units installed earlier will be retired from service or abandoned.

6/ Includes combined heat and power plants and electricity-only plants in the commercial and industrial sectors; and small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid.

7/ Represents own-use industrial hydroelectric power.

Note: Totals may not equal sum of components due to independent rounding. Data for 2003 are model results and may differ slightly from official EIA data reports.

Sources: 2002 and 2003 generation: EIA, Annual Energy Review 2003, DOE/EIA-0384(2003) (Washington, DC, September 2004). Projections: EIA, AEO2005 National Energy Modeling System run aeo2005.d102004a.



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Annual Energy Outlook 2005

Market Trends - Electricity Demand and Supply

Continued Growth in Electricity Use Is Expected in All Sectors

Total electricity sales are projected to increase at an average annual rate of 1.9 percent in the AEO2005 reference case, from 3,481 billion kilowatt-hours in 2003 to 5,220 billion kilowatt-hours in 2025 (Figure 66). From 2003 to 2025, annual growth in electricity sales is projected to average 1.6 percent in the residential sector, 2.5 percent in the commercial sector, and 1.3 percent in the industrial sector.

The average size of homes is projected to be larger in 2025 than in 2003 in terms of both square footage and ceiling height, with corresponding increases in electricity use for heating, cooling, and lighting. In addition, expected population shifts to warmer climates increase the amount of electricity used for air conditioning, although the projected increases are mitigated in part by the implementation of a more stringent efficiency standard for air conditioners and heat pumps in 2006.

Projected efficiency gains for electric equipment in the commercial sector are offset by the continuing penetration of new telecommunications technologies and medical imaging equipment, increased use of office equipment, and more rapid additions of floorspace.

Although electricity use is projected to increase with the growth of industrial output, increases in electricity sales to the industrial sector are expected to be offset by a 2.7-percent average annual increase in onsite generation.

Early Capacity Additions Use Natural Gas, Coal Plants Are Added Later

With growing electricity demand and the retirement of 43 gigawatts of inefficient, older generating capacity, 281 gigawatts of new capacity (including end-use combined heat and power) will be needed by 2025. Most retirements are expected to be older oil- and natural-gas-fired steam capacity, along with smaller amounts of older oil- and natural-gas-fired combustion turbines and coal-fired capacity, which are not competitive with newer natural gas combustion turbine or combined-cycle capacity.

More than 60 percent of new capacity additions are projected to be natural-gas-fired combined-cycle, combustion turbine, or distributed generation technologies (Figure 67). More than 80 percent of the capacity additions will be needed after 2010, when the current excess of generation capacity has been reduced. As natural gas prices rise later in the forecast, new coal-fired capacity is projected to become increasingly competitive, accounting for nearly one-third of the capacity expansion expected in the reference case. Most of the new coal capacity is expected to use advanced pulverized coal technology and to begin operation after 2015. About 16 gigawatts of capacity using advanced clean coal technology, with higher capital costs but relatively low fuel costs, is also expected to be added.

About 5 percent of the projected capacity expansion consists of renewable generating units. Another 7 gigawatts of distributed generation, mostly gas-fired microturbines, is also expected to be added by 2025. Oil-fired steam plants with higher fuel costs and lower efficiencies are expected to be used only for new industrial combined heat and power capacity.

Capacity Additions Are Expected To Be Required in All Regions

Most areas of the United States currently have excess generation capacity, but all the electricity demand regions (see Appendix G for definitions) are expected to need additional, currently unplanned, capacity by 2025 (Figure 68). Some new plants already are under construction, nearly all of which are expected to be completed by 2010.

The need for new capacity is expected to be greatest in the Southeast and the West. Although comparatively small geographically, the Southeast accounts for about 30 percent of projected total demand in 2025 and a comparable share of expected capacity additions. The size of the region's

Figure 66. Annual electricity sales by sector, 1970-2025 (billion kilowatt-hours)

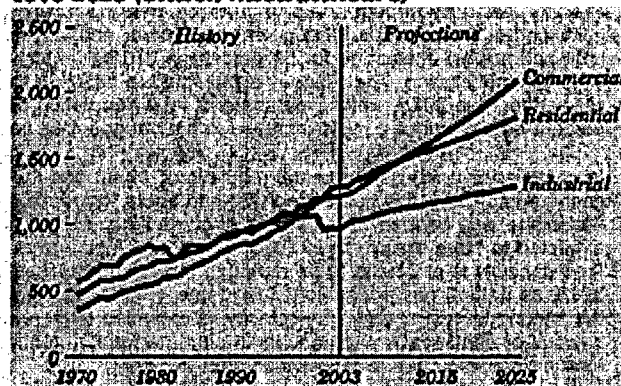


Figure data

Figure 67. Electricity generation capacity additions by fuel type, including combined heat and power, 2004-2025 (gigawatts)

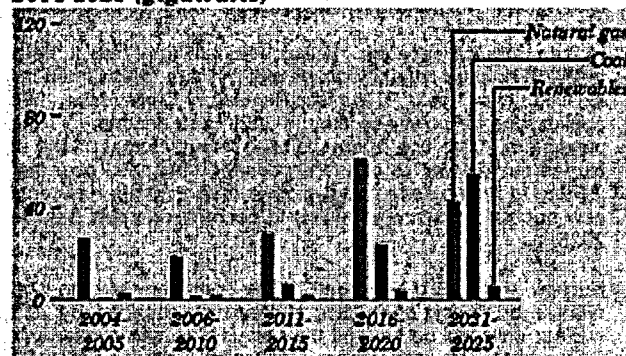


Figure data

Figure 68. Electricity generation capacity additions, including combined heat and power, by region and fuel, 2004-2025 (gigawatts)



electricity market is the principal reason for the amount of new capacity required, and the projected growth in its demand for electricity growth is also slightly higher than the national average. The West, which geographically is the largest electricity demand region, currently represents less than 20 percent of the Nation's total electricity demand, but it accounts for 25 percent of projected capacity additions. Relatively strong growth in demand is projected for the West.

Capacity additions in the Southeast and the West are expected to be considerably more diverse than in the other areas of the country, where most additions are projected to be natural-gas-fired capacity. Almost all additions of coal-fired and renewable capacity are expected to be in these two areas. Of the 87 gigawatts of new coal-fired capacity, the Southeast and West account for 36 percent and 40 percent, respectively. Nationally, new renewable generating capacity is expected to total 15 gigawatts, with 28 percent and 34 percent located in the Southeast and West.

Natural Gas and Coal Meet Most Needs for New Electricity Supply

Coal-fired power plants are expected to continue supplying most of the Nation's electricity through 2025 (Figure 69). In 2003, coal-fired plants (including utilities, independent power producers, and end-use combined heat and power) accounted for 51 percent (1,970 billion kilowatthours) of all electricity generation. Their output is projected to increase to 2,890 billion kilowatthours in 2025, while their share of total generation declines to 50 percent as a result of a rapid increase in natural-gas-fired generation.

In compliance with environmental regulations, about one-third of existing coal-fired capacity has been fitted with scrubbers to reduce sulfur dioxide emissions, and another 27 gigawatts of currently existing capacity is expected to have scrubbers in 2025. A total of 87 gigawatts of new coal-fired capacity is projected to be added in the reference case, mostly after 2010, as natural gas prices continue to rise. Nuclear generation, currently the second-largest source of electricity, is expected to increase modestly, as a result of additional improvements in plant performance and expansions of existing capacity, before leveling off after 2017.

