Competitive Electricity Prices: An Update[1]

by
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Throughout the country, States are moving to make their electricity generation markets more competitive. Although the timing will surely vary, most States plan to implement significant changes in the pricing of electricity between now and the first few years of the 21st century. By estimating competitive generation prices based on marginal costs, this paper illustrates that the range of generation prices across the regions of the country can be expected to narrow with competition. However, it also shows that substantial differences in total electricity prices among regions will remain, because of differences in resource availability, the costs of nongeneration (transmission and distribution) services, climate, and taxes.

Background

Historically, electricity prices in the United States have not been set by market forces. Consumers' electricity supply choices have been limited to the utilities franchised to serve their areas. Similarly, electricity suppliers have not been free to pursue customers outside their designated service territories. Utilities have built generation, transmission, and distribution capacity only to serve the needs of the customers in their service territories, and the price of electricity has been set administratively, based on the average cost of producing and delivering power to customers.

The regulatory structure of the U.S. electric power industry evolved from the belief that the supply of electricity was a natural monopoly, and that one supplier could provide services at the lowest cost. For a variety of reasons, both economic and technological, that view has changed. Today, the relationship between consumers and suppliers of electricity is poised for change.[2] Most States plan to implement significant changes in the procurement and pricing of electricity between now and the first few years of the 21st century. Thus, in the near future, some of the services currently provided by local utilities will be available from other suppliers.

The electricity business is made up of three major functional service components or sectors: generation, transmission, and distribution. The generation sector is the production arm of the business—the power plants where electricity is produced. The transmission sector can be thought of as the interstate highway system of the business—the large, high-voltage power lines that deliver electricity from power plants to local areas. The distribution sector can be thought of as the local delivery system—the relatively low-voltage power lines that bring power to homes and businesses. While it is expected that most consumers will continue to purchase distribution services from their local utilities and buy transmission services from a centralized pool, generation services are expected to be available from many sources.

For the most part, the prices for transmission and distribution services are expected to continue to be set administratively on the basis of the average cost of service. Some alternative approaches for pricing transmission services are being considered. In contrast, competitive market forces will set generation prices. Buyers and sellers of power will work together, through power pools or one-on-one negotiations, to set the price of electricity. As in all competitive markets, the supplier in the market[3] who has the highest costs will determine the price at any level of demand. During most time periods, the generation price of electricity will be set by the operating costs of the most expensive (in terms of operating costs) generating unit needed to meet demand, or what in economics is referred to as the "marginal cost" of production. When consumers' demand for electricity rises (for example, on a hot summer day), the generation price will rise as units with higher operating costs are brought on line. Conversely, on cool spring weekends when air conditioning is not needed and many businesses are closed, prices will be relatively low.

[1]This paper updates the work prepared in *Electricity Prices in a Competitive Environment: Marginal Cost Pricing of Generation Services and Financial Status of Electric Utilities*, DOE/EIA-0614 (Washington, DC, August 1997). This paper is based on work prepared for the *Annual Energy Outlook 1998*, DOE/EIA-0383(98) (Washington, DC, December 1997).

[2]For a discussion of the changing structure of the electricity industry, see L.S. Hyman, *America's Electric Utilities: Past, Present and Future* (Arlington, VA: Public Utilities Reports, Inc., 1994), and Energy Information Administration, *The Changing Structure of the Electric Power Industry: An Update*, DOE/EIA-0562(96) (Washington, DC, December 1996).

[3]A supplier who is in the market is one who is able to find customers at the prices it is offering. During a low demand period there could be many suppliers who are unable to sell any output and, therefore, will have no impact on the price.

The movement toward competitive pricing of generation has several implications. Generation prices are likely to become more volatile, changing as consumers' needs move up and down across seasons and from hour to hour during the day. For example, as the temperature rises on a hot summer day, the use of air conditioning will increase, and the price of electricity will rise as plants with higher operating costs are used to meet demand. Competitive prices based on marginal costs will also be more sensitive to any factors that affect the operating costs of the marginal generators. For example, if the cost of fuel to marginal generators rises unexpectedly, the impact on prices will be readily apparent. With traditional cost-of-service pricing, these impacts are muted, because the costs for all plants are averaged together.

