Arizona: Overview of Retail Competition Plan and Market Response

Administrator and Start Date

The Electric Competition Act (HB 2663), which was signed May 29, 1998, allowed for a phase in approach to competition beginning with 20% of system load by December 31, 1998, and 100% by December 31, 2000. The Arizona Corporation Commission (ACC) finalized rules for restructuring on October 10, 2000. All areas of the state are open to retail competition beginning January 1, 2001.

Services Open to Competition

Generation, metering and billing. From December 31, 1998 through December 31, 2000, billing and metering services could be provided on a competitive basis for customers who were receiving competitive generation services and who had loads greater than 1 MW. After December 31, 2000, all customers are eligible for competitive billing and metering services.[1]

Consumer Options

The two main investor-owned utilities are Arizona Public Service Company (APS) and Tucson Electric Power Company (TEP). Customers are also served by several electric cooperatives including Arizona Electric Power and Navopache Electric. Customers may remain with their distribution utility, choose a competitive supplier or aggregate together to receive service.

Alternative Suppliers Licensed to Provide Service

Competitive suppliers must be certified, and, in order to be certified, must show technical and financial capability.[2] As of September 2001, there are no alternative suppliers offering service to Arizona customers.

Pricing Trends

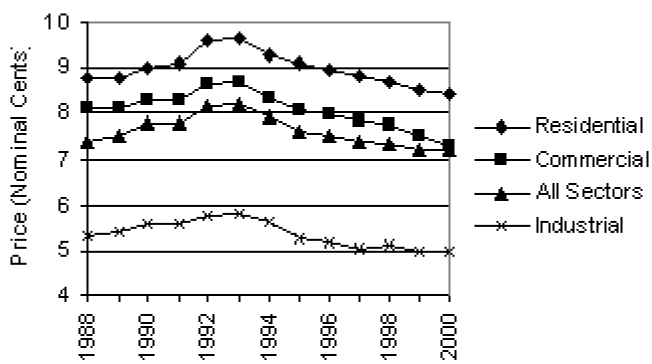
As shown in Table 1, retail prices increased in the residential, commercial, and industrial sectors between 1988 and 1993. Since that time, prices have steadily declined, and year 2000 prices were lower than 1988 prices in all three sectors.

Table 1. Average Annual Price per KWh by Sector (nominal cents)

	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
Residential	8.8	8.8	9.0	9.1	9.6	9.7	9.3	9.1	9.0	8.8	8.7	8.5	8.4
Commercial	8.1	8.1	8.3	8.3	8.6	8.7	8.3	8.1	8.0	7.8	7.8	7.5	7.3
Industrial	5.3	5.4	5.6	5.6	5.8	5.8	5.6	5.3	5.2	5.1	5.1	5.0	5.0
All Sectors	7.4	7.5	7.8	7.8	8.1	8.2	7.9	7.6	7.5	7.4	7.3	7.2	7.2

Source: Energy Information Administration

Figure 1. Average Annual Price Per KWh by Sector



Price Changes for Standard Offer (or Regulated) Service

Under the Settlement Agreement for Arizona Public Service Company (APS), residential customers will receive rate reductions of 7.5% over four years.[3] All Tucson Electric Power Company (TEP) customers will receive a 1% rate reduction retroactive to July 1, 1999, and another 1% reduction on July 1, 2000. TEP cannot raise these rates until December 31, 2008.[4]

Standard Offer Service Provider

Until 2001, the distribution utility will offer standard offer service and non-competitive services at regulated rates. After January 1, 2001, electricity for standard offer service will be purchased from the competitive market, and at least 50% will be purchased through a competitive bidding process.[5] The distribution utility will be the provider of last resort for customers who are not served by a competitive supplier for whatever reason.[6]

Recovery of Stranded Costs/Transition Costs

Stranded costs will be determined by the ACC by taking the net difference between the original cost of assets, which includes generation assets, purchased power contracts, fuel contracts and regulatory assets, and the market value of these assets. Other costs eligible for recovery include reasonable costs from divestiture, and employee severance and retraining costs.[7] Distribution utilities must make mitigation efforts,[8] after which the ACC will determine the magnitude of stranded costs, the amount of any stranded cost recovery charges, and the time period over which charges can be collected.[9] A competitive transition charge may be assessed on all customers to recover stranded costs,[10] and securitization may be allowed if the ACC determines this will offer lower charges to customers.[11] The ACC may review and adjust stranded cost charges periodically.[12]