Natural gas is expected to have the largest increase in its share of total electricity generation, from 17 percent in 2003 to 20 percent in 2010 and 24 percent in 2025, and by 2010 it is expected to overtake nuclear power as the second-largest source of electricity production. Generation from renewable sources, including hydropower, is projected to increase by 36 percent from 2003 to 2025, but its share of total electricity supply is projected to decline from 9 percent in 2003 to 8 percent in 2025.

Nuclear Power Plant Capacity Factors Are Expected To Increase Modestly

The United States currently has 104 commercial nuclear reactors licensed to operate, providing about 20 percent of the total 3,690 billion kilowatthours of electricity generated in 2003 (Figure 70). The performance of U.S. nuclear units has improved recently; the national average capacity factor rose to 90 percent in 2002 before dropping slightly to 88 percent in 2003. It is assumed that performance improvements will continue even as the plants age, leading to a weighted average capacity factor of 92 percent after 2010.

In the reference case, no nuclear units are projected to be retired from 2003 to 2025. Nuclear capacity grows slightly, due to assumed increases at existing units. The U.S. Nuclear Regulatory Commission (NRC) approved 8 applications for power uprates in 2003, and another 12 were approved or pending in 2004. The reference case assumes that all the uprates will be carried out, as well as others expected by the NRC over the next 15 years, leading to an increase of 3.5 gigawatts in total nuclear capacity by 2025. No new nuclear units are expected to become operable between 2003 and 2025.

Nuclear units would be retired if their operation were no longer economical relative to the cost of building replacement capacity. By 2025, the majority of nuclear units will be beyond their original license expiration dates. As of December 2004, license renewals for 30 nuclear units had been approved by the NRC, and 16 other applications were being reviewed. As many as 28 additional applicants have announced intentions to pursue license renewals over the next 3 years, indicating a strong interest in maintaining the existing stock of nuclear plants.

Least Expensive Technology Options Are Likely Choices for New Capacity

Technology choices for new generating capacity are made to minimize cost

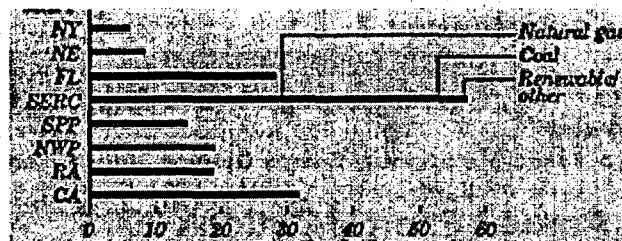


Figure data

Figure 69. Electricity generation by fuel, 2003 and 2025 (billion kilowatthours)

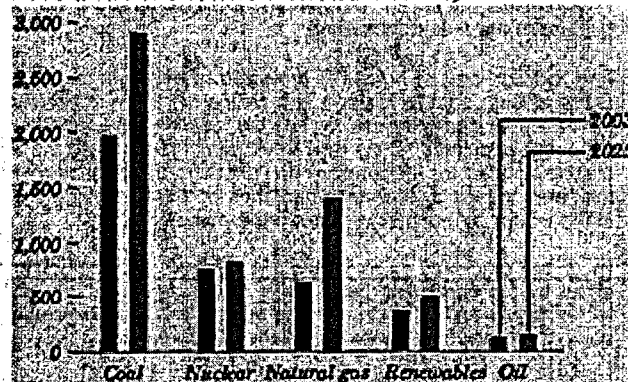


Figure data

Figure 70. Electricity generation from nuclear power, 1973-2025 (billion kilowatthours)

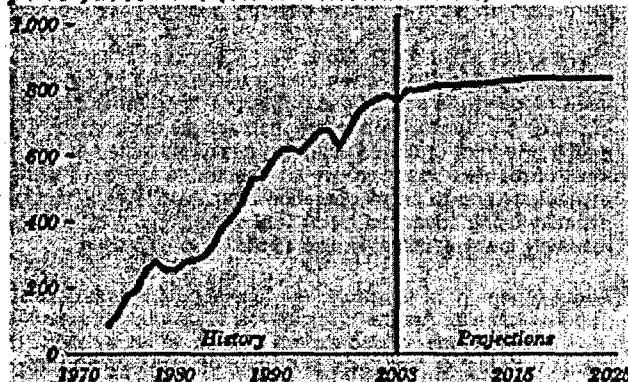


Figure data

while meeting local and Federal emissions constraints. The choice of technology for capacity additions is based on the least expensive option available (Figure 71) [136]. The reference case assumes a capital recovery period of 20 years. In addition, the cost of capital is based on competitive market rates, to account for the risks of siting new units.

Capital costs are expected to be reduced over time (Table 27), at rates that depend on the current stage of development for each technology. For the newest technologies, capital costs are initially adjusted upward to reflect the optimism inherent in early estimates of project costs. As project developers gain experience, the costs are assumed to decline. The decline continues at a progressively slower rate as more units are built. The performance (efficiency) of new plants is also assumed to improve, with heat rates for advanced combined cycle and coal gasification units declining to 6,333 and 7,200 Btu per kilowatt-hour, respectively, by 2010.

Coal and Nuclear Fuel Costs Are Expected To Be Stable

Electricity production costs are a function of the costs for fuel, operations and maintenance, and capital. Fuel costs make up most of the operating costs for fossil-fired units. For a new coal-fired plant built today, fuel costs would represent about one-half of total operating costs, whereas the share for a new natural-gas-fired plant would be almost 90 percent. For nuclear units, fuel costs typically are a much smaller portion of total production costs, and nonfuel operations and maintenance costs make up a much larger share.

The impact of higher natural gas prices in the projections is offset by increased generation from coal-fired and nuclear power plants and by higher generation efficiencies as new capacity is installed. Although natural gas prices have been volatile in recent years, delivered prices to electricity generators are projected to peak at \$6 per million Btu in 2004, then drop by almost 30 percent by 2010 before climbing steadily to almost \$5.50 per million Btu in 2025 (Figure 72). Nuclear fuel costs, currently around \$0.40 per million Btu (roughly 4 mills per kilowatt-hour), are projected to rise to about \$0.60 per million Btu in 2025. Delivered petroleum prices to electricity generators follow a price path similar to that for natural gas prices, with a sharp drop through 2010 followed by a steady rise through 2025. Despite increasing fuel costs, the natural gas share of total generation is projected to increase from 16 percent in 2003 to 24 percent in 2025 because of the higher efficiency of gas-fired capacity.

Average Electricity Prices Decline From 2001 Highs, Then Gradually Rise

Average U.S. electricity prices, in real 2003 dollars, are expected to decline by 11 percent, from 7.4 cents per kilowatt-hour in 2003 to 6.6 cents in 2011 (Figure 73), then rise to 7.3 cents per kilowatt-hour in 2025. Prices follow the trend of the generation cost component of price, which makes up 65 percent of the total price of electricity and changes mainly in response to changes in natural gas prices. The distribution component, 28 percent of the total electricity price, is expected to decline from 2003 to 2025 at an average annual rate of 0.7 percent, as the cost of distribution infrastructure is spread over a growing amount of total electricity trade. Transmission prices are expected to increase at an average annual rate of 1.0 percent because of the additional investment needed to meet projected growth in electricity demand. Electricity prices for individual customer classes are projected to follow the average price trend, declining through 2011 and then increasing for the remainder of the forecast. Residential and commercial prices in 2025 are projected to be slightly lower than 2003 prices, and industrial prices are expected to be slightly higher than in 2003.

