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Renewable Energy 1998:

Issues and Trends

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"Wind Energy Developments: Incentives in Selected Countries"	Louise Guey-Lee	202/426-1143	louise.guey-lee@eia.doe.gov

Preface

Renewable Energy 1998: Issues and Trends is the first in an expected series of biannual analysis reports on topical renewable energy issues. The precursor of this report is the *Renewable Energy Annual* series of reports that has now been split into an annual data report (see *Renewable Energy Annual 1998 With Data for 1997*, DOE/EIA-0603(98), December 1998) and this report. The next "Issues and Trends" report is scheduled for publication at the end of 2000.

This report presents five papers, each of which has been recently published electronically as a feature article. Two of the papers cover material that applies generally to renewable energy. Three of the papers analyze issues specific to a particular renewable resource or technology.

Given the deregulation of the electric power industry, the cost of renewable generated electricity is of particular interest. "Renewable Electricity Purchases: History and Recent Developments" presents an analysis of prices of renewable-based electricity that utilities have paid to nonutilities, the primary generators of renewable electricity. The average price utilities paid for electricity generated by nonutilities using renewable energy was 8.8 cents per kilowatthour in 1995, the most recent year for which complete data were available. This compares with 5.5 cents per kilowatthour for electricity purchased from nonrenewable nonutility generators.

The higher prices for renewable-based electricity reflect, in part, the effects of the Public Utility Regulatory Policies Act (PURPA) which required utilities to purchase power from qualified facilities at full avoided costs. Since natural gas prices did not rise as much as expected, estimates of future avoided costs were higher than ever materialized. Therefore, as older contracts expire, new contracts reflect lower avoided costs.

"Transmission Pricing Issues For Electricity Generation From Renewable Resources" examines the effect on renewable-generated electricity of transmission tariffs in an "open access" environment. Among the factors discussed are congestion pricing and the role of Independent System Operators. The type of transmission pricing mechanism (tariff) used impacts the economics of generating electricity from each renewable resource differentially, and is therefore of concern to those proposing market-based support mechanisms for renewable electricity.

"Analysis of Geothermal Heat Pump Manufacturers Survey Data" presents the results of the first two EIA surveys of shipments of geothermal heat pumps. An average of over 53,300 geothermal heat pumps were shipped annually over the period 1994 through 1997. Annual shipment data are presented by model and customer type, and by region; exports are also shown. The paper includes a technical discussion of heat pumps, including their classification and system economics, as well as Department of Energy support in their development, and a case study of the United States Army's Fort Polk military base in Leesville, Louisiana, the largest installation of geothermal heat pumps in the world.

Biomass is the largest of the non-hydroelectric renewable energy sectors, with wood being the largest part of biomass energy. The Forest Products Industry, which includes the forestry, lumber, wood product, and pulp and paper industries, is the largest user of wood for energy. "A View of the Forest Products Industry from a Wood Energy Perspective" describes the composition and operations of this industry. With various federal and state legislative bills to increase the use of renewable energy under consideration, an understanding of this industry is a necessary ingredient to a proper appraisal of the role of biomass, and wood in particular, in new renewable-based electricity generation.

Wind generating capacity in the United States increased annually until 1992, and worldwide, the United States was the leader in wind generating capacity until 1997 when it was overtaken by Germany. The reasons for uneven growth in capacity within and across countries are examined in "Wind Energy Developments: Incentives in Selected Countries." In particular, the wind energy programs in the United States, Germany, Denmark and India are discussed, especially in terms of available support mechanisms. The major difference between the United States and the other countries analyzed is the price guaranteed for wind energy, with

U.S. producers receiving between one-half and two-thirds of the price level guaranteed to producers in the other countries.

The Energy Information Administration was established formally by the Department of Energy Organization Act of 1977 (Public Law 95-91). The legislation requires EIA to carry out a comprehensive, timely, and accurate program of energy data collection and analysis. It also vests EIA with considerable independence in determining its mission and the data and analyses it chooses to present.

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Renewable Electricity Purchases: History and Recent Developments

by Louise Guey-Lee[1]

Introduction

Numerous proposals at both Federal and State levels to allow competition in the sale of electricity have sparked interest in the cost of renewable-based electricity.[2] Most of these proposals attempt to "set aside" a share of the electricity market for renewables,[3] recognizing that renewable electricity generation (except for hydropower) is more costly than conventionally generated electricity. Environmental concerns about emissions from fossil fuels have also stimulated increased interest in renewable energy. Thus, for a variety of reasons, there is a compelling need to know how much the United States is paying for renewable electricity, both in aggregate and on a cost per kilowatthour basis, compared to electricity from other sources. By analyzing the prices utilities have paid nonutilities to purchase renewable-based electricity, this chapter provides some basis for addressing that question.

This chapter presents an overview of renewable purchased power prices with an explanation of the role of the Public Utility Regulatory Policies Act of 1978 (PURPA). Beginning in the 1980s, PURPA stimulated renewable-based generation. It also created the "qualifying facility" status for renewables—a designation that guarantees those facilities the right to sell electricity generated to a utility at favorable prices. Prices which utilities paid for power purchases from "nonutilities" are given by facility qualifying status, fuel type, State or region, and Standard Industrial Classification (SIC) Code. Although the analysis used to develop them made maximum use of available data, there are significant limitations on interpreting these prices. These limitations are discussed in the Appendix. It is also essential to point out that this chapter contains information on the price that utilities have paid to purchase renewable electricity—not on the cost that nonutilities incurred to produce that electricity.

Overview

Nonutilities[4] provided 13 percent of total utility power purchases in 1995, almost 25 percent of which was renewable-based. Thus, renewable energy provided only a small fraction (3 percent) of U.S. utility power purchases.[5] However, this market is the major outlet for nonutility renewable power, as utilities purchased 53 percent of renewable electricity generated by nonutilities in 1995. Historically, this electricity was sold at much higher prices than the national average electricity price per kilowatthour.[6] In 1995, U.S. retail prices (i.e., the priced paid by the end-use customer) averaged 6.89 cents/kilowatt hour (Figure 1). By comparison, utility purchases from other utilities,[7] which are made on a competitive basis and may be regarded as reflecting "wholesale" prices, averaged 3.53 cents/kilowatthour. The average price utilities paid nonutilities was significantly higher, averaging 6.31 cents/kilowatthour nationwide. Higher still was the price utilities paid nonutilities for renewable-based electricity (Figure 2). The average purchase price of electricity from nonutility qualifying facilities[8] using renewable energy was 9.05

[1] Louise Guey-Lee is an economist with the Office of Coal, Nuclear, Electric and Alternate Fuels, Energy Information Administration.

[2] For a broader understanding of electric power industry restructuring, see Energy Information Administration, *Challenges of Electric Power Industry Restructuring for Fuel Suppliers*, DOE/EIA-0623 (Washington, DC, September 1998).

[3] Broadly, renewable energy includes any source that is either regenerative or virtually inexhaustible. For the purposes of this report, sources meeting these criteria are: wind, solar thermal, photovoltaic, geothermal, conventional hydroelectric, and biomass.

[4] Essentially, a nonutility is an entity that owns 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, and which do not file forms listed in the Code of Federal Regulations, Title 18, Part 141.

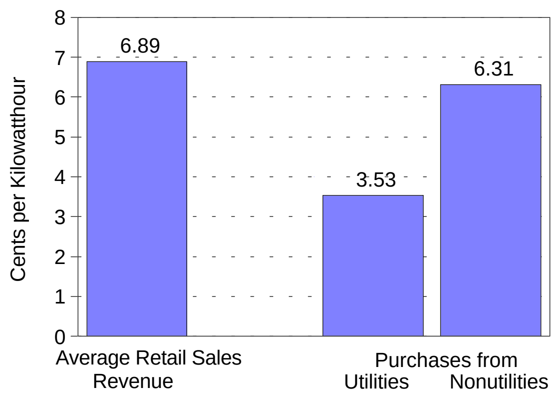
[5] Data on power purchased by one nonutility from another is not collected by the Department of Energy and is thus excluded.

[6] See Appendix for detailed discussion of data sources and limitations.

[7] In this chapter, "Utilities" include power marketers, many of which sell large quantities of low-cost hydropower.

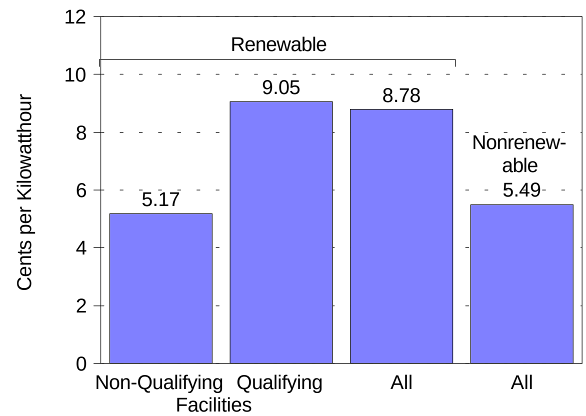
[8] See the following section on the history of PURPA for an explanation of "qualifying" and "nonqualifying" facilities.

Figure 1. U.S. Electric Utility Average Price per Kilowatthour for Purchased Power Compared to Average Retail Sales Revenue, 1995



Source: Table 9 and Energy Information Administration, *Electric Power Annual 1995,* Volume II, DOE/EIA-0348(95/2) (Washington, DC, December 1996), Table 7.

Figure 2. U.S. Electric Utility Average Price for Purchases from Nonutilities by Energy Source and QF Status, 1995



Source: Estimates documented in this chapter and related unpublished data.

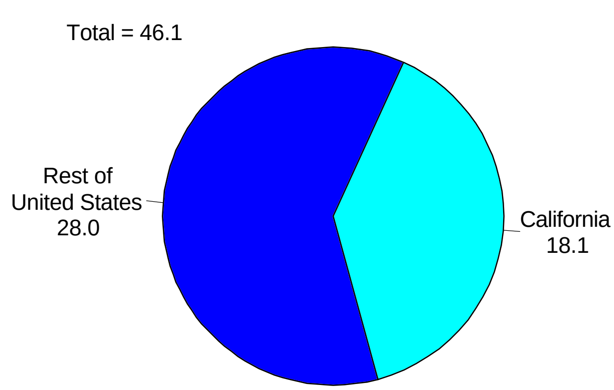
cents/kilowatthour—some 31 percent higher than the average U.S. retail price.

California accounts for 39 percent of the purchases from renewable nonutility facilities (Figure 3). California's significant role is due to the availability of renewable resources and extensive support traditionally offered to renewable energy. Although utility purchases of non-utility renewable-based power represent just 15 percent of California's total (Figure 4), they are important because of the high "wholesale" price paid for them—8.04 cents/kilowatthour (Figure 5)–compared with other purchases. This price, however, must be put into perspective. California has expensive electricity in general when compared with the rest of the Nation: 9.91 cents/kilowatthour in 1995, versus the U.S. average of 6.89 cents/kilowatthour.

A look at renewable nonutility purchases shows striking differences as well. California utilities paid an average of 12.79 cents/kilowatthour to nonutility qualifying facilities using renewable energy, but only 3.33 cents/kilowatthour to nonqualifying renewable non-utilities, which were entirely hydroelectric facilities (Figure 6).

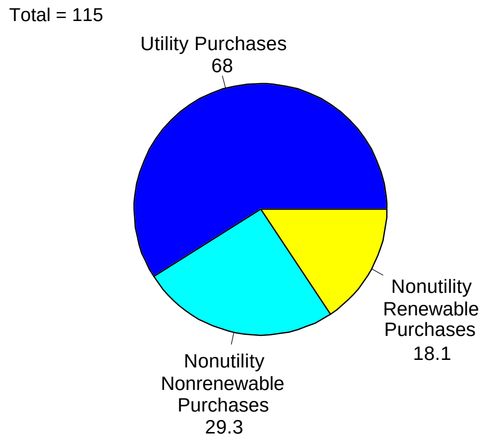
Although no precise measure of the incentives provided to renewable energy is available, analysis of price data in this chapter suggests one order of magnitude of the incentive–subject to nontrivial data limitations. In some cases, such as California, the incentive seems large for electricity from particular renewables when prices utilities paid to those facilities were compared to those paid to non-renewable facilities. The reason high prices were paid to renewable-based nonutilities is that in the 1980s when many utilities signed long-term (10 year) PURPA-based contracts, it was presumed that natural gas prices would rise to much higher levels than they are today. This raised the utilities' estimates of avoided costs.

Figure 3. California Electric Utility Purchases of Nonutility Renewable Power as a Share of U.S. Purchases, 1995
(Billion Kilowatthours)



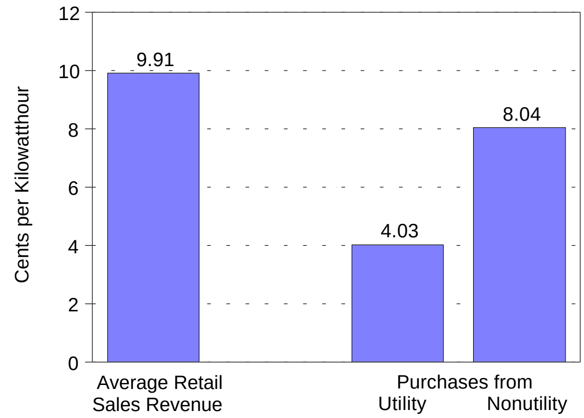
Source: Table 10.

Figure 4. California Electric Utility Purchases from Utilities and Nonutilities by Energy Source, 1995
(Billion Kilowatthours)



Source: Tables 9 and 10.

Figure 5. California Electric Utility Average Price per Kilowatthour for Purchased Power Compared to Average Retail Sales Revenue, 1995



Source: Table 9 and Energy Information Administration, *Electric Power Annual* 1995, Volume II, DOE/EIA-0348(95/2) (Washington, DC, December 1996), Table 7.

History of PURPA and Nonutilities

Interest in renewable energy rose during the 1970s when oil embargoes, rising energy prices, and concerns over air pollutants raised questions about the Nation's continued dependence on fossil fuels. As world energy prices tripled in 1974, the development of alternative energy sources became a national priority. In response to the Nation's "energy crisis," President Carter signed into law the National Energy Act of 1978, a compendium of five statutes that sought to decrease the Nation's dependence on foreign oil and increase domestic energy conservation and efficiency. PURPA was the most significant bill of the National Energy Act in that it fostered the development of facilities to generate electricity from renewable energy sources. A brief summary of PURPA's provisions and impact is presented below.

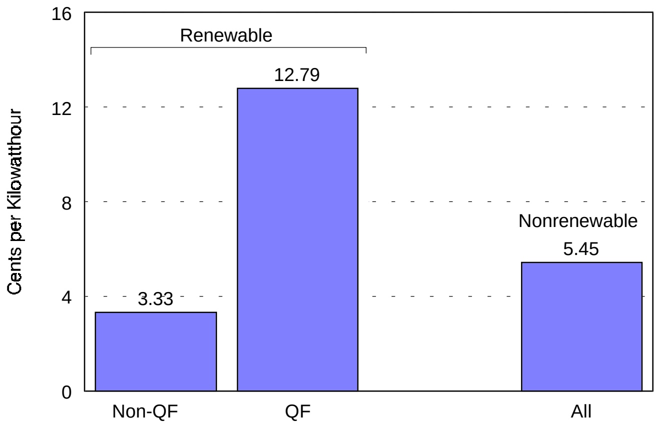
PURPA, among other things, required utilities to pay favorable power rates to two groups of nonutilities: (1) small power producers using renewable energy sources; and (2) cogenerators. PURPA permitted these operations to be designated as "qualifying facilities" (QFs) under certain conditions. To qualify for QF status under PURPA, both cogenerators and small power producers must have less than 50 percent ownership by electric utilities. QF cogenerators under PURPA must produce electricity and another form of useful thermal output through the sequential use of energy and meet certain operating and efficiency criteria. Small power producer QFs must generally be rated less than 80 megawatts, with at least 75 percent of the total energy input provided by renewable energy. Important to the analysis of purchased power prices is the fact that QF cogenerators do not have to use renewable fuels. Also worth noting is that renewable cogenerators are a mixture of QF and non-QF facilities.

PURPA required utilities to buy electricity from QFs at rates not to exceed a utility's "avoided cost," or the incremental cost to the electric utility of alternative electric energy which the utility would have generated or purchased from another source (an extensive discussion of avoided cost is provided later). The Federal Energy Regulatory Commission (FERC), responsible for certifying QFs and general implementation of PURPA, left the determination of the utility's avoided cost to the States and their utility commissions.

During the 1970s, the Federal renewable energy program grew rapidly, including funding for renewable energy research and development, residential and business tax credits for certain renewable technologies, and joint participation with the private sector in demonstration projects and commercialization of new technologies.

States that had a progressive renewable energy policy, such as California's renewable tax credit, helped influence the development of renewable energy technologies. However, PURPA was the major catalyst behind the massive growth in the number of nonutility power

Figure 6. California Electric Utility Purchases from Nonutilities by Energy Source and QF Status, 1995



Source: Estimates documented in this report and related unpublished data.

producers.[9] After an initially rapid expansion, the number of new filings for QF status has decreased over the last several years as the cost of alternative energy sources, which formed the basis for avoided costs, turned out to be much lower than previously forecast.

A major point to bear in mind when analyzing the data in this chapter is that PURPA only affected entities wishing to sell power. Facilities which generated only for their own use were unaffected by PURPA, and most such facilities have a non-QF status.

Nonutility Renewable Capacity

By the end of 1996, the total installed capacity of nonutility power producers of 1 megawatt or more was 73,189 megawatts.[10, 11] Of this, 58,345 megawatts (80 percent) came from QFs. Total nonutility capacity using renewable energy was 17,172 megawatts from 908 facilities (Table 1). Of this amount, 12,583 megawatts was at qualified facilities. Between 1992 and 1996, QF capacity increased about 1,181 megawatts, while non-QF capacity increased by only 199 megawatts. In the South Atlantic region alone, renewable QF capacity increased by 398 megawatts. The importance of QFs varies by region. For example, in the Southern regions,[12] QFs composed 63 percent of renewable capacity in 1996, while in the Pacific region, QFs were 79 percent of the total. In the mid-Atlantic region, QF status accounted for 95 percent of renewable nonutility capacity.

Of the 17,172 megawatts of nonutility renewable electric capacity existing at the end of 1996, 7,053 megawatts were wood and wood waste facilities; 3,419 megawatts were conventional hydroelectric; and 3,063 megawatts were municipal solid waste (MSW facilities) and landfills (Figure 7). Between 1992 and 1996, conventional hydroelectric capacity increased 735 megawatts and MSW and landfill capacity rose 550 megawatts. Wind capacity declined from a peak of 1,822 megawatts in 1992 due to retirements exceeding additions[13] (Table 2). Due to State incentives and favorable climate conditions, nonutilities have developed more capacity using renewable sources (except for hydroelectric) in California than in any other State. California had 4,772 megawatts of renewable capacity in 1995, or nearly 30 percent of the U.S. total. The second-largest State, according to nonutility renewable capacity, was Florida, with 1,210 megawatts of biomass facilities (Table 3).

Manufacturing processes also affect the development of electric renewable energy facilities. Many nonutility power producers use steam or hot water to produce products other than electricity and then use the waste heat to produce electricity. In addition, these manufacturing processes can produce renewable waste (for example, sawdust) that can be combusted to produce energy. By industrial classification, electric, gas, and sanitary services (or SIC Code 49 facilities) had the largest renewable capacity of all industry groups: 10,026 megawatts in 1996 (Table 4), representing nearly 60 percent of the total for all groups. Paper and Allied products was second with 5,680 megawatts. Agriculture and other industry groups had the smallest amount of capacity.[14] Nearly half of SIC Code 49 capacity was in the Pacific region in 1996. Approximately 1,000 megawatts of this capacity have come on board since 1992.

[9] PURPA did, however, restrict nonutility power sales to the "host" utility; i.e., the utility whose service area included the nonutility facility.

[10] The one megawatt threshold is used by the Form EIA-867, "Annual Nonutility Power Producer Report." Significant wind and biomass capacity exists below one megawatt, but is not included here for lack of data.

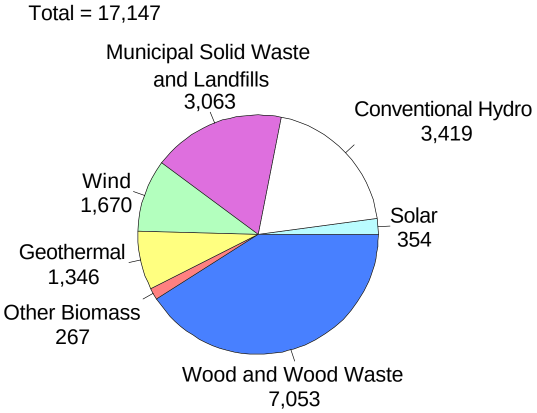
[11] Energy Information Administration, *Electric Power Annual, Volume II 1997*, DOE/EIA-0348(97/2) (Washington, DC, October 1998).

[12] Southern regions include South Atlantic, East South Central, and West South Central.

[13] This occurred because many of the PURPA "Standard Offer 4" contracts began expiring in the mid-1990s.

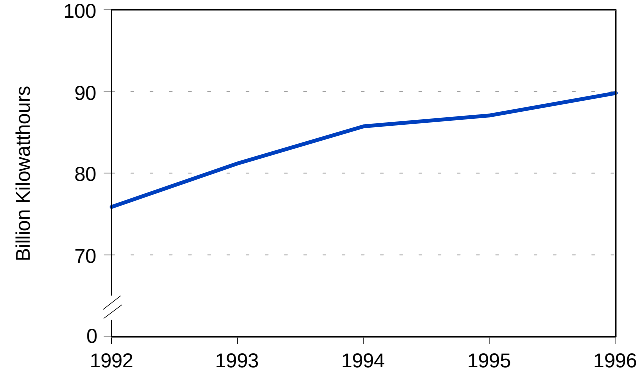
[14] The industry group for mining had no renewable nonutility facilities.

Figure 7. Installed Renewable Capacity at U.S. Nonutility Generating Facilities by Energy Source, 1996
(Megawatts)



Source: Table 2.

Figure 8. Gross Renewable Generation for U.S. Nonutility Generating Facilities, 1992 Through 1996



Source: Table 5.

Nonutility Renewable Generation

In 1996, nonutility power producers generated 382,423 million kilowatthours of electricity,[15] of which renewable sources generated 89,793 million kilowatthours (Table 5). Qualifying facilities produced 68,594 million kilowatthours from renewable sources, or about three-fourths of total renewable generation. QF renewable generation rose 18 percent between 1992 and 1996, and non-QF renewable generation in 1996 was 6 percent below its 1994 peak. A considerable amount of non-QF generation comes from entities generating electricity only for their own use.

Two-thirds of 1996 nonutility renewable generation was from biomass,[16] predominantly in the South (Table 6). Geothermal contributed 11 percent, wind nearly 4 percent, and solar almost 1 percent. Total renewable generation increased every year from 1992 through 1996 (Figure 8), showing an overall growth of 18 percent, a major portion of which was derived from conventional hydroelectric and municipal waste facilities.

Southern regions produced 38 percent of total nonutility renewable generation, while the Pacific region contributed 27 percent. For 1995, State-level data are shown, revealing that California had the most renewable generation at 20,801 million kilowatthours, or nearly 25 percent of the U.S. total (Table 7). Geothermal energy provided the largest share of California's renewable generation, with 8,011 million kilowatthours. California was followed by Florida and Maine, each at almost 6,000 million kilowatthours in 1995.

In terms of the major industry groups, electric/sanitary services (SIC Code 49) produced 58 percent of total generation in 1996, while Paper and Allied products produced 34 percent (Table 8). Since 1992, electric/sanitary services nonutility generation has grown nearly 27 percent.

Electric Utility Purchases of Nonutility Generation

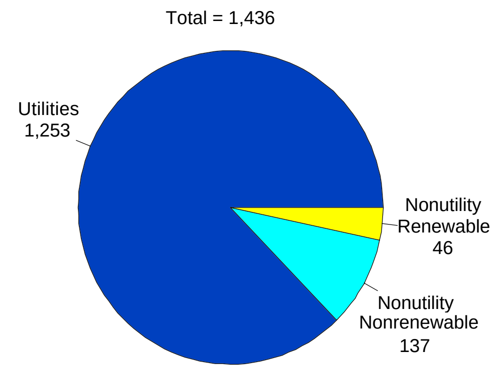
The main focus of the remainder of this chapter is the price of power which electric utilities purchased from non-utility facilities using renewable energy. These include all the nonutilities that are QFs under PURPA and some non-qualified facilities (all hydroelectric).

Prior to PURPA, electric utilities purchased power almost exclusively from other utilities. Purchases from industrial producers did exist, but were very small. Not only did PURPA change the type of capacity built and the generation mix as discussed earlier, but it also changed the way sales of electricity were contracted and how rates were determined.

[15] Energy Information Administration, *Electric Power Annual, Volume II 1997*, DOE/EIA-0348(97/2) (Washington, DC, October 1998).
[16] Biomass includes the "Wood/Wood Waste," "Municipal Waste," and "Other Biomass" categories.

Details of PURPA contracts, under which utilities purchased power from nonutilities, and how they were implemented—particularly in California—are essential to interpreting the purchased power price data in this section. However, in order to emphasize the results of the price analysis and maintain continuity with the previous discussion, purchased power data will be provided first, followed by a discussion of PURPA contracts. Electricity purchases during 1995 (the most current year for which data was available at the time of this analysis) and the average price paid for these purchases are discussed below.

Figure 9. U.S. Electric Utility Purchases from Other Utilities and Nonutilities by Energy Source, 1995
(Billion Kilowatthours)



Source: Tables 9 and 10.

Total U.S. Power Purchases

Purchases. U.S. electricity purchases by utilities totaled 1,436,072 million kilowatthours in 1995 (Table 9). Of this amount, 87 percent was purchased from utilities and other generators (Figure 9), with the remaining 13 percent purchased from nonutilities. One-fourth of the nonutility purchases was generated by renewable sources. Purchases from utilities tended to be evenly distributed across regions, whereas purchases from nonutilities (though much smaller) were concentrated in California, New York, and the Southern states.

Expenditures. The total cost of power purchases from all sources was $55.8 billion dollars. About 21 percent of this cost was for power from nonutilities. Among the States, California and New York utilities had the largest total expenditures for nonutility power, together accounting for half of total expenditures for power purchased from nonutilities.

Prices. The national average price for utility purchases from the group "Utility / Other,"[17] which includes large power marketers that sell large quantities of low-cost hydroelectric power, was 3.53 cents per kilowatthour. Regionally, prices ranged from a high of 5.11 cents in New England and 4.22 cents in the South Atlantic down to 3.0-3.5 cents per kilowatthour in most other regions.

In contrast, the average cost of power from nonutilities was 6.31 cents per kilowatthour, nearly double the cost of purchases from utilities and other sources. The most expensive regions were the Pacific, at 7.75 cents per kilowatthour, followed by New England, and the Mid-Atlantic and South Atlantic Regions. It should be noted that average retail (end use) electricity prices in these regions are also higher than the national average. Also, regional averages conceal individual States where nonutility purchased power prices may be competitive with utility prices.[18]

Renewable Purchased Power

All Sources

Purchases. Electric utility purchases of renewable electric power account for 25 percent of purchases from nonutilities in 1995, or 46,052 million kilowatthours (Table 10). Pacific region utilities, led by California, made 43 percent of U.S. renewable power purchases (19,821 million kilowatthours). Although nonutilities in the Southern regions produced 38 percent of nationwide nonutility renewable generation (Table 6), southern utility renewable purchases from nonutilities accounted for only 15 percent of U.S. nonutility renewable purchases (Table 10). This is because some industries in the south with major power requirements (e.g., the pulp and paper industry) produce electricity principally for their own use. Approximately 15,345 million kilowatthours, or one-third of total renewable purchases, were from municipal solid waste and landfills (Figure 10).

[17] Includes utilities, power marketers, power pools, and utilities in Canada and Mexico as defined for the Form EIA-861, "Annual Electric Utility Report."

[18] In Louisiana, the current nonutility generating market was developed in a competitive market and reportedly produced electricity at an average unit cost of less than 3.9 cents per kilowatthour in 1994. Electric utilities, operating under the traditional governmental utility regulation, are said to produce electricity at an average unit cost of more than 5.7 cents per kilowatthour. See http: / / ecep.usl.edu / lep / non-util / 001.htm.

Major portions also came from wood and wood waste, geothermal, and conventional hydroelectric.

Although all non-QF renewable power purchases were from hydropower facilities, the reverse is not true. Over 55 percent of the 7 ,474 million kilowatthours of hydropower which utilities purchased from nonutilities was from QFs.[19]

Expenditures. Electric utility costs of purchased renewable electric power from nonutilities was $4.041 billion, or around 35 percent of the U.S. total nonutility power revenues from sales to utilities. More than half of these costs ($2.210 billion) were for electricity sold in California (Table 11). Nearly $1 billion each was for power from geothermal sources, wood and wood waste, and municipal solid waste and landfills.

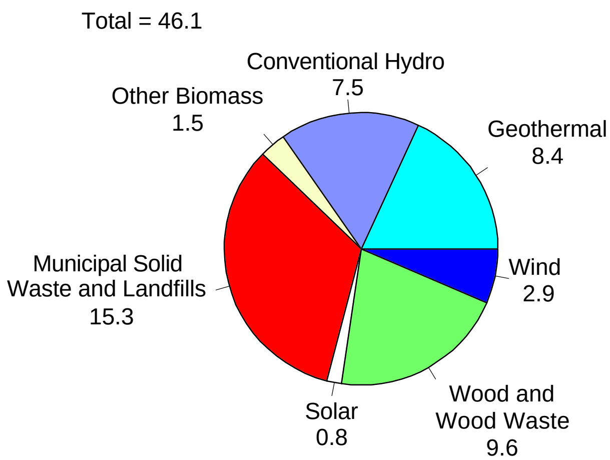
Prices. The nationwide average cost paid by electric utilities in 1995 for renewable power was 8.78 cents per kilowatthour, or 2.5 cents per kilowatthour above the 6.31 cent average for all nonutility purchases (Table 12). Qualifying facilities received an average of 9.05 cents per kilowatthour for renewable-based electricity, while nonqualifying facilities (hydropower only) received only an average of 5.17 cents per kilowatthour (Figure 2). By comparison, utilities paid nonutilities an average of 5.49 cents per kilowatthour for non-renewable electricity.

Excluding conventional hydroelectric power, California utilities paid prices considerably higher than the rest of the United States, ranging from 11 to 15 cents per kilowatthour. By comparison, utilities in other regions paid prices generally averaging 4 to 9 cents per kilowatthour. In addition, the cost varied by energy source. Solar (exclusively in California) was highest at 15.80 cents per kilowatthour, while municipal solid waste was lowest at 6.27 cents per kilowatthour (Figure 11).

Purchases by Industry Group

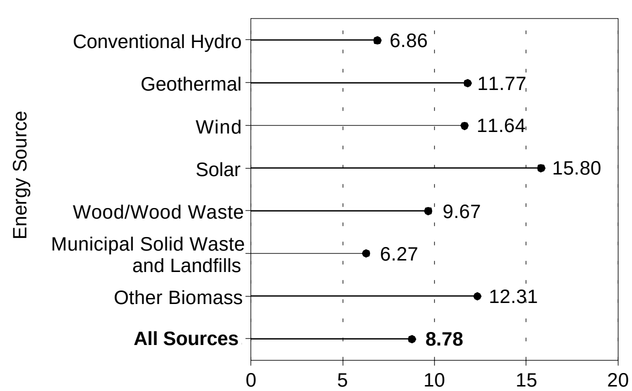
Expenditures. SIC Code 49 facilities (electric utilities, gas and sanitary services) sold 41,586 million kilowatthours, or 90 percent of renewable electric power sold to utilities by nonutilities (Table 13). Paper and Allied Products provided 2,865 million kilowatthours, while the mining group contributed nothing. SIC Code 49 received a comparable amount, 93 percent ($3.761 billion) of total utility expenditures on renewable electric power purchased from nonutilities (Table 14). Paper and Allied Products received $177 million.

Figure 10. U.S. Electric Utility Purchases of Renewable Electric Power from Nonutility Facilities by Energy Source, 1995
(Billion Kilowatthours)



Source: Table 10.

Figure 11. U.S. Electric Utility Average Price per Kilowatthour of Renewable Electric Power Purchased from Nonutility Facilities by Energy Source, 1995
(Cents per Kilowatthour)



Source: Table 10.

[19] This figure is derived from information in Tables 10 and 16.

Prices. The average price paid to SIC Code 49 facilities was highest at 9.05 cents per kilowatthour (Table 15). Paper and Allied Products received an average of 6.18 cents per kilowatthour. Facilities in the "Other Industry" group received the lowest price, 4.37 cents per kilowatthour. Some of the lowest average prices (about 2 cents per kilowatthour) were for very small sales by other industries. Among the States, California's SIC Code 49 facilities received one of the higher payments at 12.29 cents per kilowatthour.

Non-Qualified Facilities

Only 7 percent of renewable electricity purchased was from non-qualified nonutility facilities, all of which use conventional hydropower (Table 16). Across the country, most power from non-qualified facilities (non-QFs) was sold at lower prices than power from qualified facilities, with some exceptions in the Middle Atlantic and West South Central regions.

In 1995, 3,300 million kilowatthours of electricity were purchased from non-QFs by utilities at an average price of 5.17 cents per kilowatthour. This price is considerably lower than the 9.05 cents per kilowatthour paid to QFs. The New England region was highest at 8.41 cents per kilowatthour for non-QFs. Also higher than average were the Middle Atlantic and West South Central regions. The electric utilities in East North Central, West North Central, South Atlantic, Mountain, and Pacific regions paid less than the average price.

Significantly among the states, California accounted for 1,071 million kilowatthours, or nearly one-third, of the nation's total non-QF renewable purchases. This power was sold at an average cost of 3.33 cents per kilowatthour, a rate one-third lower that the national average received by non-QFs. Other low-priced states include Michigan, Wisconsin, Georgia, West Virginia and Vermont—all less than 3 cents per kilowatthour.

Interpreting Purchased Power Prices

The Appendix provides a detailed discussion of data limitations which affect the prices shown above, while the next section explains how PURPA affected the contracts utilities were required to sign with nonutilities for purchasing renewable-based power. To summarize, two major points should be kept in mind when analyzing the prices presented above:

1. Because all nonhydroelectric renewable nonutility facilities which sold power to utilities are PURPA QFs, the prices utilities paid for power from those facilities reflect PURPA avoided costs, as implemented by State Public Utility Commissions. Thus, prices paid to these facilities are based on regulatory factors, not market prices. Further, these prices are not appropriate to use when conjecturing about the price to be paid for renewable-based electricity in scenarios of the future involving market-based electricity industry restructuring and/or incentives to support renewable energy (e.g., renewable portfolio standards).

