Renewable Electricity Purchases: History and Recent Developments

by Louise Guey-Lee

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)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. 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. 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 renewable electricity base. 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. 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.

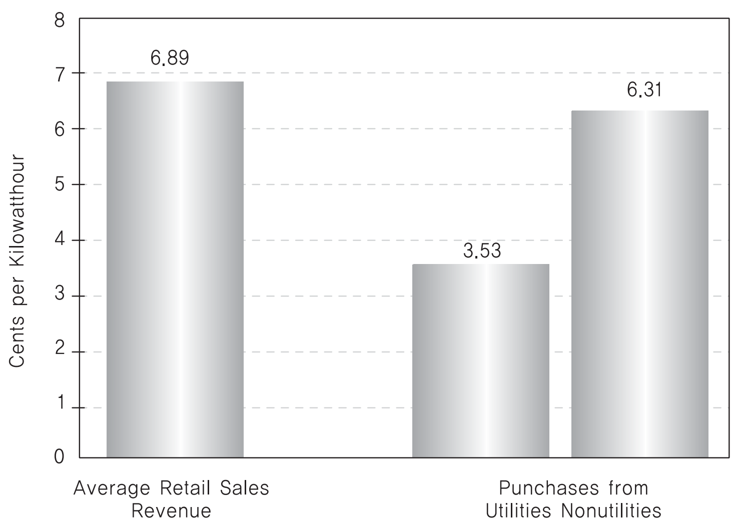
In addition, marketing strategies to promote renewables, possible now under FERC's open access environment, create some issues unique to renewables. For example, customers willing to pay a premium for renewable energy and the renewable facilities providing them power may be in different regions. This 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.

Overview

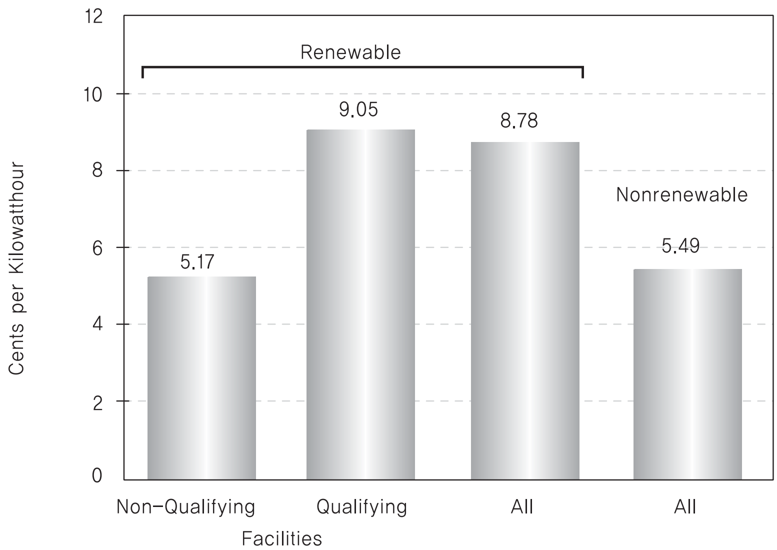
Nonutilities provided 13 percent of total utility power purchases in 1995, almost 25 percent of which was renewable-based. Thus, renewable energy provided only a small fraction (3 percent) of U.S. utility power purchases. However, this market is the major outlet for nonutility renewable power, as utilities 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. 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, 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 using renewable energy was 9.05 cents/kilowatthour--some 31 percent higher than the average U.S. retail price.

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



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

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.

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 nonutility 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.