Competition in retail and wholesale generation markets can strongly influence electricity prices. In 2004, 17 States and the District of Columbia had competitive retail electricity markets in operation. Montana, Nevada, New Mexico, and Oklahoma have delayed opening competitive retail markets; Arkansas has repealed its restructuring legislation; and California's competitive retail market is suspended. Many States have cited a lack of operational wholesale markets and inadequate generation and transmission capacity as reasons for delaying retail competition.

Increases in Nonhydropower Renewable Generation Are Expected

Despite strong growth in renewable electricity generation as a result of technology improvements and expected higher fossil fuel costs, grid-connected generators using renewable fuels (including combined heat and power and other end-use generators) are projected to remain minor

Figure 71. Levelized electricity costs for new plants, 2015 and 2025 (2003 mills per kilowatt-hour)

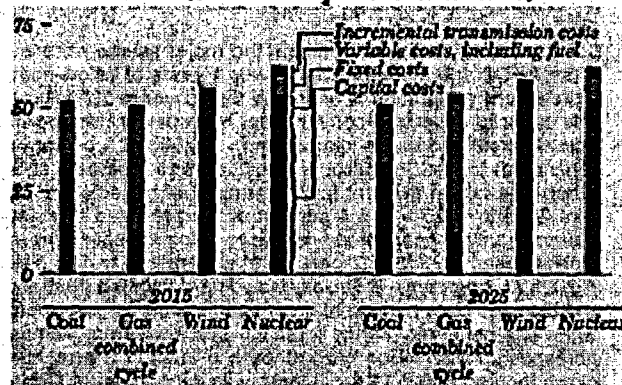


Figure data

Table 27. Costs of producing electricity from new plants, 2015 and 2025

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Costs	2015		2025	
	Advanced coal	Advanced combined cycle	Advanced coal	Advanced combined cycle
	2003 mills per kilowatt-hour			
Capital	31.68	11.63	28.87	11.08
Fixed	4.59	1.36	4.59	1.36
Variable	12.28	34.88	13.98	39.06
Incremental transmission	3.24	2.80	3.41	2.86
Total	51.79	50.67	50.85	54.36

Figure 72. Fuel prices to electricity generators, 1990-2025 (2003 dollars per million Btu)

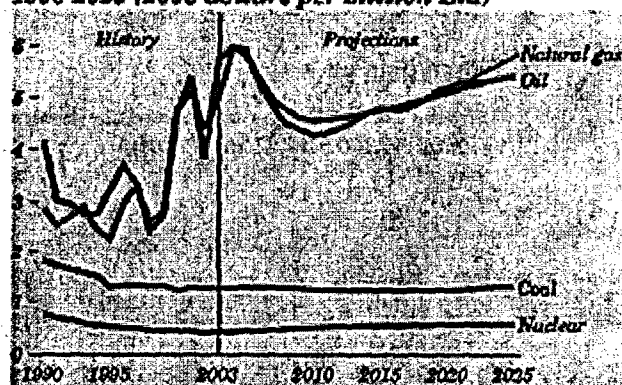
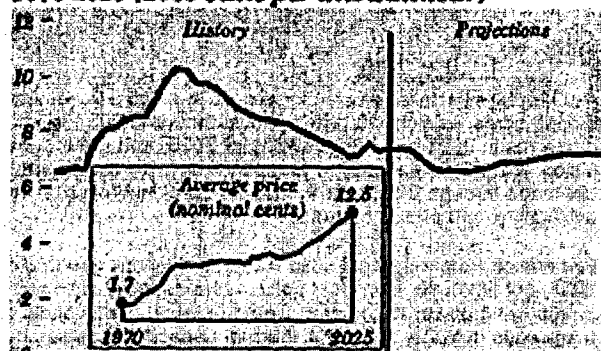


Figure data

Figure 73. Average U.S. retail electricity prices, 1970-2025 (2003 cents per kilowatt-hour)



contributors to U.S. electricity supply. From 359 billion kilowatthours in 2003 (9.3 percent of total generation) renewable generation increases to only 489 billion kilowatthours (8.5 percent) in 2025 (Figure 74).

Conventional hydropower remains the major source of renewable generation in the AEO2005 reference case. After 4 years of below-normal precipitation, hydroelectric generation is expected to recover in 2005; however, with little new capacity expected, conventional hydropower generation is projected to increase from 275 billion kilowatthours in 2003 (7.1 percent of total generation) to just 307 billion kilowatthours (5.3 percent of the total) in 2025. Other renewables account for 5.3 percent of projected additions to capacity from 2003 to 2025 and 6.4 percent of the projected increase in generation. Generation from nonhydropower renewables increases from 84 billion kilowatthours in 2003 (2.2 percent of generation) to 182 billion kilowatthours in 2025 (3.2 percent). Biomass, including combined heat and power systems and biomass co-firing in coal-fired plants, is the largest source of other renewable generation in the forecast. Electricity from biomass combustion increases from 37 billion kilowatthours in 2003 (1.0 percent) to 81 billion kilowatthours in 2025 (1.4 percent), with 49 percent of the increase coming from dedicated power plants and the rest primarily from combined heat and power.

Biomass, Wind, and Geothermal Lead Growth in Renewables

Figure 75. Nonhydroelectric renewable electricity generation by energy source, 2003-2025 (billion kilowatthours)

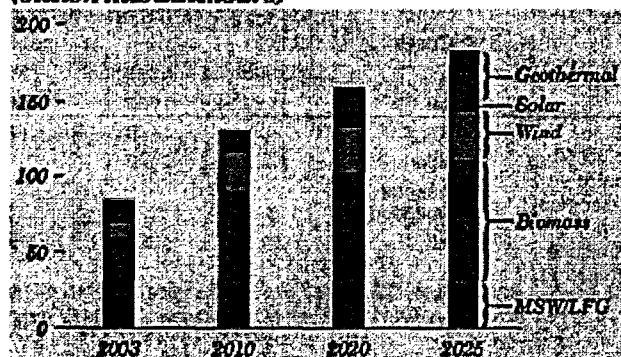


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Figure 76. Additions of renewable generating capacity, 2003-2025 (gigawatts)

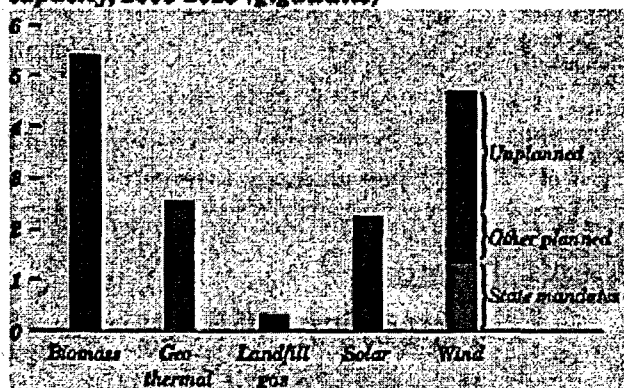


Figure data

AEO2005 projects significant increases in electricity generation from both geothermal and wind power (Figure 75). In the West, geothermal output increases from 13 billion kilowatthours in 2003 to 33 billion kilowatthours in 2025. Wind-powered generating capacity increases from 6.6 gigawatts in 2003 to 11.3 gigawatts in 2025, and generation from wind capacity increases from less than 11 billion kilowatthours in 2003 to 35 billion in 2025. The mid-term prospects for wind power are uncertain, depending on response to the recent extension of the Federal production tax credit through 2005 and the likelihood of further extensions, as well as responses to State programs, technology improvements, transmission availability, and public interest.