2. By 1995, some of the long-term PURPA contracts signed in the mid-1980s had expired. Thus, the prices shown reflect an unknown mixture of original PURPA contracts with high avoided cost bases and new contracts with prices determined at much lower levels (see following section).

PURPA Contracts

Section 210(b) of PURPA mandates that the rates an electric utility pays a QF shall: (1) be just and reasonable to electric consumers and in the public interest, (2) not discriminate against qualifying cogenerators or qualifying small producers. It also prohibits FERC from prescribing a rule which provides for a rate for a purchase from a QF which exceeds the incremental cost to the electric utility of the purchase of alternative electric energy. Section 210(d) of PURPA defines the incremental cost of alternative electric energy as the cost to the utility of the electric energy which, but for the purchase from a cogenerator or small power producer, such utility would generate or purchase from another source.

In 1980, FERC promulgated regulations implementing Section 210 of PURPA defining avoided costs at the highest level allowed by the law, the full avoided costs. FERC regulations permit QFs to elect between being paid the utility's avoided cost calculated at the time power is delivered or at the time the obligation is incurred, regardless of when the power is delivered (lock-in rule). Avoided costs calculated at the time of the obligation, but above the purchasing utility's avoided costs at the time of delivery, do not violate FERC's regulations. Although challenged, FERC's ruling was ultimately upheld.[20]

[20] Soon after FERC promulgated its PURPA regulations, its full avoided cost rule was challenged. The Court of Appeals of the District of Columbia found the rule inconsistent with PURPA's mandate that rates be just and reasonable. However, the Supreme Court reversed the lower court's decision and upheld FERC's full avoided cost rule.

The FERC established general guidelines delegating responsibility for the determination of avoided costs to the States. At the time PURPA was enacted, oil prices were rising and predicted by some analysts to reach $100 a barrel by 1998. Today, in contrast, oil sells for under $12 a barrel.[21] This was the foundation many States used for setting the high avoided costs in utility power purchase contracts with QFs. In other cases, States may simply have been aggressive in implementing PURPA to encourage QF development (e.g., including capacity charges in determining avoided costs).

PURPA did not require public utilities to enter into long-term power sales agreements, though many States required utilities to offer long-term contracts of 10 to 20 years with QFs. These contracts included the Six-Cent Rule in New York[22] and Standard Offer contracts in California.[23] State government policies implementing PURPA favored QFs and produced an enormous growth in nonutility power producers and renewable electric generation during the 1980s. While PURPA was effective in the revitalization of nonutility power producers and renewable electric power, it was not necessarily the least-cost alternative to generating electricity.

In California, prices for Standard Offer contracts during the 1980s ranged from 10 to 20 cents per kilowatthour. A decade later, when the original Standard Offer contracts started to expire, owners of renewable energy facilities could not renew their contracts at the original rates. Sometimes original contracts were replaced by Interim and later, Final Standard Offer contracts. As Standard Offer contracts expired and wholesale prices declined to less than 3 cents per kilowatthour, there was a slowdown in the construction of new capacity and a gradual retirement of existing capacity.

In the mid 1980s, several States, considering the difficulty of estimating future avoided costs, concluded that avoided costs could be established through competitive bidding among QFs as opposed to setting them administratively. Maine was the first State to put competitive bidding into practice. However, during the early 1990s, with wholesale prices and avoided cost at less than 3 cents per kilowatthour, renewable electricity projects were not profitable. California introduced various programs that would require utilities to purchase QF capacity at prices in excess of their avoided costs. Utilities in California opposed these programs and initiated regulatory and legal actions. In 1995, FERC issued a decision clarifying the limits on States in setting rates that would exceed a utility's avoided cost. The FERC noted that States have other ways aside from PURPA to encourage the use of renewable resources, including imposing a tax on fossil-fueled generators or by giving a tax incentive to alternative generation. FERC also clarified that it would not entertain requests to invalidate existing QF contracts.

As a result of FERC's decision, California chose to include in its restructuring legislation, Assembly Bill 1890 (AB 1890), which placed a tax on electricity sold by investor-owned utilities, the funds from which would then be redistributed in support of renewable technologies. Enacted in 1996, AB 1890 directed the collection of $540 million from investor-owned utility ratepayers from 1998 through 2002 to support existing, new, and emerging renewable electric generation technologies. The program has a competitive bidding mechanism to reward the most cost-effective projects with a cents-per-kilowatthour amount (subject to a price cap). The benefits specified in AB 1890 are production credits rather than investment tax credits.

Between 1978 and 1987, in addition to Federal tax preferences,[24] California had a tax preference for renewable energy facilities. The combination of these tax credits and high marginal income tax rates[25] created an incentive for capital-intensive renewable energy projects (especially wind). One reason for the elimination of the investment tax credits is the perception that these programs had been abused to produce tax savings rather than to generate renewable energy.

[21] Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(98/08) (Washington, DC, October 1998), p. 111.

[22] In 1981, New York State enacted legislation which established a minimum price of 6 cents per kilowatthour for utility purchases from QFs. This precipitated a large number of QF projects in New York and a challenge of the 6-cent law by utilities as it exceeded their avoided costs. New York repealed the law in 1992, but grandfathered many of the contracts executed prior to the effective date of the repeal.

[23] In California, QFs typically enter pre-approved contracts called Standard Offer Contracts with utility companies. These contracts reflect the difference between short- and long-term costs based on the utility costs they displace. Short-run avoided costs are generally calculated to reflect the costs they would displace for a short-term commitment to deliver energy. These costs are based on the utility's marginal operating costs, varying with the fuel in use and seasonal demand. Long-run avoided costs are designed, in addition to reflecting marginal costs, to include the costs of a resource (capital costs) that the utility would construct in lieu of the QF resource. In California this resulted in establishing relatively high avoided costs compared to other states. Additional information about renewable energy in California is available on the California Energy Commission's web site: www.energy.ca.gov/renewables/index.html

[24] Primarily a 15-percent Federal energy investment tax credit in addition to the standard 10 percent investment tax credit.

[25] Marginal income tax rates were reduced to a maximum of 28 percent in 1982, then increased slightly in 1986.

Concluding Comments

PURPA provided an opportunity to expand the use of renewable energy sources in electricity markets. As the electric industry restructures, proponents of repealing PURPA are challenging its provisions as being inconsistent with competitive wholesale markets. State commissions continue to modify their rules to mitigate the impact of PURPA. In 1996, for example, the Idaho Public Utilities Commission terminated its previous rule requiring 20 year terms for utility contracts to purchase QF power and replaced it with a rule requiring terms of only 5 years for facilities exceeding 1 megawatt. The New York Public Service Commission adopted procedures to allow electric utilities to curtail power purchases from QFs when their contracts allow curtailments. The Commission has also authorized utilities to collect data to determine whether or not QFs are complying with PURPA eligibility requirements. Other States have adopted or have pending initiatives, such as implementing market-based rates to determine avoided costs, that attempt to alleviate some of the financial impacts of PURPA.

Since 1997, more than a dozen proposed electric restructuring bills have been introduced in Congress, and the Administration's "Comprehensive Electricity Competition Plan" was also released in March 1998.[26] Most of these promote and preserve public benefits, proposing to secure the future of renewable electricity through a renewable portfolio standard (RPS) or a public benefit fund similar to the fund in California. The RPS would require electricity sellers to cover a percentage of their electricity sales with generation from non-hydroelectric renewable technologies. Most proposals repeal prospectively the "must buy" provision of PURPA.

The future prospect for renewable electricity will be dependent on the fate of PURPA, how aggressive Federal and State agencies are in setting incentives (such as an RPS, system benefit charge, or net metering, etc.) for electricity from renewables sources, and the willingness of the public to support green pricing programs.

[26] For a discussion of restructuring proposals and issues, see Energy Information Administration, *Challenges of Electric Power Industry Restructuring for Fuel Suppliers*, DOE/EIA-0623 (Washington, DC, September 1998).

Table 1. Installed Renewable Capacity at U.S. Nonutility Generating Facilities by Qualifying Facility Status and Census Division, 1992 Through 1996 (Megawatts)

Census Division	QF Capacity[a]		Non-QF Capacity		Total Capacity	
	Number of Facilities	Capacity (megawatts)	Number of Facilities	Capacity (megawatts)	Number of Facilities	Capacity (megawatts)
			1992			
New England	85	1,644	47	382	132	2,026
Middle Atlantic	93	1,111	28	90	121	1,201
East North Central	47	383	22	310	69	692
West North Central	10	120	7	75	17	195
South Atlantic	64	1,986	38	1,092	102	3,078
East South Central	17	535	6	330	23	865
West South Central	16	680	11	568	27	1,248
Mountain	47	506	19	175	66	680
Pacific	227	4,438	101	1,367	328	5,805
U.S. Total	**606**	**11,402**	**279**	**4,389**	**885**	**15,791**
			1993			
New England	87	1,617	47	382	134	1,999
Middle Atlantic	97	1,138	26	87	123	1,225
East North Central	50	469	22	278	72	747
West North Central	12	125	7	102	19	227
South Atlantic	68	2,099	38	1,068	106	3,168
East South Central	16	541	9	524	25	1,066
West South Central	18	707	12	569	30	1,276
Mountain	52	531	19	168	71	699
Pacific	221	4,465	101	1,371	322	5,836
U.S. Total	**621**	**11,692**	**281**	**4,550**	**902**	**16,242**
			1994			
New England	87	1,601	47	373	134	1,974
Middle Atlantic	103	1,259	25	78	128	1,336
East North Central	50	438	25	296	75	733
West North Central	13	148	7	112	20	260
South Atlantic	74	2,357	43	1,414	117	3,771
East South Central	16	555	14	849	30	1,404
West South Central	18	757	12	538	30	1,295
Mountain	53	542	17	156	70	698
Pacific	217	4,373	99	1,363	316	5,736
U.S. Total	**632**	**12,030**	**288**	**5,178**	**920**	**17,208**
			1995			
New England	84	1,563	45	394	129	1,957
Middle Atlantic	106	1,346	24	75	130	1,421
East North Central	60	527	18	267	78	794
West North Central	15	156	7	112	22	269
South Atlantic	75	2,318	42	1,202	117	3,521
East South Central	20	779	12	631	32	1,410
West South Central	21	867	10	463	31	1,330
Mountain	52	550	18	167	70	717
Pacific	209	4,283	91	1,268	300	5,551
U.S. Total	**642**	**12,390**	**267**	**4,580**	**909**	**16,970**
			1996			
New England	82	1,512	47	411	129	1,924
Middle Atlantic	106	1,329	24	75	130	1,404
East North Central	65	553	20	278	85	832
West North Central	15	157	8	121	23	278
South Atlantic	75	2,384	43	1,260	118	3,644
East South Central	17	848	13	636	30	1,484
West South Central	23	957	11	466	34	1,423
Mountain	51	548	19	169	70	717
Pacific	207	4,294	82	1,173	289	5,467
U.S. Total	**641**	**12,583**	**267**	**4,588**	**908**	**17,172**

[a]Nonutility generating facilities that have obtained status as qualifying facilities under the Public Utility Regulatory Policies Act of 1978.

Notes: Renewable data presented in this table differs slightly from that found in the Energy Information Administration's *Electric Power Annual 1997 Volume II* (Washington, DC, October 1998) due to slight differences in the definition of renewable energy sources. See Appendix, Table A1 of this article for details. Totals may not equal sum of components because of independent rounding.

Source: Energy Information Administration, Form EIA-867, "Annual Nonutility Power Producer Report."

Table 2. Installed Renewable Capacity at U.S. Nonutility Generating Facilities by Energy Source and Census Division, 1992 Through 1996
(Megawatts)

Census Division	Conventional Hydroelectric	Geothermal	Wind	Solar	Wood/Wood Waste[a]	Municipal Waste[b]	Other Biomass[c]	Total
				1992				
New England	579	--	--	--	909	W	W	2,026
Middle Atlantic	418	--	--	--	121	662	--	1,201
East North Central	100	--	--	--	417	175	--	692
West North Central	73	--	--	--	77	46	--	195
South Atlantic	205	--	--	--	2,079	747	46	3,078
East South Central	--	--	--	--	850	W	W	865
West South Central	193	--	--	--	1,033	5	18	1,248
Mountain	290	224	--	--	159	7	--	680
Pacific	825	1,030	1,822	360	1,088	355	325	5,805
U.S. Total	**2,684**	**1,254**	**1,822**	**360**	**6,733**	**2,513**	**425**	**15,791**
				1993				
New England	587	--	--	--	846	W	W	1,999
Middle Atlantic	421	--	--	--	141	663	--	1,225
East North Central	101	--	--	--	458	188	--	747
West North Central	73	--	--	--	105	49	--	227
South Atlantic	209	--	--	--	2,158	755	46	3,168
East South Central	--	--	--	--	1,056	10	--	1,066
West South Central	193	--	--	--	1,054	W	W	1,276
Mountain	317	224	--	--	150	7	--	699
Pacific	832	1,094	R1,796	360	1,016	379	358	5,836
U.S. Total	**R2,734**	**1,318**	**R1,796**	**360**	**6,984**	**2,591**	**459**	**16,242**
				1994				
New England	586	--	--	--	818	W	W	1,974
Middle Atlantic	441	--	--	--	145	750	--	1,336
East North Central	115	--	--	--	417	200	--	733
West North Central	73	--	W	--	105	50	W	260
South Atlantic	568	--	--	--	2,358	799	46	3,771
East South Central	172	--	--	--	1,217	W	W	1,404
West South Central	193	--	--	--	1,071	7	23	1,295
Mountain	317	234	--	--	140	7	--	698
Pacific	898	1,102	W	354	1,077	382	W	5,736
U.S. Total	**3,364**	**1,335**	**1,737**	**354**	**7,350**	**2,744**	**325**	**17,208**
				1995				
New England	584	--	--	--	W	634	W	1,957
Middle Atlantic	485	--	--	--	W	823	W	1,421
East North Central	103	--	--	--	477	215	--	794
West North Central	73	--	W	--	105	59	W	269
South Atlantic	568	--	--	--	2,045	862	46	3,521
East South Central	172	--	--	--	1,224	W	W	1,410
West South Central	193	--	--	--	1,087	25	26	1,330
Mountain	323	237	--	--	150	7	--	717
Pacific	899	1,057	W	354	866	W	268	5,551
U.S. Total	**3,399**	**1,295**	**1,723**	**354**	**6,766**	**3,038**	**396**	**16,970**

See notes at end of table.

Table 2. Installed Renewable Capacity at U.S. Nonutility Generating Facilities by Energy Source and Census Division, 1992 Through 1996 (Continued)

Census Division	Conventional Hydroelectric	Geothermal	Wind	Solar	Wood/Wood Waste[a]	Municipal Waste[b]	Other Biomass[c]	Total
				1996				
New England	589	--	--	--	663	W	W	1,924
Middle Atlantic	485	--	--	--	164	754	--	1,404
East North Central	105	--	--	--	486	241	--	832
West North Central	81	--	W	--	105	59	W	278
South Atlantic	568	--	--	--	2,103	927	46	3,644
East South Central	172	--	--	--	1,297	W	W	1,484
West South Central . . .	195	--	W	--	1,141	27	W	1,423
Mountain	322	237	--	--	150	7	--	717
Pacific	902	1,108	1,515	354	944	397	148	5,467
U.S. Total	**3,419**	**1,346**	**1,670**	**354**	**7,053**	**3,063**	**267**	**17,172**

[a] Includes wood, wood waste, wood liquors, peat, railroad ties, utility poles, and wood sludge.

[b] Includes municipal solid waste, landfill gas, digester gas, and methane.

[c] Other biomass includes agricultural byproducts/waste, solid by-products, liquid acetonitrile waste, medical waste, straw, tires, fish oil, tall oil, sludge waste, closed-loop biomass, and waste alcohol.

W = Withheld to avoid disclosure of individual company data.

R=Revised.

Notes: Renewable data presented in this table differs slightly from that found in the Energy Information Administration's *Electric Power Annual 1997 Volume II* (Washington, DC, October 1998) due to slight differences in the definition of renewable energy sources. See Appendix, Table A1 of this article for details. Totals may not equal sum of components because of independent rounding.

Source: Energy Information Administration, Form EIA-867, "Annual Nonutility Power Producer Report."

Table 3. Installed Renewable Capacity at U.S. Nonutility Generating Facilities by Energy Source and State, 1995
(Megawatts)

State	Conventional Hydroelectric	Geothermal	Wind	Solar	Wood/ Wood Waste[a]	Municipal Waste[b]	Other Biomass[c]	Total
Alabama	--	--	--	--	W	--	W	781
Alaska	--	--	--	--	W	--	--	W
Arizona	--	--	--	--	--	--	--	--
Arkansas	W	--	--	--	367	W	--	370
California	658	1,022	1,680	354	606	293	160	4,772
Colorado	32	--	--	--	--	5	--	36
Connecticut	W	--	--	--	--	214	W	267
Delaware	--	--	--	--	--	--	--	--
District of Columbia	--	--	--	--	--	--	--	--
Florida	--	--	--	--	637	527	46	1,210
Georgia	W	--	--	--	501	W	--	518
Hawaii	26	35	W	--	--	W	108	257
Idaho	265	--	--	--	140	--	--	404
Illinois	18	--	--	--	--	35	--	53
Indiana	--	--	--	--	--	14	--	14
Iowa	5	--	--	--	--	7	--	12
Kansas.	2	--	--	--	--	--	--	2
Kentucky	--	--	--	--	W	--	--	W
Louisiana	192	--	--	--	476	--	17	685
Maine	359	--	--	--	541	66	--	966
Maryland	--	--	--	--	W	W	--	138
Massachusetts	W	--	--	--	W	318	--	396
Michigan	29	--	--	--	327	137	--	492
Minnesota	65	--	W	--	105	W	--	244
Mississippi	--	--	--	--	345	--	--	345
Missouri	--	--	--	--	--	--	--	--
Montana	W	--	--	--	W	--	--	23
Nebraska	--	--	--	--	--	--	--	--
Nevada	W	237	--	--	--	--	--	W
New Hampshire	91	--	--	--	123	23	--	237
New Jersey	W	--	--	--	--	182	W	204
New Mexico	--	--	--	--	--	W	--	W
New York	383	--	--	--	74	366	--	823
North Carolina	368	--	--	--	W	W	--	589
North Dakota	--	--	--	--	--	--	W	W
Ohio	3	--	--	--	W	W	--	32
Oklahoma	--	--	--	--	W	W	--	80
Oregon	W	--	--	--	129	W	--	257
Pennsylvania	W	--	--	--	W	275	--	394
Rhode Island	3	--	--	--	--	14	--	16
South Carolina	W	--	--	--	282	W	--	315
South Dakota	--	--	--	--	--	--	--	--
Tennessee	172	--	--	--	99	10	--	280
Texas	--	--	--	--	181	W	W	196
Utah	10	--	--	--	--	--	--	10
Vermont.	W	--	--	--	W	--	--	75
Virginia	22	--	--	--	410	175	--	607
Washington	101	--	--	--	92	32	--	226
West Virginia	144	--	--	--	--	--	--	144
Wisconsin	52	--	--	--	130	20	--	202
Wyoming	W	--	--	--	--	--	--	W
U.S. Total	**3,399**	**1,295**	**1,723**	**354**	**6,766**	**3,038**	**396**	**16,970**

[a] Includes wood, wood waste, wood liquors, peat, railroad ties, utility poles, and wood sludge.
[b] Includes municipal solid waste, landfill gas, digester gas, and methane.
[c] Other biomass includes agricultural byproducts/waste, solid by-products, liquid acetonitrile waste, medical waste, straw, tires, fish oil, tall oil, sludge waste, closed-loop biomass, and waste alcohol.

W = Withheld to avoid disclosure of individual company data.

Notes: Renewable data presented in this table differs slightly from that found in the Energy Information Administration's *Electric Power Annual 1997 Volume II* (Washington, DC, October 1998) due to slight differences in the definition of renewable energy sources. See Appendix, Table A1 of this article for details. Totals may not equal sum of components because of independent rounding.

Source: Energy Information Administration, Form EIA-867, "Annual Nonutility Power Producer Report."

Table 4. Installed Renewable Capacity at U.S. Nonutility Generating Facilities Attributed to Major Industry Groups by Census Division, 1992 Through 1996
(Megawatts)

Census Division	Agriculture/ Forestry	Mining	Paper and Allied Products[a]	All Other Manufacturing	Electric/ Sanitary Services[b]	Other Industry Groups	Total
			1992				
New England	--	--	772	38	1,216	--	2,026
Middle Atlantic	--	--	111	W	1,034	W	1,201
East North Central	--	--	345	W	241	W	692
West North Central	--	--	98	W	63	W	195
South Atlantic	46	--	1,965	158	896	13	3,078
East South Central	--	--	844	6	15	--	865
West South Central	--	--	1,008	31	209	--	1,248
Mountain	--	--	124	W	433	W	680
Pacific	64	--	310	537	4,876	18	5,805
U.S. Total	**111**	**--**	**5,577**	**909**	**8,982**	**211**	**15,791**
			1993				
New England	--	--	670	33	1,295	--	1,999
Middle Atlantic	--	--	113	54	1,058	--	1,225
East North Central	--	--	346	W	294	W	747
West North Central	--	--	126	W	66	W	227
South Atlantic	46	--	2,044	162	909	7	3,168
East South Central	--	--	1,043	8	15	--	1,066
West South Central	--	--	1,009	57	210	--	1,276
Mountain	--	--	124	W	460	W	699
Pacific	55	--	305	509	4,950	18	5,836
U.S. Total	**102**	**--**	**5,780**	**900**	**9,257**	**204**	**16,242**
			1994				
New England	--	--	663	36	1,275	--	1,974
Middle Atlantic	--	--	W	W	1,220	--	1,336
East North Central	--	--	323	W	302	W	733
West North Central	--	--	W	41	89	W	260
South Atlantic	46	--	2,110	509	1,099	7	3,771
East South Central	--	--	1,209	180	15	--	1,404
West South Central	--	--	1,046	37	212	--	1,295
Mountain	--	--	113	W	469	W	698
Pacific	33	--	267	394	5,025	18	5,736
U.S. Total	**79**	**--**	**5,972**	**1,245**	**9,705**	**207**	**17,208**
			1995				
New England	--	--	656	11	1,290	--	1,957
Middle Atlantic	--	--	W	W	1,359	--	1,421
East North Central	--	--	324	33	361	77	794
West North Central	--	--	W	41	98	W	269
South Atlantic	46	--	1,723	508	1,237	7	3,521
East South Central	--	--	1,118	186	106	--	1,410
West South Central	--	--	1,042	76	212	--	1,330
Mountain	--	--	124	W	478	W	717
Pacific	56	--	236	302	4,937	19	5,551
U.S. Total	**102**	**--**	**5,401**	**1,181**	**10,079**	**208**	**16,970**

See notes at end of table.

Table 4. Installed Renewable Capacity at U.S. Nonutility Generating Facilities Attributed to Major Industry Groups by Census Division, 1992 Through 1996 (Continued)

Census Division	Agriculture/ Forestry	Mining	Paper and Allied Products[a]	All Other Manufacturing	Electric/ Sanitary Services[b]	Other Industry Groups	Total
				1996			
New England	--	--	667	11	1,245	--	1,924
Middle Atlantic	--	--	113	W	1,289	W	1,404
East North Central	--	--	344	W	410	W	832
West North Central	--	--	126	41	111	--	278
South Atlantic	46	--	1,731	513	1,286	68	3,644
East South Central	--	--	1,192	185	107	--	1,484
West South Central	--	--	1,096	59	268	--	1,423
Mountain	--	--	124	W	478	W	717
Pacific	49	--	288	280	4,833	18	5,467
U.S. Total	**95**	**--**	**5,680**	**1,109**	**10,026**	**262**	**17,172**

[a] Includes SIC codes 2621 (paper mills) and 2631 (paperboard mills).
[b] SIC code 49 (electric, gas, and sanitary services).
W = Withheld to avoid disclosure of individual company data.
Notes: Renewable data presented in this table differs slightly from that found in the Energy Information Administration's *Electric Power Annual 1997 Volume II* (Washington, DC, October 1998) due to slight differences in the definition of renewable energy sources. See Appendix, Table A1 of this article for details. For definitions of major industry groups, see Executive Office of the President, Office of Management and Budget, *Standard Industrial Classification Manual, 1987* (Washington, DC, 1987). Totals may not equal sum of components because of independent rounding.
Source: Energy Information Administration, Form EIA-867, "Annual Nonutility Power Producer Report."

Table 5. Gross Renewable Generation at U.S. Nonutility Generating Facilities by Qualifying Facility Status and Census Division, 1992 Through 1996
(Million Kilowatthours)

Census Division	QF Generation[a]		Non-QF Generation		Total Generation	
	Number of Facilities	Generation (Million Kilowatthours)	Number of Facilities	Generation (Million Kilowatthours)	Number of Facilities	Generation (Million Kilowatthours)
			1992			
New England	85	9,246	47	1,867	132	11,112
Middle Atlantic	93	6,801	28	400	121	7,201
East North Central	47	2,360	22	1,278	69	3,637
West North Central	10	633	7	374	17	1,006
South Atlantic	64	11,436	38	4,712	102	16,148
East South Central	17	3,048	6	2,109	23	5,156
West South Central	16	4,104	11	2,491	27	6,594
Mountain	47	2,103	19	528	66	2,631
Pacific	227	18,501	101	3,891	328	22,392
U.S. Total	**606**	**58,229**	**279**	**17,648**	**885**	**75,878**
			1993			
New England	87	9,802	47	1,786	134	11,588
Middle Atlantic	97	6,933	26	363	123	7,296
East North Central	50	2,759	22	1,311	72	4,071
West North Central	12	681	7	391	19	1,072
South Atlantic	68	11,174	38	4,703	106	15,877
East South Central	16	3,012	9	3,002	25	6,014
West South Central	18	4,262	12	3,076	30	7,338
Mountain	52	2,597	19	705	71	3,303
Pacific	221	19,811	101	4,849	322	24,660
U.S. Total	**621**	**61,032**	**281**	**20,187**	**902**	**81,219**
			1994			
New England	87	9,569	47	1,928	134	11,496
Middle Atlantic	103	7,477	25	337	128	7,814
East North Central	50	3,035	25	1,412	75	4,447
West North Central	13	743	7	424	20	1,167
South Atlantic	74	11,988	43	6,415	117	18,403
East South Central	16	3,185	14	4,735	30	7,920
West South Central	18	4,300	12	2,867	30	7,166
Mountain	53	2,664	17	577	70	3,242
Pacific	217	20,364	99	3,742	316	24,106
U.S. Total	**632**	**63,325**	**288**	**22,436**	**920**	**85,761**
			1995			
New England	84	9,696	45	1,964	129	11,660
Middle Atlantic	106	7,665	24	288	130	7,953
East North Central	60	3,500	18	1,222	78	4,723
West North Central	15	818	7	450	22	1,268
South Atlantic	75	12,815	42	5,721	117	18,536
East South Central	20	4,567	12	3,300	32	7,866
West South Central	21	4,685	10	2,470	31	7,155
Mountain	52	2,829	18	779	70	3,608
Pacific	209	19,498	91	4,817	300	24,316
U.S. Total	**642**	**66,074**	**267**	**21,011**	**909**	**87,085**

See notes at end of table.

Table 5. Gross Renewable Generation at U.S. Nonutility Generating Facilities by Qualifying Facility Status and Census Division, 1992 Through 1996 (Continued)

Census Division	QF Generation[a]		Non-QF Generation		Total Generation	
	Number of Facilities	Generation (Million Kilowatthours)	Number of Facilities	Generation (Million Kilowatthours)	Number of Facilities	Generation (Million Kilowatthours)
			1996			
New England	82	9,981	47	2,290	129	12,271
Middle Atlantic	106	8,411	24	353	130	8,764
East North Central	65	3,917	20	1,291	85	5,209
West North Central	15	815	8	440	23	1,255
South Atlantic	75	13,169	43	5,908	118	19,078
East South Central	17	4,514	13	3,414	30	7,928
West South Central	23	4,829	11	2,351	34	7,180
Mountain	51	2,820	19	835	70	3,655
Pacific	206	20,137	82	4,317	288	24,454
U.S. Total	**640**	**68,594**	**267**	**21,199**	**907**	**89,793**

[a] Nonutility generating facilities that have obtained status as qualifying facilities under the Public Utility Regulatory Policies Act of 1978.

Notes: Renewable data presented in this table differs slightly from that found in the Energy Information Administration's *Electric Power Annual 1997 Volume II* (Washington, DC, October 1998) due to slight differences in the definition of renewable energy sources. See Appendix, Table A1 of this article for details. Totals may not equal sum of components because of independent rounding.

Source: Energy Information Administration, Form EIA-867, "Annual Nonutility Power Producer Report."

Table 6. Gross Renewable Generation for U.S. Nonutility Generating Facilities by Energy Source and Census Division, 1992 Through 1996
(Million Kilowatthours)

Census Division	Conventional Hydroelectric	Geothermal	Wind	Solar	Wood/Wood Waste[a]	Municipal Waste[b]	Other Biomass[c]	Total
				1992				
New England	W	--	--	--	4,943	3,235	W	11,112
Middle Atlantic	1,916	--	--	--	1,168	4,116	--	7,201
East North Central	515	--	--	--	2,351	715	56	3,637
West North Central	W	--	--	--	382	W	--	1,006
South Atlantic	1,095	--	--	--	10,642	4,179	231	16,148
East South Central	--	--	--	--	5,070	W	W	5,156
West South Central	663	--	--	--	5,780	43	109	6,594
Mountain	600	1,214	--	--	764	W	W	2,631
Pacific	1,626	7,363	2,916	746	5,710	2,333	1,697	22,392
U.S. Total	**9,446**	**8,578**	**2,916**	**746**	**36,810**	**15,006**	**2,375**	**75,878**
				1993				
New England	2,526	--	--	--	5,260	3,499	303	11,588
Middle Atlantic	1,724	--	--	--	1,238	4,334	--	7,296
East North Central	520	--	--	--	2,569	904	77	4,071
West North Central	336	--	--	--	457	W	W	1,072
South Atlantic	963	--	--	--	10,656	3,994	263	15,877
East South Central	--	--	--	--	5,949	W	W	6,014
West South Central	1,246	--	--	--	5,922	41	128	7,338
Mountain	948	1,588	--	--	709	W	W	3,303
Pacific	3,249	8,161	R3,036	897	5,163	2,402	1,752	24,660
U.S. Total	**11,511**	**9,749**	**R3,036**	**897**	**37,925**	**15,555**	**2,546**	**81,219**
				1994				
New England	2,709	--	--	--	4,822	3,657	308	11,496
Middle Atlantic	1,877	--	--	--	1,405	4,531	--	7,814
East North Central	533	--	--	--	2,812	1,022	79	4,447
West North Central	339	--	W	--	471	303	W	1,167
South Atlantic	2,983	--	--	--	10,862	4,347	210	18,403
East South Central	1,047	--	--	--	6,798	W	W	7,920
West South Central	983	--	--	--	5,984	40	160	7,166
Mountain	837	1,637	--	--	712	W	W	3,242
Pacific	1,918	8,486	W	824	5,495	2,605	W	24,106
U.S. Total	**13,227**	**10,122**	**3,482**	**824**	**39,361**	**16,606**	**2,139**	**85,761**
				1995				
New England	2,561	--	--	--	4,620	4,113	365	11,660
Middle Atlantic	1,584	--	--	--	W	4,960	W	7,953
East North Central	488	--	--	--	2,966	1,193	75	4,723
West North Central	303	--	W	--	W	376	W	1,268
South Atlantic	2,799	--	--	--	10,737	4,705	296	18,536
East South Central	835	--	--	--	6,964	W	W	7,866
West South Central	962	--	--	--	5,993	40	160	7,155
Mountain	1,171	1,659	--	--	719	W	W	3,608
Pacific	4,070	8,253	W	824	4,092	2,695	W	24,316
U.S. Total	**14,774**	**9,912**	**3,185**	**824**	**37,986**	**18,182**	**2,222**	**87,085**

See notes at end of table.

Table 6. Gross Renewable Generation for U.S. Nonutility Generating Facilities by Energy Source and Census Division, 1992 Through 1996 (Continued)

Census Division	Conventional Hydroelectric	Geothermal	Wind	Solar	Wood/Wood Waste[a]	Municipal Waste[b]	Other Biomass[c]	Total
					1996			
New England	3,235	--	--	--	4,350	4,321	366	12,271
Middle Atlantic	2,337	--	--	--	1,310	5,075	42	8,764
East North Central	525	--	--	--	3,121	1,468	95	5,209
West North Central	382	--	W	--	441	372	W	1,255
South Atlantic	3,042	--	--	--	10,642	5,051	343	19,078
East South Central	897	--	--	--	6,959	W	W	7,928
West South Central	980	--	W	--	5,912	W	157	7,180
Mountain	1,280	1,663	--	--	662	W	W	3,655
Pacific	3,878	8,535	3,266	903	4,497	2,530	845	24,454
U.S. Total	**16,555**	**10,198**	**3,400**	**903**	**37,895**	**18,966**	**1,877**	**89,793**

[a] Includes wood, wood waste, wood liquors, peat, railroad ties, utility poles, and wood sludge.

[b] Includes municipal solid waste, landfill gas, digester gas, and methane.

[c] Other biomass includes agricultural byproducts/waste, solid by-products, liquid acetonitrile waste, medical waste, straw, tires, fish oil, tall oil, sludge waste, closed-loop biomass, and waste alcohol.

Notes: Renewable data presented in this table differs slightly from that found in the Energy Information Administration's *Electric Power Annual 1997 Volume II* (Washington, DC, October 1998) due to slight differences in the definition of renewable energy sources. See Appendix, Table A1 of this article for details. Totals may not equal sum of components because of independent rounding.

Source: Energy Information Administration, Form EIA-867, "Annual Nonutility Power Producer Report."