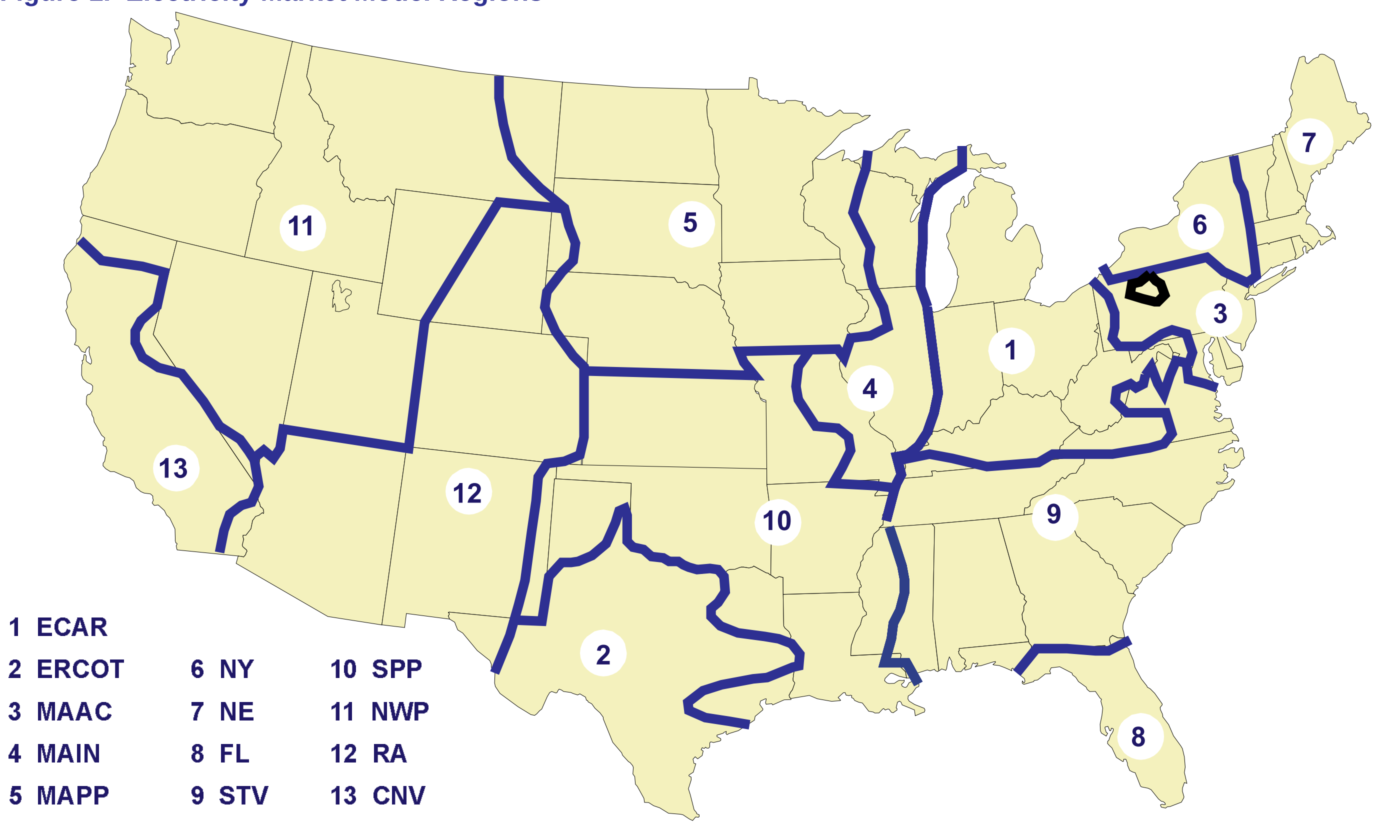
Both of the above characteristics of competitive prices were illustrated by national-level model results in the *Annual Energy Outlook 1998* (*AEO98*).[4] This report illustrates a third impact of the move to competitive generation pricing—the narrowing of the range of prices across regions of the country. Concentrating on the period 2005 to 2020 (after competition has been phased in), electricity prices are presented regionally for the generation component, the combined transmission and distribution component, and generation sector taxes.

Methodology

To simulate the transition to competitive electricity generation prices, prices based on average costs (cost-of-service pricing) and on marginal costs (competitive pricing) were calculated for each of 13 U.S. electricity supply regions (Figure 1) for the period 1998 through 2008.[5] An average price for each of the transition years was estimated using a weighted average of the two prices. Initially, in 1998, a 0.90 weight was given to the cost-of-service price, and a 0.10 weight was given to the competitive price. The weights were shifted over time, so that by 2008 the competitive price received a 1.0 weight and the cost-of-service price was no longer used. Transmission and distribution system prices were calculated from average costs throughout the projection period.

The gradual shift toward the competitive generation price was meant to reflect the path being taken by the States. Some States, such as California, are allowing consumers to choose their electricity suppliers (generators) as early as 1998. However, they are also allowing utilities to recover the costs of investments that were made to serve these customers over a certain number of years. Thus, the impacts of unfettered competition in the generation market will not be seen for a few years. In addition, even if consumers are free to choose their suppliers

Figure 1. Electricity Market Model Regions



Source: Energy Information Administration, Office of Integrated Analysis and Forecasting.

[4]See Energy Information Administration, *Annual Energy Outlook 1998*, DOE/EIA-0383(98) (Washington, DC, December 1997), "Electricity Pricing in a Competitive Environment," pp. 20-23.

[5]The Electricity Market Model (EMM) submodule of the National Energy Modeling System (NEMS) represents the supply and demand for electricity in 13 regions based on the regions and selected subregions of the North American Electric Reliability Council (NERC).

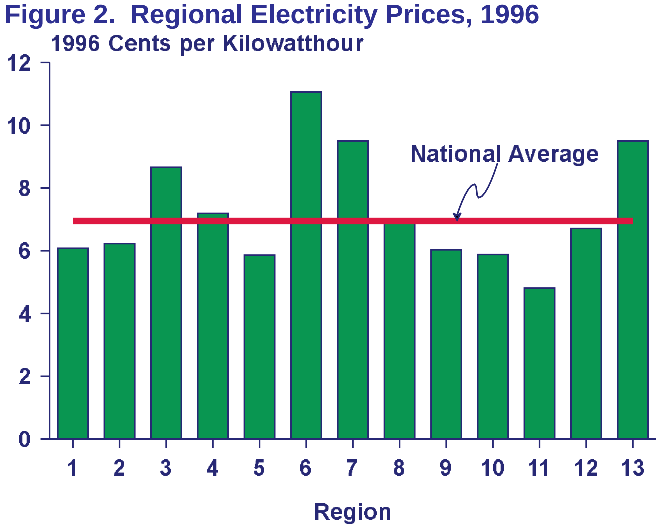
in the next few years, it could take several more years for the new market institutions needed to support competition to evolve fully.

Regional Competitive Electricity Prices

In today's market, average electricity prices vary substantially among different regions of the country (Figure 2). Prices in the highest cost region are nearly 2.3 times (230 percent) the prices in the lowest cost region. Many factors—such as differences in regional fuel availability and prices, labor and construction costs, climate, taxes, and customer mix (residential, commercial, and industrial)—contribute to the differences. For example, access to economical hydroelectric power is a major factor in the relatively low electricity prices seen in the Northwest. Conversely, the lack of low-cost hydroelectric or coal-fired power plants in the New York and New England regions is one factor in their relatively high prices. Still, the range in regional electricity prices is considerably larger than that seen for other energy products. For example, excluding Alaska and Hawaii, average gasoline prices in November 1997 differed by only 39 percent across the States. Similarly, fuel oil prices (excluding taxes) differed by only 29 percent across the States in November 1997.[6] Even when taxes are added, gasoline prices across the continental United States differ by only 54 percent.

In competitive markets, large regional price differences for a product would be expected to attract the attention of both suppliers and consumers. With the opportunity to make greater profits, low-cost suppliers would want to enter high-price markets. Similarly, consumers—especially those who use large quantities of the product—would move into regions with low prices and out

Figure 2. Regional Electricity Prices, 1996



Source: AEO98 National Energy Modeling System, run BASECOMP.D101797A (October 1997).

of regions with high prices. Over time, these forces would tend to narrow the price differences between regions. Absent large transportation and local market costs, which in this analysis are assumed not to be affected by competitive pressure, the "price gap" should be quite narrow in the long run.