APS will recover $350 million in stranded costs through a competitive transition charge,[13] and TEP will recover $450 million of stranded costs through a fixed competitive transition charge, and the remainder through a "floating" transition charge. TEP's fixed transition charge will be 0.93 cents per/kWh, and will be charged until December 31, 2008 or until all stranded costs have been recovered, whichever is earlier. The floating transition charge will be determined quarterly and will equal the difference between a customer's bundled rate and the sum of the market generation charge (a charge related to the market price for generation), an adder (the adder will average 4.2 mills, but will be adjusted for each customer class and stratum), and the unbundled charges for distribution, transmission, metering, billing, ancillary services, fixed must-run generation, system benefits, and the fixed transition charge. It is possible that in a given quarter, the floating transition charge will have a negative value, in which case it will be credited to the customer's bill. The floating transition charge will be collected until December 31, 2008.[14]

Table 2. Transition/Stranded Costs

Company	Stranded Costs Eligible for Recovery	Time Period
Arizona Public Service Co.	$350 million	Until December 31, 2004
Tucson Electric Power	$683 million	Until December 31, 2008

Source: APS and TEP Settlement Agreements

Table 3. APS Competitive Transition Charges

	1999	2000	2001	2002	2003	2004
Residential(per kWh)	$.0093	$.0084	$.0063	$.0056	$.005	$.0036
Sm. Non-res. (per kW/mo.)	$2.43	$2.2	$1.66	$1.46	$1.3	$.94
Lg. Non-res. (per kW/mo.)	$2.82	$2.55	$1.89	$1.72	$1.51	$1.09
Average Retail (per kWh)	**$.0067**	**$.0061**	**$.0054**	**$.0048**	**$.0043**	**$.0031**

Note: Small Non Residential are customers with loads of under 3 MW; Large Non Residential are customers with loads of 3 MW and above.
Source: APS Settlement Agreement

Customer Switching and Eligibility

As of January 1, 2001, all customers are eligible to choose a competitive supplier for generation, metering, or billing services.

Switching Process

***Sign-up Method*:** After a customer contacts a competitive supplier and authorizes a switch in writing, the competitive supplier will contact the distribution utility and give it the written authorization to effect the switch.

***Right of Rescission*:** The customer has three business days in which to rescind his authorization if he changes his mind about switching suppliers. He must notify the competitive supplier in writing if he intends to cancel his order.

***Restrictions and Minimum Stay Requirements*:** There may be a switching charge for changing suppliers.

Switching Activity

Although all customers in Arizona are eligible to receive service from an alternative electric supplier, as of September 2001 there are no alternative suppliers offering competitive services in Arizona. Since competition opened in 1999, only a limited number of customers (less than one percent) have received competitive service from suppliers. The amount of load served by alternative suppliers was at the most 50-70 MW, and comprised mainly large industrial customers, and a few medium and large commercial customers. All of these customers were subsequently returned to service from their incumbent distribution utility when the alternative suppliers chose to withdraw from the market. There have been no offers by alternative suppliers to residential customers.

Public Benefits Programs

The ACC rules assign a systems benefit charge, which will fund programs for low-income customers, energy efficiency, environmental concerns, research and development, nuclear fuel disposal, and nuclear plant decommissioning. Distribution utilities will file for review of the amount of the systems benefit charge every three years.[15]

Renewables: Distribution utilities will recover part of the costs for the environmental portfolio standard (see miscellaneous section below) through systems benefits charges. Additional costs will be recovered by a customer environmental portfolio surcharge of $0.000875 per kWh. There is a surcharge cap of $0.35 for residential customers, and of $13 per month per meter or per service for non-residential customers who use less than 3000 kW per month. Non-residential customers that use 3000 kW per month or more will have a surcharge cap of $39.[16]

Separation of Generation and Transmission

By 2001, distribution utilities must transfer all generation assets and services to an affiliate or another company. Distribution utilities must file Codes of Conduct for their relations with their affiliates, which will be subject to approval by the ACC.[17] APS has until December 31, 2002 to transfer its generation assets to an affiliate.[18] TEP will also transfer its generation assets to a subsidiary by December 31, 2002.[19]

State RTO Involvement

The ACC supports the development of an RTO or an ISO to provide nondiscriminatory transmission access and to promote an efficient, robust electric market. Absent an RTO or ISO, an Arizona Independent Scheduling Administrator (AISA) will be developed.[20] All distribution utilities owning or operating Arizona transmission facilities must form an AISA. Distribution utilities are directed to file for approval of the AISA with FERC within 60 days of the ACC's adoption of final rules.[21]

New Plant Construction and Planning

Arizona suppliers have plans for 9,351 MW generation plants to be constructed between 2001 and 2007.[22] According to Energy Information Administration data, suppliers in Arizona have planned a total of 6,383 MW of capacity additions between 2000 and 2004.[23]

Slamming/Cramming Rules

A competitive supplier must have the written authorization of a customer to switch, which must include no inducements, and clear print confirming rates, terms and conditions, and the nature of service. If a supplier switches a customer without his consent, it will have to pay the charges to switch the customer back to his original supplier and pay three months worth of service to the previous supplier. Suppliers who switch customers without consent are subject to possible penalties and revocation or suspension of the provider's certificate to provide service in Arizona.[24]

Customer Billing

A customer may receive one bill from the distribution utility or two bills, one from the supplier for generation services, and one from the distribution utility for transmission and distribution services.