Generation from municipal solid waste and landfill gas (MSW/LFG) is projected to increase by 7 billion kilowatthours, to 29 billion kilowatthours in 2025, but little new municipal solid waste capacity is expected. Solar technologies generally are projected to remain too costly to be competitive in supplying power to the grid. Central-station photovoltaic capacity increases in the forecast from about 40 megawatts in 2003 to 400 megawatts in 2025, and solar thermal capacity increases from about 400 megawatts to more than 500 megawatts. In contrast, individual grid-

Figure data

Figure 74. Grid-connected electricity generation from renewable energy sources, 1970-2025 (billion kilowatthours)

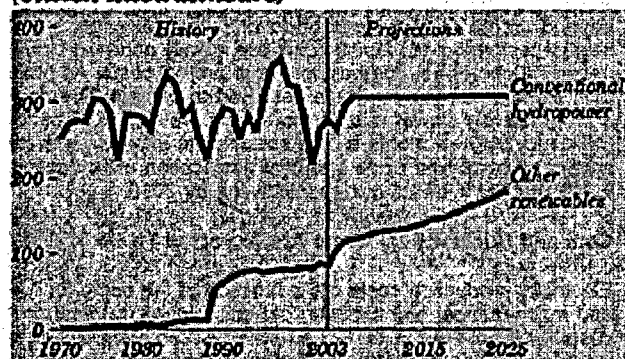


Figure data

connected photovoltaic installations grow rapidly, from about 60 megawatts in 2003 to nearly 1,800 megawatts in 2025. Grid-connected photovoltaics and solar thermal, which together provided about 0.7 billion kilowatthours of electricity in 2003, are projected to supply nearly 6 billion kilowatthours in 2025 [137].

State Programs Will Continue To Support Renewable Energy Use

In the AEO2005 reference case, 14.9 gigawatts of new nonhydroelectric renewable energy capacity is projected to enter service from 2003 through 2025, including 10.6 gigawatts in the electric power sector, 2.6 gigawatts of combined heat and power, and 1.7 gigawatts of end-use applications. In the electric power sector, 1.6 gigawatts is projected as a result of State requirements and goals (wind 1.3 gigawatts, geothermal and landfill gas each 0.1 gigawatt, plus smaller amounts of biomass, waste, and solar capacity) and the rest from commercial projects (Figure 76).

Most new renewables capacity projected in the near term results from specific projects and State programs. After 2010, the projected growth in renewable energy capacity is based on its ability to become competitive in electricity markets. The Federal production tax credit for wind plants was not extended until late in 2004, and so only 213 megawatts of new wind capacity is expected to be completed in 2004. In 2005, however, more than 1 gigawatt of new capacity is expected to enter service before the credit expires on December 31.

Because States with renewable energy requirements have not added capacity as rapidly as projected in earlier forecasts, projections for new capacity resulting from State renewable portfolio standards, mandates, and nonmandatory goals are reduced in AEO2005, but they are still significant, including 903 megawatts expected in Texas, 146 megawatts each in California and Minnesota, 141 megawatts in Nevada, 80 megawatts in New Mexico, and 65 megawatts in Pennsylvania.

Renewables Are Expected To Become More Competitive Over Time

The competitiveness of both conventional and renewable generation resources is based on the most cost-effective mix of capacity that satisfies the demand for electricity across all hours and seasons. Baseload technologies tend to have low operating costs and set the marginal cost of power only during the hours of least demand. Dispatchable geothermal and biomass resources compete directly with new coal and nuclear plants, which to a large extent determine the avoided cost [138] for baseload energy (Figure 77). In some regions and years, new geothermal or biomass plants may be competitive with new coal-fired plants, but their development is limited by the availability of geothermal resources or competitive biomass fuels.

Intermittent technologies—specifically, wind and solar—can be used only when resources are available. Because of their relatively low operating costs and limited resource availability, the avoided costs of these technologies are determined largely by the operating costs of the most expensive units operating when their resources are available. Solar generators tend to operate during peak load periods, when gas-fired combustion turbines and combined-cycle units with higher fuel costs tend to determine avoided cost. The levelized cost of solar thermal generation is projected to be significantly higher than its avoided cost through 2025. The availability of wind resources varies among regions, but wind plants generally tend to displace intermediate load generation. Thus, the avoided costs of wind power will be determined largely by the low-to-moderate operating costs of combined-cycle and coal-fired plants. In some regions and years, the levelized costs for wind power are projected to be below its avoided costs.

Gas-Fired Technologies Lead New Additions of Generating Capacity

The AEO2005 reference case uses the cost and performance characteristics of generating technologies to select the mix and amounts of new generating capacity for each year in the forecast. Values for technology characteristics are determined in consultation with industry and government specialists, but uncertainty surrounds the assumptions for new technologies. In the high fossil fuel case, capital costs, heat rates, and operating costs for advanced fossil-fired generating technologies (integrated coal gasification combined cycle, advanced combined cycle, and advanced combustion turbine) reflect a 10-percent reduction from reference case levels in 2025. The low fossil fuel case assumes no change in capital costs and heat rates for advanced technologies from their 2005 levels.

Natural gas technologies make up the largest share of new capacity additions in all cases, but the mix of current and advanced technologies varies (Figure 78). In the high fossil fuel case, advanced technologies are used for 84 percent (173 gigawatts) of projected gas-fired capacity additions, compared with 69 percent (110 gigawatts) in the low fossil fuel case. The coal share of total capacity additions varies from 22 percent to 33 percent in the cases. In the low fossil fuel case, only a negligible amount of advanced coal-fired generating capacity is added. In the high fossil fuel case, advanced coal technologies are more competitive, making up 65 percent of all coal-fired capacity additions. The projections for average fossil fuel efficiency in the electric power sector in 2025 are 37 percent in the reference case, 38 percent in the high fossil fuel case, and 36 percent in the low fossil fuel case, based on different assumptions about the penetration of advanced technologies in the cases.