The market forces described above are expected to affect regional electricity prices, especially those for generation services, as competition takes hold. By 2005, the range in the total price of electricity across regions is expected to fall to 4.2 cents, much lower than the 6.3-cent range seen in 1996 (Figure 3). Excluding the New York and New England regions, which have very high non-generation sector prices, the range is much narrower, at just over 2 cents per kilowatthour by 2020. The nearly 100-percent regional price gap is still much larger than that seen for gasoline and fuel oil. However, as mentioned for New York and New England, the competitive generation sector is not the source of most of the remaining gap.

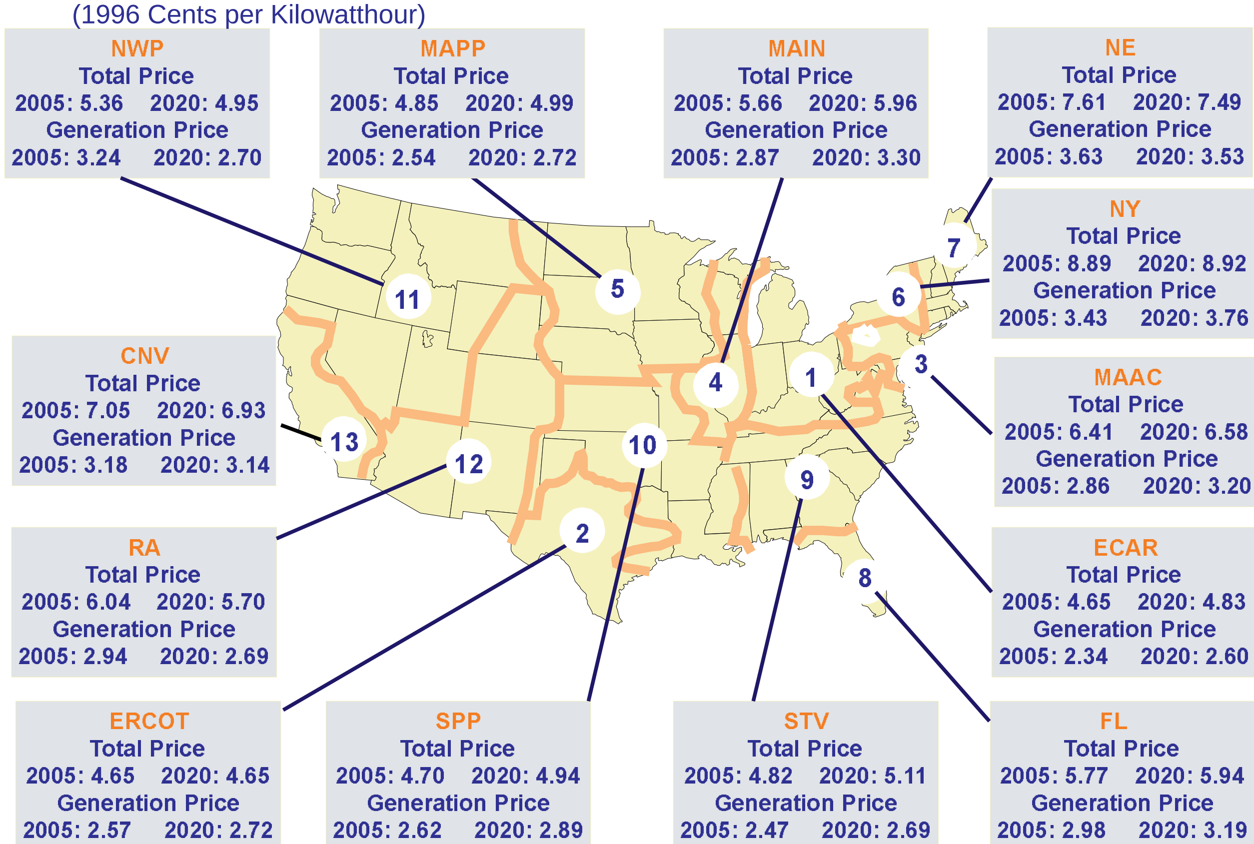
In 2005, the range in generation sector prices across the regions is expected to be less than 1.3 cents (Figure 3). By 2020, the range narrows even further to just over 1.1 cents. The variation in generation prices, especially in the early years, is due primarily to the different mix of plants in the regions. The plant types setting the marginal price, in descending order of operating costs, include: high operating cost oil / gas turbines (although many of these plants can burn either oil or natural gas, most use gas) designed to run infrequently; older, inefficient oil / gas steam plants; newer, more efficient oil / gas combined-cycle plants; and coal-fired plants with low fuel costs. As a result, the regions with the lowest generation prices are those dominated by low operating cost existing coal or hydroelectric plants.

In region 1 (ECAR), more than 85 percent of the total existing capacity is coal or nuclear powered. In regions like this, coal-fired plants will set the marginal price during many hours of the year, especially in the early years of the projections, before a large number of new plants are built (Figure 4). Conversely, regions that rely more heavily on older, less efficient oil and gas steam plants will tend to have the highest competitive generation prices. This is true in regions 6 and 7, New York and New England, both of which have large amounts of oil and gas steam capacity. It is possible that these plants may be retired soon after competition takes hold and, thus, that there impact on prices will be lessened.