Table 7. Gross Renewable Generation for U.S. Nonutility Generating Facilities by Energy Source and State, 1995 (Million Kilowatthours)

State	Conventional Hydroelectric	Geothermal	Wind	Solar	Wood/ Wood Waste[a]	Municipal Waste[b]	Other Biomass[c]	Total
Alabama	--	--	--	--	4,313	--	W	W
Alaska	--	--	--	--	W	--	W	134
Arizona	--	--	--	--	W	--	--	W
Arkansas	--	--	--	--	1,653	W	W	1,678
California	3,155	8,011	3,107	824	2,739	2,023	942	20,801
Colorado	125	--	--	--	--	W	W	161
Connecticut	W	--	--	--	--	1,392	W	1,667
Delaware	--	--	--	--	--	--	--	--
District of Columbia	--	--	--	--	--	--	--	--
Florida	--	--	--	--	2,404	3,312	192	5,908
Georgia	W	--	--	--	3,222	W	76	3,369
Hawaii	83	242	W	--	W	W	280	1,021
Idaho	936	--	--	--	W	--	W	1,507
Illinois	77	--	--	--	W	244	W	362
Indiana	--	--	--	--	--	86	--	86
Iowa	12	--	--	--	W	W	--	61
Kansas.	11	--	--	--	--	--	--	11
Kentucky	--	--	--	--	W	--	--	W
Louisiana	W	--	--	--	2,787	--	W	3,852
Maine	1,727	--	--	--	3,393	444	148	5,711
Maryland	--	--	--	--	W	526	W	708
Massachusetts	221	--	--	--	W	2,015	W	2,376
Michigan	W	--	--	--	1,926	697	W	2,766
Minnesota	W	--	W	--	508	327	--	1,173
Mississippi	--	--	--	--	2,047	--	W	W
Missouri	--	--	--	--	--	--	W	W
Montana	W	--	--	--	W	--	--	105
Nebraska	--	--	--	--	--	--	--	--
Nevada	W	1,659	--	--	--	--	--	W
New Hampshire . . .	406	--	--	--	881	181	--	1,468
New Jersey	W	--	--	--	--	1,298	W	1,331
New Mexico	--	--	--	--	--	W	--	W
New York	1,223	--	--	--	580	1,901	--	3,705
North Carolina	1,796	--	--	--	1,730	W	W	3,583
North Dakota	--	--	--	--	--	--	W	W
Ohio	W	--	--	--	380	W	--	408
Oklahoma	--	--	--	--	W	W	--	301
Oregon	W	--	--	--	571	W	--	1,009
Pennsylvania	350	--	--	--	806	1,761	--	2,917
Rhode Island	W	--	--	--	--	W	--	91
South Carolina	65	--	--	--	1,663	W	W	1,798
South Dakota	--	--	--	--	--	--	--	--
Tennessee	835	--	--	--	600	W	W	1,493
Texas	--	--	--	--	1,256	W	W	1,324
Utah	43	--	--	--	--	--	--	43
Vermont.	W	--	--	--	W	--	--	347
Virginia	78	--	--	--	1,536	739	9	2,361
Washington	477	--	--	--	662	W	W	1,350
West Virginia	808	--	--	--	--	--	--	808
Wisconsin	276	--	--	--	658	W	W	1,101
Wyoming	--	--	--	--	--	--	--	--
U.S. Total	**14,774**	**9,912**	**3,185**	**824**	**37,986**	**18,182**	**2,222**	**87,085**

[a] Includes wood, wood waste, wood liquors, peat, railroad ties, utility poles, and wood sludge.

[b] Includes municipal solid waste, landfill gas, digester gas, and methane.

[c] Other biomass includes agricultural by products/waste, solid byproducts, liquid acetonitrile waste, medical waste, straw, tires, fish oil, tall oil, sludge waste, and waste alcohol.

W = Withheld to avoid disclosure of individual company data.

Notes: Renewable data presented in this table differs slightly from that found in the Energy Information Administration's *Electric Power Annual 1997 Volume II* (Washington, DC, October 1998) due to slight differences in the definition of renewable energy sources. See Appendix, Table A1 of this article for details. Totals may not equal sum of components because of independent rounding.

Source: Energy Information Administration, Form EIA-867, "Annual Nonutility Power Producer Report."

Table 8. Gross Renewable Generation for U.S. Nonutility Generating Facilities Attributed to Major Industry Groups by Census Division, 1992 Through 1996
(Million Kilowatthours)

Census Division	Agriculture/ Forestry	Mining	Paper and Allied Products[a]	All Other Manufacturing	Electric/ Sanitary Services[b]	Other Industry Groups	Total
				1992			
New England	--	--	4,135	170	6,807	--	11,112
Middle Atlantic	--	--	851	W	6,007	W	7,201
East North Central	--	--	1,978	W	1,352	W	3,637
West North Central	--	--	509	109	W	W	1,006
South Atlantic	W	--	10,100	759	5,130	W	16,148
East South Central	--	--	5,054	W	W	--	5,156
West South Central	--	--	5,654	163	778	--	6,594
Mountain	--	--	607	W	1,799	W	2,631
Pacific	W	--	1,394	2,546	18,114	W	22,392
U.S. Total	**382**	**–**	**30,283**	**4,378**	**40,436**	**399**	**75,878**
				1993			
New England	--	--	4,094	176	7,317	--	11,588
Middle Atlantic	--	--	992	162	6,142	--	7,296
East North Central	--	--	1,951	W	1,710	W	4,071
West North Central	--	--	555	W	335	W	1,072
South Atlantic	W	--	10,155	706	4,869	W	15,877
East South Central	--	--	5,926	25	63	--	6,014
West South Central	--	--	5,700	274	1,363	--	7,338
Mountain	--	--	559	W	2,361	W	3,303
Pacific	W	--	1,022	2,396	20,947	W	24,660
U.S. Total	**349**	**--**	**30,955**	**4,191**	**45,107**	**615**	**81,219**
				1994			
New England	--	--	3,883	169	7,444	--	11,496
Middle Atlantic	--	--	W	W	6,675	--	7,814
East North Central	--	--	2,132	208	1,888	219	4,447
West North Central	--	--	W	169	415	W	1,167
South Atlantic	W	--	10,145	2,641	5,484	W	18,403
East South Central	--	--	6,774	1,077	69	--	7,920
West South Central	--	--	5,861	205	1,100	--	7,166
Mountain	--	--	550	W	2,383	W	3,242
Pacific	W	--	1,138	1,738	20,975	W	24,106
U.S. Total	**275**	**--**	**32,172**	**6,317**	**46,432**	**565**	**85,761**
				1995			
New England	--	--	3,796	32	7,832	--	11,660
Middle Atlantic	--	--	W	W	7,023	--	7,953
East North Central	--	--	2,096	214	2,126	287	4,723
West North Central	--	--	W	174	489	W	1,268
South Atlantic	W	--	9,950	2,458	5,976	W	18,536
East South Central	--	--	6,156	873	837	--	7,866
West South Central	--	--	5,782	286	1,087	--	7,155
Mountain	--	--	575	W	2,571	W	3,608
Pacific	W	--	1,190	1,231	21,558	W	24,316
U.S. Total	**313**	**--**	**31,036**	**5,370**	**49,500**	**866**	**87,085**

See notes at end of table.

Table 8. Gross Renewable Generation for U.S. Nonutility Generating Facilities Attributed to Major Industry Groups by Census Division, 1992 Through 1996 (Continued)

Census Division	Agriculture/ Forestry	Mining	Paper and Allied Products[a]	All Other Manufacturing	Electric/ Sanitary Services[b]	Other Industry Groups	Total
				1996			
New England	--	--	3,820	36	8,415	--	12,271
Middle Atlantic	--	--	896	W	7,846	W	8,764
East North Central	--	--	2,163	W	2,596	W	5,209
West North Central	--	--	526	W	548	W	1,255
South Atlantic	W	--	9,782	2,695	6,274	W	19,078
East South Central	--	--	6,163	936	830	--	7,928
West South Central	--	--	5,740	256	1,184	--	7,180
Mountain	--	--	509	W	2,611	W	3,655
Pacific	W	--	1,280	1,080	21,762	W	24,454
U.S. Total	**311**	**--**	**30,880**	**5,376**	**52,065**	**1,162**	**89,793**

[a] Includes SIC codes 2621 (paper mills) and 2631 (paperboard mills).

[b] SIC code 49 (electric, gas, and sanitary services).

W = Withheld to avoid disclosure of individual company data.

Notes: Renewable data presented in this table differs slightly from that found in the Energy Information Administration's *Electric Power Annual 1997 Volume II* (Washington, DC, October 1998) due to slight differences in the definition of renewable energy sources. See Appendix, Table A1 of this article for details. For definitions of major industry groups, see Executive Office of the President, Office of Management and Budget, *Standard Industrial Classification Manual, 1987* (Washington, DC, 1987). Totals may not equal sum of components because of independent rounding.

Source: Energy Information Administration, Form EIA-867, "Annual Nonutility Power Producer Report."

Table 9. U.S. Electric Utility Purchases, Costs, and Average Price per Kilowatthour for Electricity Purchased from Nonutility Facilities and Utilities by Census Division and State, 1995

Census Division and State	Purchases (Million Kilowatthours)		Total Cost (Million Dollars)		Average Price (Cents/ Kilowatthour)	
	Nonutilities[a]	Utilities[b]	Nonutilities[a]	Utilities[b]	Nonutilities[a]	Utilities[b]
New England	**17,147**	**93,353**	**1,313**	**4,772**	**7.65**	**5.11**
Connecticut	3,507	15,308	285	539	8.13	3.52
Maine	3,466	9,121	320	356	9.23	3.91
Massachusetts	9,132	45,346	580	2,639	6.35	5.82
New Hampshire	1,033	9,086	128	509	12.35	5.60
Rhode Island	3	6,825	(*)	427	4.18	6.26
Vermont	7	7,667	(*)	303	6.11	3.95
Middle Atlantic	**48,386**	**113,805**	**3,023**	**3,329**	**6.25**	**2.93**
New Jersey	9,310	25,906	680	958	7.31	3.70
New York	31,176	52,445	1,904	1,307	6.11	2.49
Pennsylvania	7,900	35,454	439	1,064	5.55	3.00
East North Central	**10,114**	**139,439**	**538**	**3,947**	**5.32**	**2.83**
Illinois	258	23,944	4	748	1.6	3.12
Indiana	60	25,772	1	762	2.13	2.96
Michigan	9,592	20,986	527	615	5.49	2.93
Ohio	47	44,734	1	1,156	1.68	2.58
Wisconsin	157	24,003	5	666	3.16	2.78
West North Central	**483**	**134,418**	**17**	**3,889**	**3.54**	**2.89**
Iowa	45	14,459	3	459	5.73	3.18
Kansas	11	8,323	(*)	306	2.41	3.68
Minnesota	287	31,593	11	931	3.81	2.95
Missouri	17	41,946	1	1,087	5.05	2.59
Nebraska	45	22,783	1	647	1.92	2.84
North Dakota	39	8,242	1	245	2.42	2.97
South Dakota	39	7,073	1	214	1.61	3.02
South Atlantic	**24,568**	**238,694**	**1,519**	**10,078**	**6.18**	**4.22**
Delaware	69	5,538	5	179	7.97	3.23
District of Columbia	147	9,679	5	315	3.27	3.25
Florida	9,084	41,708	444	1,868	4.89	4.48
Georgia	313	46,937	33	2,003	10.50	4.27
Maryland	1,031	17,357	28	611	2.70	3.52
North Carolina	3,550	45,244	223	2,443	6.28	5.40
South Carolina	44	27,555	1	1,135	2.42	4.12
Virginia	9,737	37,987	742	1,311	7.62	3.45
West Virginia	593	6,690	37	213	6.29	3.18
East South Central	**366**	**180,041**	**5**	**6,831**	**1.45**	**3.79**
Alabama	238	32,565	2	1,216	0.99	3.73
Kentucky	(*)	39,763	(*)	1,253	2.00	3.15
Mississippi	50	24,965	1	996	1.74	3.99
Tennessee	79	82,748	2	3,366	2.66	4.07
West South Central	**20,678**	**120,563**	**647**	**4,228**	**3.13**	**3.51**
Arkansas	51	27,638	1	866	1.85	3.13
Louisiana	1,016	27,221	58	872	5.74	3.20
Oklahoma	3,595	14,502	222	486	6.18	3.35
Texas	16,017	51,201	365	2,005	2.28	3.92
Mountain	**8,481**	**75,661**	**407**	**2,428**	**4.80**	**3.21**
Arizona	29	15,022	1	493	1.81	3.28
Colorado	3,152	29,071	145	984	4.61	3.38
Idaho	496	3,392	28	79	5.61	2.33
Montana	570	5,476	24	148	4.19	2.70
Nevada	2,903	9,252	160	242	5.52	2.62
New Mexico	967	7,248	41	265	4.24	3.66
Utah	364	3,522	8	117	2.24	3.32
Wyoming	--	2,677	--	99	--	3.69

See notes at end of table.

Table 9. U.S. Electric Utility Purchases, Costs, and Average Price per Kilowatthour for Electricity Purchased from Nonutility Facilities and Utilities by Census Division and State, 1995 (Continued)

Census Division and State	Purchases (Million Kilowatthours)		Total Cost (Million Dollars)		Average Price (Cents/ Kilowatthour)	
	Nonutilities[a]	Utilities[b]	Nonutilities[a]	Utilities[b]	Nonutilities[a]	Utilities[b]
Pacific	**55,942**	**159,853**	**4,337**	**4,830**	**7.75**	**3.02**
Alaska	1	2,682	(*)	101	0.41	3.78
California	47,333	68,017	3,806	2,739	8.04	4.03
Hawaii	3,231	6	254	(*)	7.86	6.15
Oregon	964	41,323	62	909	6.41	2.20
Washington	4,413	47,825	216	1,079	4.89	2.26
U.S. Total	**182,934**	**1,253,138**	**11,551**	**44,230**	**6.31**	**3.53**

[a]Includes qualifying cogenerators, qualifying small power producers and other nonutility generators as defined for the Form EIA-867, "Annual Nonutility Power Producer Report."

[b] While the FERC Form 1 classifies power marketers as nonutilities, for purposes of this analysis, the "Utilities" category includes purchases from conventional utilities (investor-owned, cooperative, municipally-owned, Federal/State and other public utilities), power pools, power marketers, and utilities in Canada and Mexico as defined for the Form EIA-861, "Annual Electric Utility Report."

(*) Denotes value less than one-half unit of measure.

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

Source: 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."

Table 10. U.S. Electric Utility Purchases of Renewable Electric Power from Nonutility Facilities by Energy Source, Census Division, and State, 1995
(Million Kilowatthours)

Census Division and State	Conventional Hydroelectric	Geothermal	Wind	Solar	Wood/Wood Waste[a]	Municipal Waste[b]	Other Biomass[c]	Total
New England	**995.50**	**--**	**--**	**--**	**3,024.25**	**3,482.47**	**307.11**	**7,809.33**
Connecticut	31.97	--	--	--	--	1,219.96	193.69	1,445.62
Maine	590.04	--	--	--	2,156.53	397.27	112.70	3,256.54
Massachusetts	184.95	--	--	--	126.16	1,698.71	0.71	2,010.53
New Hampshire	187.42	--	--	--	740.19	166.53	--	1,094.13
Rhode Island	--	--	--	--	--	--	--	--
Vermont	1.13	--	--	--	1.37	--	–	2.50
Middle Atlantic	**1,492.88**	**--**	**--**	**--**	**746.81**	**4,430.10**	**--**	**6,669.79**
New Jersey	10.92	--	--	--	--	1,118.31	--	1,129.24
New York	1,136.96	--	--	--	366.07	2,181.80	--	3,684.83
Pennsylvania	345.00	--	--	--	380.73	1,129.99	--	1,855.72
East North Central	**83.63**	**--**	**--**	**--**	**936.23**	**880.74**	**9.43**	**1,910.04**
Illinois	12.05	--	--	--	--	210.03	--	222.08
Indiana	--	--	--	--	--	43.86	--	43.86
Michigan	54.28	--	--	--	933.60	486.48	9.34	1,483.70
Ohio	4.73	--	--	--	2.46	20.60	--	27.79
Wisconsin	12.57	--	--	--	0.17	119.77	0.09	132.60
West North Central	**77.24**	**--**	**54.59**	**--**	**33.94**	**274.24**	**0.77**	**440.78**
Iowa	12.30	--	--	--	0.02	0.02	--	12.34
Kansas	10.35	--	--	--	--	--	--	10.35
Minnesota	54.59	--	54.59	--	33.92	274.22	--	417.32
Missouri	--	--	--	--	--	--	(*)	(*)
Nebraska	--	--	--	--	--	--	--	--
North Dakota	--	--	--	--	--	--	0.77	0.77
South Dakota	--	--	--	--	--	--	--	--
South Atlantic	**373.38**	**--**	**--**	**--**	**1,596.78**	**4,003.74**	**87.84**	**6,061.75**
Delaware	--	--	--	--	--	--	--	--
District of Columbia	--	--	--	--	--	--	--	--
Florida	--	--	--	--	228.88	2,796.64	83.35	3,108.86
Georgia	9.18	--	--	--	0.98	--	(*)	10.16
Maryland	--	--	--	--	--	436.75	--	436.75
North Carolina	30.27	--	--	--	347.91	35.51	--	413.70
South Carolina	54.95	--	--	--	390.79	48.85	--	494.59
Virginia	29.87	--	--	--	628.22	685.99	4.49	1,348.58
West Virginia	249.11	--	--	--	--	--	--	249.11
East South Central	**--**	**--**	**--**	**--**	**1.09**	**--**	**2.57**	**3.66**
Alabama	--	--	--	--	0.45	--	2.57	3.01
Kentucky	--	--	--	--	--	--	--	--
Mississippi	--	--	--	--	0.64	--	--	0.64
Tennessee	--	--	--	--	--	--	--	--
West South Central	**869.53**	**--**	**--**	**--**	**55.00**	**3.26**	**75.99**	**1,003.78**
Arkansas	--	--	--	--	49.66	0.23	--	49.89
Louisiana	869.53	--	--	--	--	--	75.89	945.42
Oklahoma	--	--	--	--	0.01	3.03	--	3.04
Texas	--	--	--	--	5.33	--	0.10	5.43
Mountain	**977.20**	**798.67**	**--**	**--**	**502.02**	**42.87**	**11.88**	**2,332.65**
Arizona	--	--	--	--	--	--	--	--
Colorado	84.99	--	--	--	--	42.87	--	127.87
Idaho	808.40	--	--	--	502.02	--	11.88	1,322.30
Montana	49.29	--	--	--	--	--	--	49.29
Nevada	19.13	798.67	--	--	--	--	--	817.81
New Mexico	--	--	--	--	--	--	--	--
Utah	15.38	--	--	--	--	--	--	15.38
Wyoming	--	--	--	--	--	--	--	--

See notes at end of table.

Table 10. U.S. Electric Utility Purchases of Renewable Electric Power from Nonutility Facilities by Energy Source, Census Division, and State, 1995 (Continued)

Census Division and State	Conventional Hydroelectric	Geothermal	Wind	Solar	Wood/Wood Waste[a]	Municipal Waste[b]	Other Biomass[c]	Total
Pacific	**2,604.22**	**7,647.72**	**2,862.46**	**784.72**	**2,738.18**	**2,227.95**	**955.52**	**19,820.76**
Alaska	--	--	--	--	0.47	--	0.06	0.53
California	1,954.67	7,647.72	2,856.67	784.72	2,328.84	1,659.44	843.89	18,075.95
Hawaii	31.51	--	5.78	--	0.57	344.05	110.54	492.45
Oregon	351.78	--	--	--	220.15	67.83	--	639.76
Washington	266.26	--	--	--	188.15	156.63	1.03	612.07
U.S. Total	**7,473.59**	**8,446.39**	**2,917.04**	**784.72**	**9,634.31**	**15,345.38**	**1,451.10**	**46,052.54**

[a] Includes wood, wood waste, wood liquors, peat, railroad ties, utility poles, and wood sludge.

[b] Includes municipal solid waste, landfill gas, digester gas, and methane.

[c] Other biomass includes agricultural byproducts/waste, solid byproducts, liquid acetonitrile waste, medical waste, straw, tires, fish oil, tall oil, sludge waste, closed-loop biomass, and waste alcohol.

(*) Denotes value less than 0.005 million kilowatthours.

Notes: Renewable data presented in this table differs slightly from that found in the Energy Information Administration's *Electric Power Annual 1997 Volume II* (Washington, DC, October 1998) due to slight differences in the definition of renewable energy sources. See Appendix, Table A1 of this article for details. Totals may not equal sum of components because of independent rounding.

Source: 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."

Table 11. U.S. Electric Utility Costs of Renewable Electric Power Purchased from Nonutility Facilities by Energy Source, Census Division, and State, 1995
(Million Dollars)

Census Division and State	Conventional Hydroelectric	Geothermal	Wind	Solar	Wood/Wood Waste[a]	Municipal Waste[b]	Other Biomass[c]	Total
New England	**93.34**	**--**	**--**	**--**	**290.02**	**296.27**	**24.10**	**703.73**
Connecticut	2.62	--	--	--	--	102.44	15.46	120.53
Maine	57.86	--	--	--	192.50	45.71	8.56	304.64
Massachusetts	14.93	--	--	--	10.44	127.54	0.07	152.98
New Hampshire	17.90	--	--	--	87.05	20.58	--	125.53
Rhode Island	--	--	--	--	--	--	--	--
Vermont	0.02	--	--	--	0.03	--	--	0.05
Middle Atlantic	**129.09**	**--**	**--**	**--**	**53.19**	**215.63**	**--**	**397.91**
New Jersey	0.68	--	--	--	--	46.97	--	47.65
New York	105.10	--	--	--	22.94	105.33	--	233.37
Pennsylvania	23.31	--	--	--	30.25	63.33	--	116.89
East North Central	**2.91**	**--**	**--**	**--**	**61.42**	**38.10**	**0.52**	**102.95**
Illinois	0.19	--	--	--	--	3.21	–	3.40
Indiana	--	--	--	--	--	1.18	--	1.18
Michigan	2.19	--	--	--	61.36	29.13	0.52	93.19
Ohio	0.18	--	--	--	0.05	1.07	--	1.30
Wisconsin	0.36	--	--	--	0.01	3.52	0.01	3.88
West North Central	**2.59**	**--**	**3.06**	**--**	**0.94**	**12.20**	**0.01**	**18.82**
Iowa	0.61	--	--	--	(*)	(*)	--	0.61
Kansas	0.25	--	--	--	--	--	--	0.25
Minnesota	1.73	--	3.06	--	0.94	12.20	--	17.94
Missouri	--	--	--	--	--	--	(*)	(*)
Nebraska	--	--	--	--	--	--	--	--
North Dakota	--	--	--	--	--	--	0.01	0.01
South Dakota	--	--	--	--	--	--	--	--
South Atlantic	**24.37**	**--**	**--**	**--**	**104.88**	**175.70**	**6.97**	**311.91**
Delaware	--	--	--	--	--	--	--	--
District of Columbia	--	--	--	--	--	--	--	--
Florida	--	--	--	--	13.14	125.99	4.31	143.44
Georgia	0.43	--	--	--	0.02	--	(*)	0.45
Maryland	--	--	--	--	--	14.36	--	14.36
North Carolina	1.36	--	--	--	23.23	1.29	--	25.88
South Carolina	2.80	--	--	--	27.12	1.81	--	31.73
Virginia	1.47	--	--	--	41.37	32.24	2.65	77.72
West Virginia	18.32	--	--	--	--	--	--	18.32
East South Central	**--**	**--**	**--**	**--**	**0.08**	**--**	**0.40**	**0.48**
Alabama	--	--	--	--	0.07	--	0.40	0.46
Kentucky	--	--	--	--	--	--	--	--
Mississippi	--	--	--	--	0.01	--	--	0.01
Tennessee	--	--	--	--	--	--	--	--
West South Central	**55.70**	**--**	**--**	**--**	**1.01**	**0.05**	**2.69**	**59.45**
Arkansas	--	--	--	--	0.92	(*)	--	0.92
Louisiana	55.70	--	--	--	--	--	2.69	58.39
Oklahoma	--	--	--	--	(*)	0.04	--	0.04
Texas	--	--	--	--	0.09	--	(*)	0.10
Mountain	**48.58**	**42.39**	**--**	**--**	**25.26**	**1.07**	**0.49**	**117.78**
Arizona	--	--	--	--	--	--	--	--
Colorado	3.75	--	--	--	--	1.07	--	4.82
Idaho	39.65	--	--	--	25.26	--	0.49	65.40
Montana	2.74	--	--	--	--	--	--	2.74
Nevada	1.46	42.39	--	--	--	--	--	43.85
New Mexico	--	--	--	--	--	--	--	--
Utah	0.98	--	--	--	--	--	--	0.98
Wyoming	--	--	--	--	--	--	--	--

See notes at end of table.

Table 11. U.S. Electric Utility Costs of Renewable Electric Power Purchased from Nonutility Facilities by Energy Source, Census Division, and State, 1995 (Continued)

Census Division and State	Conventional Hydroelectric	Geothermal	Wind	Solar	Wood/Wood Waste[a]	Municipal Waste[b]	Other Biomass[c]	Total
Pacific	**155.96**	**951.36**	**336.38**	**124.02**	**394.64**	**223.05**	**143.40**	**2,328.81**
Alaska	--	--	--	--	--	--	--	--
California	111.84	951.36	336.03	124.02	367.18	185.34	134.67	2,210.43
Hawaii	1.77	--	0.36	--	0.03	29.39	8.69	40.24
Oregon	26.80	--	--	--	19.51	3.51	--	49.81
Washington	15.56	--	--	--	7.91	4.82	0.05	28.34
U.S. Total	**512.55**	**993.74**	**339.45**	**124.02**	**931.45**	**962.06**	**178.58**	**4,041.84**

[a] Includes wood, wood waste, wood liquors, peat, railroad ties, utility poles, and wood sludge.

[b] Includes municipal solid waste, landfill gas, digester gas, and methane.

[c] Other biomass includes agricultural byproducts/waste, solid byproducts, liquid acetonitrile waste, medical waste, straw, tires, fish oil, tall oil, sludge waste, closed-loop biomass, and waste alcohol.

(*) Denotes value less than 0.005 million dollars.

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

Source: 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.”

Table 12. U.S. Electric Utility Average Price per Kilowatthour of Renewable Electric Power Purchased from Nonutility Facilities by Energy Source, Census Division, and State, 1995
(Cents per Kilowatthour)

Census Division and State	Conventional Hydroelectric	Geothermal	Wind	Solar	Wood/Wood Waste[a]	Municipal Waste[b]	Other Biomass[c]	Total
New England	**9.38**	**--**	**--**	**--**	**9.59**	**8.51**	**7.85**	**9.01**
Connecticut	8.20	--	--	--	--	8.40	7.98	8.34
Maine	9.81	--	--	--	8.93	11.51	7.60	9.35
Massachusetts	8.07	--	--	--	8.28	7.51	10.23	7.61
New Hampshire	9.55	--	--	--	11.76	12.36	--	11.47
Rhode Island	--	--	--	--	--	--	--	--
Vermont	2.14	--	--	--	2.14	--	--	2.14
Middle Atlantic	**8.65**	**--**	**--**	**--**	**7.12**	**4.87**	**--**	**5.97**
New Jersey	6.23	--	--	--	--	4.20	--	4.22
New York	9.24	--	--	--	6.27	4.83	--	6.33
Pennsylvania	6.76	--	--	--	7.94	5.60	--	6.30
East North Central	**3.49**	**--**	**--**	**--**	**6.56**	**4.33**	**5.54**	**5.39**
Illinois	1.60	--	--	--	--	1.53	--	1.53
Indiana	--	--	--	--	--	2.68	--	2.68
Michigan	4.04	--	--	--	6.57	5.99	5.52	6.28
Ohio	3.70	--	--	--	2.22	5.19	--	4.67
Wisconsin	2.83	--	--	--	3.32	2.94	7.45	2.93
West North Central	**3.36**	**--**	**5.61**	**--**	**2.78**	**4.45**	**1.44**	**4.27**
Iowa	4.95	--	--	--	5.92	6.07	--	4.96
Kansas	2.45	--	--	--	--	--	--	2.45
Minnesota	3.17	--	5.61	--	2.78	4.45	--	4.30
Missouri	--	--	--	--	--	--	3.90	3.90
Nebraska	--	--	--	--	--	--	--	--
North Dakota	--	--	--	--	--	--	1.43	1.43
South Dakota	--	--	--	--	--	--	--	--
South Atlantic	**6.53**	**--**	**--**	**--**	**6.57**	**4.39**	**7.93**	**5.15**
Delaware	--	--	--	--	--	--	--	--
District of Columbia	--	--	--	--	--	--	--	--
Florida	--	--	--	--	5.74	4.51	5.18	4.61
Georgia	4.65	--	--	--	2.31	--	2.58	4.42
Maryland	--	--	--	--	--	3.29	--	3.29
North Carolina	4.49	--	--	--	6.68	3.64	--	6.26
South Carolina	5.10	--	--	--	6.94	3.71	--	6.42
Virginia	4.92	--	--	--	6.58	4.70	59.02	5.76
West Virginia	7.35	--	--	--	--	--	--	7.35
East South Central	**--**	**--**	**--**	**--**	**7.41**	**--**	**15.43**	**13.04**
Alabama	--	--	--	--	15.42	--	15.43	15.43
Kentucky	--	--	--	--	--	--	--	--
Mississippi	--	--	--	--	1.86	--	--	1.86
Tennessee	--	--	--	--	--	--	--	--
West South Central	**6.41**	**--**	**--**	**--**	**1.84**	**1.47**	**3.54**	**5.92**
Arkansas	--	--	--	--	1.85	2.01	--	1.85
Louisiana	6.41	--	--	--	--	--	3.54	6.18
Oklahoma	--	--	--	--	1.72	1.43	--	1.43
Texas	--	--	--	--	1.77	--	1.73	1.77
Mountain	**4.97**	**5.31**	**--**	**--**	**5.03**	**2.49**	**4.11**	**5.05**
Arizona	--	--	--	--	--	--	--	--
Colorado	4.41	--	--	--	--	2.49	--	3.77
Idaho	4.90	--	--	--	5.03	--	4.11	4.95
Montana	5.55	--	--	--	--	--	--	5.55
Nevada	7.64	5.31	--	--	--	--	--	5.36
New Mexico	--	--	--	--	--	--	--	--
Utah	6.37	--	--	--	--	--	--	6.37
Wyoming	--	--	--	--	--	--	--	--

See notes at end of table.

Table 12. U.S. Electric Utility Average Price per Kilowatthour of Renewable Electric Power Purchased from Nonutility Facilities by Energy Source, Census Division, and State, 1995 (Continued)

Census Division and State	Conventional Hydroelectric	Geothermal	Wind	Solar	Wood/Wood Waste[a]	Municipal Waste[b]	Other Biomass[c]	Total
Pacific	**5.99**	**12.44**	**11.75**	**15.80**	**14.41**	**10.01**	**15.01**	**11.75**
Alaska	--	--	--	--	--	--	--	--
California	5.72	12.44	11.76	15.80	15.77	11.17	15.96	12.23
Hawaii	5.62	--	6.15	--	5.93	8.54	7.86	8.17
Oregon	7.62	--	--	--	8.86	5.17	--	7.79
Washington	5.84	--	--	--	4.21	3.08	4.43	4.63
U.S. Total	**6.86**	**11.77**	**11.64**	**15.80**	**9.67**	**6.27**	**12.31**	**8.78**

[a] Includes wood, wood waste, wood liquors, peat, railroad ties, utility poles, and wood sludge.

[b] Includes municipal solid waste, landfill gas, digester gas, and methane.

[c] Other biomass includes agricultural byproducts/waste, solid byproducts, liquid acetonitrile waste, medical waste, straw, tires, fish oil, tall oil, sludge waste, closed-loop biomass, and waste alcohol.

Notes: Data for 1995 are final.

Source: 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."

Table 13. U.S. Electric Utility Purchases of Renewable Electric Power from Nonutility Facilities by Industry Group, Census Division, and State, 1995
(Million Kilowatthours)

Census Division and State	Agriculture/ Forestry	Mining	Paper and Allied Products[a]	All Other Manufacturing	Electric/ Sanitary Services[b]	Other Industry Groups	Total
New England	**--**	**--**	**1,229.03**	**5.09**	**6,575.21**	**--**	**7,809.33**
Connecticut	--	--	--	2.06	1,443.57	--	1,445.62
Maine	--	--	1,225.15	3.03	2,028.36	--	3,256.54
Massachusetts	--	--	0.52	--	2,010.01	--	2,010.53
New Hampshire	--	--	0.86	--	1,093.27	--	1,094.13
Rhode Island	--	--	--	--	--	--	--
Vermont	--	--	2.50	--	--	--	2.50
Middle Atlantic	**--**	**--**	**204.98**	**(*)**	**6,464.81**	**--**	**6,669.79**
New Jersey	--	--	--	--	1,129.24	--	1,129.24
New York	--	--	4.14	(*)	3,680.68	--	3,684.83
Pennsylvania	--	--	200.84	--	1,654.89	--	1,855.72
East North Central	**--**	**--**	**6.40**	**8.01**	**1,708.69**	**186.94**	**1,910.04**
Illinois	--	--	--	--	222.08	--	222.08
Indiana	--	--	--	--	43.86	--	43.86
Michigan	--	--	5.40	5.55	1,295.26	177.49	1,483.70
Ohio	--	--	--	2.46	25.33	--	27.79
Wisconsin	--	--	0.99	--	122.16	9.44	132.60
West North Central	**--**	**--**	**--**	**47.40**	**383.94**	**9.44**	**440.78**
Iowa	--	--	--	0.04	12.30	--	12.34
Kansas	--	--	--	--	10.35	--	10.35
Minnesota	--	--	--	46.59	361.29	9.44	417.32
Missouri	--	--	--	--	--	(*)	(*)
Nebraska	--	--	--	--	--	--	--
North Dakota	--	--	--	0.77	--	--	0.77
South Dakota	--	--	--	--	--	--	--
South Atlantic	**19.30**	**--**	**892.70**	**19.21**	**5,123.76**	**6.77**	**6,061.75**
Delaware	--	--	--	--	--	--	--
District of Columbia	--	--	--	--	--	--	--
Florida	19.30	--	10.44	--	3,079.12	--	3,108.86
Georgia	--	--	0.98	(*)	9.18	--	10.16
Maryland	--	--	--	--	429.98	6.77	436.75
North Carolina	--	--	--	10.73	402.97	--	413.70
South Carolina	--	--	390.79	--	103.80	--	494.59
Virginia	--	--	490.49	--	858.09	--	1,348.58
West Virginia	--	--	--	8.48	240.63	--	249.11
East South Central	**--**	**--**	**--**	**0.64**	**3.01**	**--**	**3.66**
Alabama	--	--	--	--	3.01	--	3.01
Kentucky	--	--	--	--	--	--	--
Mississippi	--	--	--	0.64	--	--	0.64
Tennessee	--	--	--	--	--	--	--
West South Central	**--**	**--**	**0.94**	**57.24**	**945.60**	**--**	**1,003.78**
Arkansas	--	--	0.94	48.72	0.23	--	49.89
Louisiana	--	--	--	0.04	945.37	--	945.42
Oklahoma	--	--	--	3.04	--	--	3.04
Texas	--	--	--	5.43	--	--	5.43
Mountain	**--**	**--**	**362.59**	**74.55**	**1,511.27**	**384.23**	**2,332.65**
Arizona	--	--	--	--	--	--	--
Colorado	--	--	--	--	127.87	--	127.87
Idaho	--	--	362.59	74.55	500.92	384.23	1,322.30
Montana	--	--	--	--	49.29	--	49.29
Nevada	--	--	--	--	817.81	--	817.81
New Mexico	--	--	--	--	--	--	--
Utah	--	--	--	--	15.38	--	15.38
Wyoming	--	--	--	--	--	--	--

See notes at end of table.