Sensitivity Cases Look at Possible Reductions in Nuclear Power Costs

The AEO2005 reference case assumptions for the cost and performance characteristics of new technologies are based on cost estimates by

Figure 77. Levelized and avoided costs for new renewable plants in the Northwest, 2010 and 2025 (2003 mills per kilowatthour)

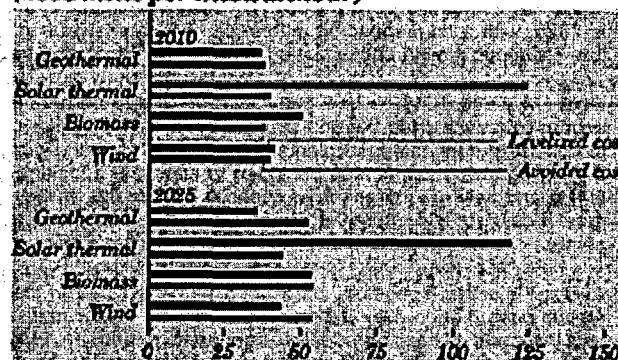
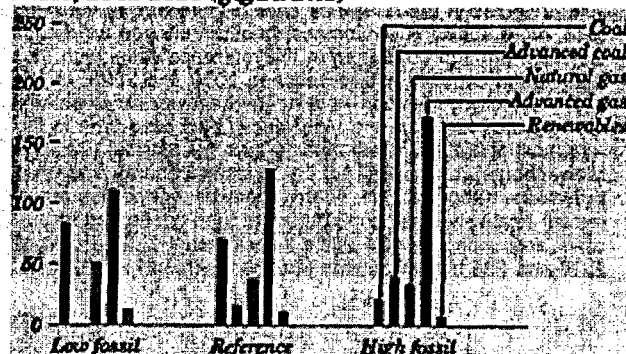


Figure data

Figure 78. Cumulative new generating capacity by technology type in three fossil fuel technology cases, 2003-2025 (gigawatts)



government and industry analysts, allowing for uncertainties about new, unproven designs. Two alternative nuclear cost cases analyze the sensitivity of the projections to lower costs for new nuclear power plants. The advanced nuclear cost case assumes capital and operating costs 20 percent below the reference case in 2025, reflecting a 28-percent reduction in overnight capital costs from 2005 to 2025. (Earlier analysis showed that a 10-percent reduction in capital and operating costs would be insufficient to stimulate new nuclear construction.) The vendor estimate case assumes reductions relative to the reference case of 18 percent initially and 38 percent in 2025. These costs are consistent with estimates from British Nuclear Fuels Limited for the manufacture of its advanced pressurized-water reactor (AP1000). Cost and performance characteristics for all other technologies are assumed to be the same as those in the reference case.

Projected nuclear generating costs in the two alternative nuclear cost cases are competitive with the generating costs projected for new coal- and natural-gas-fired units toward the end of the projection period (Figure 79). In the advanced nuclear case 7 gigawatts of new nuclear capacity is added by 2025, and in the vendor estimate case 25 gigawatts is added by 2025. The additional nuclear capacity displaces primarily projected new coal-fired capacity. The projections in Figure 79 are average generating costs, assuming generation at the maximum capacity factor for each technology; the costs and relative competitiveness of the technologies could vary across regions.

Rapid Economic Growth Would Boost New Coal and Renewable Capacity

The projected annual average growth rate for GDP from 2003 to 2025 ranges from 3.6 percent in the high economic growth case to 2.5 percent in the low economic growth case. The difference leads to a 4-percent change in projected electricity demand in 2010 and a 12-percent change in 2025, with a corresponding difference of 105 gigawatts in the amount of new capacity projected to be built from 2003 to 2025 in the high and low economic growth cases, including combined heat and power in the end-use sectors.

Most (74 percent) of the new capacity projected to be needed in the high economic growth case beyond that added in the reference case is expected to consist of new coal-fired plants. The stronger demand growth assumed in the high growth case is also projected to stimulate additions of renewable plants and new natural-gas-fired capacity (Figure 80). In the low economic growth case, total capacity additions are reduced by 53 gigawatts, and 70 percent of that projected reduction is in coal-fired capacity additions.

Average electricity prices in 2025 are 5 percent higher in the high economic growth case than in the reference case, due to higher natural gas prices and the costs of building additional generating capacity. Electricity prices in 2025 in the low economic growth case are projected to be 4 percent lower than in the reference case. In the high economic growth case, a 5-percent increase in consumption of fossil fuels results in a 6-percent increase in carbon dioxide emissions from electricity generators in 2025.

Lower Cost Assumptions Increase Biomass and Geothermal Capacity

The impacts of key assumptions about the availability and cost of nonhydroelectric renewable energy resources for electricity generation are shown in two alternative technology cases. In the low renewables case, the cost and performance of generators using renewable resources are assumed to remain unchanged throughout the forecast. The high renewables case assumes cost reductions of 10 percent in 2025 on a site-specific basis for hydroelectric, geothermal, biomass, wind, and solar generating capacity (however, no new additions of conventional hydropower are projected in any of the cases, given the lack of suitable new sites for development).

In the low renewables case, construction of new renewable capacity is less than projected in the reference case (Figure 81). In the high renewables case, more additions of biomass, geothermal, and wind capacity are projected through 2025 than in the reference case, with most of the incremental capacity added between 2010 and 2025. In 2025, projected total electricity generation from nonhydropower renewables is 52 billion kilowatthours higher in the high renewables case than in the reference case, with most of the increment coming from geothermal (22.8 billion kilowatthours), biomass (18.0 billion kilowatthours), and wind energy (10.1 billion kilowatthours). Still, nonhydropower renewables are projected to remain relatively small contributors to total generation in the high renewables case, accounting for 134 billion kilowatthours (2.9 percent of the total) in 2010 and 235 billion kilowatthours (4.1 percent) in 2025.

Figure data

Figure 79. Levelized electricity costs for new plants by fuel type in two nuclear cost cases, 2015 and 2025 (2003 cents per kilowatthour)

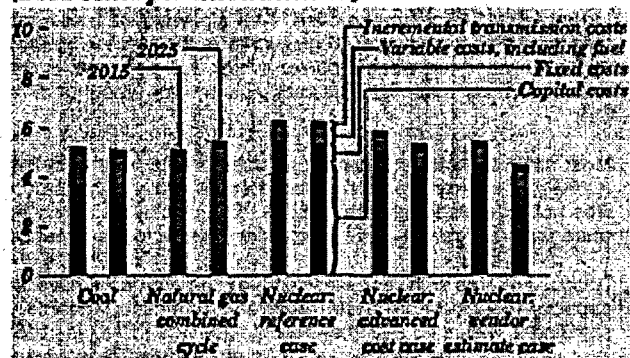


Figure data

Figure 80. Cumulative new generating capacity by technology type in three economic growth cases, 2003-2025 (gigawatts)



Figure data

Figure 81. Nonhydroelectric renewable electricity generation by energy source in three cases, 2010 and 2025 (billion kilowatthours)

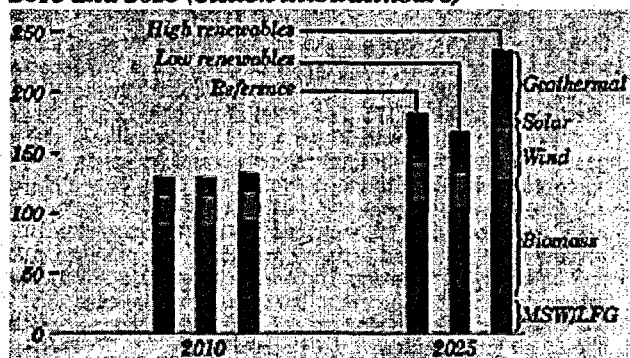


Figure data

Notes and Sources

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URL: <http://www.eia.doe.gov/oiaf/aeo/electricity.html>

Figure 67. Electricity generation capacity additions by fuel type, including combined heat and power, 2004-202

	Natural Gas	Coal	Renewables
2004-2005	26.37697	0.5939	2.45728
2006-2010	18.51608	1.189	1.80812
2011-2015	28.74526	6.54403	1.70839
2016-2020	61.55847	24.02512	3.76169
2021-2025	42.87408	54.56932	5.42419