Over time, new gas-fired combustion turbine and combined-cycle plants are expected to dominate new power plant additions in all regions. Such relatively low-cost plants are expected to bring down generation costs in almost all regions, especially where they are relatively high today. As a result, existing plants will not play as

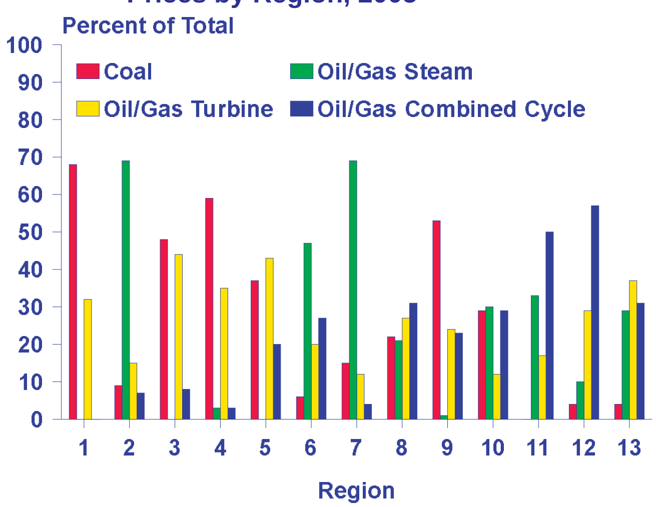
[6]Energy Information Administration, *Petroleum Marketing Monthly*, DOE / EIA-0380(98 / 02) (Washington, DC, February 1998).

Figure 3. Total Electricity Prices and Generation Prices by Region, 2005 and 2020
(1996 Cents per Kilowatthour)



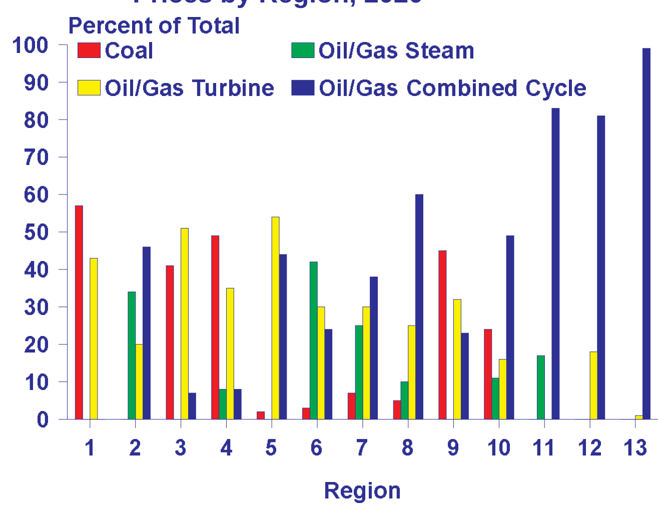
Source: AEO98 National Energy Modeling System, run BASECOMP.D101797A (October 1997).

Figure 4. Plant Types Setting Marginal Electricity Prices by Region, 2005



Source: AEO98 National Energy Modeling System, run BASECOMP.D101797A (October 1997).

Figure 5. Plant Types Setting Marginal Electricity Prices by Region, 2020

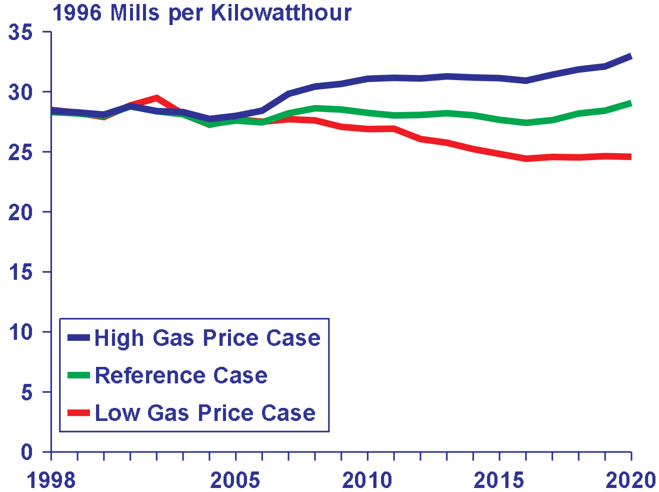


Source: AEO98 National Energy Modeling System, run BASECOMP.D101797A (October 1997).

important a role in setting the marginal price in 2020, and the range in generation sector prices across the regions will narrow further (Figure 5).

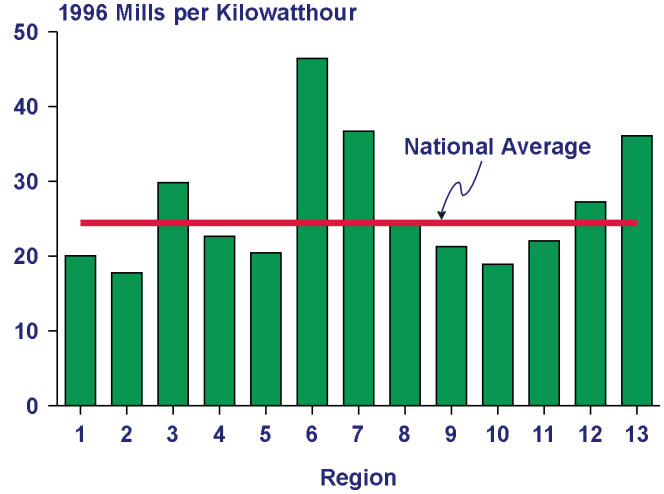
As discussed at the national level in *AEO98*, the competitive generation price will be sensitive to any factors that raise the operating costs of the generators setting the marginal price. For example, if natural gas prices turn out to be higher or lower than expected, competitive generation prices will be directly affected. Figure 6 illustrates this point at the national level. When the price of gas delivered to generators is assumed to be 18 percent higher, the competitive generation price is projected to be 13 percent higher in 2020 than in the reference competitive case. Similarly, when the price of gas delivered to generators is 18 percent lower, the competitive

Figure 6. National Average Generation Prices in Alternative Gas Price Cases, 1998-2020



Source: AEO98 National Energy Modeling System, runs BASECOMP.D101797A, LOGCOMP.D101697A, and HOGCOMP.D101697A (October 1997).