Table 13. U.S. Electric Utility Purchases of Renewable Electric Power from Nonutility Facilities by Industry Group, Census Division, and State, 1995 (Continued)

Census Division and State	Agriculture/ Forestry	Mining	Paper and Allied Products[a]	All Other Manufacturing	Electric/ Sanitary Services[b]	Other Industry Groups	Total
Pacific	**107.90**	**--**	**168.62**	**589.09**	**18,870.13**	**85.03**	**19,820.76**
Alaska	--	--	0.53	--	--	--	0.53
California	26.59	--	--	506.20	17,543.14	0.02	18,075.95
Hawaii	81.31	--	--	61.31	349.83	--	492.45
Oregon	--	--	--	0.38	639.38	--	639.76
Washington	--	--	168.09	21.20	337.77	85.01	612.07
U.S. Total	**127.20**	**--**	**2,865.26**	**801.24**	**41,586.42**	**672.41**	**46,052.54**

[a] Includes SIC codes 2621 (paper mills) and 2631 (paperboard mills).
[b] SIC code 49 (electric, gas, and sanitary services).
(*)Denotes value less than 0.005 million.

Notes: Data for 1995 are final. See Technical Notes for Standard Industrial Classifications for these industry groups. Totals may not equal sum of components because of independent rounding.

Source: 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."

Table 14. U.S. Electric Utility Costs of Renewable Electric Power Purchases from Nonutility Facilities by Industry Group, Census Division, and State, 1995
(Million Dollars)

Census Division and State	Agriculture/ Forestry	Mining	Paper and Allied Products[a]	All Other Manufacturing	Electric/ Sanitary Services[b]	Other Industry Groups	Total
New England	**--**	**--**	**88.34**	**0.23**	**615.17**	**--**	**703.73**
Connecticut	--	--	--	0.05	120.47	--	120.53
Maine	--	--	88.26	0.17	216.21	--	304.64
Massachusetts	--	--	0.01	--	152.97	--	152.98
New Hampshire	--	--	0.02	--	125.52	--	125.53
Rhode Island	--	--	--	--	--	--	--
Vermont	--	--	0.05	--	--	--	0.05
Middle Atlantic	**--**	**--**	**18.90**	**(*)**	**379.01**	**--**	**397.91**
New Jersey	--	--	--	--	47.65	--	47.65
New York	--	--	0.16	(*)	233.21	--	233.37
Pennsylvania	--	--	18.74	--	98.15	--	116.89
East North Central	**--**	**--**	**0.12**	**0.15**	**91.92**	**10.77**	**102.95**
Illinois	--	--	--	--	3.40	--	3.40
Indiana	--	--	--	--	1.18	--	1.18
Michigan	--	--	0.08	0.09	82.51	10.50	93.19
Ohio	--	--	--	0.05	1.24	--	1.30
Wisconsin	--	--	0.03	--	3.59	0.26	3.88
West North Central	**--**	**--**	**--**	**1.13**	**17.56**	**0.14**	**18.82**
Iowa	--	--	--	(*)	0.61	--	0.61
Kansas	--	--	--	--	0.25	--	0.25
Minnesota	--	--	--	1.11	16.69	0.14	17.94
Missouri	--	--	--	--	--	(*)	(*)
Nebraska	--	--	--	--	--	--	--
North Dakota	--	--	--	0.01	--	--	0.01
South Dakota	--	--	--	--	--	--	--
South Atlantic	**0.37**	**--**	**47.38**	**0.33**	**263.60**	**0.23**	**311.91**
Delaware	--	--	--	--	--	--	--
District of Columbia	--	--	--	--	--	--	--
Florida	0.37	--	0.23	--	142.84	--	143.44
Georgia	--	--	0.02	(*)	0.43	--	0.45
Maryland	--	--	--	--	14.13	0.23	14.36
North Carolina	--	--	--	0.25	25.63	--	25.88
South Carolina	--	--	27.12	--	4.61	--	31.73
Virginia	--	--	20.01	--	57.72	--	77.72
West Virginia	--	--	--	0.08	18.23	--	18.32
East South Central	**--**	**--**	**--**	**0.01**	**0.46**	**--**	**0.48**
Alabama	--	--	--	--	0.46	--	0.46
Kentucky	--	--	--	--	--	--	--
Mississippi	--	--	--	0.01	--	--	0.01
Tennessee	--	--	--	--	--	--	--
West South Central	**--**	**--**	**0.02**	**1.04**	**58.39**	**--**	**59.45**
Arkansas	--	--	0.02	0.90	(*)	--	0.92
Louisiana	--	--	--	(*)	58.39	--	58.39
Oklahoma	--	--	--	0.04	--	--	0.04
Texas	--	--	--	0.10	--	--	0.10
Mountain	**--**	**--**	**14.91**	**5.31**	**82.02**	**15.54**	**117.78**
Arizona	--	--	--	--	--	--	--
Colorado	--	--	--	--	4.82	--	4.82
Idaho	--	--	14.91	5.31	29.64	15.54	65.40
Montana	--	--	--	--	2.74	--	2.74
Nevada	--	--	--	--	43.85	--	43.85
New Mexico	--	--	--	--	--	--	--
Utah	--	--	--	--	0.98	--	0.98
Wyoming	--	--	--	--	--	--	--

See notes at end of table.

Table 14. U.S. Electric Utility Costs of Renewable Electric Power Purchases from Nonutility Facilities by Industry Group, Census Division, and State, 1995 (Continued)

Census Division and State	Agriculture/ Forestry	Mining	Paper and Allied Products[a]	All Other Manufacturing	Electric/ Sanitary Services[b]	Other Industry Groups	Total
Pacific	**7.12**	**--**	**7.39**	**58.10**	**2,253.50**	**2.70**	**2,328.81**
Alaska	--	--	--	--	--	--	--
California	1.09	--	--	53.06	2,156.28	(*)	2,210.43
Hawaii	6.03	--	--	4.46	29.74	--	40.24
Oregon	--	--	--	0.01	49.80	--	49.81
Washington	--	--	7.39	0.57	17.67	2.70	28.34
U.S. Total	**7.49**	**--**	**177.05**	**66.30**	**3,761.63**	**29.37**	**4,041.84**

[a] Includes SIC codes 2621 (paper mills) and 2631 (paperboard mills).

[b] SIC code 49 (electric, gas, and sanitary services).

(*)Denotes value less than 0.005 million.

Notes: Data for 1995 are final. See Technical Notes for Standard Industrial Classifications for these industry groups. Totals may not equal sum of components because of independent rounding.

Source: 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."

Table 15. U.S. Electric Utility Average Price per Kilowatthour of Renewable Electric Power Purchased from Nonutility Facilities by Industry Group, Census Division, and State, 1995
(Cents per Kilowatthour)

Census Division and State	Agriculture/ Forestry	Mining	Paper and Allied Products[a]	All Other Manufacturing	Electric/ Sanitary Services[b]	Other Industry Groups	Total
	Average Price						
New England	**--**	**--**	**7.19**	**4.49**	**9.36**	**--**	**9.01**
Connecticut	--	--	--	2.63	8.35	--	8.34
Maine	--	--	7.20	5.75	10.66	--	9.35
Massachusetts	--	--	2.22	--	7.61	--	7.61
New Hampshire	--	--	1.78	--	11.48	--	11.47
Rhode Island	--	--	--	--	--	--	--
Vermont	--	--	2.14	--	--	--	2.14
Middle Atlantic	**--**	**--**	**9.22**	**1.40**	**5.86**	**--**	**5.97**
New Jersey	--	--	--	--	4.22	--	4.22
New York	--	--	3.76	1.40	6.34	--	6.33
Pennsylvania	--	--	9.33	--	5.93	--	6.30
East North Central	**--**	**--**	**1.82**	**1.84**	**5.38**	**5.76**	**5.39**
Illinois	--	--	--	--	1.53	--	1.53
Indiana	--	--	--	--	2.68	--	2.68
Michigan	--	--	1.55	1.67	6.37	5.92	6.28
Ohio	--	--	--	2.22	4.91	--	4.67
Wisconsin	--	--	3.30	--	2.94	2.81	2.93
West North Central	**--**	**--**	**--**	**2.38**	**4.57**	**1.45**	**4.27**
Iowa	--	--	--	6.01	4.95	--	4.96
Kansas	--	--	--	--	2.45	--	2.45
Minnesota	--	--	--	2.39	4.62	1.45	4.30
Missouri	--	--	--	--	--	3.90	3.90
Nebraska	--	--	--	--	--	--	--
North Dakota	--	--	--	1.43	--	--	1.43
South Dakota	--	--	--	--	--	--	--
South Atlantic	**1.92**	**--**	**5.31**	**1.72**	**5.14**	**3.38**	**5.15**
Delaware	--	--	--	--	--	--	--
District of Columbia	--	--	--	--	--	--	--
Florida	1.92	--	2.18	--	4.64	--	4.61
Georgia	--	--	2.32	0.66	4.65	--	4.42
Maryland	--	--	--	--	3.29	3.38	3.29
North Carolina	--	--	--	2.30	6.36	--	6.26
South Carolina	--	--	6.94	--	4.44	--	6.42
Virginia	--	--	4.08	--	6.73	--	5.76
West Virginia	--	--	--	1.00	7.58	--	7.35
East South Central	**--**	**--**	**--**	**1.86**	**15.43**	**--**	**13.04**
Alabama	--	--	--	--	15.43	--	15.43
Kentucky	--	--	--	--	--	--	--
Mississippi	--	--	--	1.86	--	--	1.86
Tennessee	--	--	--	--	--	--	--
West South Central	**--**	**--**	**1.85**	**1.82**	**6.18**	**--**	**5.92**
Arkansas	--	--	1.85	1.85	2.01	--	1.85
Louisiana	--	--	--	2.21	6.18	--	6.18
Oklahoma	--	--	--	1.43	--	--	1.43
Texas	--	--	--	1.77	--	--	1.77
Mountain	**--**	**--**	**4.11**	**7.12**	**5.43**	**4.04**	**5.05**
Arizona	--	--	--	--	--	--	--
Colorado	--	--	--	--	3.77	--	3.77
Idaho	--	--	4.11	7.12	5.92	4.04	4.95
Montana	--	--	--	--	5.55	--	5.55
Nevada	--	--	--	--	5.36	--	5.36
New Mexico	--	--	--	--	--	--	--
Utah	--	--	--	--	6.37	--	6.37
Wyoming	--	--	--	--	--	--	--

See notes at end of table.

Table 15. U.S. Electric Utility Average Price per Kilowatthour of Renewable Electric Power Purchased from Nonutility Facilities by Industry Group, Census Division, and State, 1995 (Continued)

Census Division and State	Agriculture/ Forestry	Mining	Paper and Allied Products[a]	All Other Manufacturing	Electric/ Sanitary Services[b]	Other Industry Groups	Total
	Average Price						
Pacific	**6.60**	**--**	**4.38**	**9.86**	**11.94**	**3.18**	**11.75**
Alaska	--	--	--	--	--	--	--
California	4.09	--	--	10.48	12.29	2.05	12.23
Hawaii	7.42	--	--	7.28	8.50	--	8.17
Oregon	--	--	--	2.16	7.79	--	7.79
Washington	--	--	4.40	2.69	5.23	3.18	4.63
U.S. Total	**5.89**	**--**	**6.18**	**8.27**	**9.05**	**4.37**	**8.78**

[a] Includes SIC codes 2621 (paper mills) and 2631 (paperboard mills).

[b] SIC code 49 (electric, gas, and sanitary services).

Notes: Data for 1995 are final. See Technical Notes for Standard Industrial Classifications for these industry groups.

Source: 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."

Table 16. U.S. Electric Purchases, Costs, and Average Price per Kilowatthour for Renewable Electric Power Purchased from Nonutility Facilities by QF Status, Census Division, and State, 1995

Census Division and State	Purchases from QFs[a]			Purchases from Non-QFs[a]			Total Purchases Renewable Facilities		
	Million Mwh	Million Dollars	Cents per kWh	Million Mwh	Million Dollars	Cents per kWh	Million Mwh	Million Dollars	Cents per kWh
New England	**7,632**	**689**	**9.03**	**178**	**15**	**8.41**	**7,809**	**704**	**9.01**
Connecticut	1,421	118	8.33	25	2	8.75	1,446	121	8.34
Maine	3,166	297	9.38	90	8	8.35	3,257	305	9.35
Massachusetts	1,995	152	7.62	16	1	5.74	2,011	153	7.61
New Hampshire	1,048	121	11.56	46	4	9.42	1,094	126	11.47
Rhode Island	--	--	--	--	(*)	--	--	(*)	--
Vermont	1	(*)	2.14	1	(*)	2.14	3	(*)	2.14
Middle Atlantic	**6,459**	**384**	**5.94**	**211**	**14**	**6.63**	**6,670**	**398**	**5.97**
New Jersey	1,129	48	4.22	--	--	--	1,129	48	4.22
New York	3,496	221	6.31	189	13	6.70	3,685	233	6.33
Pennsylvania	1,833	116	6.30	22	1	6.00	1,856	117	6.30
East North Central	**1,909**	**103**	**5.39**	**1**	(*)	**2.74**	**1,910**	**103**	**5.39**
Illinois	222	3	1.53	--	--	--	222	3	1.53
Indiana	44	1	2.68	--	--	--	44	1	2.68
Michigan	1,484	93	6.28	(*)	(*)	1.50	1,484	93	6.28
Ohio	28	1	4.67	--	--	--	28	1	4.67
Wisconsin	132	4	2.93	1	(*)	2.81	133	4	2.93
West North Central	**422**	**18**	**4.30**	**19**	**1**	**3.69**	**441**	**19**	**4.27**
Iowa	12	1	5.05	1	(*)	3.70	12	1	4.96
Kansas	10	(*)	2.45	--	--	--	10		2.45
Minnesota	399	17	4.33	18	1	3.69	417	18	4.30
Missouri	(*)	(*)	3.90	--	--	--	(*)	(*)	3.90
Nebraska	--	--	--	--	--	--	--	--	--
North Dakota	1	(*)	1.43	--	--	--	1	(*)	1.43
South Dakota	--	--	--	--	--	--	--	--	--
South Atlantic	**6,026**	**311**	**5.16**	**36**	**1**	**2.88**	**6,062**	**312**	**5.15**
Delaware	--	--	--	--	--	--	--	--	--
District of Columbia	--	--	--	--	--	--	--	--	--
Florida	3,109	143	4.61	--	--	--	3,109	143	4.61
Georgia	5	(*)	8.86	6	(*)	0.83	10	(*)	4.42
Maryland	437	14	3.29	--	--	--	437	14	3.29
North Carolina	397	25	6.35	17	1	3.89	414	26	6.26
South Carolina	490	31	6.43	5	(*)	5.09	495	32	6.42
Virginia	1,349	78	5.76	--	--	--	1,349	78	5.76
West Virginia	241	18	7.58	8	(*)	1.00	249	18	7.35
East South Central	**4**	(*)	**13.04**	**--**	**--**	**--**	**4**	(*)	**13.04**
Alabama	3	(*)	15.43	--	--	--	3	(*)	15.43
Kentucky	--	--	--	--	--	--	--	--	--
Mississippi	1	(*)	1.86	--	--	--	1	(*)	1.86
Tennessee	--	--	--	--	--	--	--	--	--
West South Central	**134**	**4**	**2.79**	**870**	**56**	**6.41**	**1,004**	**59**	**5.92**
Arkansas	50	1	1.85	--	--	--	50	1	1.85
Louisiana	76	3	3.54	870	56	6.41	945	58	6.18
Oklahoma	3	(*)	1.43	--	--	--	3	(*)	1.43
Texas	5	(*)	1.77	--	--	--	5	(*)	1.77
Mountain	**1,785**	**93**	**5.23**	**547**	**24**	**4.46**	**2,333**	**118**	**5.05**
Arizona	--	--	--	--	--	--	--	--	--
Colorado	93	3	3.60	34	1	4.21	128	5	3.77
Idaho	862	45	5.27	460	20	4.34	1,322	65	4.95
Montana	7	(*)	6.12	42	2	5.45	49	3	5.55
Nevada	818	44	5.36	--	--	--	818	44	5.36
New Mexico	--	--	--	--	--	--	--	--	--
Utah	5	(*)	4.95	11	1	7.00	15	1	6.37
Wyoming	--	--	--	--	--	--	--	--	--

See notes at end of table.

Table 16. U.S. Electric Purchases, Costs, and Average Price per Kilowatthour for Renewable Electric Power Purchased from Nonutility Facilities by QF Status, Census Division, and State, 1995 (Continued)

Census Division and State	Purchases from QFs[a]			Purchases from Non-QFs[a]			Total Purchases Renewable Facilities		
	Million Mwh	Million Dollars	Cents per kWh	Million Mwh	Million Dollars	Cents per kWh	Million Mwh	Million Dollars	Cents per kWh
Pacific	**18,381**	**2,269**	**12.34**	**1,440**	**60**	**4.16**	**19,821**	**2,329**	**11.75**
Alaska	1	--	--	--	--	--	1	--	--
California	17,005	2,175	12.79	1,071	36	3.33	18,076	2,210	12.23
Hawaii	461	38	8.34	32	2	5.62	492	40	8.17
Oregon	404	34	8.37	236	16	6.79	640	50	7.79
Washington	511	22	4.28	101	6	6.39	612	28	4.63
U.S. Total	**42,753**	**3,871**	**9.05**	**3,300**	**171**	**5.17**	**46,053**	**4,042**	**8.78**

[a] QF = Qualifying facility. Defined as a nonutility generating facility that has obtained status as a qualifying facility under the Public Utility Regulatory Policies Act of 1978.

(*)Denotes value less than one-half the unit of measure.

kWh = Kilowatthour.

MWh = Megawatthour.

Notes: Data for 1995 are final. See Technical Notes for Standard Industrial Classifications for these industry groups. Totals may not equal sum of components because of independent rounding.

Source: 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."

Appendix

Renewable Electricity Purchased Power Prices Methodology

Renewable Energy Sources

Broadly, renewable energy includes any source that is regenerative or virtually inexhaustible. Thus, sources the Energy Information Administration (EIA) classifies as renewable are: wind, solar, photovoltaic, geothermal, hydropower, and biomass (See Table A1 for details.) Although the EIA collects no data specifically on the cost of producing renewable-based electricity, it and the Federal Energy Regulatory Commission (FERC) do collect some information on the prices utilities pay for the power they purchase.

The EIA collects a wide variety of information about the U.S. electric power industry. This includes detailed data on capability and generation for utilities (Forms EIA 759 and 860)[27] and nonutilities (Form EIA 867).[28] Though these annual surveys have no information on electricity prices, various Federal electric power industry financial surveys have this data. These include FERC Form 1, Form EIA-412, and the U.S. Department of Agriculture's Rural Utilities Service (RUS) forms. Each has information on electric utility power purchase quantities and prices paid.[29]

The main focus of this study is on renewable power sold by nonutilities reporting on the EIA-867 survey. The EIA-867 survey collects information, including power sales, from all nonutility generating facilities with a rated capacity of 1 megawatt or greater. Conventional hydroelectric facilities and a small number of other renewable facilities, all operated by electric utilities, are excluded from the study because of limitations on the data. By merging information from the EIA-867 survey with EIA's Financial Surveys Bulk Power Database,[30] data about capability, generation and the purchase price of renewable power could be assembled by certain characteristics, (e.g. renewable fuel type, industry grouping or SIC Code, geographic division, and QF status).

Methodology

The EIA does not explicitly collect price data for renewable electricity. Instead, prices were calculated by merging data sources and making certain assumptions to be explained here. In short, the Financial Surveys Bulk Power Database has information on the utilities' quantity of purchases and the total amount paid, but it does not identify the energy source. However, this information in the Financial Surveys Bulk Power Database can be linked to the EIA-867 nonutility survey, which does report data for energy source, sales to utilities, and the quantity of power sold.

To facilitate making the link between the two databases and to improve accuracy, certain procedures were adopted. First, renewable facilities reporting that they used renewable energy sources to generate power were identified from the EIA-867 survey. The names of the utilities sold to and the amount sold were identified. This information was then matched with the Financial Surveys Bulk Power Database, from which the utilities' reported purchases and amounts paid were taken. In cases where more than one energy source had been consumed in generation, the purchased quantity was allocated to type of energy source by using the appropriate proportion to the type of energy consumed for generation, according to Form EIA-867 survey data.

Some care was taken to match names of facilities in both databases using a dictionary of aliases and information

[27] Refers to Form EIA-759, "Monthly Power Plant Report," and Form EIA-860, "Annual Electric Generator Report."

[28] For facilities 1 megawatt or greater capacity reporting on Form EIA-867, "Annual Nonutility Power Producer Report."

[29] Refers to Federal Energy Regulatory Commission, FERC Form 1, "Annual Report of Major Electric Utilities, Licensees and Others," 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."

[30] The Financial Bulk Power Database assimilates information from all Federal electric power industry surveys mentioned.

Table A1. Renewable Energy Sources

Water
Geothermal
Wind
Solar
Biomass
Wood/Wood Waste
Black Liquor
Peat
Railroad Ties
Red Liquor
Sludge Wood
Spent Sulfite Liquor
Utility Poles[a]
Wood/Wood Waste
Municipal Waste[b]
Digester Gas
Landfill Gas
Methane
Municipal Solid Waste
Other Biomass
Agricultural Byproducts/Waste
Closed Loop Biomass
Fish Oil
Liquid Acetonitrile Waste
Medical Waste
Sludge Waste
Solid Byproducts
Straw
Tall Oil
Tires
Waste Alcohol
Excluded
Paper Pellets
Pitch[c]

[a]In previous EIA reports, utility poles were included as an “other” nonrenewable source. Since the poles used in electricity generation are wood, they are included here as a renewable source.

[b]In previous EIA reports, digester gas and methane were included as “other” nonrenewable sources. Since these fuels are reported primariliy by waste treatment facilities, they are included here as renewables.

[c]In previous EIA reports, pitch was included as a wood source. However, since it is reported primarily by chemical companies, it is excluded here.

found in the National Renewable Energy Laboratory’s Renewable Energy Plant Information System (REPIS), thus minimizing nonmatches.

Data Sources and Limitations

Surveys/Databases

“EIA 867 Nonutility Survey” refers to the Energy Information Administration, Form EIA-867, “Annual Nonutility Power Producer Report.” “Financial Surveys Bulk Power Database” includes the merged 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.” “REPIS” refers to U.S. Department of Energy, National Renewable Energy Laboratory, Energy Efficiency and Renewable Energy Network, Renewable Electric Plant Information System. “QF Filings” refers to the publicly available applications to FERC to obtain status as a “Qualified Facility.”

Data Element Sources

Renewable Fuel Type, Installed Capacity, State: EIA 867 Nonutility Survey, REPIS, and QF Filings. Note: Facilities with more than half their generation from renewable energy were classified as renewable.

Qualified Facility Status: EIA 867 Nonutility Survey and QF Filings.

SIC Code and Generation: EIA 867 Nonutility Survey. Note: generation is allocated to fuel type according to the mix of reported energy units of fuel input to generation.

Electric utility sold to and quantity: EIA 867 Nonutility Survey

Electric utility purchases, amount, price, and generator purchased from: Financial Surveys Bulk Power Database. Note anomalies occurred in the price data when the utilities had some abnormality such as a high demand charge (take or pay contract) and a small amount purchased. Oddities also occurred when the price was low—presumably waste disposal options with revenue from electricity sales a secondary objective.

Confidentiality Issues

Information found on the Form EIA 867 Nonutility Survey, Schedules III through VII, is held confidential under the provisions of the Freedom of Information Act (FOIA). Hence, in Tables 1–8 information is withheld when there are three or fewer respondents in a table cell, or one respondent has more than 90 percent of the value in a cell.

Information on fuel type, though reported on Schedule II of the Form EIA-867, was obtained from two public sources, REPIS and FERC QF filings. Purchase price information was obtained from the EIA's Financial Surveys Bulk Power Database, which is nonconfidential. Thus, no data in Tables 9–16 were suppressed.

Limitations

Although EIA made every effort to include all nonutility purchased power data in this analysis, there are some gaps. The largest one is structural: the power one industrial firm sells to another. The Federal government does not collect data on power transactions between industrial firms. The amount of these purchases is unknown. Not having information on this sector is particularly unfortunate here, because such transactions are only made if both parties perceive there is a benefit to selling / purchasing power. Thus, they would represent a true look at nonutility power purchases made under the type of competitive conditions which some restructuring proposals hope to foster.

In addition, transactions involving nonutilities with hydropower and biomass-based generating facilities with capacity rated at less than 1 megawatt were excluded. This arises largely because the EIA-867 survey does not collect information from facilities under this threshold. REPIS does contain all facilities, including those with a rated capacity less than 1 megawatt, but it was judged too difficult to use, given the perceived benefit.

Another major limitation involves prices ascribed to power purchases from facilities with both renewable and non-renewable fuels. The EIA-867 fuel inputs are for total generation and not power sold, yet the utility costs used are for total power purchased. There is thus an unknown bias in the prices shown for multifuel facilities.

As indicated above, this analysis included all EIA-867 facilities which sold any renewable power to utilities. This has the effect of assigning to renewables purchased power costs which could be from principally nonrenewable facilities. Since renewable energy is perceived to be more expensive than nonrenewable energy, this process should cause renewable purchased power prices shown to be lower than what they might be in fact. The opposite approach was considered—excluding all but "pure" renewable facilities. This approach would eliminate the price bias but would, in some cases, severely limit the amount of generation data available and call into question whether the average prices shown were truly representative. Finally, a small number of transactions could not be matched between the Bulk Power Database and the EIA-867 / REPIS and were not useable for this analysis.

Regarding prices, EIA has insufficient data to examine prices in the level of detail desirable. For example, EIA data does not give any indication of the position on the load curve for electricity sold; thus, there is some inherent inaccuracy in some of the price comparisons made in this chapter. Ideally, one would match prices for an electricity purchase taking into account the power's position on the load curve as it was dispatched. For example, the price of renewable electricity meeting peak load would be compared with the price on non-renewable electricity meeting peaking load. Undoubtedly, the difference between these two statistics would be less than the comparisons made in this chapter in Figure 2. However, no data exists to make this comparison.

Also, it must be recognized that the prices presented here for 1995 represent a mixture of prices based on contracts signed in the mid-1980s and some that were renewed in the early 1990s. EIA has no data to permit separating "old" and "new" contracts. Finally, in cases where there were two or more energy sources consumed in generation, an average price common to all was assigned. To the extent fossil fuels were used in greater proportion compared to non-hydroelectric renewables, this may have understated renewable prices.

The above material relates to limitations on the availability and quality of data. In addition, the data need to be qualified in terms of what they represent. The financial data presented in this chapter represent *prices paid*, most often under the umbrella of avoided cost. These data should not be interpreted as representing the cost of generation, or the cost of generation plus a regulated mark-up. While (as indicated previously) PURPA's avoided cost philosophy was supposed to relate to the concept of cost, it was a cost projected up to 10 years in advance. The projections of conventional generating fuel prices, as mentioned earlier, were much higher than those which were realized. It is therefore not surprising that considerable anecdotal evidence in the biomass area strongly suggests that current actual generating costs, plus a reasonable return on investment, are much lower than comparable prices paid shown in this chapter.

Transmission Pricing Issues for Electricity Generation from Renewable Resources

by Larry Prete[1]

Abstract

This article discusses how the resolution of transmission pricing issues which have arisen under the Federal Energy Regulatory Commission's (FERC) "open access" environment may affect the prospects for renewable-based electricity. After giving some preparatory material on the deregulated electricity market and on renewable energy characteristics relevant to electricity transmission, the article discusses alternatives being considered for pricing transmission, provides qualitative impacts of those choices on renewable electricity transmission costs, and concludes with alternatives for reducing renewable-based electricity transmission costs.

Introduction

Historically, transmission pricing has not been a concern for renewable generating facilities. Most renewable generation (excluding hydroelectric) in the United States has been developed, owned, financed, and operated by nonutility generators (NUG). Renewable NUG power plants generally have operated under FERC's "qualifying facility" (QF)[2] status, selling their power to the utility in whose service territory they were located. Utilities purchased this power under long-term contracts at a specified rate that included all transmission services (bundled rates).

Now, however, FERC's "open access" policy makes transmission lines available competitively and requires various transmission services to be priced separately from generation.[3] For a couple of reasons, it is important to consider how new transmission pricing schemes may affect renewables. One major reason is that substantial growth in renewable-based electricity could occur under a number of Federal and State electricity restructuring and greenhouse gas reduction proposals.[4] Many States are presently establishing policies affecting renewables (e.g., renewable portfolio standards, system benefit charges), and more States are expected to follow. The Administration has proposed a Federal electric restructuring plan that includes renewable incentives. These policies will also result in new renewable capacity. Growth is expected in renewable-based electricity under these scenarios, even though in most circumstances renewable-based generation is considerably more expensive than fossil fuel-based electricity. But even if such programs do not materialize, the limited opportunities where renewables can be economically competitive with conventional generation represent substantial growth potential from the present

[1] Larry Prete is an engineer with the Office of Coal, Nuclear, Electric and Alternate Fuels, Energy Information Administration. He gratefully acknowledges the contributions from the papers: "Transmission Pricing and Renewables: Issues, Options, and Recommendations," Stoft, Steven; Webber, Carrie; and Wiser, Ryan, Lawrence Berkeley National Laboratory; "What is Happening to Independent System Operators?" and "Open Access Transmission and Renewable Energy Technologies," Kevin Porter, National Renewable Energy Laboratory. Mr. Porter also provided a detailed technical review of the article.

[2] The Public Utility Regulatory Policies Act of 1978 (PURPA) facilitated the emergence of certain electricity-producing companies called qualifying facilities (QF). QFs are defined as small power producers and cogenerators. To maintain QF status, small power producers must obtain at least 75 percent of energy inputs for electricity generation from renewable resources (geothermal, biomass, wind, solar, or hydropower) and have an installed capacity of less than 80 megawatts. QF's receive certain benefits but must meet specific ownership, operating, and efficiency requirements established by the Federal Energy Regulatory Commission (FERC). One benefit requires the host electric utility to purchase the output of the nonutility at the utility's "avoided cost."

[3] FERC's "open access" policies were promulgated in two rulings, known as Orders 888 and 889. See National Renewable Energy Laboratory, "Open Access Transmission and Renewable Energy Technologies," by Kevin Porter, NREL/SP-460-21427, Golden, CO (September 1996). The website for this document is: http://www.nrel.gov/research/ceaa/emaa/open_access/index.html.

[4] Energy Information Administration, *Annual Energy Outlook 1998: Issues in focus*, http://www.eia.doe.gov/oiaf/aeo98/issues.html#issues2; and Energy Information Administration, *Impacts of the Kyoto Protocol on U.S. Energy Markets and Economic Activity*, SR/OIAF/98-03, Washington, DC, (October 1998).

renewable electricity base.[5] Since large quantities of (non-hydro) renewable electricity may be on the horizon for the first time, concurrent with a radical change in electricity market structure, examining the impact of transmission policies on renewable-based electricity seems timely.

Second, while transmission costs are only about 2 percent of total utility operating and maintenance costs,they represent 12 percent of total electric plant in service.[6] Thus, to the extent that renewables require or cause changes in transmission and distribution equipment from those which would occur if a similar amount of conventional generation were added, the impact on electric plant could be nontrivial.

Already, some transmission issues have surfaced with these projects, and more can be expected. Most of these issues relate to three characteristics of renewable-based generation: (1) Availability–due either to the intermittent nature of many renewables or the expected capacity factor; (2) Distance of the resource from load centers; and (3) The relationship of electricity demand to maximum output potential from certain renewable sources.

In addition, marketing strategies to promote renewables, possible now under FERC's open access environment, create some issues unique to renewables. For example, customers willing to pay a premium for renewable energy and the renewable facilities providing them power may be in different regions. This is quite possible because of marketing efforts to "bundle" such customers, who may cross transmission regions. Either bundling customers or building capacity requires reserving transmission capacity, and that is typically not contracted for until after the green marketing campaign is announced or a commitment to a new renewables facility is made.

Thus, for a variety of reasons, transmission issues for renewables in a restructured electricity market are of current interest.

Background

Electricity Restructuring

The transition to a fully competitive wholesale market for electricity is altering the purchase and sale of electricity, as well as transmission services. Regarding generation, long-term contracts specifying generation facilities will likely be replaced by short-term contracts, based on spot market prices and quantities. Also, "merchant" facilities are being built with either no pre-existing contracts for power, or contracts for only a small percent of the power output. Another change is that power from a single facility may be sold to multiple customers, rather than under than a single long-term contract to a purchasing utility.

The outlook for transmission services is totally different. Even though the FERC has ordered electricity transmission facilities to be made available to all generators on comparable terms ("open access") and transmission services to be operated and priced independently of generation ("unbundling"), transmission rates will continue to be regulated. Hence, transmission facilities will be built partially based upon the expectation that such investments will be recovered through traditional rate-making procedures. However, there is no consensus at present on the appropriate way to price transmission services in order both to provide incentives for investment in needed transmission facilities and to utilize transmission facilities efficiently.

With access to the transmission system being opened,[7] transmission facilities and the transmission operator assume a much more important role compared to their role under a regulated monopoly environment. There are greater opportunities for expanded wholesale trade with lower cost generation replacing higher cost generation in expanded geographical regions and transmission systems when capacity and systems operation constraints permit. The establishment of independent system operators (ISO) and transmission protocols

[5] The cost for wind generation is estimated at 5 cents / kWh or less at some sites, depending on the methodology used (i.e., inclusion of a production tax credit, various financial incentives, financing, availability and price of land). Also, renewables typically (but not always) compete with natural gas, which is not always available in some regions (i.e., parts of the Pacific Northwest and New England). In these regions, renewables compete reasonably well.

[6] Energy Information Administration, *Financial Statistics of Major U.S. Investor-Owned Electric Utilities 1997,* DOE / EIA-0437(97), Washington, DC, (December 1998).

[7] Open access to transmission facilities is limited as FERC has jurisdiction over only investor-owned utilities. Municipal and cooperative electric utilities are not required to provide open access unless under reciprocity. Open access is also subject to system integrity requirements. Some utilities reserve some transmission capacity for reliability reasons, otherwise known as capacity benefit margin (CBM), which has caused some controversy.

should encourage the entry of new buyers and sellers increasing bulk power (wholesale) transactions.

Transmission pricing is likely to have mixed effects on the total cost of renewable-based electricity transmission charges. Many electric generating facilities using renewables are "qualifying facilities" (QFs) under the Public Utility Regulatory Policies Act (PURPA). PURPA guarantees that these qualifying facilities can sell their electricity to the host (local) utility. Renewable generating facilities however, may benefit from open access and transport electricity to a more favorable competitive market than a "host" utility. Under open access, renewable energy generating facilities can use the transmission system to sell power to any utility. In States where "retail" competition is permitted, electricity may also be sold to any retail customer. Thus, provided transmission access is available and at a competitive price, customers who want renewable-based power (such as in "green power" programs) will be able to purchase it directly from a renewable power supplier.