Affiliate Name and Logo Issues

The ACC rules direct distribution utilities to create Codes of Conduct which do not allow joint advertising and marketing of a distribution utility and its affiliate, and which govern the use of the distribution utility's name and logo.[25] All distribution utilities have filed Codes of Conduct which prohibit the use of the distribution utility's name and logo in its affiliate's promotional advertising materials.[26]

Usage of Customer Information

Customer account information and proprietary information cannot be released unless authorized, in writing, by a customer.[27]

Standardized Labeling

Distribution utilities and competitive suppliers must provide customers with a consumer information label:

***Content*:** The label will include the price to be charged for generation services, price variability information, customer service information, and the time period for which this information is valid.[28] Upon the request of a customer, a supplier must also provide information on the fuel mix and emissions characteristics of the resource portfolio.[29] Suppliers must also prepare an annual disclosure report that aggregates the resource portfolios of the supplier and its affiliates.[30]

***Timing*:** The information disclosure label will be provided in a prominent position in all marketing materials that are directed exclusively toward Arizona customers. In materials not directed exclusively to Arizona customers, suppliers must indicate that a label will be provided to customers upon request.[31] The customer information label, supplier's terms of service, and the annual disclosure report will be provided to customers prior to initiation of service, prior to processing a written authorization for customers with demand less than 1 MW, to anyone upon request, and in semi-annual and annual reports.[32]

Consumer Education

The ACC will initiate programs to educate retail electric customers about changes to the electric industry.[33]

Other Consumer Protection Measures

The ACC may require a bond if it deems necessary.[34] If a competitive supplier is going to cease service to customers, it must provide at least 45 days written notice to allow customers the time to procure service from other suppliers.[35] If a customer will be returned to standard offer service, the supplier must give 5 days notice.[36]

Retail Choice in Gas Sales

Arizona has no programs for residential customer choice of natural gas providers.

Miscellaneous

The ACC has mandated the use of an Environmental Portfolio Standard, which provides that distribution utilities must derive at least 0.2% of their energy sold from renewable resources. Competitive suppliers are exempt from the provision until 2004, but may participate voluntarily. The percentage of energy to come from renewable resources will increase each year, so that by 2012, 1.1% of total retail sales will come from renewable resources. In 2001, the Environmental Portfolio makeup shall be at least 50% solar electric, increasing to 60% by 2004.[37]

Notes

1. Ariz. Rev. Stat. § 40-202.B.4 (2001).

2. Ariz. Admin. Code R14-2-1603.B (2001).

3. APS Settlement Agreement (May 14, 1999).

4. TEP Settlement Agreement (Dec. 1, 1999).

5. Ariz. Admin. Code R14-2-1606 (2001).

6. Ariz. Rev. Stat. § 40-202.B.5 (2001).

7. Ariz. Admin. Code R14-2-1601.39 (2001).

8. *Id.* at R14-2-1607.A.

9. *Id.* at R14-2-1607.E.

10. *Id.* at R14-2-1607.F.

11. *Id.* at R14-2-1607.H.

12. *Id.* at R14-2-1607.I.

13. APS Settlement Agreement (May 14, 1999).

14. TEP Settlement Agreement (Dec. 1, 1999).

15. Ariz. Admin. Code R14-2-1608 (2001).

16. *Id.* at R14-2-1618.A.

17. *Id.* at R14-2-1615.

18. APS Settlement Agreement (May 14, 1999).

19. TEP Settlement Agreement (Dec. 1, 1999).

20. Ariz. Admin. Code R14-2-1609.C (2001).

21. *Id.* at R14-2-1609.D.

22. SNL Securities New Plant Alert <www.snl.com/energy/eisrptl.pdf>.

23. Energy Information Administration, Inventory of Nonutility Electric Power Plants in the United States, 1999, Table 6. Energy Information Administration, Inventory of Electric Utility Power Plants in the United States, Table 22.

24. Ariz. Admin. Code R14-2-1612.C (2001).

25. *Id.* at R14-2-1616.B.

26. *See* APS Code of Conduct (Apr. 13, 2000) and TEP Code of Conduct (Aug. 2, 2000).

27. Ariz. Admin. Code R14-2-1612.E (2001).

28. *Id.* at R14-2-1617.A.

29. *Id.* at R14-2-1617.B.

30. *Id.* at R14-2-1617.E.

31. *Id.* at R14-2-1617.C.

32. *Id.* at R14-2-1617.G.

33. Ariz. Rev. Stat. § 40-113 (2001).

34. Ariz. Admin. Code R14-2-1603.J (2001)

35. *Id.* at R14-2-1612.G.