Figure 7. Transmission and Distribution Costs by Region, 2005



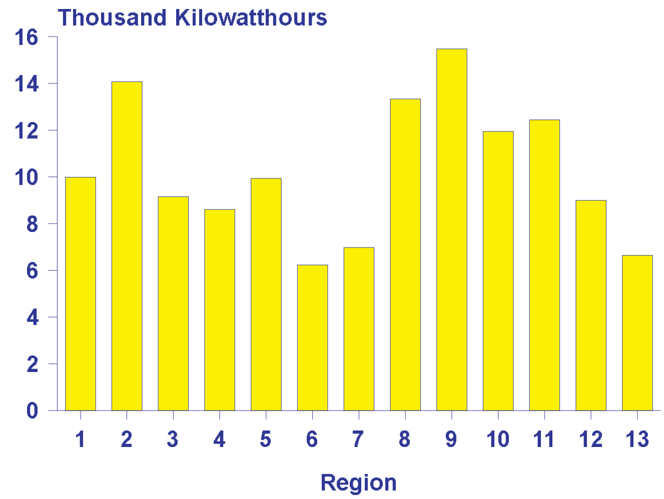
Source: AEO98 National Energy Modeling System, run BASECOMP.D101797A (October 1997).

generation price is 15 percent lower in 2020 than in the reference competitive case.

Generation sector prices account for 1.3 cents of the 4.2-cent range in regional prices remaining in 2005. Prices for transmission and distribution services (the vast majority of which are for distribution) account for a much larger share. Across the regions, the projected transmission and distribution prices in 2005 range from less than 2 cents per kilowatthour in the Texas (ERCOT) and SPP regions (regions 2 and 10), to nearly 5 cents per kilowatthour in the New York region (region 6) (Figure 7).

Many factors contribute to the range in transmission and distribution pricing, including regional construction and labor cost differences. One of the most important is the variance in average customer consumption across the regions (Figure 8). Because transmission and distribution system costs consist mainly of the capital costs for wire, poles, substations, and transformers, the per-kilowatthour cost is lower where the level of consumption per customer is higher. In other words, in the Southeast, where climate conditions cause customers to use a relatively large amount of electricity for air conditioning, the capital costs of the distribution system can be spread out over the high consumption base. In contrast, in New York, New England, and California, where cooling needs are less pronounced and alternatives fuels are available for heating, average customer consumption is relatively low and per-kilowatthour transmission and distribution costs are higher, because they are recovered over a much smaller sales base.

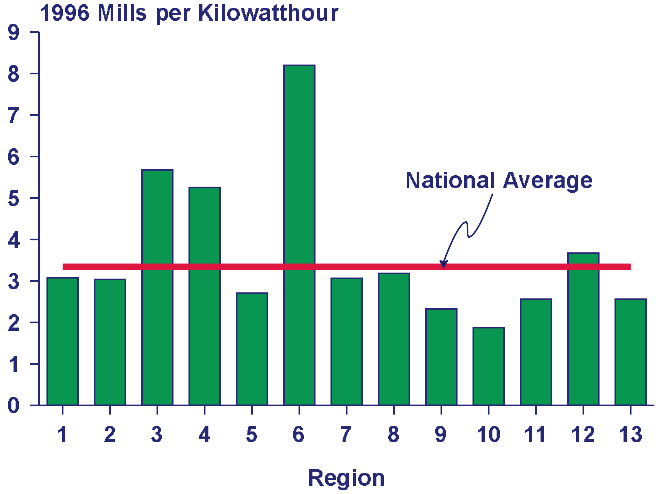
Figure 8. Average Electricity Sales to Residential Customers by Region, 1996



Source: Energy Information Administration, Form EIA-861, "Annual Electric Utility Report" (1996).

Another factor contributing to the remaining price gap among the regions after generation sector competition is phased in are different regional tax levels. As is the case for gasoline, all the States tax their electric utilities differently. In the generation sector, taxes typically add a few mills (tenths of a cent) per kilowatthour to the price. Across the regions, however, the level varies from 2 to 8 mills per kilowatthour (Figure 9).

Figure 9. Taxes on Electricity Generation by Region, 2005



Source: AEO98 National Energy Modeling System, run BASECOMP.D101797A (October 1997).

Comparisons with Earlier Results

The projected competitive electricity prices in this report are on average 0.5 cents per kilowatthour lower in 2005 and beyond than those presented in the August 1997 report.[7] The reasons include assumptions of lower construction costs and lower operations and maintenance (O&M) costs, as well as improved historical calibration of general and administrative (G&A) expenses. These updates were made during the preparation for *AEO98*, upon which this analysis is based. The earlier report was based on the *Annual Energy Outlook 1997* (*AEO97*). With respect to the magnitude of the impacts, the adjustments to G&A expenses had the greatest impact.

Power plant construction costs were significantly lower in *AEO98* than those assumed in *AEO97*. For example, in *AEO97* new pulverized coal plants were expected to cost $1,458 per kilowatt (1996 dollars) or approximately $583 million for a typical 400-megawatt plant. In *AEO98*, the same plant was expected to cost only $432 million, or 26 percent less. Similarly, a new 400-megawatt advanced combined-cycle plant was assumed to cost only $229 million ($572 per kilowatt) in *AEO98*, versus $253 million in *AEO97*. The lower cost assumptions reflect the continuing efforts by designers and constructors to develop more economical standardized power plants so that they can remain competitive.

Plant O&M costs can be broken into nonfuel and fuel components. Nonfuel O&M costs include the labor and other services (lubricants, coolants, limestone, rents, etc.) needed to run a plant. Over the past 10 to 15 years, nonfuel O&M costs have declined significantly. Between 1981 and 1995, the nonfuel O&M costs per kilowatthour of generation at coal-fired plants have declined by 22 percent, or approximately 2 percent annually. Over the same period, the number of employees per megawatt of capacity has fallen by 20 percent. Although further declines are far from certain, analysis of recent data shows that, from plant to plant, the costs still vary significantly, and growing competition is expected to increase the pressure to reduce them. As a result, for both *AEO97* and *AEO98* it was assumed that nonfuel O&M costs would continue to decline, falling by an additional 25 percent over the next 10 years. The impact of this assumption was greater in *AEO98*, however, because nonfuel O&M costs were represented for specific plants rather than by plant type as in *AEO97*.