The other side of open access transmission is that there will likely be a greater number of buyers and sellers, including new categories of players such as "green power" marketers and power brokers. This will increase competition and exert a downward pressure on electricity prices, placing higher cost renewables at a disadvantage. Although electricity from renewable energy will have access to more markets, renewable generating technologies will face stiff price competition from other generating technologies. Some of this competition may be ameliorated, however, if Federal and/or State restructuring legislation includes renewable portfolio standards (RPS) or other renewable provisions to support renewable energy such as system benefit charges.

For a discussion on the history of open access transmission, see the report, "Open Access Transmission and Renewable Energy Technologies." [8]

Characteristics of Renewable Resources for Siting Generating Facilities

Another factor related to transmission of particular importance to renewables is generation facility siting. Renewable resources for power generation are site-specific in ways distinct from conventional sources. Oil, gas, coal, and uranium can economically be transported over most of the country, so generation facilities using these sources can be located where electricity demand and other considerations dictate.[9] In contrast, renewable resources either cannot be moved or can be moved only short distances at reasonable cost. Each renewable resource is distinct in this regard, as will be discussed below.

The largest source of renewable electricity is conventional hydroelectric power (approximately 80 percent). Hydro power growth is constrained by the lack of available new sites, high construction costs, growing environmental concerns, and competing uses for water resources. Remotely located, run-of-river sites with limited intermittent electric capacity are generally not economically viable.

Biomass includes all organic material stemming from plants, trees and crops (including wood and wood waste) that is available throughout much of the United States. The high costs associated with handling, transporting, and storing large quantities of biomass effectively negate any scale economies associated with building large conversion facilities. As a result, many biomass generating facilities are built to support biomass-related industrial applications (e.g., paper and paper products) where feedstock costs are either low or negative.[10] These facilities tend to be located remote from electricity demand centers, so the cost of constructing additional transmission facilities for selling excess power is often high. In the near term, the largest market for "pure electric" use of biomass is co-firing in low percentages at fossil-fired electric generating facilities.

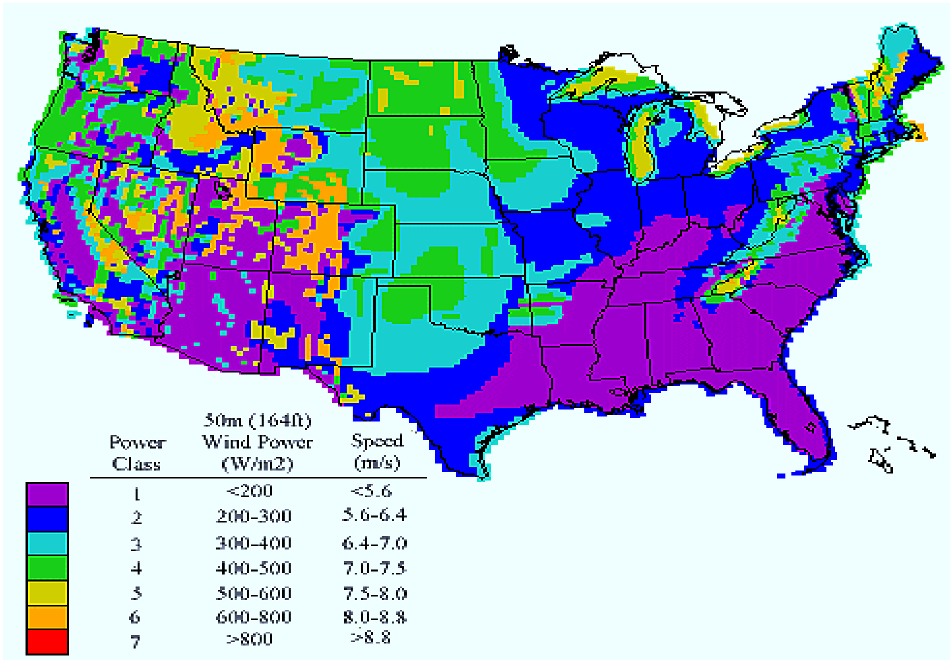
U.S. wind, solar, and geothermal resources are shown in Figures 1, 2, and 3, respectively. Areas potentially suitable for wind energy applications are dispersed throughout much of the United States (Figure 1). However, only areas designated "Class 4" or greater are suitable for wind turbine technology currently under development. These areas are constrained by land availability, transmission and access constraints, public acceptance, environmental, and other technological and institutional constraints.

[8] National Renewable Energy Laboratory, by Kevin Porter, NREL/SP-460-21427, Golden, CO (September 1996). The website for this document is: http://www.nrel.gov/research/ceaa/emaa/open_access/index.html.

[9] A number of issues not related to this article that can affect facility siting, such as land use around metropolitan areas, water usage and quality, etc.

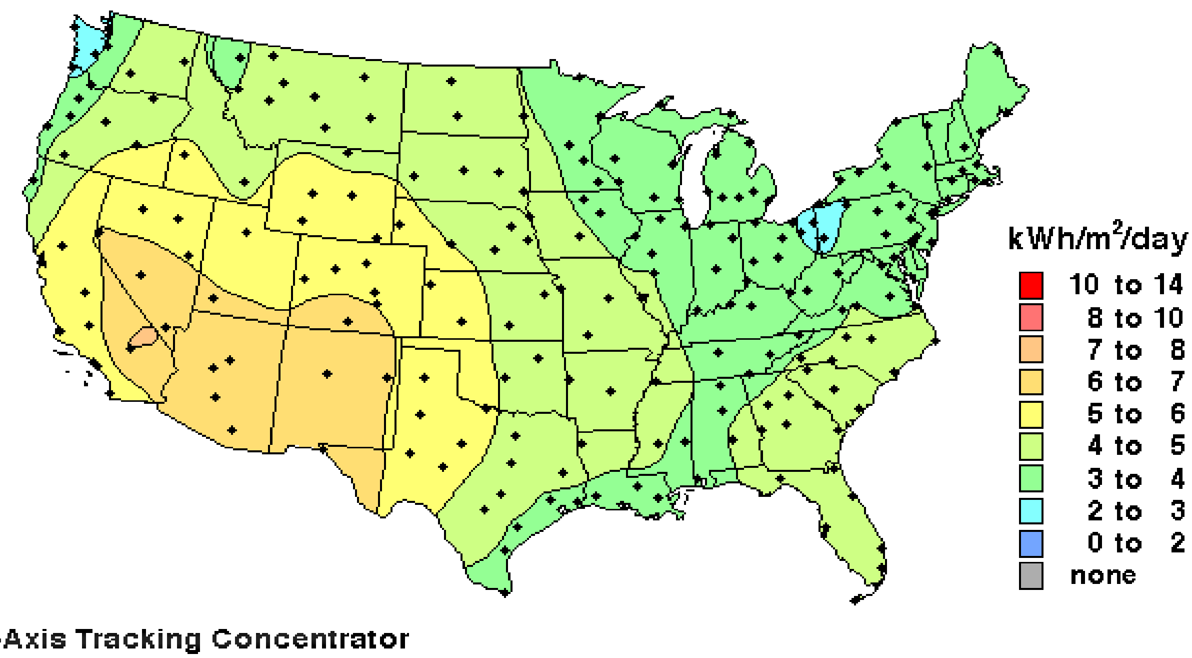
[10] A considerable amount of biomass consumed for energy is waste from other industrial processes. As such, energy production from biomass is a waste disposal alternative, and the "pure" energy cost is the total cost of energy production less the cost of other waste disposal options (which in some cases may have many regulatory constraints placed upon them).

Figure 1. U.S. Annual Wind Power Resources



Source: National Renewable Energy Laboratory.

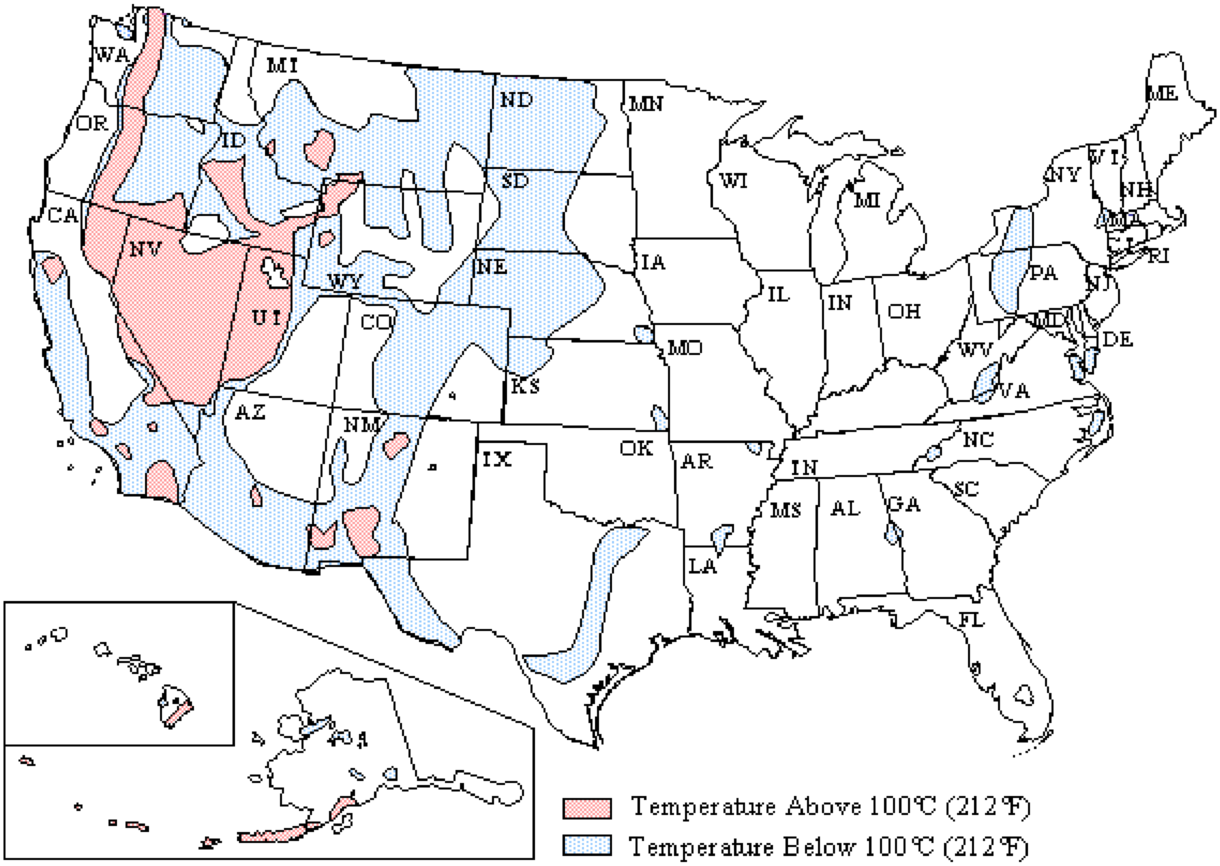
Figure 2. Annual Average Daily Total Solar Resources



Note: This map shows the distribution of solar resources in the contiguous United States available to two-axis tracking concentrators. It is a spatial interpolation of solar radiation values derived from the 1961-1990 National Solar Radiation Data Base (NSRDB). Maps of average values are produced by averaging all 30 years of data for each of the 239 NSRDB sites. Though useful for identifying the general distribution of solar resource, this map should be used with caution for site-specific resource evaluations because variations in solar radiation not reflected in the map can exist, introducing uncertainty into resource estimates. (Map is not drawn to scale.)

Source: National Renewable Energy Laboratory. Derived from the map available on the following website on February 18, 1999: http://rredc.nrel.gov/solar/old_data/nsrdb/redbook/atlas/.

Figure 3. U.S. Geothermal Resources



Source: Geothermal Heat Pump Consortium.

Siting is a two-edged sword for solar thermal and photo voltaic (PV) electricity. On the negative side, viable solar thermal resources are limited to the southwestern United States (Figure 2), where water availability (for solar thermal utilizing steam turbines) limits power generation potential. However, most of the country is suitable for producing electricity using solar PV during daylight. Further, PV generating facilities can be installed at the point of demand, with back-up power provided by conventional sources elsewhere on the system.[11] Hence, PV electricity is the renewable generating technology least likely to be affected by transmission pricing policies. However, how retail transmission access and distributive utility concepts evolve (e.g., net metering policies[12]) could have a significant impact on PV electricity.

Economically feasible, high-temperature geothermal resources occurring mostly west of the Rocky Mountains (Figure 3) are more limited in scope than either wind or solar. Further, the nature of using geothermal resources is such that the generating plant must be located at the hot water site. Hence, siting is more constrained for geothermal than for other renewable resources used to generate electricity. Another constraint on geothermal power use is that generating plants using so-called "high-temperature" geothermal resources are relatively inefficient causing geothermal production costs to be comparatively high relative to fossil-fueled steam plants. The economic feasibility would be further limited if investment in constructing long transmission access lines were required.

[11] Non-transmission issues involving back-up power are significant but are beyond the scope of this article.

[12] Measures the difference between the total generation of a facility and the electricity consumed by the facility with a single meter that can read electricity flows in and out of the facility.

Characteristics of Renewable Generating Facilities

Compared with conventionally fueled generating facilities, many renewable facilities (excluding some biomass and hydro power) have different design and operating characteristics. These generally include: lower and more highly variable capacity factors, intermittent availability, and longer distances from existing transmission lines and/or load centers. A characteristic specific to wind and solar/PV resources is that their availability tends to be greatest when demand for electricity is highest (daytime in the South and West). The coincidence of maximum resource availability and peak demand offsets some of the other negative characteristics for solar/PV and wind. Also, biomass and geothermal facilities often run at capacity factors closer to that of conventionally fueled generating plants. However, as geothermal operations mature at a given site, the water temperature/pressure can decrease, driving up the heat rate even further and decreasing the portion of the demand curve over which plant operation is viable.

Transmission Pricing

This section provides principles for transmission pricing, examines transmission pricing options, and discusses the role which the new Independent System Operators (ISO) will play in transmission and what practices the recently created ISO's have adopted.

Pricing Concepts

Although transmission costs represent only about 2 percent of an investor-owned utilities' operating expenses, they are nonetheless important. Workable competitive power markets require ready access to a network of transmission and distribution lines that connect regionally dispersed end-users with generators. Because power flows at one location impact electric transmission costs across the network, transmission pricing may not only determine who gets access and at what price but also encourage efficiencies in the power generation market.

Transmission constraints can prevent the most efficient plants from operating. These constraints also can determine the location of generation that affect the amount of power losses for transmission. Transmission prices that ignore these concepts will produce an inefficient system. Transmission pricing that considers transmission constraints (congestion pricing) should encourage the building of new transmission and/or generating capacity that will improve system efficiency.

In addition to meeting revenue requirements, transmission pricing should ideally do the following:

- promote efficient day-to-day operation of the bulk power market
- encourage investment and determine location of generation
- encourage investment and determine location of transmission lines
- compensate owners of transmission assets; and
- be fair and practical to implement.

The pricing options below should be evaluated with these criteria in mind.

Pricing Options

The simplest and most common type of transmission pricing is postage stamp pricing. A postage stamp rate is a fixed charge per unit of energy transmitted within a particular zone, regardless of the distance that the energy travels. Transmitting across several utility systems or zones and accumulating utility or zone access charges is often called "pancaking." Postage stamp rates are based on average system costs and may have a variety of rate designs, based on energy charges (cents per kWh), demand charges (cents per kW), or both energy and demand charges. Rates often include separate charges for peak and off-peak periods, may vary by season, and, in some cases, set different charges for weekday versus weekend and holiday usage. Transmission services also are generally offered on both a firm and non-firm basis. Firm transmission service guarantees service subject to emergency curtailments or system congestion. In contrast, non-firm transmission service is more economical than firm service, but is subject to curtailment or interruption, often with little or no notice by transmitting utilities.

Historically, firm transmission service contracts were long term. Non-firm agreements can be either short or long term. Under FERC Order 888, utilities are required to offer both point-to-point and network transmission service. Point-to-point service has specified points of delivery and receipt, transmission direction, and quantities. Network service typically is negotiated through a longer-term contract and involves flexible delivery points and quantities. Network service typically is arranged to meet a wholesale customer's varying native load requirements. Thus, even with a postage-stamp rate, the terms and conditions of posted prices may vary substantially.

Traditional transmission pricing is based on a routing scheme known as a "contract path." A contract path rate is one which follows a fictional transmission path agreed upon by transaction participants. Contract path pricing may be selected to minimize transmission charges and also to avoid "pancaking." However, contract path pricing does not reflect actual power flows through the transmission grid, including loop and parallel path flows.[13]

An alternative is "flow-based pricing." One type is "megawatt-mile" pricing, where the transmission rates explicitly reflect the cost of transmission, based on both the megawatts of power flow and the distance between the receipt and delivery points. The cost of transmission per megawatt-mile is the total cost averaged over megawatt miles of usage.

Much of the interest in transmission pricing reform involves moving away from utility-by-utility contract path pricing to regional transmission tariffs based on power flows, as well as "congestion pricing." Congestion pricing sets transmission rates to allocate limited transmission capabilities over constrained interfaces to those transmission customers that most value the ability to make power transfers. Thus, rates increase as the demand for electricity transmission increases and the system is used efficiently. Congestion on transmission systems is not reflected in either the postage-stamp or megawatt-mile pricing described. Prices that do not increase as congestion increases will tend to allocate the transmission capacity inefficiently, because available capacity is not necessarily allocated to the user for which the transmission has the greatest value.

Congestion costs can either be assigned directly to users causing the congestion or shared among all users. When the transmission system becomes congested so that no more power can be transferred from a specified point of delivery to a specified point of receipt, more expensive generation may have to operate on one side of the transmission constraint than the other. In a competitive market, regardless of the form of transmission pricing utilized, this would create a difference in generation prices between the two locations. (Any lower cost power generated on one side of a constraint could be sold at the higher price on the other side of the constraint, assuming the difference exceeds the transmission cost, in the absence of the congestion.) The difference between these electricity prices is the "economic price of transmission." It reflects the cost of congestion and losses. In the absence of congestion pricing for transmission service, these "economic rents" would represent a windfall to the generation suppliers that are able to sell through the congested interconnection. As a result, transmission prices will recover congestion rents from those suppliers who are able to complete transactions through the constrained interface.

There are many ways to allocate revenues from congestion pricing. In California, such revenues are used to reduce the access fees that all transmission customers pay. Another proposal is to create a system of transmission congestion contracts. These would establish comprehensive set of rights to either make power transfers or receive compensation for the inability to do so through redistribution of congestion rentals to the holders of transmission congestion contracts.

Development of Independent System Operators

The electric power industry has increasingly accepted the concept of an "Independent System Operator" (ISO). An ISO is created when transmission-owning utilities transfer operating control (not ownership) over designated transmission facilities to an independent nonprofit organization. The expected benefit of an ISO is to ensure equal and fair access to the transmission system precluding discriminatory practices and reducing self-dealing and other market power abuses. Currently, six ISOs are operating and a number of ISOs are in different planning stages. The six operating ISOs are: California ISO; Electric Reliability Council of Texas (ERCOT) ISO; Pennsylvania, New Jersey, Maryland (PJM) ISO; New England ISO; New York ISO and; Mid-America Interconnected Network (MAIN) ISO.

The responsibilities of ISOs are very broad, going beyond the role of ensuring equal and fair access to the transmission system. To obtain the FERC's approval, an ISO must comply with generic principles provided in Order 888, although the ISO has latitude in the detailed implementation. ISO functions can be classified broadly under two categories: the facilitation of a wholesale

[13] Electricity flows on all available transmission paths between generators and points of use according to the laws of physics. The actual flow of electricity is referenced as flowing "parallel" to contractual paths (transmission paths) that are reserved for the flow of electricity, but are not actually used.

power market, and the control of the transmission grid and related facilities. The relative importance of the functions within these two categories, and the details of how they are performed, vary among ISOs.

Transmission Pricing Through an ISO

Most ISOs have proposed "zone pricing," at least as an interim method before single-system pricing. With zone pricing, the transmission grid is divided into zones, and the transmission customer pays one rate based on the zone where the energy is withdrawn, regardless of how many zones in the ISO are crossed. The PJM-ISO has defined 10 zones corresponding to the service areas of the transmission owners in the ISO. The rates for a particular zone are based on the revenue requirements of the transmission owners in the zone. While zone pricing is practical and meets the revenue requirements of the transmission owners, it does not necessarily allocate cost fairly among the users of the transmission system.

Zone pricing, in some instances, is considered an interim method. FERC recommended a system-wide uniform rate without zones, based on the average revenue requirements of transmission owners across the ISO region. However, an average uniform price may result in "cost shifting" when the revenue requirement of high- and low-cost transmission owners are averaged. Zone pricing, or a uniform rate, also does not account for or resolve parallel power flows. FERC's guidance was that PJM-ISO should eventually change to pricing based on electrical characteristics and power flows instead of boundaries.

Some regions planning to create an ISO have proposed using a megawatt-mile method for pricing transmission (e.g., Southwest Power Pool, Mid-Continent Area Power Pool). This approach is a distance-based method that takes into account parallel power flows using power flow modeling techniques. This method gives no credit for counter flows and is administratively much more complicated than other methods, as each transaction must be calculated; rates must therefore be re-calculated for each change to a transaction or each additional transaction.

Three methods for pricing congestion have been proposed by the ISOs.

- The PJM and New York ISOs are using location-based marginal pricing (LBMP). LBMP is based on the cost of supplying energy to the next increment of load at a specific location on the transmission grid. LBMP determines the price that buyers will pay for energy in a competitive market at specific locations, and measures congestion costs by taking the difference in the LBMP between the two locations. When no congestion exists, the LBMP will be the same at each location.

- The California ISO divided its region into congestion zones. Transmission constraints are small within each zone but large between zones. A usage charge is imposed on all customers who send energy across zones. The charges are determined from bids voluntarily submitted by a scheduling coordinator to increase or decrease power generation in their zone at a specified cost.

- The New England ISO bases congestion charges on the cost of out-of-merit dispatch. Costs are allocated to each load based on the percent each load represents of the total load. Though this method is simple to implement, it does not produce price signals on how to alleviate the congestion. However, New England ISO does not have a significant transmission congestion problem.

The Federal Energy Regulatory Commission and other industry participants seem to view the concept of an ISO as the solution to open-access. However, ISOs are going through an evolution. Not only are there significant differences in the operations and pricing schemes among existing ISOs, there are also differences in the operations and pricing schemes for proposed ISOs. Recently, the Department of Energy (DOE), by Section 202(a) of the Federal Power Act that gives DOE the authority to divide the country into regions for purposes of reliability transmission, gave FERC authority to establish boundaries for ISOs.[14] The DOE believes that providing FERC with authority to establish boundaries for ISOs or other appropriate transmission entities could aid in the orderly formation of a properly-sized transmission institutions and enhance the development of ISOs in a rational, comprehensive manner. Also, by helping FERC in addressing reliability issues, the reliability of the transmission system would be increased.

[14] *Megawatt Week*, Monday, October 5, 1998.

Impact of Transmission Pricing on Renewable Electricity Transmission Costs

A problem with pricing transmission to provide the proper signals to the electricity market–for any type of generation—is that the marginal cost of transmission for completing any given power transfer typically is only a fraction of the embedded costs included in transmission tariffs. Actual transmission pricing schemes set rates well above marginal cost to recover the fixed costs of the transmission system as well. The methodology used to recover fixed costs (in excess of marginal costs) can change the allocation of costs among different types of generation.

In general, transmission charges will be related to one or more of the following: the distance electricity is transmitted; the amount of electricity transmitted; and the reservation, if any, made by the generator for access to transmission lines (known as "capacity reservation"). How these pricing schemes would affect the cost of renewable-based generation depends upon how the characteristics of renewable generation—intermittence and capacity factor, distance from load centers, and coincidence with peak load—relate to these factors.

Intermittence and capacity factor. The capacity factor of a power plant is the amount of energy actually produced divided by the total amount of energy it could have produced operating at full capacity over a specified time period. Certain technologies using renewable resources, such as wind and solar, operate intermittently as the resource is available. This results in relatively low capacity factors. Other technologies, such as internal combustion or gas turbine, are used intermittently and at low capacity factors to serve specific loads. However, these technologies have more flexibility than wind or solar to match load on a steady basis, and thus can schedule output to coincide with reserved transmission capacity. Pricing schemes that have high firm (take-or-pay) charges for transmission capacity could reduce the competitiveness of intermittent/low capacity factor generators. Under take-or-pay arrangements, also known as capacity-based pricing, a fee is paid for the total capacity reserved, regardless of the amount of energy transmitted. The intermittent operation of some facilities means that these power producers could pay a significant amount for unutilized capacity under capacity-based contracts.

If access fees are based on energy, then intermittent renewables will pay only for transmission services equal to their energy output. This would increase the competitiveness of intermittent renewables but raises an issue of fairness related to another transmission pricing concept: scheduling. Generators which can schedule electricity transmission far in advance generally pay lower rates. Renewables with high intermittence are unlikely to find advanced scheduling feasible, as it generally involves capacity-based charges in exchange for firm service. Purchasing non-firm transmission service is a possibility and is discussed extensively later in the report.

Distance from load centers. Certain renewable resources tend to be located further from large areas of electricity demand. Geothermal and wind resources often fall into this category. Because it is inefficient to move biomass resources more than 50 miles for fuel to generate electricity, distance from load centers is also an issue for biomass. However, because many industrial applications of biomass-based electricity occur in the pulp and paper industry where facilities are located in forested areas, this is less of an issue than it is for geothermal and wind.

Under distance-based transmission pricing schemes (e.g., zone and megawatt-mile), remotely generated electricity will incur high transmission costs. Offsetting this disadvantage is that within the areas of resource availability (especially wind, solar, and certain types of biomass), renewable facilities can locate competitively at remote locations, where the cost of bringing in conventional fuels or building transmission/ distribution facilities is quite high.

If congestion pricing is adopted, then the marginal price of utilizing the last few increments of transmission capacity may be quite high. This could encourage "distributed generation "(small generators located along the distribution system) to help reinforce transmission and/or distribution systems, rather than large central power plants. Wind and photovoltaic technologies are ideally suited for such applications, given resource availability. Micro gas turbines may also be able to compete in such applications.

Coincidence with peak load. The price for transmission capacity is significantly affected by capacity demand according to the time of day. Certain technologies using renewables have little flexibility in determining the intermittent periods when they operate.[15] Transmission

[15] Fortunately, renewable availability sometimes occurs coincident with peak demand. An example is solar-based electricity, which is generally feasible in the southwestern U.S. where peak demand occurs during daylight hours.

congestion, though generally occurring during periods of peak load, may also occur at other times. Technologies whose intermittent availability follows system load are said to have a "high coincidence." Under congestion pricing, facilities with a high coincidence with system peak are likely to incur higher transmission costs than those with lower coincidence with system peak. However, higher transmission costs may be offset by higher payments for electricity delivered during peak demand periods.

The challenge for designing access fees to recover fixed costs is to send generators and end users price signals that reflect the true cost of electricity and using the transmission / distribution system. The next section provides some possible transmission pricing schemes which would lower renewable electricity transmission costs while following the pricing concepts mentioned earlier.

Alternatives to Reduce Transmission Costs for Renewable Electricity

Under current transmission pricing, most generation is sold through take-or-pay, capacity-based transmission charges to reserve firm capacity. Generators using renewables with intermittence and low capacity factors generally have high transmission costs per unit of electricity generated under these pricing schemes. Under capacity-based pricing schemes, generators using renewables pay for unutilized capacity when the renewable resource is unavailable. Alternatives to reduce transmission costs include purchasing non-firm transmission service, buying firm service that matches generation patterns (if available), selling unutilized transmission capacity in a secondary market, and selling power to a power marketer which bundles generation produced by several small facilities.

The alternatives to renewable facility owners purchasing firm services may, however, be limited by financing considerations. In traditional electricity markets, renewable facility owners would first obtain qualifying status from FERC. Because PURPA requires the host utility to purchase a QF's output at avoided cost, the facility has a virtual guarantee on selling its power, paving the way to obtain project financing. If transmission is bid and purchased competitively, however, it may be necessary for renewable (and perhaps other) facilities to purchase firm transmission capacity as a condition of obtaining financing. Another option could be for facilities to obtain insurance (if available) against the times when generation is available but transmission is not.

Generally, non-firm transmission is scheduled, and no advance capacity reservation is needed. The ability to accurately schedule non-firm transmission service to meet a generator's forecast of output depends on the predictability of the availability of the generation and the advance notice and duration of the reservation required by the transmission provider. Scheduled non-firm service that matches the output of the generator would be analogous to an energy charge where the generator pays for the service used. Generators that use intermittently available resources, such as solar and wind that varies from hour to hour, would need to be able to schedule non-firm service on short notice. However, scheduling non-firm service on short notice and for brief durations can result in both availability and price risk.

The FERC has authorized an effort to test the feasibility of hour-ahead transmission scheduling. On September 29, 1998, it approved a request of the Commercial Practices Working Group (CPWG) of the North American Electric Reliability Council for a four-month experiment, starting November 1, 1998, for handling next-hour requests for transmission service. In accepting CPWG's proposal, FERC stated: "If the transmission provider is not able to respond consistently to customers' reservations or schedule requests for hourly transmission service within 15 minutes of queue time, then the customer retains the option of providing the transmission provider with a confirmation of the reservation or schedule by means of telephone or facsimile. If a reservation is entered or confirmed by telephone or facsimile, the transmission provider may require the customer to enter the reservation on the OASIS electronically, after-the-fact, within one hour of the start of the reservation. It is up to the transmission provider (and not the individual customer) to determine whether it can consistently handle such hourly transmission service requests within 15 minutes during the pendency of the experiment. If a transmission provider cannot respond consistently within 15 minutes, the transmission provider cannot require customers to enter reservations and schedules electronically prior to the scheduling deadline."

Buying firm service that matches generation patterns. Generators that use renewables with predictable resource availability (i.e., geothermal, biomass) may be able to minimize transmission costs by purchasing firm transmission based on the anticipated output. This option is based on the predictability of the renewable resource compared to the advance notice and duration of the reservation required by the transmission provider to reserve firm service.

Selling unutilized firm transmission capacity in a secondary market. Some of the cost of unutilized firm transmission capacity can be recovered through the sale of the unutilized capacity in a secondary market. Selling transmission services in a secondary market entails both a price risk and the risk of being unable to find a buyer. This would be even more difficult for facilities using renewable resources such as wind or solar that have unpredictable availability. FERC's price cap on capacity reassignments that limit the capacity holders' profits through reassignment also makes this option less attractive.

Selling power to a marketer. Most generation using renewables is built by non-utility generators that do not have a diversified generation profile. In contrast, utilities or power marketers may purchase generation from renewable resources as part of a generation portfolio. The utilities' or power marketers' diverse portfolio allows them to purchase and utilize transmission services more efficiently.

Summary

The transition from bundling electricity transmission and generation costs to a market where transmission is owned and priced separately could have major impacts on the quantity and location of renewable-based generation. Even though transmission costs only represent about 2 percent of total electricity costs currently, transmission availability and access issues can alter where generation can be feasiblely placed on the transmission system.

Renewable resources tend to exhibit the following characteristics different from conventional fuels used to generate electricity: they are often located remotely from electricity demand centers and cannot be "shipped" feasiblely, if at all; they are often available only intermittently; and some renewables tend to be available in approximate coincidence with electricity demand (peak coincidence). Remote location increases the cost of transmitting power under distance-based pricing schemes. Intermittent availability either increases the cost of providing electricity or increases the risk that transmission capacity will not be available whenever renewable generation is. The peak coincidence of some renewables (e.g., solar, wind, photovoltaic) with electricity demand could raise transmission costs under congestion pricing schemes, but the price received for peak electricity may well offset or exceed the higher costs.

Alternative pricing schemes which could reduce the cost of transmitting renewable-based electricity include purchasing non-firm transmission service, buying firm service that matches generation patterns, and selling unutilized firm transmission capacity in a secondary market.

FERC has authorized a trial of hour-ahead transmission scheduling. Scheduling anything other than firm service could have an impact on proposed renewable projects, because project financiers have traditionally assumed that transmission access was guaranteed for renewable NUGs.

Appendix

History of Open Transmission Access

Historically, electric utilities provided service to consumers within designated franchise service territories. Regulation of electric utilities was based on the premise that the generation, transmission, and distribution of electricity are natural monopolies, characterized by economies of scale and scope and the need for large capital investments. By the mid-1980s, the exhaustion of economies of scale for large baseload steam generation, together with the development of a new generation of small efficient technologies (viz., combined-cycle units and combustion turbines) and low natural gas prices, created opportunities for nonutility power producers to compete financially with utility-owned, central-station generation, helping sustain the deregulation of the electric power industry.

The deregulation of the electric power industry was initiated by the passage of the Public Utility Regulatory Policies Act of 1978 (PURPA). PURPA facilitated the emergence of certain electricity-producing companies called qualifying facilities (QF). QFs are defined as small power producers and cogenerators. To maintain QF status, small power producers must obtain at least 75 percent of energy inputs for electricity generation from renewable resources (geothermal, biomass, wind, solar, or Hydro power) and have an installed capacity of less than 80 megawatts.[16] QF's receive certain benefits but must meet specific ownership, operating, and efficiency requirements established by the Federal Energy Regulatory Commission (FERC). One benefit requires the host electric utility to purchase the output of the nonutility at the utility's "avoided cost." [17] Nonutility facilities using renewable sources developed under PURPA have generally not used the electric grid to transmit power to be sold to utilities other than the host utility (a transaction known as "wheeling"). Proposed Federal electric restructuring legislation to ensure that regional markets are truly competitive and operate efficiently as possible advocate repeal of PURPA's must buy provision. In competitive markets, the market ccess protections for QFs provided by PURPA are no longer needed to ensure fair opportunities for nonutility power producers and avoids the need for troublesome regulatory determinations of avoided cost. Regulatory determinations of avoided costs largely stopped in the late 1980s, replaced by avoided cost determinations through competitive bidding.

The evolution of the electric generation function of the electric power industry from a highly regulated, monopolistic industry to a less regulated, competitive industry, was spurred by the passage of the Energy Policy Act of 1992 (EPACT). Transmission lines are generally owned by investor-owned utilities operating as regional monopolies. These utilities have historically controlled whether and to whom electricity could be transported in interstate commerce. With the passage of EPACT, Congress broadened the scope of wholesale competition. EPACT gave FERC, for the first time, the authority to order utilities to provide transmission access in order to facilitate competition in wholesale power markets.