36. *Id.* at R14-2-1612.J.

37. ACC, Decision No. 63364, Docket No. RE-00000C-00-0377 (Feb. 8, 2001).

California: Overview of Retail Competition Plan and Market Response

Administrator and Start Date

The state restructuring legislation (AB 1890) initiating electric restructuring in California was signed on September 23, 1996. It provided for retail choice to begin January 1, 1998, but this date was delayed for three months until March 31, 1998 to ensure all systems were operable. Customer retail choice began simultaneously with the start of the independent system operator (Cal ISO), which operates the state's transmission grid, and the power exchange (PX), which would handle trades of electric power in California.[1] AB 1890 envisioned that the California Public Utilities Commission (CPUC) would implement a four-year transition to a competitive market that would end in 2002. The information contained in this summary, unless otherwise noted, describes the features of California's plan as envisioned by AB 1890. A summary of selected recent changes appears at the end of the profile.

Services Open to Competition

Generation, metering and billing. Metering and billing were unbundled from other distribution services and customers who choose alternate suppliers for these services received a credit (ranging from $0.05 to $1.41 for residential customers and from $0.18 to $27.57 for industrial customers). The alternative supplier would then assess a separate charge for these services.

Consumer Options

Electricity customers in California have two options:

1. They can buy generation services from their distribution utility, which will buy the electricity from the power exchange and sell it to the customer at no additional mark-up or profit (referred to in this summary as "standard offer service"); or

2. They can buy generation services from an alternative supplier, which will either generate the electricity itself, or buy it wholesale from the power exchange or other generation source and resell it to the customer.

Alternative Suppliers Licensed to Provide Service

Suppliers must show proof of technical, operational and financial capability in order to be licensed. Suppliers must also post a $25,000 bond.[2] California does not maintain information on the number of suppliers actually providing service to customers.

Pricing Trends

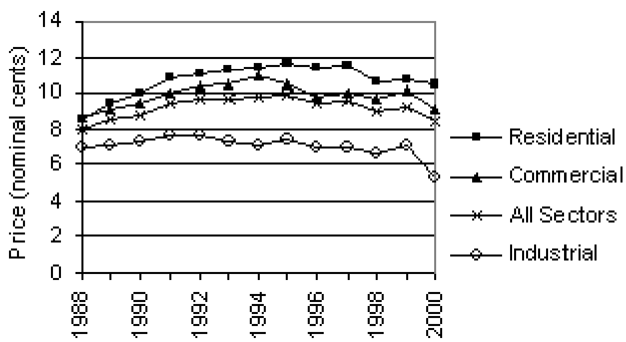
Overall, prices for the residential and commercial sectors rose throughout the first part of the decade, peaking between 1994 - 1995 (see Table 1 below). Prices then declined gradually, although by 2000 they had not yet declined to 1988 levels. Industrial prices held relatively steady during the same period, reaching their highest points in 1991 and 1992, although they also began declining gradually during the latter part of the decade. Prices for the industrial sector in 2000 were lower than prices in 1988.

Table 1. Average Annual Price per kWh by Sector (nominal cents)

	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
Residential	8.5	9.4	10.0	10.8	11.1	11.3	11.4	11.6	11.3	11.5	10.6	10.7	10.5
Commercial	8.7	9.1	9.5	10.0	10.3	10.5	10.9	10.5	9.8	10.0	9.7	10.1	9.1
Industrial	6.9	7.1	7.3	7.6	7.6	7.3	7.1	7.4	7.0	7.0	6.6	7.1	5.4
All Sectors	8.0	8.5	8.8	9.4	9.7	9.7	9.8	9.9	9.5	9.5	9.0	9.2	8.4

Source: Energy Information Administration

Figure 1. Average Annual Price Per KWh by Sector



Price Changes for Standard Offer (or Regulated) Service

Rates for all customers were frozen on June 1, 1996. As of January 1, 1998, residential and small commercial rates were reduced 10% for customers of the three investor-owned utilities (San Diego Gas & Electric (SDG&E), Southern California Edison (SCE), and Pacific Gas & Electric (PG&E)). The rate freeze and reduction was to be in effect until March 31, 2002 or until all stranded costs are recovered, whichever is earlier.[3] The rate reductions are financed by bonds, paid back by ratepayers over a 10 year period which ends January 2008.[4]

The transition period for SDG&E customers ended July 1, 1999. SDG&E obtained CPUC approval to end the 10% rate reduction and it began billing its customers the actual charge for electricity purchases through the Power Exchange (PX) (the wholesale electricity spot market in California). (See discussion below on Wholesale Electricity Purchasing and Pricing.) This resulted in substantial increases for customers who had received standard offer service when wholesale prices started to increase during the summer of 2000. Subsequently, the California Legislature and the CPUC enacted a rate ceiling, retroactive to June 1, 2000. The ceiling defers costs over 6.5 cents/kWh to be recovered in subsequent periods.