With respect to fuel costs, the projected average fossil fuel prices to power generators are 5 percent lower in 2005 in *AEO98* than they were in *AEO97*. Lower prices for coal, which accounts for over half of the power generated in the United States, is the major reason. As shown in Figures 4 and 5, in some regions of the country, coal-fired plants are often the marginal plants running, especially in the early years of the projections. At the national level, coal prices to power generators in 2005 were assumed to be 11 percent lower in *AEO98* than in *AEO97*. This difference is maintained throughout the projections. Between 1970 and 1996, average minemouth coal prices in real 1996 dollars declined by $4.32 per ton, and they are expected to decline by an additional $5.23 between 1996 and 2020. In *AEO98* the assumed decline is more rapid, as the result of a reassessment of coal mining labor productivity and greater penetration of production from Western surface mines that are less expensive to operate. With respect to natural gas, the story is the opposite: projected prices are higher in *AEO98* than in *AEO97*. Throughout the projection period, natural gas prices to power plants are between 10 and 20 percent higher in *AEO98*.

In the uniform system of accounts used by electric utilities, G&A expenses cover a wide array of cost categories, including employee pensions and benefits, administrative and general salaries, office supplies and expenses, outside services employed, miscellaneous general expenses, and various insurance categories. The majority of these costs are labor related, associated with employee salaries, pensions and benefits. In 1996, investor-owned utilities spent $13.5 billion on G&A, or 12 percent of their total operating costs. G&A expenses are not reported at the plant level, however, and as a result it is not possible to determine the degree to which they reflect plant operating costs.

In competitive markets, a product supplier will be willing to sell the next unit of output at a price equal to the immediate cost of producing it—what in economics is referred to as the short-run marginal cost. Costs that do

[7] Energy Information Administration, *Electricity Prices in a Competitive Environment: Marginal Cost Pricing of Generation Services and Financial Status of Electric Utilities*, DOE/EIA-0614 (Washington, DC, August 1997).

not vary with output are not included in short-run marginal costs. For example, for fossil power plants the key component of short-run marginal costs is fuel costs. To get one more kilowatthour of electricity out, a certain amount of coal, gas, or oil has to be put in.

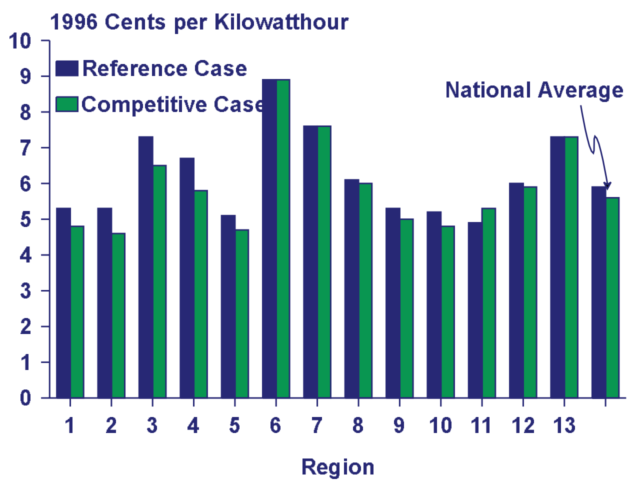
Labor costs for staff working at a plant whether or not it is running at full capacity are not included in short-run marginal costs, because they do not vary with output. However, to the extent that labor costs increase with output (for example, when staffing levels are increased to run a plant at a higher capacity factor), those costs are included in the cost of producing the next kilowatthour.

Unfortunately, because the historical data are not uniformly reported at the plant level, and because regulated operation may not be indicative of how a plant is operated in a competitive market, it is not possible to determine what portion of the G&A costs should be included as part of a supplier's bid price (the same is true for nonfuel O&M costs discussed previously). Modeling experiments were carried out with different portions included in competitive electricity prices. From the experiments it was determined that, unless the majority of the G&A costs were included, competitive generation prices would not be high enough to support the construction of new power plants that would be needed as demand grows. In the previous report, model runs were prepared assuming various levels of inclusion of these costs. In this report, as in the moderate response case of the previous report, all the G&A costs were included in marginal generation costs; however, more recent data were used here, and overall G&A costs were reduced significantly. Including these costs added about 0.2 to 0.3 cents per kilowatthour to the competitive price.

As in the previous report, competitive markets are expected to lead to lower prices relative to cost-of-service regulated prices in nearly all regions through 2010 (Figure 10). Only in the Northwest, where regulated prices are very low, are competitive prices expected to be higher by a small amount. The differences seen in Figure 10 should not be viewed as the total impact of competition. The reference case in this report is not a "no competition" case but includes the impacts of wholesale market competition that has been occurring for many years. The difference between the two cases shown in the figure should be seen as the impact of moving to competitive, marginal cost pricing of generation services to retail consumers. Also, regions 6, 7, and 13 were treated as fully competitive in the reference case, and they show only minute differences between the cases.

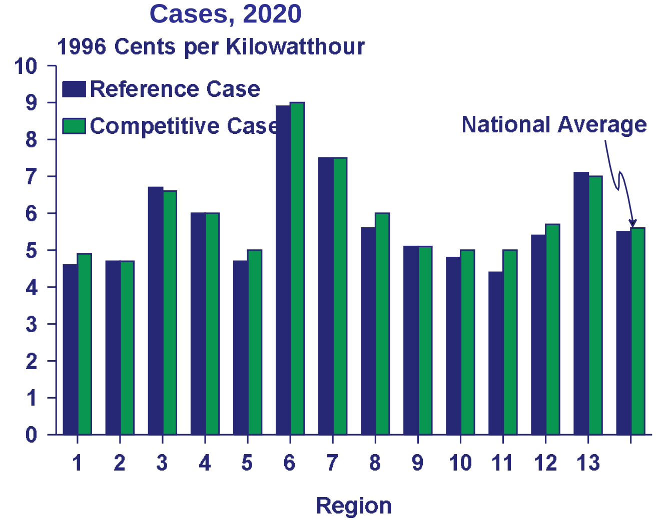
After 2010, the projected competitive prices begin to rise slowly, although in most regions they remain nearly equal to or below reference case prices through 2015. By 2020, several regions have competitive prices slightly above reference case levels (Figure 11). The key to these results is the expected future price of natural gas. These expectations are important because the majority of capacity built to meet growing demand over the next 20 years is expected to be fueled with natural gas. As a result, the impact of natural gas prices on competitive generation prices will grow over time. If natural gas prices turn out to be lower than expected in the *AEO98* reference case, competitive generation prices could be lower than or equal to the projected regulated prices in all regions. However, the opposite is also true.