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

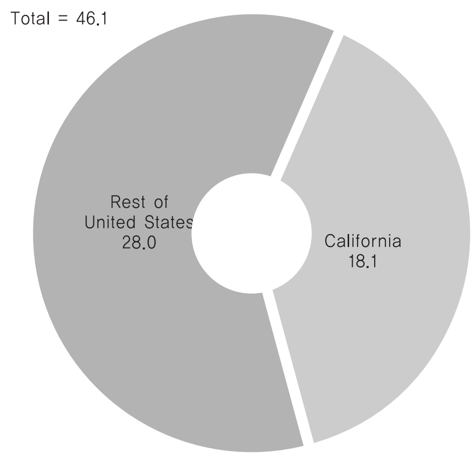
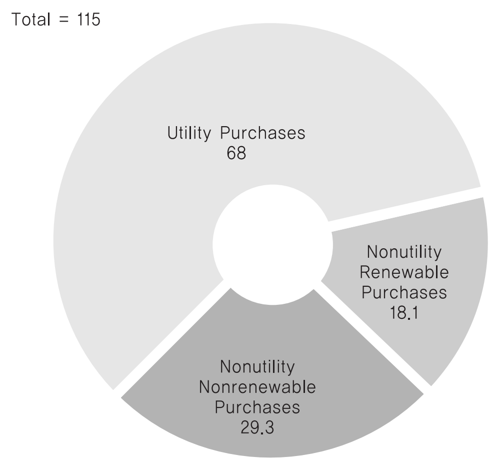


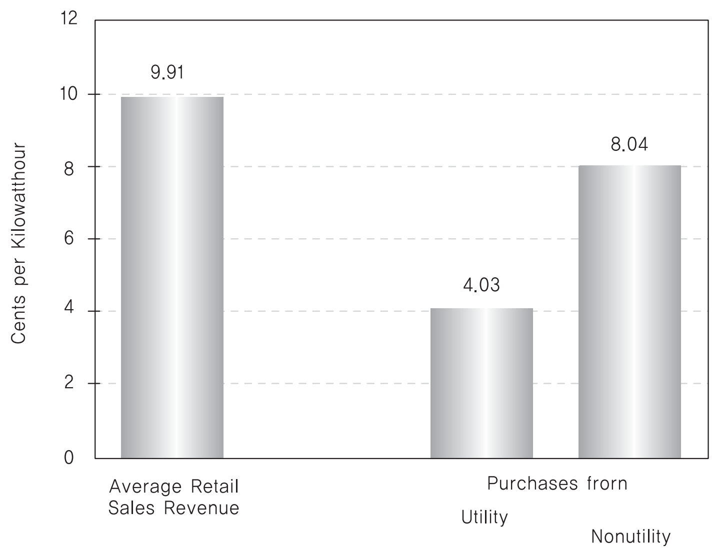
Figure 4. California Electric Utility Purchases from Utilities and Nonutilities by Energy Source, 1995
(Billion Kilowatthours)



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).

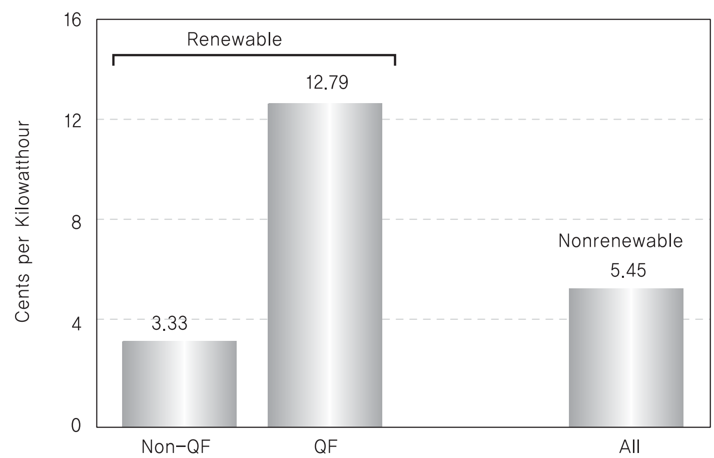
Although no precise measure of the incentives provided to renewable energy is available, analysis of price data in this chapter suggests one order of magnitude of the incentive-subject to nontrivial data limitations. In some cases, such as California, the incentive seems large for electricity from particular renewables when prices utilities paid to those facilities were compared to those paid to nonrenewable 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 5. California Electric Utility Average Price per Kilowatthour for Purchased Power Compared to Average Retail Sales Revenue, 1995



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

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.