On March 27, 2001, the CPUC issued a decision approving a 3 cents/kWh rate increase for SCE and PG&E customers (an increase of about 46%), and making permanent the 1 cent/kWh rate increase approved January 4, 2001.[5] In May 2001, the CPUC set a tiered rate structure for this increase, under which SCE and PG&E residential customers will face rate increases between zero and 80%, depending on usage. Rate increases for commercial customers will be between 34 and 45%, and increases for industrial customers will average 50%. These rates were effective as of June 1, 2001.[6]

Standard Offer Service

Distribution utilities provide standard offer service to customers not choosing an alternative supplier or whose supplier has exited the market, procuring power from the PX (see discussion below on Wholesale Electricity Purchasing and Pricing).

Shopping Credit Rates

The shopping credit is an offset equal to the avoided costs of electricity at PX prices for customers who have chosen an alternative supplier.

Recovery of Stranded Costs/Transition Costs

Stranded costs were to be collected through a non-bypassable competition transition charge (CTC) to all customers. Eligible costs include costs for generation-related assets and obligations, including generation facilities and generation-related regulatory assets, nuclear settlements, and power purchase contracts. Most stranded costs can be collected only until December 31, 2001 (a four-year transition). CPUC determination of eligible costs and their valuation are final and cannot be rescinded, altered or amended,[7] though they will be adjusted through March 31, 2002 in order to track accrual and recovery of costs.[8] Transition charges will be applied to each customer based on the amount of electricity purchased by the customer.[9] Distribution utilities were required to exhaust all mitigation efforts. In 1997, the California Legislature enacted legislation that allows the distribution utilities $7.3 billion in bonds to pay off stranded investments through a charge for residential and small commercial customers.[10]

Annual recovery of stranded costs (during the four-year transition period) varies depending on wholesale PX prices. To determine the stranded costs recovered through the CTC, the PX costs, authorized revenue requirements for transmission, distribution nuclear decommissioning, public purpose programs, and rate reductions bonds are deducted from actual revenues. The residual is available to be applied to stranded costs. Thus, the lower the wholesale rate of electricity (*i.e.*, a lower PX price), the greater the share of the fixed generation charge that applies to stranded cost recovery.

Because there were lower wholesale PX price than originally forecast during 1998 and 1999, more of the frozen rate revenues were applied to stranded costs and stranded costs were recovered quickly. The CPUC had established a four year transition period; however, it took approximately 15-17 months to recover all stranded costs for SDG&E. As wholesale prices increased in 2000, this precluded additional stranded cost recovery for SCE and PG&E.

Customer Switching and Eligibility

All customers became eligible to switch suppliers as of March 31, 1998. A customer may switch suppliers at any time, in accordance with his agreement with the alternative supplier.[11] Customers with peak loads greater than 20 kW have to have an hourly meter; beginning in January 1999, customers with a peak load of less than 20 kW have the option of purchasing an hourly meter.[12]

Switching Process

***Sign-up Method*:** After a customer agrees to buy generation from an alternative supplier, the new supplier will notify the distribution company about the change in suppliers.

***Right of Rescission*:** A customer has three days from the day he or she signs an agreement (or offer to purchase) to cancel his or her switch to the new supplier.[13]

Switching Activity

The following charts show switching activity by the four customer classes in California. Although there was little residential and small commercial customer switching activity, medium commercial and industrial switching was more robust. The trend toward greater switching dissipated, however, as wholesale prices increased since the summer of 2000 and customers returned to the standard offer provider (*i.e.*, the incumbent distribution utility).

***Residential Sector*:** The number of residential customers served by alternative suppliers rose steadily from the inception of customer choice, reaching its highest level during the first quarter of 2000. After that quarter, the number of customers switched began to slowly decline, and then fell by almost a half between January and April of 2001. In spite of the large number of switches, the number of residential switches in terms of percentage of total customers and load has been small. Even at their highest point, less than 2% of customers and less than 3% of total load had switched.

Table 2. Residential Customers

Number of Residential Customers Served by Alternative Suppliers

Jul-98	Oct-98	Jan-99	Apr-99	Jul-99	Oct-99	Jan-00	Apr-00	Jul-00	Oct-00	Jan-01	Apr-01	Jul-01
57,753	72,738	82,692	89,268	108,511	142,529	159,992	164,636	152,023	150,718	148,517	78,211	59,265

% of Residential Customers Served by Alternative Suppliers

Jul-98	Oct-98	Jan-99	Apr-99	Jul-99	Oct-99	Jan-00	Apr-00	Jul-00	Oct-00	Jan-01	Apr-01	Jul-01
0.7%	0.9%	0.9%	1.0%	1.2%	1.6%	1.8%	1.9%	1.7%	1.7%	1.6%	0.9%	0.6%