Figure 10. Total Electricity Prices by Region in the Reference and Competitive Generation Cases, 2010



Source: AEO98 National Energy Modeling System, runs BASECOMP.D101797A and AEO98B.D100197A (October 1997).

Figure 11. Total Electricity Prices by Region in the Reference and Competitive Generation Cases, 2020



Source: AEO98 National Energy Modeling System, runs BASECOMP.D101797A and AEO98B.D100197A (October 1997).

Other factors could also change these results. For example, fully competitive retail generation pricing could lead to greater efficiency improvements than were assumed for this analysis. Also, in the Northwest, some analysts expect that the costs associated with mitigating the impact of large hydroelectric facilities on fish populations will grow in the future. Such potential costs were not included in this analysis; if they were, they could narrow or eliminate the gap between regulated and competitive prices.

As another example, a large proportion of the power produced in the Northwest is produced at federally owned facilities. For this report it was assumed that those facilities would sell their power at competitive market-based rates, even if they were higher than regulated rates. On the other hand, regulators in the Northwest together with Federal authorities may choose an alternative approach, such as returning all or a portion of any windfall profits earned by low-cost public utilities to ratepayers.

Finally, this analysis did not assume any improvement in transmission and distribution service costs, which were assumed to be determined by a regulated cost-of-service methodology. Some State deregulation proposals do include alternatives to the cost-of-service pricing approach used historically for transmission and distribution pricing. Where such proposals are adopted, utilities will have increased incentive to reduce transmission and distribution costs as well as generation costs.

Conclusion

Over the next 10 to 20 years, competitive pressures are expected to narrow the range in electricity prices currently seen across the country, especially prices for generation services. With competitive pricing in the generation sector, by 2005 the range of total electricity prices across regions is expected to decline from the 6.3-cent level seen in 1996 to 4.2 cents. Most of the remaining difference is expected to come from nongeneration sector (primarily transmission and distribution) costs.

Several factors could alter these results. Some cost factors may rise. For example, more resources may be needed to manage the network with a potentially much larger group of suppliers. It is also possible that competitive pressures will lead to greater cost reductions than expected. For example, new technologies may allow suppliers to produce—and customers to consume—electricity more efficiently. The results presented here rest on the assumptions used in preparing the *AEO98* model projections. Further refinements and improvements can be expected as additional data become available from newly emerging competitive electricity markets.

Appendix A

Table A1. Regional Price Components
(1996 Mills per Kilowatthour)