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 producers. 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. Of this, 58,345 megawatts (80 percent) came from QFs. Total nonutility capacity using renewable energy was 17,172 megawatts from 908 facilities. 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, 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. 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.

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, 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. 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.

Nonutility Renewable Generation

In 1996, nonutility power producers generated 382,423 million kilowatthours of electricity, of which renewable sources generated 89,793 million kilowatthours. 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, predominantly in the South. 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.

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

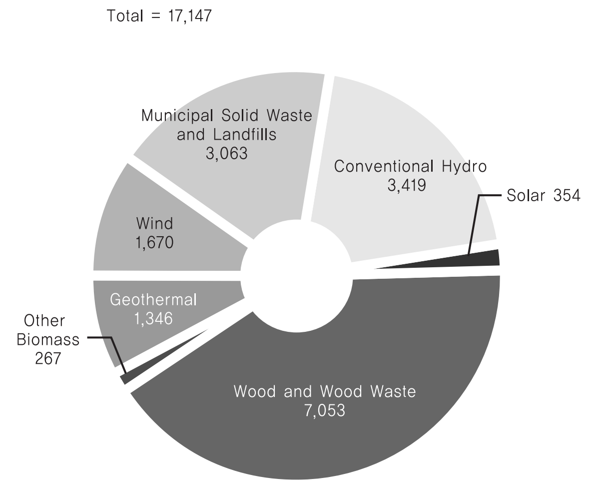
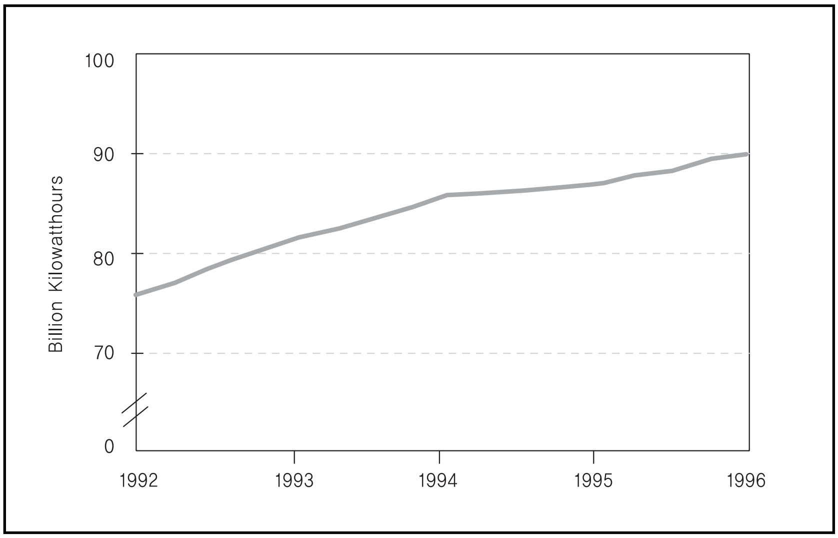


Figure 8. Gross Renewable Generation for U.S. Nonutility Generating Facilities, 1992 Through 1996



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. 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. 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.

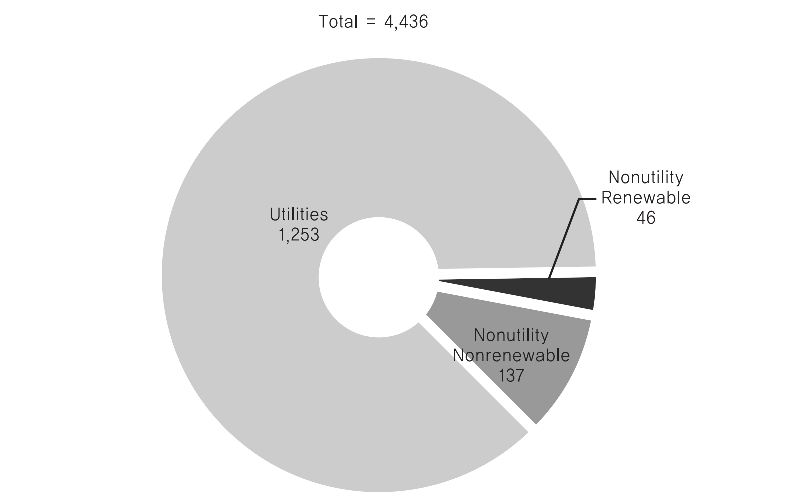
Purchases from industrial producers did exist, but were very small. Not only did PURPA change the type of capacity built and the generation mix as discussed earlier, but it also changed the way sales of electricity were contracted and how rates were determined.