% of Residential Load served by Alternative Suppliers

Jul-98	Oct-98	Jan-99	Apr-99	Jul-99	Oct-99	Jan-00	Apr-00	Jul-00	Oct-00	Jan-01	Apr-01	Jul-01
0.8%	1.0%	1.1%	1.2%	1.5%	1.9%	2.2%	2.3%	2.1%	2.0%	1.9%	1.1%	0.9%

Monthly Number of Residential Customers Switching Back to a Utility

Jul-98	Oct-98	Jan-99	Apr-99	Jul-99	Oct-99	Jan-00	Apr-00	Jul-00	Oct-00	Jan-01	Apr-01	Jul-01
499	1,134	803	2,424	1,071	2,388	2,190	2,625	3,125	3,323	14,684	6,373	7,391

Source: Califomia Public Utilities Commission

In addition, the number of residential customers switching back to the distribution utilities has increased slowly over time, although it jumped during the last quarter of 2000, from 3,323 in October 2000 to 14,684 in January 2001.

***Commercial Sector*:** As with residential customers, the number of commercial customers switching to alternative suppliers increased steadily from the inception of customer choice in California, peaking in the first quarter of 2000, and then declining as shown in Table 3. Like the pattern with residential customers, the number of small commercial customer switches fell dramatically during the first quarter of 2001, although the number of medium commercial customer switches remained constant during this period. Small commercial customers switching to alternative suppliers comprised a small percentage of the total customer and load base, accounting for less than 4% of total customers and 6% of total load. The number of medium-sized customer switches decreased significantly between January and April 2001, rising again in July. The percent load switched from January to July 2001 dropped from about 11% to 5%.

Table 3. Commercial Customers

Number of Commercial Customers Served by Alternative Suppliers

Size	Jul-98	Oct-98	Jan-99	Apr-99	Jul-99	Oct-99	Jan-00	Apr-00	Jul-00	Oct-00	Jan-01	Apr-01	Jul-01
Small	17,741	22,723	24,745	26,767	28,690	32,528	35,852	38,195	27,370	22,845	15,339	7,706	6,776
Medium	6,254	7,845	10,648	11,372	12,137	12,737	13,349	13,981	11,531	10,029	7,704	2,084	4,230

% of Commercial Customers Served by Alternative Suppliers

Size	Jul-98	Oct-98	Jan-99	Apr-99	Jul-99	Oct-99	Jan-00	Apr-00	Jul-00	Oct-00	Jan-01	Apr-01	Jul-01
Small	1.8%	2.3%	2.5%	2.7%	2.9%	3.3%	3.7%	3.9%	2.8%	2.3%	1.5%	0.8%	0.7%
Medium	3.3%	4.0%	5.4%	5.7%	6.1%	6.5%	6.7%	7.2%	6.0%	5.2%	3.9%	1.0%	2.1%

% of Commercial Load served by Alternative Suppliers

Size	Jul-98	Oct-98	Jan-99	Apr-99	Jul-99	Oct-99	Jan-00	Apr-00	Jul-00	Oct-00	Jan-01	Apr-01	Jul-01
Small	2.5%	3.0%	3.4%	3.4%	3.8%	4.1%	4.7%	5.3%	4.3%	3.7%	2.2%	1.1%	0.8%
Medium	7.6%	11.1%	13.6%	13.7%	14.0%	14.6%	14.7%	14.5%	13.2%	12.4%	10.7%	2.8%	5.0%

Monthly Number of Commercial Customers Switching Back to a Utility

Size	Jul-98	Oct-98	Jan-99	Apr-99	Jul-99	Oct-99	Jan-00	Apr-00	Jul-00	Oct-00	Jan-01	Apr-01	Jul-01
Small	22	141	454	562	146	250	587	297	10,469	563	3,869	543	70
Medium	20	67	22	513	25	117	94	314	2,215	547	1,724	125	25

Note: Small commercial = < 20 kW, Medium commercial = 20 - 500 kW
Source: California Public Utilities Commission

In addition, as with the residential sector, there was a substantial increase in the number of customers that switched back to the utility as wholesale prices increased beginning in the summer of 2000.

***Industrial Sector*:** As Table 4 shows, the number of industrial customers switching to alternative suppliers rose until the beginning of 1999, after which it held relatively steady until the beginning of 2000, when it began to decline dramatically.