Region	Sector[a]	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
1	Generation	23.39	23.64	24.45	24.71	24.87	24.47	24.45	25.03	25.00	24.80	24.66	24.34	24.77	25.50	25.44	26.01
	T&D	20.04	19.99	19.99	19.99	19.99	20.00	19.99	19.89	19.83	19.84	19.81	19.80	19.72	19.64	19.58	19.56
	Taxes	3.08	3.02	3.01	2.98	2.92	2.83	3.12	2.83	2.76	2.73	2.71	2.76	2.77	2.80	2.69	2.73
	Total	46.51	46.65	47.44	47.68	47.77	47.30	47.55	47.75	47.59	47.38	47.18	46.90	47.26	47.95	47.71	48.30
2	Generation	25.66	24.55	24.49	24.73	24.95	25.28	25.49	25.60	25.83	25.76	25.86	25.82	25.43	26.22	26.73	27.17
	T&D	17.77	17.78	17.86	17.82	17.73	17.64	17.54	17.41	17.31	17.25	17.21	17.19	17.11	17.07	16.99	16.95
	Taxes	3.04	2.76	2.76	2.72	2.65	2.57	2.76	2.56	2.43	2.42	2.34	2.31	2.32	2.34	2.34	2.36
	Total	46.47	45.09	45.11	45.27	45.33	45.49	45.79	45.57	45.57	45.42	45.41	45.32	44.86	45.62	46.06	46.48
3	Generation	28.63	28.84	29.66	29.73	30.76	29.50	29.83	29.79	29.93	30.53	29.40	29.23	29.86	30.68	30.59	32.04
	T&D	29.82	29.61	29.56	29.56	29.53	29.46	29.40	29.24	29.13	29.03	29.03	29.11	29.11	29.04	28.84	28.73
	Taxes	5.68	5.61	5.58	5.47	5.43	5.21	5.33	5.12	5.00	5.11	4.96	4.90	4.96	4.94	4.88	5.04
	Total	64.13	64.06	64.80	64.75	65.71	64.18	64.57	64.16	64.06	64.67	63.39	63.23	63.93	64.66	64.32	65.81
4	Generation	28.70	28.78	30.19	30.73	31.11	30.44	30.76	31.41	31.71	31.60	30.72	30.56	30.63	31.88	31.95	32.98
	T&D	22.65	22.56	22.60	22.52	22.45	22.44	22.38	22.24	22.14	22.10	22.09	22.05	21.95	21.79	21.65	21.57
	Taxes	5.25	5.28	5.24	5.21	5.23	5.06	5.31	5.10	5.02	5.02	4.92	4.88	4.86	4.99	4.96	5.06
	Total	56.61	56.62	58.03	58.47	58.80	57.94	58.44	58.74	58.86	58.72	57.73	57.49	57.44	58.67	58.56	59.60
5	Generation	25.36	25.66	26.39	26.16	25.02	23.66	24.21	23.85	24.57	24.96	25.23	24.18	24.26	25.33	26.45	27.18
	T&D	20.44	20.58	20.55	20.54	20.49	20.50	20.51	20.53	20.47	20.45	20.53	20.55	20.46	20.32	20.18	20.12
	Taxes	2.71	2.72	2.76	2.73	2.63	2.52	2.69	2.49	2.52	2.56	2.63	2.43	2.43	2.48	2.55	2.60
	Total	48.50	48.96	49.70	49.44	48.13	46.68	47.42	46.88	47.56	47.97	48.38	47.17	47.15	48.13	49.19	49.90
6	Generation	34.28	34.35	35.33	35.71	35.42	35.39	35.19	35.44	35.68	35.70	35.26	36.00	36.09	36.08	36.95	37.61
	T&D	46.43	46.02	45.75	45.50	45.32	45.11	44.95	44.70	44.47	44.32	44.21	44.08	43.96	43.87	43.63	43.46
	Taxes	8.20	8.14	8.24	8.24	8.12	8.08	8.28	7.95	7.92	7.89	7.85	7.95	7.97	7.95	8.07	8.17
	Total	88.91	88.51	89.32	89.45	88.86	88.58	88.42	88.09	88.08	87.91	87.32	88.02	88.02	87.89	88.64	89.24
7	Generation	36.30	35.21	35.89	36.17	35.52	35.51	35.15	34.41	34.94	35.44	34.55	34.49	34.18	34.59	34.85	35.26
	T&D	36.70	36.71	36.83	36.87	36.90	36.90	36.88	36.88	36.87	36.86	36.87	37.08	37.17	37.11	37.00	36.95
	Taxes	3.06	3.00	2.97	2.94	2.88	2.85	2.97	2.72	2.71	2.71	2.83	2.71	2.60	2.65	2.61	2.64
	Total	76.06	74.92	75.69	75.98	75.30	75.26	75.01	74.02	74.52	75.01	74.24	74.28	73.95	74.35	74.47	74.85
8	Generation	29.82	29.97	30.49	31.19	31.21	31.47	31.05	31.09	31.70	31.38	31.25	31.33	31.06	31.15	31.70	31.87
	T&D	24.73	24.69	24.71	24.71	24.73	24.82	24.82	24.82	24.83	24.92	24.91	24.94	24.86	24.77	24.73	24.69
	Taxes	3.18	3.14	3.13	3.13	3.09	3.08	3.17	3.04	3.02	2.97	2.92	2.93	2.89	2.83	2.84	2.84
	Total	57.73	57.79	58.34	59.03	59.02	59.36	59.03	58.94	59.55	59.27	59.07	59.19	58.81	58.74	59.26	59.39
9	Generation	24.65	24.91	25.37	25.40	25.82	25.95	26.09	25.72	25.98	25.86	25.52	25.31	25.72	25.94	26.38	26.86
	T&D	21.27	21.37	21.46	21.57	21.66	21.78	21.86	21.90	21.93	22.06	22.15	22.20	22.27	22.31	22.34	22.32
	Taxes	2.32	2.26	2.22	2.16	2.14	2.11	2.16	2.03	2.02	2.01	1.94	1.93	1.93	1.93	1.93	1.93
	Total	48.24	48.54	49.05	49.13	49.62	49.85	50.11	49.65	49.93	49.93	49.61	49.44	49.91	50.18	50.64	51.11
10	Generation	26.22	26.36	26.76	27.22	26.92	27.35	27.27	27.54	27.44	27.14	27.30	27.02	27.19	27.89	28.05	28.94
	T&D	18.90	18.88	18.88	18.86	18.84	18.82	18.80	18.75	18.73	18.77	18.76	18.75	18.69	18.57	18.49	18.47
	Taxes	1.87	1.86	1.85	1.86	1.86	1.86	2.09	1.90	1.86	1.93	1.85	1.90	2.01	2.01	2.01	2.01
	Total	47.00	47.10	47.48	47.95	47.62	48.04	48.16	48.18	48.04	47.84	47.91	47.67	47.89	48.47	48.55	49.41
11	Generation	32.43	29.44	31.43	33.83	31.79	29.64	27.75	27.91	28.17	26.26	26.10	26.14	27.68	26.82	26.93	27.00
	T&D	22.03	21.82	21.61	21.49	21.41	21.33	21.19	21.11	21.08	21.06	21.02	21.00	20.94	20.82	20.69	20.61
	Taxes	2.56	2.35	2.42	2.51	2.38	2.23	2.16	2.07	2.06	1.94	1.90	1.87	1.95	1.90	1.87	1.87
	Total	57.03	53.61	55.46	57.83	55.58	53.20	51.10	51.09	51.31	49.25	49.02	49.02	50.57	49.54	49.49	49.48
12	Generation	29.44	28.78	29.41	29.09	28.51	27.97	27.74	28.00	27.72	27.15	26.43	26.30	26.11	27.54	26.85	26.92
	T&D	27.25	27.23	27.15	27.18	27.25	27.29	27.23	27.21	27.18	27.26	27.34	27.41	27.43	27.42	27.26	27.18
	Taxes	3.67	3.55	3.56	3.46	3.34	3.27	3.33	3.19	3.10	3.09	3.08	2.97	2.89	2.97	2.90	2.90
	Total	60.35	59.56	60.13	59.73	59.10	58.53	58.30	58.40	58.01	57.50	56.84	56.67	56.43	57.93	57.01	57.00
13	Generation	31.80	32.46	33.23	34.32	33.77	34.60	32.74	32.09	31.58	31.80	30.64	29.42	28.94	29.77	30.20	31.37
	T&D	36.09	35.84	35.87	35.92	35.91	35.89	35.68	35.55	35.59	35.77	35.93	36.14	36.09	35.97	35.92	35.93
	Taxes	2.56	2.46	2.42	2.42	2.32	2.32	2.32	2.14	2.09	2.16	2.03	1.98	1.97	1.97	1.97	1.99
	Total	70.45	70.76	71.51	72.66	72.00	72.82	70.74	69.78	69.25	69.74	68.61	67.55	66.99	67.71	68.09	69.29
National	Generation	27.60	27.44	28.20	28.62	28.51	28.24	28.03	28.07	28.21	28.04	27.66	27.41	27.63	28.18	28.42	29.07
Average	T&D	24.43	24.37	24.36	24.34	24.32	24.32	24.28	24.18	24.14	24.17	24.18	24.21	24.17	24.09	24.00	23.95
	Taxes	3.34	3.26	3.25	3.22	3.16	3.09	3.22	3.02	2.97	2.97	2.90	2.89	2.90	2.90	2.89	2.92
	Total	55.38	55.07	55.80	56.18	55.99	55.64	55.52	55.27	55.33	55.18	54.74	54.51	54.70	55.18	55.31	55.93

[a]T&D = transmission and distribution sector. Taxes = taxes on generation.
Note: 1 mill = 0.1 cent.
Source: AEO98 National Energy Modeling System, run BASECOMP.D101797A (October 1997).