In 1996, FERC issued a rulemaking establishing open transmission access (Order 888), the requirement for transmission utilities to establish Open Access Same-time Information Systems (OASIS) (Order 889), a "Golden Rule" of comparability between transmission pricing for a utility's own sales and transmission pricing for power transfers by third parties, expansion of utility data reporting on transmission capabilities, and encouragement for the formation of regional transmission groups.

FERC Order 888 established a system of non-discriminatory, open access transmission tariffs for all investor-owned utilities that own, operate, or control electric transmission in interstate commerce. Investor-owned utilities and, under a reciprocity requirement, non-investor-owned utilities taking advantage of open access tariffs, must offer others the same transmission services they provide themselves, under comparable

[16] The size restriction was temporarily removed for a period of time for certain energy sources.

[17] Avoided cost is the incremental cost to the utility of alternative electricity which the utility would generate or purchase from another source.

terms and conditions, and such other transmission services as they are reasonably capable of providing. FERC determined that six ancillary services must be included in open-access tariffs; two of these services (scheduling, system control, and dispatch; reactive supply and voltage control from generation sources) must be purchased by transmission customers, because the transmitting utility is best suited to provide these services.

Once generation is unbundled from transmission, system costs (including ancillary services) will be allocated to individual generators based, on the services they may require. This could have an impact on intermittent and small energy technologies. Intermittent renewable technologies that cannot accurately forecast hourly output have an option of making hourly schedule changes (paying for each change) or under scheduling (scheduling less power than will likely be available) to avoid these changes. In addition, a penalty may be assessed if energy deliveries deviate over a specified amount from scheduled deliveries. Renewable technologies which are generally small may be disadvantaged if fixed charge penalties are applied instead of basing the penalty upon the amount of generation.

Order 889 established standards of conduct that functionally separated the operation of transmission from utility marketing and required transmission companies to establish or participate in electronic information systems (open access same time information systems, known as OASIS) that would simultaneously provide information on transmission rates and capacity availability to all users of the transmission system. This order spells out certain standards of conduct designed to prevent employees of a public utility from obtaining preferential access to OASIS-related information or from engaging in unduly discriminatory business practices. While not mandating any specified organizational approach such as the establishment of independent system generators (ISO), utilities are required to separate their transmission operations / reliability functions from their marketing / merchant functions.

Analysis of Geothermal Heat Pump Manufacturers Survey Data

by Peter Holihan[1]

Introduction

The Energy Information Administration (EIA) collected information on shipments of geothermal heat pumps, often called ground source or geoexchange systems, for the first time in 1997. This information is based on data filed on the EIA's Form EIA-902, "Annual Geothermal Heat Pump Manufacturers Survey." In addition to discussing geothermal heat pump shipment data, this article describes how geothermal heat pumps work, system economics, and provides two case studies, including the Department of Energy's role in geothermal heat pump development.

Geothermal Heat Pump Survey Results

Results of the 1997 and 1998 EIA surveys of geothermal heat pump manufacturers showed a total of 128,745 geothermal heat pumps, or an average of almost 32,200 units annually were shipped during the period 1994 through 1997.[2] Over 37,000 units were shipped in 1997, more than in any other year (Table 1). Data from the survey indicate that for the period 1994 through 1997, ARI-330 and ARI-325 model types[3] accounted for over three-fourths of total shipments (55 percent and 25 percent, respectively).

The survey was initiated in 1997 to track the recent market penetration of geothermal heat pumps. The rise in shipments during the mid 1990's is due in part to educational efforts of utilities and groups such as the Geothermal Heat Pump Consortium and the International Ground Source Heat Pump Association. Several utilities have been effective in promoting the use of heat pumps through low interest loans, extended warranties, utility bill guarantees, or rebate programs.

The data for 1997 show that 43 percent of geothermal heat pumps were shipped to the South, followed by 28 percent to the Midwest, and 16 percent to the Northeast (Table 2). Eleven percent were shipped to the West, while 2 percent were exported.[4]

The 37,156 units shipped in 1997 had a total rated capacity equal to 139,764 tons (Table 3) or an average 3.8 tons per unit. ARI-320 units tend on average to be smallest at 3.1 tons per unit, followed by ARI-325 and ARI-330 units at almost 4 tons per unit. Non-ARI rated units are largest on average, at 5 tons per unit.

Table 1. Geothermal Heat Pump Shipments by Model Type 1994-1997
(Number of Units)

Model Type	1994	1995	1996	1997
ARI-320	R5,390	R4,851	R4,318	R7,494
ARI-325	5,924	8,615	7,603	9,724
ARI-330	16,023	18,185	18,094	18,611
Non-ARI Rated	757	838	991	1,327
Total	**R28,094**	**R32,489**	**R31,006**	**R37,156**

R = Revised.
Source: Energy Information Administration, Form EIA-902 "Annual Geothermal Heat Pump Manufacturers Survey."

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[2] The 1997 survey was the first EIA geothermal heat pump survey. It collected data for the years 1994 through 1996.

[3] See "Classification of Heat Pumps," for a description of heat pump types as classified by the Air-Conditioning and Refrigeration Institute (ARI).

[4] Because the EIA-902 survey includes only domestic manufacturers, the survey does not provide information on geothermal heat pumps imported from foreign manufacturers.

Table 2. Geothermal Heat Pump Shipments by Exports, Census Region, and Model Type, 1997
(Number of Units)

Exports and Census Region	Model Type				Total
	ARI-320	ARI-325	ARI-330	Non-ARI Rated	
Exports	R298	101	437	64	R900
Midwest	R589	2,717	6,780	492	R10,578
Northeast	R1,786	1,512	2,593	93	R5,984
South	R4,329	4,015	6,828	613	R15,785
West	R492	1,379	1,973	65	R3,909
Total	**R7,494**	**9,724**	**18,611**	**1,327**	**R37,156**

R = Revised.
Note: The Midwest census region consists of Illinois, Indiana, Iowa, Kansas, Michigan, Minnesota, Missouri, Nebraska, North Dakota, Ohio, South Dakota, and Wisconsin. The Northeast census region consists of Connecticut, Maine, Massachusetts, New Hampshire, New Jersey, New York, Pennsylvania, Rhode Island, and Vermont. The South census region consists of Alabama, Arkansas, Delaware, District of Columbia, Florida, Georgia, Kentucky, Louisiana, Maryland, Mississippi, North Carolina, Oklahoma, South Carolina, Tennessee, Texas, Virginia, and West Virginia. The West census region consists of Alaska, Arizona, California, Colorado, Hawaii, Idaho, Montana, Nevada, New Mexico, Oregon, Utah, Washington, and Wyoming.
Source: Energy Information Administration, Form EIA-902 "Annual Geothermal Heat Pump Manufacturers Survey."

Table 3. Capacity of Geothermal Heat Pump Shipments by Model Type, 1994-1997
(Total Rated Capacity in Tons)

Model Type	1994	1995	1996	1997
ARI-320	R14,248	R11,003	R15,798	R22,916
ARI-325	29,003	39,672	28,705	37,049
ARI-330	63,101	74,253	64,114	73,137
Non-ARI Rated	2,879	3,935	5,091	6,662
Total	**R109,231**	**R128,863**	**R113,708**	**R139,764**

R = Revised.
Source: Energy Information Administration, Form EIA-902 "Annual Geothermal Heat Pump Manufacturers Survey."

Table 4. Geothermal Heat Pump Shipments by Customer Type and Model Type, 1997
(Number of Units)

Customer Type	ARI-320	ARI-325	ARI-330	Non-ARI Rated	Total
Exporter	RW	RW	RW	RW	R325
Wholesale Distributor	R2,758	8,226	9,091	307	R20,382
Retail Distributor	RW	W	0	R46	R473
Installer	R3,471	1,071	8,820	791	R14,153
End-User	R35	RW	W	W	657
Others	RW	W	W	W	R1,166
Total	**R7,494**	**9,724**	**18,611**	**1,327**	**R37,156**

R = Revised.
W = Data withheld to avoid disclosure of proprietary company data.
Source: Energy Information Administration, Form EIA-902 "Annual Geothermal Heat Pump Manufacturers Survey."

The EIA surveys about 40 manufacturers of geothermal heat pumps. However, the five largest geothermal heat pump manufacturers account for 84 percent of heat pumps shipped; the 10 largest manufacturers account for 98 percent. Generally, geothermal heat pumps are shipped by manufacturers to either wholesale distributors or directly to installers (Table 4). (Installers also purchase heat pumps from wholesale distributors.) Few heat pumps are shipped directly to the end-user; instead, the end-user purchases from the installer, or possibly a retail distributor. The installer coordinates installation services, involving subcontractors as necessary. For instance, a contractor is needed to install the earth connection, which allows the earth to be used as a heat source or heat sink. Then, a heating, ventilation, and air conditioning (HVAC) contractor, which may or may not be the same, installs the geothermal heat pump.[5]

Technical Discussion of Heat Pumps

General Description

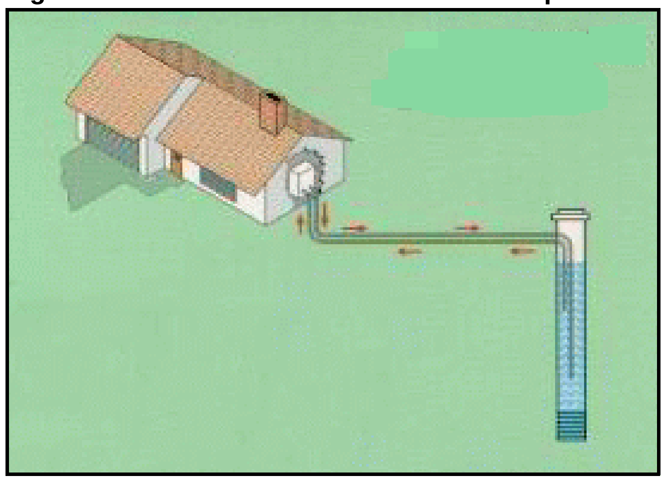
A heat pump is a machine that transfers heat both to and from a source by employing a refrigeration cycle. Although heat normally flows from higher to lower temperatures, a heat pump reverses that flow and acts as a "pump" to move the heat. Therefore, a heat pump can be used both for space heating in the winter and for cooling (air conditioning) in the summer. In the refrigeration cycle, a refrigerant (known as the "working fluid") is compressed (as a liquid) then expanded (as a vapor) to absorb and remove heat. The heat pump transfers heat to a space to be heated during the winter period and by reversing the operation, extracts (absorbs) heat from the same space to be cooled during the summer period.

The most common type of heat pump for domestic use, referred to as a "conventional" heat pump, is the air-to-air (air source) system in which heat is taken from air (heat source) at one location and transferred to air (heat sink) at another location. In the winter, a heat pump takes heat from outside air and via a working fluid transports the heat to inside the home. When the outside air temperature drops below 25-30 degree Fahrenheit, the air source heat pump uses electric resistance heat. In the summer, the heat pump reverses the process, removing heat from the home and transporting it to outside air, cooling the home in the process.

Geothermal Heat Pump Description

A geothermal heat pump (Figure 1) is a heat pump that draws heat from or removes heat to the ground or ground water, instead of air. In the winter, a geothermal heat pump transfers heat from the ground or ground water to provide space heating. In the summer, the heat transfer process is reversed; the ground or groundwater absorbs heat from the living or working space and cools the air. A geothermal heat pump benefits from nearly constant ground and ground water temperatures over most of the "temperate" climate zone found in the continental United States, regardless of outside air temperatures. These temperatures are higher on average than winter air temperatures and lower on average than summer temperatures. The heat pump does not have to work as hard to extract heat from or move heat to the ground or groundwater at a moderate temperature as from the cold air in winter or to the hot air in summer. The energy efficiency of a geothermal system is thus higher than that of a conventional heat pump. Many geothermal systems are also more efficient than fossil-fuel furnaces. As with any heat pump, the actual pump used in a geothermal system is powered by electricity.

Figure 1. Ground-Water Source Heat Pump



Source: Geothermal Heat Pump Consortium.

A geothermal heat pump can also provide hot water at greatly reduced costs using a device called a "desuperheater" that transfers excess heat from the heat pump's compressor to a hot water tank. In the summer, hot water is provided free; in the winter, water heating costs are cut approximately in half. Depending on the location, geothermal heat pumps can reduce energy consumption and, correspondingly, emissions by more than 20 percent compared to high-efficiency outside air heat pumps. Although residential geothermal heat pumps are generally more expensive to install than outside air heat pumps, they can reduce energy consumption, lower energy bills and emissions of carbon and other air pollutants, and operate without need of a backup heat source over a very wide range of climates. For commercial buildings, geothermal heat pump systems are very competitive with boilers, chillers, and cooling towers.

[5] Geothermal heat pump systems are still sufficiently rare that geothermal loop and HVAC contractors must be specially trained to install such systems. Currently, a new home or building owner interested in geothermal heat pumps can find qualified installers by contacting the local electric utility.

Classification of Heat Pumps

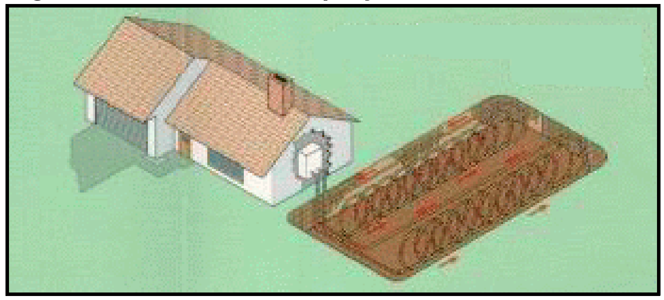
The EIA-902 Survey, "Annual Geothermal Heat Pump Manufacturers Survey," tracks shipments of the following three main types of geothermal heat pumps, as classified by the Air-Conditioning & Refrigeration Institute (ARI), and the much smaller shipped volume of non-ARI rated systems. A brief description of the three ARI-classified systems are:

ARI-320—Water-Source Heat Pumps (WSHP)—These systems are designed to be installed in commercial buildings. In some applications (not considered a geothermal system) a central cooling tower and boiler supplies cooled or heated water, respectively, to heat pumps installed in series. The heat pumps remove building heat to cooled water during the cooling season and, during the heating season, receives heat from boiler water.[6]

ARI-325—Ground Water-Source Heat Pumps (GWHP)—The GWHP is an open-loop system where ground water is drawn from an aquifer or other natural body of water into piping. At the heat pump, heat is drawn from or dumped to the water through a heat exchanger to the refrigerant in the heat pump. The heated or cooled water returns to its source (Figure 1).

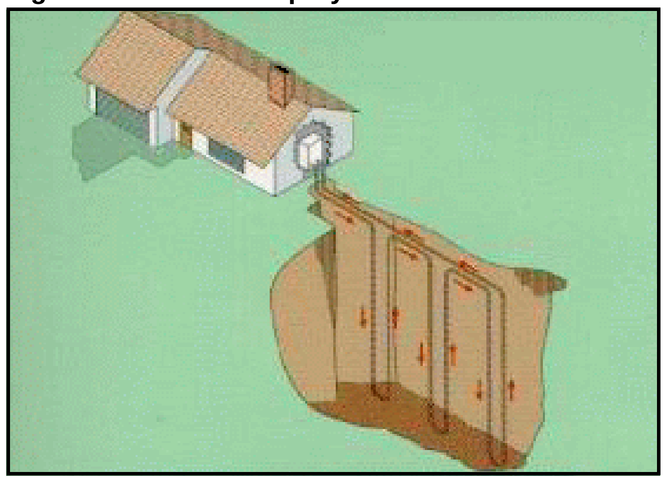
ARI-330—Ground Source Closed-Loop Heat Pumps (GSHP)—A water or water/antifreeze solution flows continuously through a closed loop of pipe buried underground. Ground heat is absorbed into or rejected from the solution flowing in the closed loop. At the heat pump, heat is drawn from or dumped to the closed loop solution via heat transfer through a heat exchanger, which then passes heat to or removes heat from the refrigerant in the heat pump. Depending on the type and area of land, systems can either be installed horizontally or vertically[7] (Figure 2 and Figure 3).

Figure 2. Horizontal Loop System



Source: Geothermal Heat Pump Consortium.

Figure 3. Vertical Loop System



Source: Geothermal Heat Pump Consortium.

Geothermal Heat Pump System Economics

Almost 70 percent of the nation's electrical energy is consumed in residential and commercial buildings,[8] including electric power used in space heating and cooling and water heating. By decreasing the amount of energy used for these services, the Nation has a major energy-saving opportunity. According to a 1993 report by the Environmental Protection Agency (EPA), geothermal heat pumps were the most energy efficient and cost effective space conditioning systems then available.[9] The EPA report found that energy efficiency translates to reduced emissions, and the emissions that are released occur at electric power plants, where emissions are monitored and controlled. The cost effectiveness of a geothermal heat pump system is highly dependent on a number of variables including installed cost of different systems, interest rates, and geographic location

[6] Not all ARI-320 units are connected to geothermal (ground/ground water) heat sources; many ARI-320 units use water from other sources than the ground (e.g., boiler/cooling tower configurations). The survey data includes only those ARI-320 units installed in a geothermal application. EIA is conducting research to determine how accurate manufacturers are in reporting the number of units used in geothermal applications.

[7] Geothermal units can be rated by the manufacturer for combined applications as ARI-325 and ARI-330. EIA is conducting research to determine how accurate the manufacturers are in reporting the application as either an ARI-325 or ARI-330 for these units.

[8] Energy Information Administration, *Annual Energy Review 1997*, DOE/EIA-0384(98) (Washington, DC, July 1998).

[9] Environmental Protection Agency, "Space Conditioning: The Next Frontier," report 430-R-93-004, April 1993.

which impact climate, soil conditions, land availability, and fuel availability and cost. However, there are both barriers to and factors for increased market penetration of geothermal heat pumps.

Barriers to Geothermal Heat Pumps

Geothermal heat pump systems generally have a higher initial (capital) cost than alternative heating and cooling systems. Based on the estimated yearly energy and maintenance cost savings, the payback period can vary from 2 to 10 years. The primary difference between the cost of a geothermal heat pump system and a conventional air source heat pump system is the investment in a ground loop for heat collection and rejection that is required for a geothermal system. The ground loop cost is the premium paid to get a system that will operate year round without backup support. In contrast, air source heat pumps lose efficiency in providing heat when outside temperatures drop below 20 to 30ºF, and switch to a higher operating cost electric resistance back-up heating system. Making a geothermal system cost-effective, relative to a conventional air source heat pump, depends upon generating annual energy cost savings that are high enough to pay for the additional cost of the ground loop in a relatively short time.[10] Other barriers to market penetration include lack of consumer information and both the difficulty in adopting new building standards and the public's reluctance to utilize new technologies.

Factors Favoring Geothermal Heat Pumps

Factors that have improved market penetration of geothermal heat pumps include rebates and low interest loans offered by electric utilities. Some electric utilities see geothermal heat pumps as a way to improve load factors in mortgage positive cash flow. In particular, they want to attract owners of new homes toward electricity rather than gas. By offering the home owner a rebate, which reduces the first-year capital cost of the heat pump system, such utilities improve the purchase economics of a geothermal heat pump relative to alternatives. Alternatively, a low interest rate loan offered for geothermal heat pumps increases their attractiveness by lowering future year costs relative to those of other heating/cooling systems (assuming the owner finances the purchase of a heating/cooling system). Also, advertising and information campaigns by the proponents of geothermal systems on their energy efficiency and economic benefits compared to alternative systems have boosted public awareness.

Fort Polk Case Study

In 1996, the world's largest installation of geothermal heat pumps was completed at the U.S. Army's Fort Polk military base in Leesville, Louisiana. The heat pumps replaced 3,243 air-source heat pumps and 760 central air conditioning/natural gas forced air furnace systems for 4,003 housing units. The housing units were apartments, townhouses, and duplexes built between 1972 and 1988. Unit floor space ranged from 900 to 1,400 square feet. The geothermal heat pump configuration implemented at Fort Polk is a closed-loop, vertical-borehole ground heat exchanger system. Each heat pump has its own ground heat exchanger of the vertical U-tube type of polyethylene pipe. Over 8,000 borehole heat exchangers were drilled. Each borehole has a 4-inch diameter and a depth of 100 to 450 feet.

An investment of $19 million was made to install the geothermal heat pumps. The expected benefit of this investment is reduced energy and maintenance costs. The energy savings portion of the savings is based on the higher energy efficiency of the geothermal heat pump system compared to the heating and cooling systems being replaced. The energy efficiency of cooling systems is measured in terms of an Energy Efficiency Rating (EER), equal to the Btus of cooling produced by the system per watt of electricity consumed, averaged over an annual basis, while the heating efficiency is measured in terms of the coefficient of performance (COP). At Fort Polk, the replaced older heating systems had EERs of 7 to 8 while the geothermal heat pumps have EERs of 15.4.[11]

The Fort Polk geothermal heat pump systems are owned and operated by an energy service company (ESCO). Such companies typically install and own energy systems, whether they be energy efficiency upgrades or energy management systems in buildings or heating and cooling systems such as the geothermal heat pumps. The end user pays the ESCO a percentage of the energy

[10] For municipally owned buildings that have low-interest loans to finance the installation, the payback period would be shorter than for a conventionally financed building.

[11] It is worth noting that new conventional cooling systems have a much higher EER rating than the displaced Fort Polk units. EIA assumes that new conventional cooling systems have an EER of between 10.0 and 17.7. See EIA's report, *Assumptions to the Annual Energy Outlook 1999*, located at http://www.eia.doe.gov/oiaf/assum99/introduction.html. Due to the nature of the buildings retrofitted at Ft. Polk, the EIA's residential demand assumptions provide the most appropriate comparison.

and maintenance cost savings the consumer sees when a more energy efficient system is installed. The payments enable the ESCO to recover its capital investment, cover the cost of financing the investment, cover system operation and maintenance expenses, and earn a profit. In the case of Fort Polk, 77.5 percent of the total savings goes to the ESCO while the U.S. Department of Defense (DOD) keeps 22.5 percent.

The geothermal heat pumps have enabled Fort Polk users to realize energy savings and to decrease peak demand for electricity relative to the systems the heat pumps replaced. Oak Ridge National Laboratory (ORNL) conducted an independent evaluation before, during, and after the replacements with sponsorship by the DOD and DOE's Office of Utility Technologies. The findings indicate that geothermal heat pump systems, in combination with other energy replacement measures, have reduced annual whole-community electrical consumption by 33 percent (26 million kilowatthours), natural gas consumption for space heating and water heating by 100 percent, summer peak electrical demand by 43 percent (7.5 megawatts), and improved load factor from 52 percent to 62 percent.[12]

Evaluating the Economics of Geothermal Heat Pump Systems

A method to evaluate the economics of a geothermal heat pump system versus an oil heat/electric air conditioning system on a comparable basis is to calculate a project's "net present value." Net present value[13] is the total cost in real (the year the investment is initially made) dollars to the purchaser of an investment over the life of that investment. The net present value is calculated using the initial capital investment of the system, a series of future payments (annual operating cost), income (rebates, revenue) over the life of the investment, and a discount rate.[14]

Table 5. Capital and Operating Cost Data
(1996 Dollars)

HVAC System	Capital Investment: Installed Cost EIA	Capital Investment: Installed Cost GHPC	Capital Investment: Utility Rebate	Capital Investment: Net Cost	Annual Costs: Heating	Annual Costs: Cooling	Annual Costs: Water Heating	Annual Costs: Domestic Energy	Annual Costs: Total Operating
Geothermal Heat Pump	15,000	19,283	2,971	16,312	978	189	243	537	1,947
Oil-fired Furnace & Electric Air Conditioning	10,000	16,200	0	16,200	1,162	236	207	572	2,142

Notes: This table is for a specific home in Connecticut and may not be indicative of other homes or homes in other regions of the country. The geoexchange equipment and ductwork cost was $10,541 and the ground loop $8,742. The oil-fired furnace and electric central air conditioning system was estimated at $16,200.

Sources: Energy Information Administration (EIA), Office of Integrated Analysis and Forecasting. "Energy Crafted Homes in Connecticut, 1998," Table 1, Geothermal Heat Pump Consortium, Inc. (GHPC).

[12] For a copy of the report, "The Evaluation of a 4000-Home Geothermal Heat Pump Retrofit at Fort Polk, Louisiana: Final Report," contact Patrick Hughes at (423) 574-9329, or, email at hughespj1@ornl.gov.

[13] Net present value is derived using the following formula: $NPV = \sum_{j=1}^{n} \frac{values_j}{(1-rate)^j}$ where n is the number of cash flows in the list of values. In this example, n, which represents the number of annual operating cost payments over a 20-year operating life, is equal to 20. The"values" are the annual operating costs; the initial (first year) operating costs is given in the table. The subsequent values for the remainder of the operating life are multiplied by the annualized escalator factor for either distillate fuel oil or electricity for New England in the residential sector.

[14] The "discount rate" attempts to place the expenditure of funds over a long time period on a same-year basis. Usually, expenditures or benefits over time are "discounted" back to the time period when the initial capital investment was made. The rate at which expenditures or benefits are discounted is determined by many factors. To place current and future costs and benefits on a financially comparable basis in a strict sense, one discounts by the expected rate of inflation to place future payments/expenditures on a comparable valuation basis. There are other factors which influence the choice of discount rate, however. Uncertainty, due either to market factors (e.g., the certainty of knowing future prices) or inexperience with new technology, can cause a potential investor to require a high discount rate (i.e., the value of future benefits or costs drops quickly as time progresses).

The following example analyzes the economics of a geothermal heat pump system versus an oil heat/ electric air conditioning system for a new home in the Northeast, specifically Connecticut. Oil-fired heating is common in this region; therefore, it is considered the basis for comparison. Relevant capital and operating cost data for the two systems in a new home are summarized in Table 5. Note that without the utility rebate, a capital cost premium is paid for the geothermal heat pump system. Note also that the initial investment is greater but the operating cost is lower for the geothermal heat pump system than for the alternative oil-fired furnace / electric air conditioning system. The operating cost of the oil-fired furnace / electric air conditioning system will increase faster in real dollars over time as the real dollar cost of oil fuel increases. Thus, the real dollar operating cost savings for a geothermal heat pump system will grow larger over time if real oil prices continue to rise.

How quickly the savings of the geothermal heat pump system grow over time is a function of the discount rate. A discount rate in its simplest terms is the cost (interest rate) of money. However, for evaluating energy efficiency investments, economic literature refers to an "implicit discount rate" or "hurdle rate." The concept of a hurdle rate, uses a empirically-based rate which is required to stimulate actual purchases, that is, the rate implicitly used by consumers. These rates are often much higher than would be expected if financial considerations alone were their source.

Among the reasons often cited for relatively high apparent discount rates for consumer energy efficiency choices are the following:

- uncertainty about future energy prices and thus about the returns from an energy investment
- uncertainty about future technologies and their cost—current investment becomes locked in and may limit future options
- lack, or high cost, of good information on efficiency and savings
- additional costs of adopting a system that may be difficult to observe or quantify
- tenure expected to be shorter than life of investment, causing some gains for energy efficiency investments to be lost to the new purchaser
- urgent replacement of a failed system, which limits the time to plan, evaluate, and install a comparatively complex and unfamiliar system
- hesitancy to replace the current working system, especially with an unknown system,
- attributes other than energy efficiency that may be important to consumers
- limited availability of funds to be able to invest in any of the options under consideration
- renter / owner incentive differences
- incentives offered by builders to minimize construction costs of housing.

From Table 5 data, a net present value for each investment can be calculated. The assumptions on which this calculation will be based are that (1) both systems have a 20-year operating life, (2) the annualized maintenance is approximately equal for both systems, (3) the real annualized escalation of distillate fuel oil price for New England in the residential sector is 0.33 percent,[15] (4) the real annualized escalation of electricity price for New England in the residential sector is -0.79 percent,[16] and (5) the long-term real (implicit) discount rate is 20 percent, typical for risk-averse residential buyers looking for short payback on investment.[17]

Given these assumptions, using GHPC data for the installed cost, the net present value cost for the geothermal heat pump system, without the rebate, is about $28,440; the net present value for the alternative, oil-fired furnace / electric air conditioning, is about $26,700. (The utility rebate for the geothermal heat pump system brings the net present value down to $25,460.) Without the utility rebate, at a 20-percent discount rate, a consumer would not purchase the geothermal heat pump system on purely an economic basis. Under the assumptions used, the break-even rate where consumers would be indifferent between systems (when the two systems have an equal net present value) is approximately 8 percent. At any discount rate greater than 8 percent, the consumer would choose the geothermal heat pump.

[15] Energy Information Administration, *Supplement to the Annual Energy Outlook 1998*, Table 11. See website location ftp://ftp.eia.doe.gov/pub/forecasting/aeo98/sup98tables/.

[16] *Ibid.*

[17] Energy Information Administration, *Annual Energy Outlook 1998*, DOE/EIA 0383(98) (Washington, DC, December 1997), p. 22. See website location http://www.eia.doe.gov/oiaf/aeo98/homepage.html.

Based on EIA data for installed cost, the discount rate at which the consumer is indifferent is between 2 and 3 percent.

It is important not to generalize the above results. One reason is that the economic feasibility of using geothermal heat pumps varies substantially between small- and large-scale applications (e.g., residential versus commercial). Also, the capital costs of the two HVAC systems compared here are based upon a single house in a private sector pilot geothermal heat pump program. EIA's National Energy Modeling System, used to develop energy forecasts through 2020, uses average regional cost and performance factors in assessing technology choices, and may well provide results which differ from those shown in this analysis.[18]

Recent Department of Energy Participation

In 1994, the U.S. Department of Energy (DOE), working closely with the Environmental Protection Agency (EPA), Edison Electric Institute, Electric Power Research Institute, International Ground Source Heat Pump Association, National Rural Electric Cooperative Association, utility sector, and geothermal associations and manufacturers helped to create the Geothermal Heat Pump Consortium (GHPC). The GHPC launched the National Earth Comfort Program, designed to foster the development of a fast-growing, self-sustaining, national GHP industry infrastructure. The DOE has also supported research and development activities through the DOE's national laboratories and industry associations. In partnership with the GHPC, the DOE's Office of Geothermal Technologies seeks to increase annual installations of GHP systems to about 400,000 by 2005 and reach about 2 million total installed by that same year. The GHPC estimates that 400,000 geothermal heat pumps are being used today for heating and cooling throughout the United States in residential, commercial, and government buildings.

The Energy Policy Act of 1992 requires the Federal government to become more energy efficient. President Clinton, by Executive Order 12902, reinforced the law by mandating a 30-percent reduction in energy use by Federal agencies by 2005, compared to a 1985 baseline. Fort Polk, Louisiana, the world's largest installation of geothermal heat pumps for residential housing, almost met the mandated energy savings with only the installation of its GHP system. By exceeding the 30-percent reduction mandate in family housing, which represented about 40 percent of base energy consumption, Fort Polk can reach its overall savings mandate by taking a few other energy saving measures.[19]

The Fort Polk project was a joint effort of the Army and an energy service company (ESCO) under an energy savings performance contract (ESPC). ESCOs provide the expertise and financing to develop, build, and maintain energy-efficiency projects for customers. Under energy savings performance contracting the goal is to renew energy consuming systems using private investment, and realize energy and maintenance cost savings that are shared between the customer and the ESCO. In performance contracting, ESCOs take on a much wider spectrum of responsibilities and risks than is common in conventional contracting.

The results at Fort Polk created the momentum to establish ESPC's in the Federal sector. The DOE Federal Energy Management Program (FEMP) has implemented National Geothermal Heat Pump "Super-ESPCs" to streamline the procurement process and encourage federal sites to consider the potential energy and cost savings of GHP-centered ESPCs. Federal agencies can now contract with ESCOs who have been competitively selected and pre-approved by FEMP to develop GHP-centered energy-efficient projects at federal sites anywhere in the United States under the Super-ESPC.

[18] *Ibid.*
[19] See the "Fort Polk Case Study" presented in this paper for additional information on the installation.

A View of the Forest Products Industry from a Wood Energy Perspective

Introduction

The Forest Products Industry comprises the forestry, lumber, wood product, and pulp and paper industries. The scope of operations of the Forest Products Industry includes forest management, timber harvesting and processing, construction materials, furniture manufacturing, and pulp and paper manufacturing. The Industry is central to providing raw material for manufacturing products such as transmission poles, boats, mobile homes, musical instruments, transport trailers, recreational vehicles, and sporting goods.

In order to understand the material presented in this article, it is essential to understand U.S. forest resources, their availability for fuel, and the ownership patterns of wood resources in varying regions of the United States. EIA has provided material on these topics in a prior issue of this publication. Chapter 6 of *Renewable Energy Annual 1995*[1] presents information on U.S. forest resources, timber harvests, forest residues, and waste wood resources. Specifically the following information is included:

- Net volume of timber (by region, species group, and timber class)
- Volume of roundwood[2] harvested for pulpwood and fuelwood (by region, species group, and timber class)
- Weight and energy yield of roundwood harvested for fuelwood
- Wood supply from logging residues (and other removals from noncommercial growing stock)
- Bark and residue from primary wood-using mills used for fuel (by region, species type and material used for fuel).

Appendix E of the same report shows timber ownership patterns in the United States, as well as regional removals from growing stock and other sources. As will be discussed later, timber procurement in the United States does not follow uniform, well-established practices, compared with those in the coal and natural gas markets. Thus, the added complexities in biomass fuel procurement can pose a challenge to increased biomass energy output.

The goals of this article are to (1) define the Forest Products Industry, (2) establish the approximate size and character of Industry subgroups that are important from an energy perspective, (3) identify the factors that most influence the energy profiles of these subgroups, and (4) identify and characterize the most important manufacturing processes used by the subgroups in terms of their energy profiles, and how influencing factors are likely to change them. This article does not discuss electric utility use of biomass to generate power.

Many external information sources were investigated to support this analysis. Primary sources consisted of company annual reports, government studies, proposed and final government agency rules, industry investment analyses, trade and environmental association data and position papers, Census Bureau data, and personal communication with industry experts.

The Forest Products Industry

The Forest Products Industry contributes significantly to the Nation's economy and employment base and accounts for 7 percent of national manufacturing output.[3] According to the American Forest and Paper Association (AFPA), its membership posted recent sales of about $230 billion per year[4] at 550 mills employing 1.6 million people in 46 States.[5] Major end-use markets of

[1] Energy Information Administration, *Renewable Energy Annual 1995*, DOE/EIA-0603(95) (Washington, DC, December 1995).

[2] *Roundwood* is a term used by the Forest Service and the Forest Products Industry to denote commercial grade wood cut from the main parts of the tree as opposed to residues from small limbs, bark, and stumps.

[3] American Forest and Paper Association, "Quick Facts About America's Forest & Paper Industry," undated brochure.