Table 4. Industrial Customers

Number of Industrial Customers Served by Alternative Suppliers

Jul-98	Oct-98	Jan-99	Apr-99	Jul-99	Oct-99	Jan-00	Apr-00	Jul-00	Oct-00	Jan-01	Apr-01	Jul-01
665	829	907	988	986	1,027	1,019	1,009	711	671	475	144	246

% of Industrial Customers Served by Alternative Suppliers

Jul-98	Oct-98	Jan-99	Apr-99	Jul-99	Oct-99	Jan-00	Apr-00	Jul-00	Oct-00	Jan-01	Apr-01	Jul-01
13.1%	16.8%	18.6%	20.2%	20.0%	20.1%	19.3%	19.3%	13.5%	12.8%	8.5%	2.5%	4.4%

% of Industrial Load served by Alternative Suppliers

Jul-98	Oct-98	Jan-99	Apr-99	Jul-99	Oct-99	Jan-00	Apr-00	Jul-00	Oct-00	Jan-01	Apr-01	Jul-01
21.0%	24.9%	28.6%	32.6%	26.0%	31.3%	31.8%	34.6%	28.1%	27.4%	13.0%	3.0%	4.9%

Monthly Number of Industrial Customers Switching Back to a Utility

Jul-98	Oct-98	Jan-99	Apr-99	Jul-99	Oct-99	Jan-00	Apr-00	Jul-00	Oct-00	Jan-01	Apr-01	Jul-01
0	3	1	18	23	2	10	56	126	26	159	11	3

Source: California Public Utilities Commission

Public Benefits Programs

Public interest programs are funded by a charge already included in frozen rates that ranges from 3.7 to 4.5 mills/kWh.[14]

Low-income: Funding for low-income customers will be provided at levels not less than 1996 authorized levels.[15] Qualified low-income customers can receive a 15% rate discount on their entire bill through the California Alternative Rates for Energy (CARE) program.

Renewables: CPUC has authority to collect funds for renewables programs until March 31, 2002.[16]

Energy Efficiency: CPUC must establish a rate to fund energy efficiency and conservation measures, public interest research, and renewable resource technology programs. Charges will be assessed through a non-bypassable portion of the local distribution service, based on usage.[17]

Separation of Generation and Transmission

Distribution utilities were required to unbundle corporate operations into transmission, generation and distribution functions. Distribution utilities were required to divest at least 50% of their fossil fuel assets, but they were able to retain their assets in renewable, hydroelectric and nuclear power.

Wholesale Electricity Purchasing and Pricing

The PX was created to organize trade of wholesale power in California. The PX is a competitive electricity auction open on a non-discriminatory basis to all.[18] Its products included electricity and ancillary (reliability) products that were generally traded on a day-ahead basis. The state's three investor owned utilities were required to sell their output and purchase all of their requirements through the

PX. Long-term contracts between the three distribution utilities and independent power producers were not allowed outside of PX markets.

State RTO Involvement

A single-state ISO was established to ensure reliability and operate the transmission systems of the three distribution utilities in California. The ISO was governed by an oversight group selected by the governor and legislature.[19]

New Plant Construction and Planning

Between 1994 and 1998, there were no applications for new plant construction in California. Since 1999, the California Energy Commission has approved 22 power plants for a total of 9,874 MW new capacity, of which 6,037 MW are currently under construction and the remaining 2,854 MW are expected to be online by the end of 2001.[20] According to information from the Western Systems Coordinating Council, California has 25,473 MW of proposed facilities through 2007.[21] According to Energy Information Administration data, suppliers in California have planned 4,519 MW of generation capacity additions between 2000 and 2004.[22]

Slamming/Cramming Rules

A residential customer cannot be switched until the change has been confirmed by an independent third party verification company. If a customer initiates the switch by calling the supplier, the independent verification requirement does not apply.[23]

A small commercial company can be switched only if one of four confirmation measures is taken: independent third-party telephone verification, receipt of a written confirmation of agreement via telephone, customer signature on a document fully explaining the nature and effect of the change, or through electronic means.[24]

Customer Billing

There are three billing options: (a) utility consolidated billing, (b) alternative supplier consolidated billing, and (c) separate bills from the distribution utility and from the alternative supplier. The alternative supplier must agree with the distribution utility on one of these methods.

Affiliate Name and Logo Issues

The affiliate cannot use the parent company's name or logo unless it provides a disclaimer stating that the affiliate is not the same company and is not regulated, and that the customer does not have to buy the affiliate's products in order to continue to receive quality regulated services from the distribution utility. A distribution utility cannot engage in joint advertising or marketing with its affiliates.[25]

Usage of Customer Information

Customer specific information to a potential alternative supplier, including billing, credit or usage information, will not be released unless a customer consents in writing.[26]

Standardized Labeling

Alternative suppliers have to disclose information about the energy resources used to generate their power on a power content label created by the California Energy Commission.[27]

***Components*:** The label compares the generation sources of the competitive supplier to the California power mix. If the competitive supplier buys its power from an individual generator, the sources will be identified specifically. If, however, the competitive supplier buys from the power exchange or other large exchange, they will claim the California power mix.

***Timing*:** Beginning in Fall 1998, the power content label must be provided in all mail or Internet advertisements, and must also be sent quarterly to customers.