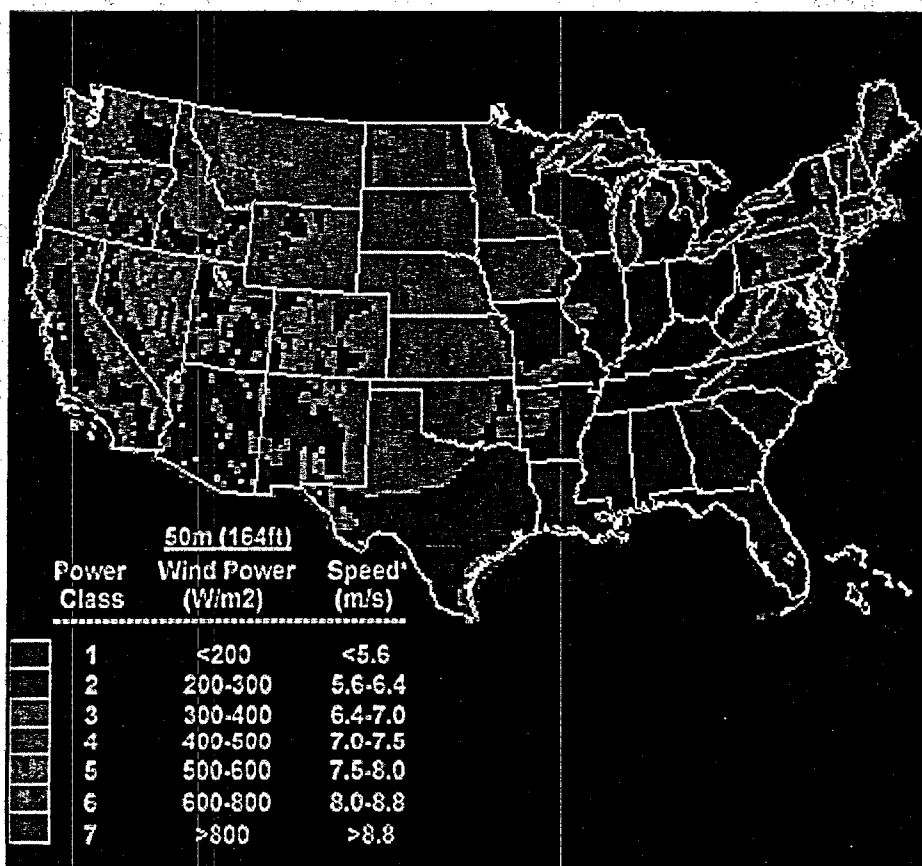
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U.S. Department of Energy - Energy Efficiency and Renewable Energy Wind and Hydropower Technologies Program

Wind Energy Resource Potential

Good wind areas, which cover 6% of the contiguous U.S. land area, have the potential to supply more than one and a half times the current electricity consumption of the United States.

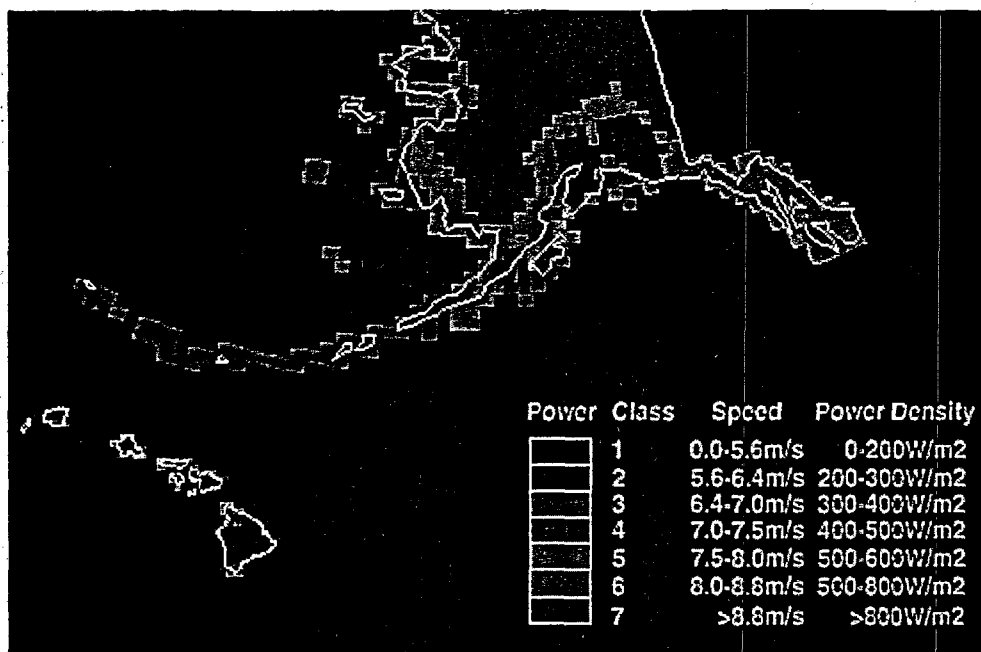
Estimates of the wind resource are expressed in wind power classes ranging from class 1 to class 7, with each class representing a range of mean wind power density or equivalent mean speed at specified heights above the ground. Areas designated class 4 or greater are suitable with advanced wind turbine technology under development today. Power class 3 areas may be suitable for future technology. Class 2 areas are marginal and class 1 areas are unsuitable for wind energy development.



U.S. Annual Wind Power Resource and Wind Power Classes - Contiguous U.S. States.

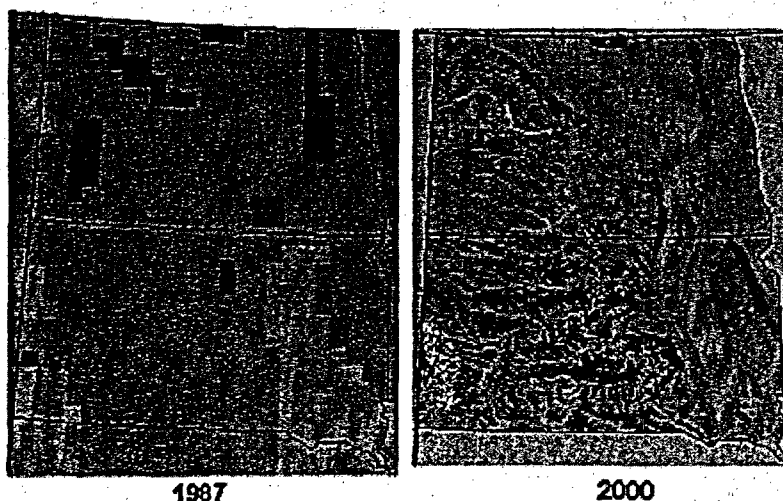
Annual Wind Power Resource





U.S. Annual Wind Power Resource and Wind Power Classes - Alaska and Hawaii.

Because techniques of wind resource assessment have improved greatly in recent years, work began in 2000 to update the U.S. wind atlas. The work will produce regional-scale maps of the wind resource with resolution down to one square kilometer. The new atlas will take advantage of modern techniques for mapping. It will also incorporate new meteorological, geographical, and terrain data. The program's advanced mapping of the wind resource is another important element necessary for expanding wind-generating capacity in the United States.

1987 U.S. Wind Atlas Map vs. 2000 High-Resolution (1-km²) Wind Map of North and South Dakota

Visit the [Wind Powering America State Wind Map](#) page to see if your state or area of interest has a newer, more detailed map available.