[4] *Ibid.*

[5] American Forest and Paper Association undated pamphlet, "Summer 1996 Quick Facts About America's Forest & Paper Industry."

the Forest Products Industry include new construction (primarily residential housing), remodeling and repair, publishing and office products, and converted paper and paperboard (cartons, bags, boxes, and containers). The Industry exported $7 billion worth of wood products and $11 billion worth of paper products in 1994.[6]

The pulp and paper industry is a major subgroup of the Forest Products Industry. The North American pulp and paper industry is frequently referenced in a global business context. Newsprint and pulp are two very important commodities of both the U.S. and Canadian forest products industries. In general, the U.S. and Canadian forest product industries share many similar market and manufacturing characteristics. Both industries appear also to employ the manufacturing machinery of a key set of vendors and have a high degree of commonality in processes and procedures. Many of the largest forest product companies have important operations in both the United States and Canada, with a number of international headquarters located in Canada.

On closer inspection, however, these markets are not totally seamless. Dissimilarities in government policy, energy resources, and raw material availability, as well as other factors introduce distinctions between the industries in the two countries.

U.S. and Canadian mills combined supply about 36 percent of the world's paper.[7] The Canadian pulp and paper industry registered recent annual sales of $29 billion, making it the country's largest trade contributor.[8] The total primary energy demand of the Canadian pulp and paper industry was about 750 trillion Btu in 1994. By comparison, the total first-use energy (formerly referred to as primary consumption) by the U.S. pulp and paper industry measured by the Energy Information Administration (EIA) in 1994 was *2,665 trillion* Btu.[9] Company-wide sales of U.S. pulp and paper industry participants are estimated at $110 billion.[10]

Wood products account for approximately 47 percent of the industrial raw material manufactured in the United States. Like all forest products, they undergo the first stages of manufacturing as harvested lumber. From an energy perspective, initial operations center around four primary product categories—sawed lumber, primary engineered wood products (i.e., plywood and panels), pulpwood and fuelwood—followed by a key group of secondary products. Secondary products include flooring, siding, molding, and other products characterized by finish-milling. An extended group of secondary wood processors includes manufacturers of furniture, mobile homes, musical instruments, boats, cartons, pallets, transmission poles, etc. A common trait shared by these manufacturers is their use of the commodity wood products (provided by primary wood product or key secondary wood product suppliers) to make durable goods or value-added nondurable goods. Larger quantities of wood are handled by primary wood processors. Consequently, from an energy perspective, more wood fuel and wood residue/by-product fuel is utilized by these businesses than is the case with other processors, sometimes called secondary mills.

Primary wood processors directly access the fiber supply resource base, either from owned timberland or on a contractual basis from a well-established network of timber owners and wood suppliers. The large volumes of wood involved in these transfers create a favorable cost basis for primary processors. The favorable cost basis extends to the use of roundwood for fuel and supply by vendors of hogged fuel.[11]

The Forest Products Industry uses wood waste as fuel for producing steam and electricity to support manufacturing. Although it is only the third-largest consumer of electricity, the Forest Products Industry self-generates more electricity than any other U.S. manufacturing group. The paper and allied products subgroup self-generates the largest percentage of its total electricity requirement of any major industrial sector (Figure 1).

The *2,665 trillion* Btu consumed by the pulp, paper, and paperboard subgroup in 1994 represented 3 percent of total U.S. energy consumption. The majority of this energy was supplied by domestic fuel sources, with 56

6 American Forest and Paper Association, undated pamphlet, *U.S. Forests 1995: Facts and Figures.*

7 Gary A. Smook, *Handbook for Pulp and Paper Technologists*, 2nd ed. (Angus Wilde Publications, Vancouver, B.C., 1992).

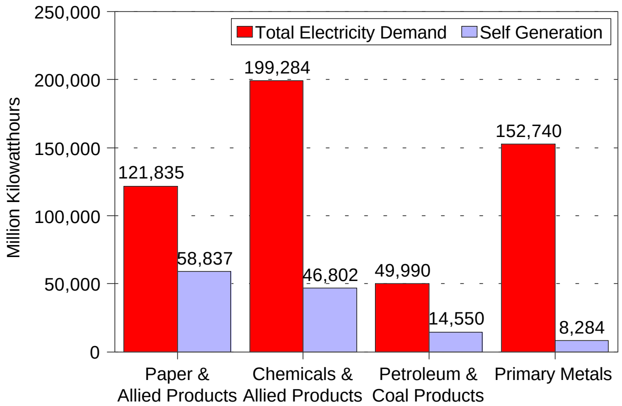
8 Paprican/Canadian Pulp and Paper Association news release dated October 21, 1996, Vancouver, B.C., Canada.

9 Energy Information Administration, *Manufacturing Consumption of Energy 1994,* DOE/EIA-0512(94) (Washington, DC, December 1997), p. 37.

10 Because several U.S. companies significantly involved in pulp and paper operation also operate in other industries, this estimate is greater than U.S. pulp and paper industry sales. See the following section for a further explanation of the actual size of U.S. pulp and paper operations.

11 *Hogged fuel* is wood that has been made into chips in a tub grinder or hammermill. The residues from timber harvesting (called slash) or silviculture are sometimes used as a source of wood for hogged fuel.

Figure 1. The Largest U.S. Electricity-Consuming Industries and Their Generation, 1994



Source: Energy Information Administration, *Manufacturing Consumption of Energy 1994*, DOE/EIA-0512(94) (Washington, DC, December 1997).

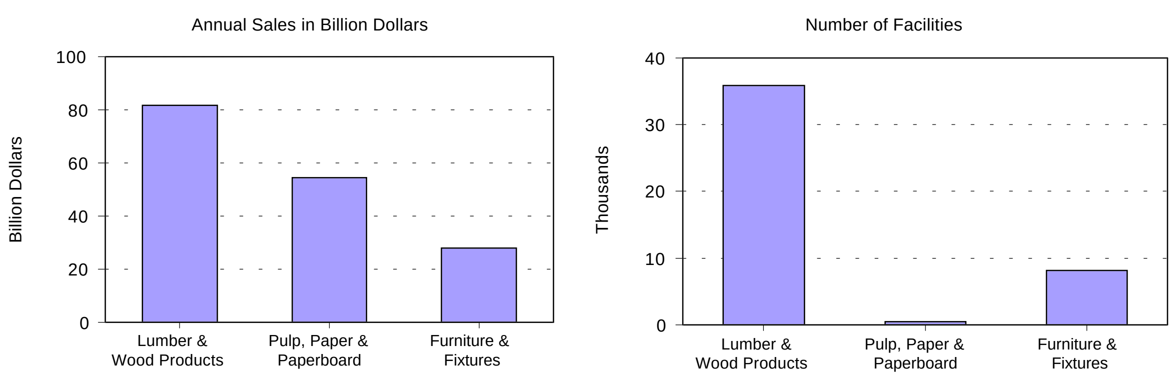
percent supplied from within the industry.[12] These factors are highly significant from an energy security standpoint. Canada's forest products industry has a comparable level of self-sufficiency.

The Structure of the Forest Products Industry

Fairly extensive government and trade data exist for the pulp and paper subgroup of the Forest Products Industry. In part, this is because pulp, paper, and paperboard mills are large, have a work force of just a few hundred, and receive statistical attention as an important, major primary wood processing subgroup. Less data exist for secondary mills, sawmills (a primary wood processing group), and fuelwood processors because their facilities are usually smaller and number in the thousands. In some cases, secondary mills produce a broad range of commodities and value-added products, which also contributes to the unavailability of detailed data.

The Census Bureau, using the Standard Industrial Classification (SIC) system, reports industrial activity according to specific end-product manufacturing categories.[13] Large corporations, of course, do not always conduct business according to sharply defined product and industry distinctions. Their corporate divisions frequently manufacture products in several of the cited categories. Figure 2 identifies some of the characteristics of three key SIC industries that include major wood processors.[14] Subgroups of these industries that are not primary or key secondary wood processors were not included in the summary data on which the figure was based. For example, the subgroups of the SIC for paper and allied products, which primarily manufacture bags and cartons from purchased mill stock, were eliminated. The adjusted subgroups that result are highly wood energy-intensive.

Figure 2. The Three Largest Wood Processors in the Forest Products Industry, 1992



Source: Selected data from the U.S. Department of Commerce, Bureau of the Census, *1992 Census of Manufacturers* (Washington, DC, 1992).

[12] American Forest and Paper Association, *Fact Sheet on 1994 Energy Use in the U.S. Pulp and Paper Industry* (Washington, DC, March 27, 1996).

[13] This system makes the following designations pertinent to this discussion: SIC 24, *Lumber and Wood Products*; SIC 25, *Furniture & Fixtures*; SIC 26, *Paper and Allied Products*. The Energy Information Administration's Manufacturing Energy Consumption Survey reports according to this system.

[14] All the data in this section are taken directly or adjusted from that contained in U.S. Department of Commerce, Bureau of the Census, *1992 Census of Manufacturers* (Washington, DC, 1992).

It is interesting to note that while nearly 36,000 businesses make up the adjusted lumber and wood products subgroup, only 529 mills constitute the pulp, paper, and paperboard products subgroup. With respect to employment profiles, only 19 percent of lumber and wood product businesses employ more than 20 people, compared to 98 percent of pulp, paper, and paperboard businesses. The lumber and wood products industry is a significant component of American small business and a key factor in the national rural economy.

Census data indicate that 72 percent of pulp mills, 95 percent of paper mills, and 89 percent of paperboard mills produce all of their primary manufacturing inputs. These data, supported by information in annual reports, demonstrate that pulp, paper, and paperboard manufacturers represent a major market for lumber and wood products companies, especially in the logging subgroup of the latter.[15] In turn, the paper industry unquestionably supports thousands of small businesses and is important to the rural economies of several regions. Likewise, some large corporations also participate in the fiber supply infrastructure via their raw material and commodity divisions.

As stated above, corporate ownership characteristics do not always link conveniently to specific SIC's. Company annual reports and investment analysis publications provide some of the detail to better understand front-end industrial processes.[16] These processes consume most of the primary manufacturing energy used in the forest products industry. Investment publication data aggregated for this paper reflect that 1995 sales by the 25 largest U.S. corporations classified as *primarily* pulp and paper manufacturers totaled $110 billion. Comparison of this information to the pulp and paper sales data in Figure 2 indicates that approximately half the business volume of these corporations is in products other than pulp and paper commodities.

Although these companies are diversified into a few unrelated areas, their operations portfolios reveal that most of their non-pulp-and-paper business is related, being mainly found upstream or downstream of primary operations. That is to say, pulp and paper companies are frequently vertically integrated either on the raw material side of primary manufacturing (i.e., forestry and logging) or on the finished product side. The latter category includes converted paper products such as boxes, containers, sanitary products, and coated or laminated papers. Acquisitions and mergers have resulted in a substantial restructuring of the pulp and paper industry, causing it to become less fragmented and more global.[17] As an example, a divestiture was recently announced by a large American container manufacturer that transferred ownership of a $1.5 billion pulp and newsprint subsidiary to a Canadian company.[18] Examples of horizontal integration include operations such as sawmills; veneer and panel board mills; and flooring, siding, and structural product mills. The characteristics of these 25 largest pulp and paper corporations are differentiated by their mix of integration in such areas. Some are oriented toward raw material resources, while others concentrate on finished goods, production, and consumer marketing.

Miscellaneous Converted Paper Products, a second paper-related SIC category isolated for this article, converts a small amount of wood-based waste to energy. Analysis of this sector indicates that converters are heavily concentrated in populous states with a heavy manufacturing and consumption base. Adding directly related[19] Census data for this SIC category (about $40.4 billion in 1992) to the aggregate sales of the selected wood processors in Figure 2 yields an adjusted total of $204.4 billion in 1992. This total (adjusted for interim economic growth up to the same statistical year for comparative purposes) is very similar to the AFPA estimate of Industry sales volume of $230 billion cited earlier.

Factors Affecting Energy Profiles of the Industry

Technology and environment are highly related factors which affect the use of energy in the Forest Products Industry, particularly in the pulp, paper, and paper board subgroups. Before discussing these topics in detail, an overview energy profile of the Forest Products Industry is presented.

[15] The logging subgroup furnishes pulp, paper, and paperboard manufacturers with "raw" wood from which pulp and paper mills make their manufacturing inputs (e.g., wood pulp).

[16] These processes include raw material handling, processing, and first-stage conversion, which is essentially the manufacture of commodity fiber products, which in turn are used as raw material for finished fiber products in later processes.

[17] Celso Foelkel, "Finance and Marketing Conference Provides International Industry Outlook," *TAPPI Journal,* August 1997, p. 234.

[18] *The Wall Street Journal*, *Business Briefs*, "Stone Container to Sell Its Pulp, Newsprint Lines, and Pare Debt," October 28, 1997.

[19] The plastic bag subdivision's $5.7 billion contribution was subtracted.

Energy Profile

In the Forest Products Industry, a large proportion of self-generated energy is derived from the waste wood by-products of production. Large amounts of energy are required for the drying process, the operation of kilns, and for steam and electricity production to power mill processes. Wood is used advantageously to satisfy part or all of the energy needed for these purposes. In the major wood-processing industries, manufacturing output not only determines the level of demand on timber resources for raw material inputs for a typical mill or facility but also strongly affects the rate of utilization of wood as fuel. Expressed in different terms, average wood raw material and wood waste usage profiles are sometimes predictable within a certain range for given products and processes.

For particular businesses, however, the ratio of wood used as a primary fuel to manufacturing output is not as predictable as in the forest products industry as a whole. Wood's use as a primary fuel may be strongly influenced by factors such as wood resource ownership, accessibility (in terms of both quantity and species), stumpage rates,[20] and the age and type of combustion system employed. Additionally, the strength or weakness of market demand for a facility's products, consequently its throughput, can influence the primary fuel, electricity, and / or steam consumption profile, as can on-hand capability to change manufacturing output to a different product. The ability to substitute products in reaction to market conditions is in some cases a determinant of profitability.

Environment and Technology: Factors of Pivotal Influence

Environmental laws, regulations, and policies affect the Forest Products Industry in two general areas: (1) wood production and (2) manufacturing. Environmental policy[21] strongly influences management and use of timberland, which is the Forest Product Industry's source of raw material. Industrial air, water, and waste management policy exerts a powerful influence on manufacturing operations. Industrial environmental policy has shaped the methods by which the Industry has made its products and generated and consumed energy for the past three decades. Today, the Industry deals with few aspects of energy without considering environmental factors, and vice versa. Environmental considerations are, in fact, key determinants of this manufacturing sector's energy profile. The energy characteristics of key Industry processes reflect this dynamic. However, many regulatory programs have matured, and Federal and State agencies are changing their enforcement focuses and strategies. Recently, governments have replaced some mandates with voluntary practices and industry initiatives. Some of them permit operational changes to be made according to individual plant equipment replacement schedules. Such changes have thus been important in changing the mode of operation of the Forest Products Industry.

Technological Innovation

Historically, technological innovations that changed or influenced output capability (mill capacity) were implemented as developed and were somewhat independent of environmental influences. In the past two decades, however, these two issues have become more closely linked.

A recent study determined that between 1900 and 1975 gross output per day of a sample of fine[22] paper mills was between 200 and 450 tons per day. Mills built after 1975, however, began to approach 1,200 tons per day in output. The study's author stated, "Expansions tend to occur together as firms identify the same window of market or technological opportunity."[23] Technical opportunities occurring in the 1970's included automation using electronic sensors and computer-aided manufacturing. (The study also helps to illustrate another important phenomenon—the cyclical nature of the paper

[20] The stumpage rate is the value or rate paid to purchase standing trees for harvest. Stumpage is usually defined as standing live or dead uncut trees. " Waste" is the volume of timber that should have been removed during harvesting and is subject to stumpage.

[21] To summarize laws and regulations affecting the Forest Products Industry, it can be noted that a 1993 Forest Service study indicates that 117 State and 522 local laws and regulations influencing the use of timberland were in effect (U.S.D.A. Forest Service, *RPA Assessment of the Forest and Rangeland Situation in the United States–1993 Update*, Forest Resource Report No. 27 (Washington, DC, June 1994), pp. 24-25. These statutes regulate timber management and harvesting, protect the general environment and sensitive habitat, preserve wooded areas, control water pollution and stream sedimentation, and protect roads and bridges. Availability of sawtimber, pulpwood, and wood chips for boiler fuel is sometimes affected by these constraints. For example, it was estimated that a 1 to 3 percent reduction of usable fiber supply nationally resulted from these State and local regulations.

[22] The reference is to paper grade.

[23] David M. Upton, Harvard Business School, "Computer Integration and Catastrophic Failure in Flexible Production," (working paper, Harvard Business School, 1994), Figure 1. The effect of market forces on Forest Product Industry output was discussed in the Energy Information Administration, *Renewable Energy Annual 1996*, DOE / EIA-0603(96) (Washington, DC, March 1997).

industry—which is not related to the focus of this article.)

During the same time the mills were achieving increases in capacity through automation, the sweeping provisions of the National Environmental Policy Act[24] began to be implemented. The revolution in digital technology that occurred during this period also influenced methods of environmental regulation. As electronic technology increased in sophistication, many of the measurement and recording capabilities critical to environmental monitoring programs became feasible.

New Processing Technologies

Today, new or newly-adopted chemical, mechanical, and biological processing technologies are being tested and employed in the paper industry. A primary driver of this change is environmental concern with toxic air emissions, toxic effluents, and solid waste by-products.[25] Although wood pulping and papermaking comprise only one of the regulated Forest Products Industries, they are the focus of great regulatory attention. This is due to their facilities being quite large and the fact that they utilize highly complex chemical, thermodynamic, and mechanical processes that can generate toxins.[26] A discussion of a few of the most important interrelated technology, environment, and energy topics related to the most energy-intensive industrial processes follows.

Extensive review reveals that the ideal solution to environmental pollution in the paper industry, from a regulatory perspective, is closed-cycle processing. This operational concept is applicable to other major industries, such as the chemical and metal industries, as well, but it is most relevant to papermaking in the Forest Products Industry. The key features of the closed-cycle approach[27] are (1) total reclamation of process water and chemicals, and (2) close automation linked to continuous monitoring and recording of effluents and emissions.

A number of alternatives to closed-cycle processing involve substitution of less harmful chemicals for the more reactive and potentially toxic agents formerly in wide use. In addition, some recent technological innovations involve alternative sequencing and combining of typical chemical agents as opposed to substituting new processes. Heat applied to these sequences is also closely monitored for optimal results. These process staging variations are customized for each mill, giving each its own energy and production economics profile. Processes using such innovations include combustion, the dewatering of pulping liquor and sludge, the deinking of newsprint recovered for recycling, medium consistency processing,[28] and high-intensity refining.[29]

[24] The National Environmental Policy Act became effective in 1970. It (1) established the *Council on Environmental Quality* (CEQ) under the Office of the President, (2) established a broad set of environmental policies, and (3) assigned and authorized specific Federal agencies to implement and enforce these policies.

[25] One of the most serious classes of pollutants involved is chlorinated organic compounds generated in pulp and paperboard manufacturing. These can result from the reaction of the organic compounds in wood with chlorine, which is frequently used in pulping, bleaching, and particle decontamination processes. Toxins in this category of pollutants can include dioxins and furans, and these carcinogens can result during downstream processes, such as pulping liquor dewatering or combustion.

[26] The largest industries, i.e., metals, petroleum, and chemicals, are regulated by EPA according to guidelines specific to those industries. The pulp and paper industry is regulated as a subset of *Chemicals and Allied Products*. Regulations stemming from the general body of air, water, and waste toxic laws are applied specifically to these industries by means of these specific guidelines. The set of guidelines that applies to the pulp and paper industry is currently being updated by EPA. As proposed, they have come to be known as the "Cluster Rules." The Cluster Rules have been strongly opposed by groups associated with logging and paper, including both industry and employee special interest groups. Generally, these interests agree that measures to protect the environment are necessary, but they advocate employment of less capital-intensive alternatives to closed-cycle processing and maximum achievable technology. Chief among the alternatives suggested is substitution of chlorine dioxide for elemental chlorine in pulping and bleaching operations, although there are several others. Total Chlorine Free (TCF) processes are advocated by environmental groups. Many plants have voluntarily switched to chlorine dioxide and the industry claims a highly positive environmental result. Chlorine dioxide is less reactive than elemental chlorine and is therefore less efficient from an operational standpoint. However, because it is less reactive, chlorine dioxide generates smaller amounts of chlorinated organic toxins and achieves a better, although not perfect, environmental performance. The final Cluster Rules ruling by EPA is pending but has not been registered as of final print.

[27] This analysis is indebted to the wealth of information contained in several studies on the pulp and paper industry by Energy Mines and Resources Canada and the Center for Mineral and Energy Technology; the discussion is based heavily on this information from here forward.

[28] This term refers to methods involving more extensive breakdown of wood fiber into smaller or more easily processed shapes by mechanical means, as compared to conventional practice.

[29] Compared to conventional methods, high-intensity refining involves the use of one or more of the following: a greater concentration of pulping and bleaching chemicals per unit of fiber volume in a containment vessel of a given size; mechanical mixing to permit more extensive contact of chemical agents with fiber surfaces; thermal mixing; and change in the sequence or intensity of conventional pulping and bleaching stages (which involve the application of chemical agents singly or in combination).

Industry size and pollution profile are important determinants of environmental policy and regulatory focus. Smaller scale forest product industries are usually both less energy intensive and less regulated. In the plywood and panel manufacturing industry, energy is consumed mainly for drying raw material and forming products. Environmental regulation is concerned primarily with the toxic volatile agents released by the adhesives and binders used in these products. Toxic substances or precursors in new adhesives[30] have been greatly reduced. Drying of wood fiber is critical to the proper adhesion of the binders and glues used in plywood and panel products and accounts for a great deal of energy use. Structural products, e.g., composite beams, are related in this respect but manufacturing processes more commonly apply mechanical energy than thermal energy in product forming.

By comparison, the dimension lumber, flooring, siding, and pole industries are fairly energy intensive because of the raw material and finished product drying that is frequently required. Treated lumber also receives attention from environmental regulators as a result of the treatment of products with toxic preservatives.

Energy Implications of Environmental and Technological Transition

Kiln Drying

A significant amount of energy is consumed by industrial operations such as wood pulping and drying. Kilns are enclosures or large machines used to dry products like lumber, poles, and raw materials such as the veneered wood and core fiber used in plywood panels. Large quantities of poles are manufactured for use in telephone signal and electricity distribution. Kiln drying is an energy-intensive process that is essential for imparting desirable properties to wood, including dimensional stability, workability, and hardening (e.g., as is required for tools), and promoting better absorption of treatments or adhesives. The United States Department of Agriculture's Forest Product Laboratory research indicates that drying operations more commonly burn wood wastes rather than fossil fuels for their energy source.[31]

Frequently, rail-mounted platforms carry the wood material in and out of a kiln. The kiln chamber is then sealed and heat is applied by steam or direct-fired air. Sometimes pressure or a vacuum is introduced into the chamber, depending on the product. Typical kiln temperatures range between 200 and 230 degrees F.[32] While absolute estimates of the energy used in kiln drying are highly specific to the conditions of a given operation, engineering data indicate that steam applied and maintained at a temperature of near the 230-degree-F limit permitted by the American National Standards Institute standard will apply heat to a product surface at a potential rate of roughly 22,000 Btu per square inch. Drying times generally vary from 1 to 6 days. Longer drying times are required for wood that receives oilborne or preservative treatments. Subjective anecdotal information indicates that the energy required to dry about 500 cubic feet of lumber from an as-received condition to a 20-percent wet basis moisture content is approximately 10 million Btu.

Poles were air dried before the late 1960's, but the majority are now kiln dried, due to the shorter residence time involved. Research on air circulation and optimum temperature and residence schedules have resulted in technologies which have reduced original kiln drying energy by as much as half of previous requirements.[33] In addition, some electricity is used as motive force for fans and product repositioning during drying. Environmental concerns involve emissions from kilns,[34] combustion systems, and treating agents.[35] Waste heat from kilns can be recovered by means of heat exchangers. Wood-drying kilns have been suggested as a candidate technology using ground-source heat pumps for supplemental energy.

[30] According to the Hardwood Plywood and Veneer Association (Internet Web site: http://www.erols.com/hpva as of July 1, 1997), manmade synthetic resins were introduced in veneer and plywood products in the 1920's and 1930's. Prior to this time, solely animal and plant adhesives were used.

[31] R. Sidney Boone, U.S.D.A. Forest Products Laboratory, "Drying of Southern Pine Poles for Preservative Treatment," *Proceedings of the 1st Southeastern Pole Conference*, November 8-11, 1992, Starkville, MS; Madison, WI: Forest Products Society: 157-162; 1994.

[32] *Ibid.*

[33] *Ibid.*

[34] Major direct emissions of concern from kilns used to dry large-scale timber (which includes utility poles) are water vapor, volatile organic compounds (e.g., methanol), and creosote. In addition, there is concern about the emissions from the sources of energy used to provide heat to the kiln (electricity and, for direct heat, usually wood waste).

[35] For poles, there are additional potential toxic releases from oilborne or preservative treatments.

Waste-to-Energy

Sawmills convert timber to dressed logs and lumber, some of which are then kiln dried, as just described. The wood waste produced by sawmills is frequently used as fuel. In fact, a typical modern sawmill produces enough waste to exceed its own energy requirement of 113 kilowatthours per ton of wood processed (equivalent to 2.25 million Btu) by 10–30 percent.[36] In some cases, waste wood in excess of requirements is used for a variety of products or for other fuel purposes (e.g., as a raw material for charcoal). Environmental concerns with sawmills are mainly focused on alternatives to stockpiling excess sawdust and finding product uses for waste to avoid the use of landfills. According to the APA—The Engineered Wood Product Association[37]—85–90 percent of the log is typically used. The bark, sawtrim, and remaining sawdust are used for energy or pulpchips. Production of additional electricity and steam for sale are also energy products. Sales of electricity to the grid, of electricity and steam to industrial customers for process energy, and of steam for district heating fall into this category.

Improvements in resins and epoxies permit clamping to replace thermosetting for some products in the engineered wood products industry with a resultant savings in energy. However, use of phenolic resin, which requires thermosetting and has some adverse environmental characteristics, is still common. Plywood and oriented strandboard markets accounted for more than half of the total demand for phenolic resin.

Bleaching

Paper companies make a host of products requiring the use of technically complex chemical, thermal, and thermochemical processes. These processes involve numerous stages and combinations of stages. Each major process is defined by distinct energy and environmental characteristics. Delignification of pulpwood and bleaching of wood pulp involve the most environmentally sensitive group of processes, due to the byproducts that result in mill effluents. The most prevalent bleaching technology currently used involves some form of chlorine. Using chlorine is economical and results in high process efficiencies. One reason chlorine is economical is that it is co-produced with sodium hydroxide, an agent required in large quantities during another stage of papermaking. The chlorinated organic compounds generated during chlorine processes are serious toxins and are a primary focus of regulation in the United States, Canada, and Europe.

Mill effluents currently require treatment by one of several methods, depending on the particular mill.[38] A variety of new technological strategies to reduce chlorinated organics are now being employed, or considered, to achieve compliance with pending regulation. These pollution reduction methods can be categorized in three ways: (1) substitution of other chemical agents for chlorine, (2) recovery of some of the chlorine used and incineration or secondary treatment of the remainder, or (3) use of closed-cycle technology in new or reconstructed mills. All these options involve increases in capital and operating costs. However, each has a different energy profile. Overall, the paper and pulpboard manufacturing industry consumed an average 26 million Btu per ton of output in 1994, but the trend in energy use in this sector is downward.[39]

The Canada Centre for Mineral and Energy Technology (CANMET) has completed a definitive study of the pulp and paper industry. Several reports produced from this study form the informational basis on which the following discussion is based.

No increase in steam consumption is required to implement the first alternative to chlorine bleaching—chemical substitution. Oxygen delignification, for example, does not require as great a degree of pulp and water heating. However, this process requires more electricity to bleach paper than if chlorine dioxide were used. As mentioned previously, chlorine dioxide is essentially co-produced "free" at the bleaching plant. The second option, recovery or treatment of chlorine, increases primary energy consumption and in some cases doubles it. An increase in total primary energy is also associated with the third option, closed-cycle processing, although it has other advantages previously mentioned. This option,

[36] Energy Information Administration, *Renewable Energy Annual 1996,* DOE/EIA-0603(96) (Washington, DC, March 1997), p. 25.

[37] This organization is the result of two prior groups, the American Plywood Association and the Engineered Wood Product Association.

[38] A pilot program called Project XL, initiated by EPA, seeks to encourage innovation by industry in pollution reduction. XL is an acronym for "excellence and leadership." An international standard, ISO 14001, dealing with mill environmental management, can be part of an XL permit. On January 17, 1997, EPA issued a news release entitled "EPA Reaches Agreement on XL Project With Weyerhaeuser Co." Under this agreement, Weyerhaeuser's Oglethorpe, GA, pulp mill will reduce the amount of chlorine compounds it uses and decrease its water usage to 10 million gallons a day, compared to the industry mill average of 25 million gallons. Weyerhaeuser gains by the agreement in that it is awarded the latitude to make process changes more quickly.

[39] The American Forest and Paper Association, *Monthly Statistical Summary* (Washington, DC, July 1996).

however, is not expected to be prevalent before the year 2010.

In 1993, CANMET established energy and material baselines to characterize papermaking methods. Energy and material use have subsequently been projected to future years. As a result of all process changes, total electricity consumption for bleaching is expected to increase 7 percent between 1993 and 1997.[40] Electrical energy costs represent 8 percent and steam represents 17 percent of bleaching expenses in Canadian mills.[41]

Closed-cycle processing requires extensive reconstruction or total facility replacement and is currently employed in only a few mills. However, closed-cycle and minimized effluent designs are likely to become more common in the next few years. State and Federal regulatory agencies are granting more latitude to mills that incorporate such improvements. This factor is critical in the highly competitive paper industry, where profitability frequently hinges on the speed with which these immense plants can diversify products and redirect mill output from poor to favorable markets. Such latitude may be especially attractive to the paper industry because production flexibility by means of computer integration has not been completely successful.[42] Nearly one-half the mills in operation after 2010 may be closed-cycle facilities (Table 1).

Other Innovations

Other recent technological innovations do not replace old processes, but represent variations of established methods of dealing with by-products or using chemical agents in various process stages. These innovations include extended delignification, biomass dewatering and combustion, dewatering of pulping liquor and sludge, deinking of newsprint (from recovered paper), medium consistency processing, and high-intensity refining.

Table 1. Selected Papermaking Technologies Ranked by Industry-Wide Energy, Economic, and Environmental Benefits and Predicted Extent of Use in Canada

Technologies	Total Energy[a]	Primary Energy[b]	Electricity	Environmental Impact	Economics	Predicted Extent of Use (percent)	
						2000	2010
Suspension Firing	1	1	8	5	3	28	45
Biomass Dewatering	2	2	5	6	2	58	74
Deinking of Newsprint	3	8	2	8	7	58	78
High-Intensity Refining	4	9	1	10	1	40	61
Medium Consistency Processing	5	5	3	9	4	40	65
Deinking Sludge Incineration	6	3	6	4	5	42	69
Fluidized-Bed Combustion	7	4	7	7	6	20	34
Closed-Cycle Bleached Kraft Mill	8	7	4	2	8	16	44
Secondary Treatment of Effluents	9	6	10	1	10	88	95
Oxygen and Ozone Bleaching	10	10	9	3	9	61	79

[a]Total Energy is the sum of fossil fuel consumption by the five sectors (residential, commercial, industrial, transportation, and electric utility) plus hydroelectric power, nuclear electric power, net imports of coal coke, and electricity generated for distribution from wood, waste, geothermal, wind, photovoltaic, and solar thermal energy.

[b]Primary Energy is the sum of fossil fuel consumption by the four end-use sectors (residential, commercial, industrial, and transportation) and generation of hydroelectric power by nonelectric utilities.

Notes: See text for explanation of technologies. "1" denotes most favorable, "10" least favorable.

Source: Canada Center for Mineral and Energy Technology, Efficiency and Alternative Energy Branch, "Research and Development Opportunities for Improvements in Energy Efficiency in the Canadian Pulp and Paper Sector to the Year 2010," February 1993, p. xiii.

[40] Canada Centre for Mineral and Energy Technology, Energy Efficiency Division, *Chemical Pulp Bleaching: Energy Impact of New and Emerging Technologies*, January 1994, p. 37.

[41] *Ibid.*, p. 38.

[42] David M. Upton, Harvard Business School, "Computer Integration and Catastrophic Failure in Flexible Production," (working paper, Harvard Business School, 1994), Figure 1. The effect of market forces on Forest Product Industry output was discussed in the Energy Information Administration, *Renewable Energy Annual 1996*, DOE/EIA-0603(96) (Washington, DC, March 1997).

Extended delignification involves longer residence time for wood chips in digesters and it is characterized by both higher steam and electricity consumption rates.[43] Biomass dewatering and combustion by suspension firing are similar. Typically, mill sludge is dewatered before it is used for fuel. In suspension firing, sludge and hog fuel are dewatered in mechanical presses, further dried by use of hot flue gas, hammermilled to a fine form, and fired in a boiler. Biomass dewatering and suspension firing offer several benefits, including substantial savings in primary energy, significant reduction in combustion emissions, and favorable process economics.

Fluidized-bed boilers have the capability to burn undewatered sludge, which can be an important capability to newsprint mills as use of recovered paper continues to increase and deinking results in increased quantities of sludge. Fluidized-bed boilers also contribute to reductions in fossil fuel emissions. However, they require new construction, whereas suspension boilers can be retrofitted.

Medium-consistency processing involves the use of higher concentration ratios of fiber to process water. This type of processing can claim only modest energy and environmental impact, and its commercial use may not occur until after the year 2000.

High-intensity refining involves changes in the operational parameters of the machinery used to break down fiber for pulping. Its use causes very little change in total primary energy consumption *(large* savings in electricity are offset by higher direct heat requirements) and has minimal environmental impact.

Table 1 ranks these technologies and predicts their acceptance by industry, based on a survey of Canadian mills. The significance of environmental impact can be seen in the table's rankings for Secondary Treatment of Effluents. Although this technology is the least favorable from an economic standpoint and ranks among the lowest in terms of energy consumption, it is the most environmentally favorable technology, and it has the highest predicted extent of use by the years 2000 and 2010.

Future Use of Biomass Energy

Biomass is the second-largest of the renewable energy sectors (after conventional hydroelectric), with wood comprising the largest component of biomass energy. The largest use of wood for energy occurs in the Forest Products Industry. Congress is discussing several bills that would increase the quantity of renewables used to generate electricity. Three important factors should be considered by policymakers as they see ways to increase the use of renewables in electricity generation:

- By far, the largest proportion of current wood-based electricity generation occurs in the Forest Products Industry (there are now only a handful of wood-fired utilities in the United States).

- Primary forest product industries are located in close proximity to timber resources. In contrast, utilities are generally located near population centers. This is of particular concern to generating plants wishing to fire with wood-based products, because transportation of wood-based energy products is much less economical than for coal.[44]

- The supply of commercial forest resources is limited and distributed among competing uses.[45] Forest product industries enjoy a well-established supply infrastructure and would be reluctant to force prices higher for pulp and other products due to an increased demand for fiber in generating electricity.