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.

Total U.S. Power Purchases

Purchases. U.S. electricity purchases by utilities totaled 1,436,072 million kilowatthours in 1995. 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 gen-

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



erated 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, 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.

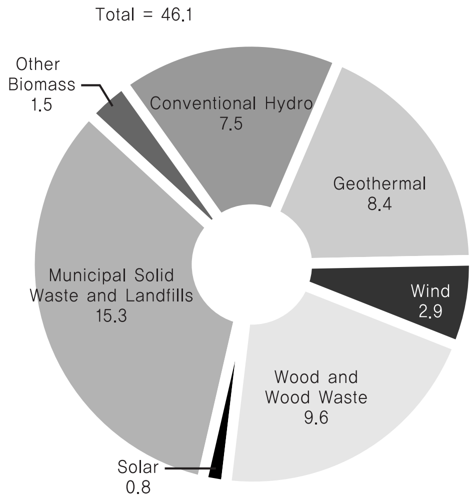
In contrast, the average cost of power from nonutilities was 6.31 cents per kilowatthour, nearly double the cost of purchases from utilities and other sources. The most expensive regions were the Pacific, at 7.75 cents per kilowatthour, followed by New England, and the Mid-Atlantic and South Atlantic 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.

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. 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, southern utility renewable purchases from nonutilities accounted for only 15 percent of U.S. nonutility renewable purchases. 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). Major portions also came from wood and wood waste, geothermal, and conventional hydroelectric.

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



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.

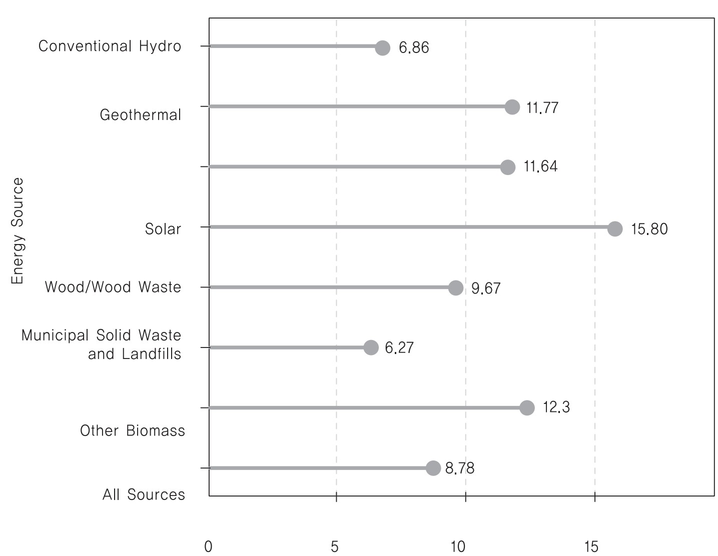
Expenditures. Electric utility costs of purchased renewable electric power from nonutilities was $4.041 billion, or around 35 percent of the U.S. total nonutility power revenues from sales to utilities. More than half of these costs ($2.210 billion) were for electricity sold in California (Table 11).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

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



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. 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. Paper and Allied Products received $177 million.

Prices. The average price paid to SIC Code 49 facilities was highest at 9.05 cents per kilowatthour. 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. 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.

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. 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 and Standard Offer contracts in California. 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 slow-down 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, California had a tax preference for renewable energy facilities. The combination of these tax credits and high marginal income tax rates 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.

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. 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.