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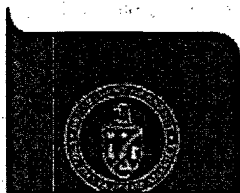
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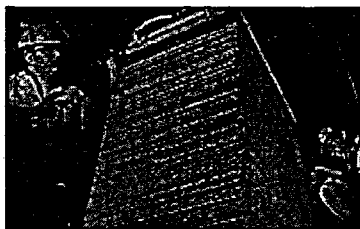
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Future Fuel Cells R&D



"So we're creating the National Climate Change Technology Initiative...to fund demonstration projects for cutting-edge technologies, such as fuel cells."

President George W. Bush
June 11, 2001

MORE INFO

Phosphoric Acid Fuel Cells
Molten Carbonate Fuel Cells
Solid Oxide Fuel Cells
Solid State Energy Conversion Alliance

Fuel cells are an energy user's dream: an efficient, combustion-less, virtually pollution-free power source, capable of being sited in downtown urban areas or in remote regions, that runs almost silently, and has few moving parts.

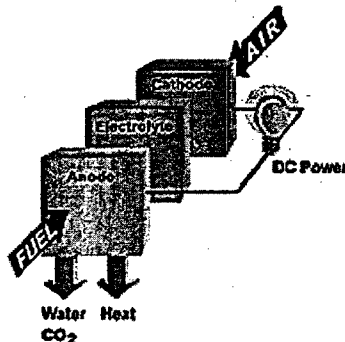
Using an electrochemical process discovered more than 150 years ago, fuel cells began supplying electric power for spacecraft in the 1960s. Today they are being used in more down-to-earth distributed generation applications: to provide on-site power (and waste heat in some cases) for military bases, banks, police stations, and office buildings from natural gas. In their most successful commercial applications, fuel cells convert the energy in waste gases from water treatment plants to electricity.

In the near future, fuel cells could be propelling automobiles and allowing homeowners to generate electricity in their basements or backyards.

Fuel cells operate much like a battery, using electrodes in an electrolyte to generate electricity. Unlike a battery, however, fuel cells never lose their charge. As long as there is a constant source of fuel – usually hydrogen produced from natural gas, and air as the source for oxygen – fuel cells will generate electricity.

DOE's Stationary Power Fuel Cell Program

The U.S. Department of Energy's Office of Fossil Energy is partnering with several fuel cell developers to develop the technology for the stationary power generation sector - that is, for power units that can be connected into the electricity grid primarily as distributed generation units. Industry participation is extensive, with more than 40 percent of the program funded by the private sector. If the joint government-industry fuel cell program is successful, the world's power industry will have a revolutionary new option for generating electricity with efficiencies, reliabilities, and environmental performance unmatched by conventional electricity generating approaches.



For most of the 1970s and early 1980s, the Federal program included development of the phosphoric acid fuel cell system, considered the "first generation" of modern-day fuel cell technologies. Largely because of the R&D support provided by the Federal program, United Technologies Corporation and its subsidiaries manufactured and sold phosphoric acid fuel cells around the world.

In the late 1980s, the department shifted its emphasis to development of advanced generations of higher temperature fuel cell technologies, specifically the molten carbonate and solid oxide fuel cell systems. Federal funding for these technologies have concluded. Private commercial manufacturing facilities have been built and commercial sales have been achieved.

While first generation fuel cells continue to spur interest in fuel cell technologies, the focus of the Department of Energy's Fossil Energy fuel cell program is to develop a much lower cost fuel cell. The target is \$400 per kilowatt or less, which is significantly lower (by about a factor of ten) than current fuel cell products. It is expected that lower cost fuel cells will lead to widespread utilization (see below).

Fuel Cell Benefits

Fuel cells are the cleanest and most efficient technologies for generating electricity from fossil fuels. Since there is no combustion, fuel cells do not produce any of the pollutants commonly emitted by boilers and furnaces. For systems designed to consume hydrogen directly, the only products are electricity, water and heat.

When a fuel cell consumes natural gas or other hydrocarbons, it produces some carbon dioxide, though much less than burned fuel. Advanced fuel cells using natural gas, for example, could potentially reduce carbon dioxide emissions by 60% compared to a conventional coal plant and by 25% compared to modern natural gas plants. Moreover,

New Electronic Technology Advances Fuel Cell Development

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Database of Fuel Cell R&D Projects

National Energy Technology Laboratory Web Site

FY 2004 Annual Report [17MB PDF]

Distributed Generation Brochure [1.4MB PDF]

SECA Brochure [7.5MB PDF]

HITEC Brochure [401kB PDF]

Program Contacts:

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PO Box 880
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Morgantown, WV 26507
304-285-4747

Samuel Blondo
Office of Fossil Energy (FE-22)
U.S. Dept. of Energy
Washington, DC 20585
301-903-5910

the carbon dioxide is emitted in concentrated form which makes its capture and storage, or sequestration, much easier.

Fuel cells are so clean that, in the United States, 26 states have financial incentives to support their installation. In fact, the South Coast Air Quality Management District in southern California and regulatory authorities in both Massachusetts and Connecticut have exempted fuel cells from air quality permitting requirements. Some 16 states have portfolio standards or set asides for fuel cells. Additionally, there are major fuel cell programs in New York (NYSERDA), Connecticut (Connecticut Clean Energy Fund), Ohio (Ohio Development Department), and California (California Energy Commission). Certain states have favorable policies that improve the economics of fuel cell projects. For example, 39 states and the District of Columbia have net metering, and 19 of those have net metering for fuel cells which obligates utilities to deduct any excess power produced by fuel cells from the customer's bill.

Fuel cells are also inherently flexible. Like batteries in a flashlight, the cells can be stacked to produce voltage levels that match specific power needs; from a few watts for certain appliances to multiple megawatt power stations that can light a community.

Cost - the Major Hurdle

So why aren't fuel cells being installed everywhere there is a need for more power?

The primary reason is cost. Fuel cells developed for the space program in the 1960s and 1970s were extremely expensive (\$600,000/kW) and impractical for terrestrial power applications. During the past three decades, significant efforts have been made to develop more practical and affordable designs for stationary power applications. But progress has been slow. Today, the most widely deployed fuel cells cost about \$4,500 per kilowatt; by contrast, a diesel generator costs \$800 to \$1,500 per kilowatt, and a natural gas turbine can be even less.

Recent technological advances, however, have significantly improved the economic outlook for fuel cells.

The U.S. Department of Energy has launched a major initiative - the Solid State Energy Conversion Alliance (www.seca.doe.gov) - to bring about dramatic reductions in fuel cell costs. The goal is to cut costs to as low as \$400 per kilowatt by the end of this decade, which would make fuel cells competitive for virtually every type of power application. The initiative signifies the Department's objective of developing a modular, all-solid-state fuel cell that could be mass-produced for different uses much the way electronic components are manufactured and sold today.

Advanced Fuel Cell Research

The High Temperature Electrochemistry Center (HITEC) Advanced Research Program was created in 2002 to provide crosscutting, multidisciplinary research supporting FutureGen. HITEC is centered at Pacific Northwest National Laboratory (PNNL) with satellite centers at Montana State University and the University of Florida. Research includes the development of low-loss electrodes for reversible solid oxide fuel cells, the development of high temperature membranes for hydrogen separation, and the study of fundamental electrochemical processes at interfaces. HITEC is also pursuing the development of high temperature electrochemical power generation and storage technologies and advanced fuel feedstock. Financial assistance will be provided to organizations capable of performing basic, fundamental and applied research to advance scientific understanding and devise concepts that apply new scientific insights toward advancement of novel electrochemical based power generation and energy storage technologies for use at large coal power plants.