Some scenarios for greatly increased biomass-energy use rely heavily on the assumption that fluidized-bed combustion (FBC) units and combined cycle generators will offset possibly higher biomass fuel costs through energy-efficient operation. This assumption is likely to be true for generation-only plants. As Table 1 shows, however, FBC technology generally does not have very good economic, energy, or environmental characteristics in the near term, when applied by pulp and paper manufacturing.

Biomass-oriented generating plants yet to be built could indeed have an energy-efficiency advantage over some

[43] Fiber breakdown by pretreatment of wood chips with a fungus that occurs naturally is used for a process, now in demonstration stage, called biopulping. An advantage of biopulping, developed by the Forest Products Laboratory and a paper industry consortium, is lower primary energy requirement.

[44] The relative inefficiency is due to two factors: 1) The energy density of wood is about half that of coal; and 2) Harvesting wood uses far more acrage in a less efficient fashion for an equivalent weight of product than for mining coal.

[45] The time horizon referred to here is 10 years. Trees grown for energy, such as willow and poplar, require at least 10 years growth before they can be harvested. Thus, the wood resource base under consideration here is confined to existing forests.

of the conventional combustion systems now in use in the Forest Products Industry. However, in the near term they are certain to face disadvantages. Biomass-generating plants must locate near[46] fuel resources, especially because of their established fuel supply infrastructure. At the same time, these facilities need to be located near existing electricity transmission lines. In contrast, pulp and paper manufacturing plants are located near their fuel resources as well as the point of electricity demand. These issues are only a few of the two-edged considerations associated with possible legislative mandates for higher renewable electric generation. Another is the cost-effectiveness of locating generating facilities near population centers, where the cost of land is high or possibly prohibitive. Yet biomass energy has demonstrated favorable environmental, employment, and energy security characteristics and is generally considered to be CO_2-neutral. The challenge of broader implementation of biomass for energy is to gain the wider involvement of those entities most able to participate, as well as to stimulate new industry.

Although certain sectors of the Forest Product Industry would indeed resist diverting more biomass resources for energy, the fact is that the majority of timber grown in the United States is available to the winning bidder. Forest product industry members are generally not self-sufficient in supply, so they purchase needed biomass products from producers or other intermediaries. Generally, these resources are nonindustrial private forest landowners not under long-term contract. Further, current forest removal (i.e., utilization) rates are such that a substantial supply of logging residue is available. Therefore, at a sufficient price, energy interests could obtain additional biomass resources. The above statements are generally more true in the East, where most wood is purchased directly from the producer.[47]

Another factor operating in energy interests' favor is that a significant volume of wood is consumed as fuelwood for home heating. The value of forest removals for this purpose is generally less than that of timber removed for industrial products. Thus, energy interests could obtain additional fuelwood without having to compete with industrial interests.

Finally, forest products companies are seeking new ways to increase timber resource utilization. One possibility is to convert logging slash into a usable product. Members of the Forest Products Industry, a very significant potential participant, have mixed views on the increased use of wood for electricity generation. Some, such as those in the pulp and paper subgroup, believe that increased demand on wood supply would drive up resource costs and place a greater strain on already tight profit margins. Others in the industry who are well situated with respect to resource ownership, or whose resource divisions are very profitable, may view biomass energy as a favorable opportunity. Regardless of resource position, biomass energy producers may increase their generation if they can operate profitably on wood fuel priced competitively with stumpage that might otherwise go for pulp and paper manufacturing. Considering all viewpoints, however, two key questions relating to the area of governmental policy seem to be emerging: Will renewable energy mandates, if enacted, stimulate the birth of a new renewable-based generating industry, with survival qualities yet to be determined? Will the Forest Products Industry overall be a formidable obstacle or a willing participant in additional biomass energy generation?

[46] A conventional rule is that biomass can be gathered economically for energy use within a 50-mile radius of the combustion site.
[47] In the West, forest industry companies currently procure much of their resources from publicly owned lands, though this is changing.

Wind Energy Developments: Incentives in Selected Countries

by Louise Guey-Lee[1]

Abstract

Incentives have long been viewed as a means of supporting technological developments until a new technology becomes cost-competitive. Wind-based electricity is not yet generally competitive with alternate sources of electricity such as fossil fuels. Thus, it is dependent on nonmarket support for development to take place.[2, 3] *Four countries—the United States, Germany, Denmark and India—had 76 percent of the world's wind generating capacity in 1997. This article briefly examines the development of wind energy in each country. It demonstrates that when sufficient support has been available, wind capacity expanded. Also, when support has been withdrawn, wind energy development has slowed markedly.*

Introduction

This paper discusses developments in wind energy for the countries with significant wind capacity. After a brief overview of world capacity, it examines development trends, beginning with the United States—the number one country in wind electric generation capacity until 1997.

World Capacity

The United States possessed 95 percent of the world's installed wind capacity in the early 1980's.[4] By 1990, however, Denmark, Germany, the Netherlands, and India had also developed significant capacity, and the U.S. share of the world capacity dropped to 75 percent. During the 1990's, European and Asian countries have continued to expand wind energy capacity. In contrast, development of U.S. capacity has been slow, with retirements since 1992 more than offsetting new additions through the end of 1997 (Table 1). By then, worldwide capacity amounted to 7,202 megawatts, up about 1,000 megawatts from 1996 and the U.S. share dropped to 22 percent (Table 2). This capacity was distributed as follows: Europe 4,453 megawatts, North America (including Canada and Mexico) 1,645 megawatts, Asia 1,044 megawatts, South and Central America 32 megawatts, Middle East and Africa 24 megawatts, and the Caribbean 4 megawatts. Growth between 1996 and 1997 was strongest in the European countries: Germany (394 megawatts), Denmark (204 megawatts) and Spain (157 megawatts).

Table 1. U.S. Wind Net Summer Capability, 1990-1997

Year	Capability (megawatts)
1990	1,405
1991	1,653
1992	1,823
1993	1,813
1994	1,745
1995	1,731
1996	1,677
1997	1,620

Source: Energy Information Administration, *Electric Power Annual 1997, Volume II*, DOE/EIA-0348(97)/2 (Washington, DC, October 1998).

United States

Early History

The U.S. central station wind industry had its start in the wake of the world oil crises of 1973-74 and 1978-79.

[1] Louise Guey-Lee is an economist with the Office of Coal, Nuclear, Electric and Alternate Fuels, Energy Information Administration.
[2] International Energy Agency, *Key Issues in Developing Renewables* (Paris, France 1997), p. 14. Current delivered cost of wind energy in IEA countries ranges 4 to 10 cents/kilowatthour despite decreases in capital costs of 30-50 percent over the preceding decade.
[3] International Energy Agency, *Renewable Energy Policy in IEA Countries, Volume I: Overview* (Paris, France, 1997), p. 33.
[4] General trends for the early years are taken from U.S. Dept. of Energy, Wind Energy Program, unpublished data.

Table 2. Wind Electric Capacity Worldwide, 1996 and 1997
(Megawatts)

Country	Year	
	1996	1997
Europe		
Germany	1,545	1,939
Denmark	857	1,061
Spain	249	406
Netherlands	299	336
United Kingdom	270	330
Sweden	105	108
Italy	71	100
Ireland	11	46
Greece	29	29
Portugal	20	20
Austria	3	20
Finland	8	12
France	10	10
Belgium	7	7
Czech Republic	7	7
Russia	5	5
Ukraine	1	5
Norway	4	4
Poland	1	3
Luxembourg	2	2
Switzerland	2	2
Latvia	1	1
Total	**3,507**	**4,453**
North America		
United States	1,677	1,620
Canada	21	23
Mexico	2	2
Total	**1,700**	**1,645**
Asia		
India	816	845
China	79	166
Japan	14	18
Australia	10	11
New Zealand	4	4
Total	**923**	**1,044**
South and Central America		
Costa Rica	20	20
Argentina	3	9
Brazil	3	3
Total	**26**	**32**
Middle East and Africa		
Iran	9	9
Israel	6	6
Egypt	5	5
Jordan	1	1
Africa	3	3
Total	**24**	**24**
Caribbean	**4**	**4**
Total World	**6,184**	**7,202**

Sources: United States: Energy Information Administration, *Electric Power Annual 1997, Volume II*, DOE/EIA-0348(97)/2 (Washington, DC, October 1998) and Rest of the World: Windicator, *Wind Power Monthly* (January 1998), p. 50.

Activities at both the Federal and State level helped launch the industry. The passage of the Public Utility Regulatory Policies Act (PURPA) in 1978 created a market for wind-generated power where none existed before.[5] Other legislation put incentives in place such as lucrative investment tax credits. In the early 1980's, combined Federal and State investment tax credits amounted to 50-55 percent of the investment.[6] These credits were important in helping establish the wind industry by reducing investor tax obligations to the government and effectively lowering the investor's cost by the amount of the tax savings. Research sponsored by California's Mello Act of 1978 portrayed wind energy as a clean, reliable, secure alternative to foreign oil and rising oil prices. So the industry was born.

Research in California identified the Altamont, Tehachapi, and San Gorgonio passes as having the best wind resources. Wind was seen as the ideal complement to California's existing hydro power supply, providing peak power while allowing hydro to be reserved for low wind periods. Using its authority under PURPA, the California Public Utilities Commission decided in favor of relatively high full avoided costs to be paid to qualified facilities (generating electricity from wind and other renewable sources) in Standard Offer 4 contracts guaranteed for ten years. The subsequent boom in investments resulted in the development of 900 megawatts of capacity and lasted through 1985, when the Federal investment tax credits expired and California credits expired shortly thereafter.

The future upon which these incentives had been based, however, did not materialize. First, oil prices took a big slide in 1986 instead of continuing to increase. Second, natural gas prices rose less than projected and improvements in gas generating technology were greater than expected. These two factors meant that when 10-year contracts expired, the basis for future full avoided costs of electricity was much lower than initially anticipated.

Third, improvements in wind generating technology were less than anticipated; thus, the cost of developing wind power remained high. Fourth, the investment tax credits were more effective in getting capacity built rather than assuring the units would be productive. Because of technological problems, some capacity factors were as low as 5 or 10 percent.[7] A number of projects were plagued with costs higher than expected and failed as a result. While investment tax credits were effective in getting capacity built, they did not guarantee reliability and performance. Fifth, environmental groups that were expected to be supportive were instead opposed to development because of problems with visual obstruction, bird kills, and noise pollution. While development continued through the end of the 1980's, these 5 factors greatly slowed the pace of wind energy development, with nearly all new projects being in California.

Recent Trends

By the 1990's, wind energy facilities began to appear in other States such as, Texas, Minnesota, Vermont, Hawaii, and Iowa. Of these additional States, Texas had the most capacity with 43 megawatts in 1997, followed by Minnesota with 25 megawatts. Both Minnesota and Iowa have plans for major expansion which would add roughly 100 megawatts each in 1998, if planned construction is completed. Although production tax credits have been the focus of much attention because of their expiration in June 1999, in recent years, Federal and State support programs have provided a broad level of support ranging from various tax incentives to research grants, shown below.[8, 9]

Investment Tax Credits. Only a handful of States still have these credits. These include Hawaii, Massachusetts, Montana, North Carolina, Oregon and Utah.

Production Tax Credits. This type of credit provides the investor or owner of qualifying property with an annual

[5] Under provisions of PURPA, qualified facilities (QFs) were guaranteed that electric utilities would purchase their output at the utilities' avoided cost, which was the incremental cost that an electric utility would incur to produce or purchase an amount of power equivalent to that purchased from the QFs. Additionally, QF's were guaranteed that electric utilities would provide back up service at prevailing (nondiscriminatory) rates.

[6] R.W. Righter, *Wind Energy in America—A History* (Norman, Oklahoma, 1996).

[7] Capacity factor is the ratio of the electrical energy actually produced by a generating unit to the maximum electrical energy that could have been produced at continuous full-power operation during the same period.

[8] See N.A. Rader and R.H. Wiser, Review Draft *Strategies for Wind Energy —A Review and Analysis of State Policy Options,* prepared for the National Wind Coordinating Committee (Washington, DC, March 1998.)

[9] For state level information, see also North Carolina Solar Center, *National Summary Report on State Financial Incentives for Renewable Energy,* prepared for the Interstate Renewable Energy Council (Raleigh, NC, July 1997) and *National Summary Report on State Programs and Regulatory Policies for Renewable Energy* (Raleigh, NC, January 1998). Updated information is found in the Database of State Incentives for Renewable Energy on their website at http://www-solar.mck.ncsu.edu/.

tax credit based on the amount of electricity generated by that facility. By focusing on production, improved project performance is encouraged. Section 1914 of the Energy Policy Act of 1992 (EPACT) created a 10-year, 1.5 cent per kilowatthour credit adjusted for inflation for new plants entering service before June 30, 1999.[10] It has been estimated that this production tax credit can lower life-cycle levelized costs of wind power by about 25 percent.[11] Much of new and planned capacity depends on this credit, which will expire on June 30, 1999, unless proposed legislation passes to extend the tax credit by five years.

Property Tax Reductions. Reductions in property taxes can be used to promote wind development by decreasing the tax burden associated with owning a wind power facility. The tax burden is relatively high compared to fossil energy because of the greater land requirements per unit of output. This policy is an effective incentive in a number of States. For example, it is estimated that in Minnesota, where property taxes are high, property tax exemptions could reduce levelized costs by 1.0 cent per kilowatthour in some cases.[12] The disadvantage of this mechanism is that it produces an incentive for development, not a market per se.

Accelerated Depreciation. Tax depreciation is a non-cash expense meant to approximate the loss of asset value over time, and is defined as the portion of an investment that can be deducted from taxable income in any given year. The Tax Reform Act of 1986, which established the modified accelerated cost recovery system (MACRS), set the current rules for federal tax depreciation. Under MACRS, wind property is currently provided a depreciation life of 5 years, substantially shorter than the 15 to 20 year depreciation lives of non-renewable power supply investments. Faster depreciation results in tax benefits early in a project's life, and is preferred by investors because an after-tax dollar is worth more today than in later years.

Direct Production Incentives. Although similar to a production tax credit, direct production incentives provide cash income directly. At the Federal level, Section 1212 of Energy Policy Act of 1992 (EPACT) provides a "Renewable Energy Production Incentive" (REPI) of 1.5 cents per kilowatthour to non-profit organizations that own wind facilities.

Direct Investment Incentives (Grants). These include programs like the Department of Energy's Turbine Verification Program in which cost sharing with utilities permits early development of wind systems preceding full-scale deployment of turbines. It also includes State monies used for seed grants to conduct resource assessments and feasibility studies.

Government Subsidized Loans. Utility-scale wind system debt interest rates typically are 1 to 2 percent higher than rates for gas-fired projects. Subsidized loans can be provided at below market interest rates, thus reducing loan payments and levelized costs. Although there is no federally subsidized loan program, a number of States including Minnesota have them. While this type of program promotes wind energy, the effect is insufficient to make wind competitive.

"Standard Offer Contracts" for Small and Distributed Projects. During the 1980's, "Standard Offer 4 Contracts," that guaranteed prices 10 years into the future (and saved on transaction costs), were instrumental in the development of wind energy. The guaranteed prices were based on each utility's "full avoided cost" of marginal generation assuming escalating energy prices (which did not materialize). As these contracts have been renewed, the new prices have been much lower and threaten the viability of operating wind generators.

Net Metering or Net Billing. Under this system, utility customers are guaranteed a market for their power by being permitted to operate a "reversible meter." When customers use more electricity than they generate, they pay for the additional electricity at retail prices as usual. Conversely, when customers generate more electricity than they use, the electric utility is obliged to purchase the additional electricity. The prices customers receive for their excess electricity varies widely by State and region and between wholesale and retail levels. So far, experience for wind and net metering is limited. Although California has a provision for net metering, it excludes wind as a source. Other States limit the size of eligible projects, so larger wind projects (greater than 50 or 100 kW) cannot participate.

Site Prospecting, Review and Permitting. Programs in California and at the Federal level have been developed to conduct site resource assessments, evaluate

[10] Note: When other financial assistance is provided to a project, the amount of the production tax credit is reduced by a formula documented in Section 1914 of EPACT.

[11] Hadley, Hill, and Perlack, *Report on the Study of the Tax and Rate Treatment of Renewable Energy Projects*, ORNL-6772 (Oak Ridge, TN, December 1993).

[12] J. Bailey and D. Morris, Institute for Local Self Reliance, *Taxing Wind Energy in Minnesota* (January 1995).

transmission issues, conduct bird population studies, settle zoning issues, and streamline permitting processes. This helped to promote the early development of wind energy projects in California. The U.S. Department of Energy Utility Wind Resource Assessment Program performed a similar function in later years.

Renewable Portfolio Standard (RPS). The terms of renewable portfolio standards vary among States, but an RPS generally requires every retail power supplier to provide a certain minimum percentage (or floor) of electricity from specified renewable sources for a given time period. A RPS can operate in tandem with a credit trading system, so suppliers sell credits for extra renewable power they generated or vice versa. If they are short of renewable power they can purchase credits to make up the difference to settle their account.[13] Legislation establishing some sort of renewable portfolio standard has passed in a number of states including Arizona, Maine, Massachusetts, and Nevada.

Renewable Setasides. In California, a recent ruling provides for a 0.7-percent surcharge on electric bills to support renewables during the four-year transition to a competitive market. Wind energy is earmarked to receive $70 million of an estimated $540 million total budgeted.[14, 15] Already, some 300 megawatts of new wind energy projects have won the opportunity to receive California Energy Commission financial incentive funds.[16]

Auctioned Contracts. Increasingly, electric utilities have acquired renewable energy competitively by issuing request for proposals (RFP's), which generator owners can bid on. In effect, the bidder guarantees to provide a given amount of electricity under specified terms for a given price. To date, most of these RFP's were issued as renewable only or technology specific only.

Green Marketing/ Pricing. These are voluntary programs in which customers agree to pay a premium to purchase "environmentally friendly" or "green" electricity. This encourages development of a market for renewable power, wind included. So far, public response has been limited. It is estimated that only 1 to 4 percent of residential consumers will participate in the near future in California's green pricing program.[17] Although there is some difficulty in determining what the premium should be,[18] utilities like Sacramento Municipal Utility District and Traverse City Light and Power have begun to use green pricing to stimulate renewables development. In Sacramento, customers pay an additional $4 per month special premium to have a photovoltaic system installed and operating on their rooftop.

State Mandates. These provisions differ for each State. In Minnesota, the State legislature has required Northern States Power to phase in construction of 425 megawatts of new wind capacity by 2002 as compensation for being allowed to store nuclear waste on site. In Iowa, the Alternative Energy Law (AEL) requires investor-owned utilities to purchase a combined total of 105 megawatts of their generation from renewable and small hydropower sources. The majority of needed capacity will be from wind power and biomass applications.

Research and Development. The United States government has long supported development of wind technology that will be economically competitive as an energy source. The Wind Energy Program, administered by the Department of Energy, is divided into three components: applied research, turbine research, and cooperative research and testing. Funding for 1997 was $29 million.

Germany

Germany has made impressive gains in installed wind capacity since 1991 and is now setting the trend for Europe's future.[19] German capacity is nearly 2,000 megawatts, up from less than 100 megawatts in 1990.[20] In mid-1997, it surpassed the United States as the country with greatest wind capacity. Germany's environmentally friendly atmosphere was largely responsible for 394 megawatts being added in 1997, with more under

[13] See Schaeffer's proposed House of Representatives Bill 655.
[14] *Wind Energy Weekly* (February 2, 1998), pp. 1-2, and *Wind Power Monthly* (January 1998), pp. 32-37.
[15] Details of the program can be found on the California Energy Commission's website at http://www.energy.ca.gov/renewables.
[16] *Wind Energy Weekly* (July 20, 1998), pp. 1-2.
[17] Lawrence Berkeley National Laboratory (LBL), *Selling Green Power in California: Product, Industry and Market Trends* (Berkeley, California, August 1998).
[18] Advocates suggest a premium of 5-15 percent as a reasonable range.
[19] The current goal of the European Wind Energy Association is to reach 8,000 megawatts of installed capacity by 2000.
[20] Windicator in *Wind Power Monthly* (January 1998), p. 50.

construction in 1998.[21] Most of Germany's development is in small, dispersed projects owned by individuals and private operating pools, not utilities. This development has been encouraged by various mechanisms, several of which are described below.

Electricity Feed Law (EFL). Since 1991, the EFL has obliged electric utilities to purchase renewable energy at guaranteed prices equal to 90 percent of retail price.[22] For wind, this amounts to Deutsche Mark (DM) .1715, or 10.5 cents per kilowatthour in 1997 for the life of the plant—a significant stimulus to development.[23] In the future, as prices come down in Europe's more competitive, liberalized electricity market, the guaranteed price is expected to be lower—about 2 percent less in 1998 for example.[24] This type of decrease is expected to gradually put economic pressure on developers.

In addition, the electric utilities are opposed to the EFL because of the burden it places on them. Efforts to declare the law unconstitutional failed, but the amendment to the EFL recently passed in Germany's Parliament is more favorable for utilities. It provides a cap (some 5 percent) on electric power taken from renewable sources.[25] This is good and bad news for the wind industry—the EFL is still in force, but there is a limit on benefits.

Investment Assistance. The Deutsche Ausgleichsbank grants to wind turbine operators soft loans with average interest rates of 1 to 2 percent below the rates in the capital market.[26] Rates are fixed for the duration of the loan and thus provide easy financing for German wind farms, when compared with the rest of Europe.

Planning Privileges. The German Building Statute Book prohibits erection of buildings and similar structures on open countryside with some exceptions.[27] Facilities for public electricity supply, including wind turbines, are permitted. This facilitates development of wind power, which has large land requirements.

250 Megawatt Program. The goal of the 250 Megawatt Program is to carry out a broad test over several years of the application of wind energy on a commercial scale.[28] As an incentive for their participation in the program, operators of the wind turbine / wind farm receive grants for the successful operation of their facilities. The current benefit is either DM .06 or .08 (about $.03 or $.04) per kilowatthour depending on whether the energy is fed into the grid or used by the owner of the turbine, respectively.

El Dorado. This program provides overseas aid to cooperative ventures between German interested parties and development partners in the Southern Hemisphere. Grants of up to 70 percent of the cost of the project are provided. At the end of 1996, this program supported development of 26 megawatts of capacity.

Research and Development (R&D). The Federal Ministry for Education, Science, Research and Technology spent about DM 5.5 million or $3.2 million on various R&D projects while the Federal Ministry of Economics contributed about DM 1 million or $0.6 million in 1996.

Denmark

Denmark ranks as the world's largest manufacturer and exporter of wind turbines and it is third in installed wind capacity. In the 1980's, before Germany and the Netherlands began wind programs, Denmark had virtually all of the wind capacity outside the United States. By 1990, this amounted to around 300 megawatts. Development has continued through the 1990's and has included two offshore projects. Despite limitations on available land space, total wind capacity was over 1,000 megawatts at the end of 1997.

Currently, about 60 percent of the world's wind turbines are manufactured in Denmark. In the twelve months ending October 1997, Denmark sold 1,021 megawatts of wind turbines.[29] About one-third, or 326 megawatts, went to domestic markets and the remainder were exported. Germany was the most popular destination,

[21] Germany is projected to add 500 megawatts of capacity in 1998. For details, see BTM Consult, APS, *International Wind Energy Development–World Market Update 1997* (Ringkobing, Denmark, March 1998).
[22] C. Flavin and S. Dunn, Worldwatch Institute, *Rising Sun Gathering Winds: Policies to Stabilize the Climate and Strengthen Economies* (Washington, DC, November 1997), p. 49.
[23] *The Solar Letter* (January 30, 1998), pp. 37-38.
[24] Personal communication with Andreas Wagner, German Wind Energy Association, January 1998.
[25] *The Sustainable Energy Industry Journal* (Issue 8, 1998), p. 38.
[26] International Energy Agency, *IEA Wind Energy 1996 Annual Report* (Paris, France, October 1997).
[27] Personal communication with Andreas Wagner, German Wind Energy Association, January 1998.
[28] International Energy Agency, *IEA Wind Energy 1996 Annual Report* (Paris, France, October 1997).
[29] *Wind Power Monthly* (December 1997), p. 23.

followed by Spain, China, and Great Britain. Over the years, the Danish government has demonstrated a great deal of support for its wind industry at home and abroad. Some selected support programs are discussed below.

Windmill Law. This law requires electric utilities to purchase output from private wind turbine owners at 85 percent of the consumer price of electricity plus ecotax relief or about Kroner .62, or 9 cents per kilowatthour.[30] Electric utilities receive Kroner .10 or 1.5 cents per kilowatthour production subsidy for power generated by wind.[31]

Energy 21. In earlier years, Denmark undertook development of wind energy to lessen dependence on imported oil. Now development is tied to its Energy 21 goal of reducing CO_2 emissions by 20 percent by 2005. This translates into an initial 1,500 megawatts of wind capacity on land and later by 2030, 4,000 megawatts offshore.[32] This plan also encourages support at the grass roots level as local planning boards have been asked to include wind in their energy plans.

Export Assistance. The Danish International Development Agency (DANIDA) provides both direct grants and project development loans to qualified importing countries.[33] India is a good example of a developing country receiving assistance. In the beginning, tied grant money was used to develop the first demonstration projects of about 20 megawatts. Joint ventures formed in these projects paved the way for future development using soft loans tied to the purchasing of Danish equipment directly, or setting up a licensing agreement with Danish companies to manufacture locally. Typically, these loans for developing countries bear low interest and have extended payback periods. The exact terms are determined by the importing country's state of development (e.g., least developed, less developed) with the most favorable terms going to the least developed countries, and so on.

Research and Development (R&D). The Danish government has long supported development of technology for its manufacturing industry. During the 1976-1996 period, total R&D funding was about Kroner 350 million ($52million).[34]

Demonstration Projects. These projects received about Kroner 170 million ($25 million) over the same time period.

India

India ranks first in the developing world for installed wind capacity. With nearly 850 megawatts of wind capacity, it ranks fourth in the world after Germany, the United States, and Denmark. Most of this development occurred in 1995 and 1996, when capacity expanded by an average of several hundred megawatts per year. Among the States, Tamil Nadu has the most capacity—approximately 75 percent of India's total in 1996— while Gujarat and Andra Pradesh have most of the remainder. With electricity demand pressing, the government favored wind projects because they had a short gestation period and no air emissions. Efforts were made to develop a domestic manufacturing industry partnered with overseas companies. Denmark, Germany, and the Netherlands were instrumental in providing assistance. Nevertheless, it is reported that the projects have been dogged with poor performance due to the turbines being improperly sized for European-type high wind speed conditions, whereas India's wind speeds are lower. In 1997, the slow economy, tight credit, and change in government resulted in total additions of less than 50 megawatts, despite the number of support mechanisms in place to support development, described below.[35]

Guaranteed Prices. Tamil Nadu and several other State electric boards have agreed to purchase wind power at about 6.4 cents per kilowatthour.[36]

Tax Benefits. These include:

- Five-year tax holidays on income from sales of electricity
- Accelerated depreciation of 100 percent on investment in capital equipment in the first year

[30] *Wind Power Monthly* (January 1998), p. 29.
[31] American Wind Energy Association, *Fact Sheet on International Wind Energy Incentives* (Washington, DC, February 1997).
[32] *Wind Power Monthly* (September 1997), p. 20.
[33] Princeton Economic Research, Inc., Draft *Government Export Assistance Available to European Wind Turbine Manufacturers*, prepared for the National Renewable Energy Laboratory (March 24, 1995).
[34] International Energy Agency, *IEA Wind Energy Annual Report 1996* (Paris, France, October 1997), pp. 40-41.
[35] *Wind Directions* (April 1997), pp. 8-11.
[36] India Renewable Energy Development Agency (IREDA), at website http://www.crest.org/renewables/ireda/wind.html (July 23, 1997).

- Excise duty and sales tax exemptions for wind turbines

- Import duties on a variety of components waived

- Moving toward a production tax incentive to encourage performance.

Project Financing. India Renewable Energy Development Agency (IREDA) was formed in 1987 to provide assistance in obtaining loans from the World Bank, the Asian Development Bank, and the Danish International Development Agency (DANIDA). This included acting as a conduit for World Bank Loans totaling $78 million specifically for wind.

Planning and Resource Assessment. India has a large wind assessment program with over 600 stations in 25 States to provide information about the best sites for development.[37]

Grants/Demonstration Projects. By the end of 1996, some 50 megawatts of demonstration capacity had become operational.[38] This capacity was concentrated in the States of Tamil Nadu and Gujarat.

Closing Comments

The United States is rich in wind resources.[39] The major difference between the United States and the other countries discussed is the price guaranteed for wind energy. U.S. producers, under new contracts, receive around 3 to 4 cents per kilowatthour.[40] In contrast, wind producers in Germany, Denmark, and India are guaranteed 10.5 cents per kilowatthour, 9 cents per kilowatthour, and 6.4 cents per kilowatthour, respectively. U.S. producers, who currently are facing the uncertain world of deregulation and competitive pricing, find investing in wind energy too risky.

In March of 1998, the Administration released its "Comprehensive Electricity Competition Plan" (CECP) with provisions for a renewable portfolio standard, a public benefit fund, and net metering. While wind would benefit from these provisions, if enacted, some of the benefits would be limited. For example, wind energy might be expected to take a major share, but not all, of the energy provided under a renewable portfolio standard. Also, wind projects typically exceed the size limitations (up to 20 kilowatts) for net metering. Further, Congress has yet to approve the CECP, so most of the U.S. wind capacity planned to come on line in the next year or two is either "mandated" as in Minnesota and Iowa or, alternatively, designed to take advantage of the production incentive which is to expire in June 1999, or both.

Future

Although the four countries studied in this article currently have 76 percent of the world's installed wind capacity, there are some interesting developments elsewhere. In 1997, Spain added some 150 megawatts of wind capacity and now surpasses both the Netherlands and the United Kingdom. Also, Spain has near-term plans for an additional 100-200 megawatts of capacity using contracts with premium prices.[41] In Asia, China expanded from 79 to 166 megawatts last year and some of China's projects are being financed using tied aid with Denmark and other mechanisms to continue development of wind energy in a country that is hungry for clean energy.

[37] *Wind Energy Weekly (*September 9, 1996), p. 5.

[38] Ministry of Non-Conventional Energy Sources, Government of India, *Annual Report 1996-1997,* pp. 50-51.

[39] For details, see the Wind Energy Resource Atlas of the United States, at website http://rredc.nrel.gov/wind/pubs/atlas.

[40] The average price of electricity for sales for resale by investor-owned utilities was 3.2 cents per kilowatthour in 1996. See Energy Information Administration, *The Changing Structure of the Electric Power Industry: Selected Issues,* DOE/EIA-0562(98) (Washington, DC, July 1998), p. 23.

[41] *The Solar Letter* (April 25, 1997), pp. 158-159.

Glossary

Alternating Current: An electric current that reverses its direction at regularly recurring intervals, usually 50 or 60 times per second.

Aquifer: A subsurface rock unit from which water can be produced.

ARI: Air-Conditioning and Refrigeration Institute

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.

Biodiesel: A renewable fuel synthesized from soy beans, other oil crops, or animal tallow which can substitute for petroleum diesel fuel.

Biomass: Organic nonfossil material of biological origin constituting a renewable energy source.

Black Liquor: A byproduct of the paper production process that can be used as a source of energy.

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.

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.

Combined Cycle: An electric generating technology in which electricity is produced from otherwise lost waste heat exiting from one or more gas (combustion) turbines. The exiting heat is routed to a conventional boiler or to a heat recovery steam generator for utilization by a steam turbine in the production of electricity. Such designs increase the efficiency of the electric generating unit.

Cull Wood: Wood logs, chips, or wood products that are burned.

Direct Current: 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.

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 byproduct 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.

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 watthours (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 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 distribution system.

Groundwater: Water occurring in the subsurface zone where all spaces are filled with water under pressure greater than that of the atmosphere.

Heat Pump: A year-round heating and air-conditioning system employing a refrigeration cycle. In a refrigeration cycle, a refrigerant is compressed (as a liquid) and expanded (as a vapor) to absorb and reject heat. The heat pump transfers heat to a space to be heated during the winter period and by reversing the operation extracts (absorbs) heat from the same space to be cooled during the summer period. The refrigerant within the heat pump in the heating mode absorbs the heat to be supplied to the space to be heated from an outside medium (air, ground or ground water) and in the cooling mode absorbs heat from the space to be cooled to be rejected to the outside medium.

Heat Pump (Air Source): An air-source heat pump is the most common type of heat pump. The heat pump absorbs heat from the outside air and transfers the heat to the space to be heated in the heating mode. In the cooling mode the heat pump absorbs heat from the space to be cooled and rejects the heat to the outside air. In the heating mode when the outside air approaches 32º F or less, air-source heat pumps loose efficiency and generally require a back-up (resistance) heating system.

Heat Pump (Geothermal): A heat pump in which the refrigerant exchanges heat (in a heat exchanger) with a fluid circulating through an earth connection medium (ground or ground water). The fluid is contained in a variety of loop (pipe) configurations depending on the temperature of the ground and the ground area available. Loops may be installed horizontally or vertically in the ground or submersed in a body of water.

Heat Pump (efficiency): The efficiency of a heat pump, that is, the electrical energy to operate it, is directly related to temperatures between which it operates. Geothermal heat pumps are more efficient than conventional heat pumps or air conditioners that use the outdoor air since the ground or ground water a few feet below the earth's surface remains relatively constant throughout the year. It is more efficient in the winter to draw heat from the relatively warm ground than from the atmosphere where the air temperature is much colder, and in summer transfer waste heat to the relatively cool ground than to hotter air. Geothermal heat pumps are generally more expensive ($2,000-$5,000) to install than outside air heat pumps. However, depending on the location geothermal heat pumps can reduce energy consumption (operating cost) and correspondingly, emissions by more than 20 percent compared to high-efficiency outside air heat pumps. Geothermal heat pumps also use the waste heat from air conditioning to provide free hot water heating in the summer

Hub Height: In a horizontal-axis wind turbine, the distance from the turbine platform to the rotor shaft.

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.

Kilowatt (kW): One thousand watts of electricity (See Watt).

Kilowatthour (kWh): One thousand watthours.

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 and have significant amounts of waste supply guaranteed.

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.

Operation 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.

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.

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.

Roundwood: Logs, bolts, and other round timber generated from the harvesting of trees.

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.

Watthour (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.

Wheeling: The use of the transmission facilities of one system to transmit power and energy by agreement of and for, another system with a corresponding wheeling charge, e.g., the transmission of electricity for compensation over a system that is received from one system and delivered to another system).

Wood Pellets: Fuel manufactured from finely ground wood fiber and used in pellet stoves.