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Clean Air Interstate Rule

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Minnesota

CAIR Reduces Minnesota's Emissions

- By 2015, CAIR will help Minnesota sources reduce emissions of sulfur dioxide (SO₂) by 40,000 tons or 36%.

SO ₂ Emissions (thousand tons)	2003	2010	2015
Minnesota SO ₂ emissions without CAIR	112	83	82
Minnesota SO ₂ emissions with CAIR	N/A	69	72

- By 2015 CAIR will help Minnesota sources reduce emissions of nitrogen oxides (NO_x) by 53,000 tons or 59%.

NO _x Emissions (thousand tons)	2003	2009	2015
Minnesota NO _x emissions without CAIR	90	72	74
Minnesota NO _x emissions with CAIR	N/A	36	37

CAIR Helps Minnesota and its Neighbors

- Because air emissions travel across state boundaries, reducing the emissions from sources in Minnesota also will reduce fine particle pollution in other areas of the country.
- Currently, Minnesota sources significantly contribute to fine particle pollution in 2 other states including:
Illinois & Indiana

CAIR Makes Minnesota's Air Cleaner

- CAIR helps Minnesota meet and maintain the National Ambient Air Quality Standards (NAAQS) for ground-level ozone and fine particle pollution.
- SO₂ and NO_x contribute to the formation of fine particles (PM) and NO_x contributes to the formation of ground-level ozone.
- Areas meeting the NAAQS are in attainment. Those areas not meeting the standards are known as "nonattainment areas".

Fine Particle Pollution

At the end of 2004, no Minnesota counties were designated nonattainment

for EPA's health-based standards for fine particle pollution.

Ground-level Ozone

At the end of 2004, no Minnesota counties were designated nont attainment for EPA's health-based standards for ground-level ozone pollution.

CAIR Is Smart for Minnesota's Economy

- CAIR helps maintain coal as a viable fuel/energy source.
- Regional electricity prices are not significantly impacted by CAIR, and are projected to be below 2000 levels.

Average Retail Electricity Prices (AREP) in 1999 dollars	2000	2010	2015
Minnesota's AREP without CAIR (mills/kWh*)	57.4	52.8	49.3
Minnesota's AREP with CAIR (mills/kWh*)	N/A	52.9	49.6

*mill = 1/10 of a cent

Notes:

- 1) Partial counties are identified by (P) following the county name.
- 2) Projections concerning future levels of air pollution in specific geographic locations were estimated using the best scientific models available. They are estimations, however, and should be characterized as such in any description. Actual results may vary significantly if any of the factors that influence air quality differ from the assumed values used in the projections shown here.
- 3) Small emission increases can occur in a State under CAIR where shifts in power generation occur, but overall improvements occur throughout the CAIR region. The Final CAIR includes a compliance supplement pool of NOx allowances (roughly 200,000 allowances) for the annual program, which could lead to slightly higher annual NOx emissions than are stated here.
- 4) The data presented here is based on recently completed, revised IPM modeling, reflecting CAIR as finalized. This recent data may differ slightly from modeling results in the Final CAIR Federal Register Notice and RIA which were based on modeling that was completed before EPA had determined the final scope of CAIR. The primary difference in the earlier modeling included AR, DE, and NJ in the annual SO2/NOx requirements, and did not include an ozone season cap on any states.
- 5) Emissions reductions take into account state and federal pollution control programs in place when EPA last updated its models in mid-2004. Reductions from more recent state programs or settlement actions are not reflected in these tables.
- 6) Retail electricity prices are by NERC region.

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On March 10, 2005, EPA issued the Clean Air Interstate Rule (CAIR), a rule that will achieve the largest reduction in air pollution in more than a decade. CAIR will ensure that Americans continue to breathe cleaner air by dramatically reducing air pollution that moves across state boundaries. In 2015, CAIR will provide health and environmental benefits valued at more than 25 times the cost of compliance.

CAIR will permanently cap emissions of sulfur dioxide (SO₂) and nitrogen oxides (NO_x) in the eastern United States. CAIR achieves large reductions of SO₂ and/or NO_x emissions across 28 eastern states and the District of Columbia. When fully implemented, CAIR will reduce SO₂ emissions in these states by over 70 percent and NO_x emissions by over 60 percent from 2003 levels. This will result in \$85 to \$100 billion in health benefits and nearly \$2 billion in visibility benefits per year by 2015 and will substantially reduce premature mortality in the eastern United States. The benefits will continue to grow each year with further implementation.

A closely related action is the EPA Clean Air Mercury Rule, the first ever federally-mandated requirements that coal-fired electric utilities reduce their emissions of mercury. Together the Clean Air Mercury Rule and the Clean Air Interstate Rule create a multi-pollutant strategy to reduce emissions throughout the United States.

The Bush Administration continues to believe that the President's Clear Skies legislation is a more efficient, effective, long-term mechanism to achieve large-scale national reductions. Clear Skies legislation applies nationwide and is modeled on the highly successful Acid Rain Program. The Agency remains committed to working with Congress to pass legislation.

Where to find more information:

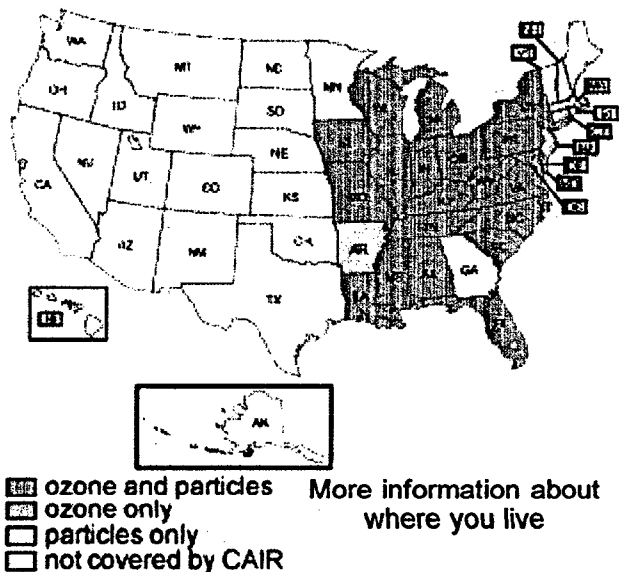
Where You Live - Descriptions of the health and environmental benefits of the Clean Air Interstate Rule in each of the 28 states in the Eastern US and the District of Columbia.

Basic Information - Summary of the Clean Air Interstate Rule as well as a summary of

"CAIR will result in the largest pollution reductions and health benefits of any air rule in more than a decade. The action we are taking will require all 28 states to be good neighbors, helping states downwind by controlling airborne emissions at their source."

**--Steve Johnson, Acting EPA Administrator
3/10/2005**

States Covered by CAIR



the design of the program and the benefits it would provide.

Regulatory Actions - Links to proposed and final rules, fact sheets, and other rulemaking documents.

Charts and Tables - A collection of printable charts, tables, and graphics demonstrating the health and environmental benefits of the Clean Air Interstate Rule.

Technical Information - Technical support information and links to related information.

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