Consumer Education

The bill requires distribution utilities to create customer education plans to inform customers of changes in the electricity market and help them make choices.[28]

Other Consumer Protection Measures

Licensed suppliers have to provide consumers with written description of their services, including information that enables comparisons between price, services, and generation mix.[29] Customers can request to be placed on a "no-telemarketer" list.[30]

Retail Choice in Gas Sales

California has had a small retail choice program for residential and small commercial natural gas customers since 1995.[31]

Miscellaneous

Ninety percent of residential customers who have chosen a competitive supplier are receiving "green" power. There is a statewide credit for renewable energy purchases. Green power providers can offer renewable based energy at lower cost than the prices offered by distribution utilities.[32]

Recent Changes

California's retail and wholesale electricity systems are undergoing major changes ordered by the California Legislature, FERC, and the CPUC. Significant changes include elimination of the requirement for distribution utilities to use the California PX for most transactions, revised composition of the PX and ISO boards of director, involvement of the state to develop long-term supply agreements for generators, financial difficulties for the distribution utilities potentially addressed by state purchase of the transmission grid, accelerated licensing procedures for new generation and transmission, and demand side management initiatives. The CPUC has ended retail competition in California. In addition, the PX has declared bankruptcy and is no longer operating. PG&E also has filed for bankruptcy. On September 6, 2001, the PUC adopted decisions approving the California Department of Water Resources (DWR) service agreements with each of the distribution utilities. These agreements set the terms for the distribution utility's delivery of DWR power to retail customers, as well as the billing and collection arrangements with DWR. The PUC has delayed voting on other DWR-related orders, including the adoption of the proposed rate agreement between the PUC and DWR setting out the collection and recovery of DWR's revenue requirements, and the adoption of rate orders for distribution utilities.[33]

Notes

1. AB 1890, §365.

2. CPUC, Opinion Regarding Consumer Protection, D98-03-072 (Mar. 26, 1998).

3. CPUC, How the California Electric Industry is Changing <www.cpuc.ca.gov/static/industry/electric/electric+restructuring/historical+information/overview.htm>.

4. *Id*.

5. CPUC, D-01-03-082 (Mar. 27, 2001).

6. Energy Information Administration, Status of State Electric Industry Restructuring <www.eia.doe.gov/cneaf/electricity/chg_str/regmap.html>.

7. AB 1890, §367.b

8. *Id*., §367.d.

9. *Id*., §371.

10. Nuclear Energy Institute, "Stranded Costs, Decommissioning, Provisions of Commission Order or Legislative Statute" (Aug. 2000) <www.nei.org/documents/strandedcosts.pdf>.

11. AB 1890, §394.4.

12. Energy Information Administration, Status of State Electric Industry Restructuring <www.eia.doe.gov/cneaf/electricity/chg_str/regmap.html>.

13. AB 1890, §395.

14. Energy Information Administration, Status of State Electric Industry Restructuring <www.eia.doe.gov/cneaf/electricity/chg_str/regmap.html>.

15. AB 1890, §382.

16. *Id*., §381.

17. *Id*., §381.

18. *Id*., §355.

19. *Id*., §345.

20. California Energy Commission, Update on Energy Commission Review of California Power Projects (May 10, 2001).

21. California Energy Commission, Database of Proposed Generation Within the Western Systems Coordinating Council (Mar. 20, 2001).

22. Energy Information Administration, Inventory of Nonutility Electric Power Plants in the United States, 1999, Table 6. Energy Information Administration, Inventory of Electric Utility Power Plants in the United States, Table 22.

23. AB 1890 §366.e.

24. *Id.*, §366.d.

25. CPUC, Affiliate Transaction Rules, Appendix A, D97-12-088 (Dec. 16, 1997).

26. AB 1890 §394.4.

27. California Energy Commission, California's Power Content Label <www.energy.ca.gov/consumer-power_content_label.html>.

28. AB 1890 §392.

29. *Id.*, §394.4.

30. *Id.*, §394.7.

31. Energy Information Administration, Retail Unbundling - California <www.eia.doe.gov/oil_gas/natural_gas/restructure/state/ca.html>.

32. Energy Information Administration, Status of State Electric Industry Restructuring <www.eia.doe.gov/cneaf/electricity/chg_str/regmap.html>.

33. PUC Decisions 01-09-013 (San Diego Gas & Electric); 01-09-014 (Southern California Edison); 01-09-015 (PG&E). *See also* "California's PG&E Asks Court to Order DWR to Prove Power Costs Reasonable." *Electric Power Daily* (Aug. 22, 2001), *and* PUC Agenda with results <http://www.cpuc.ca.gov/PUBLISHED/AGENDA/9514.htm#P652_54820>

Illinois: Overview of Retail Competition Plan and Market Response

Administrator and Start Date

Customer choice in Illinois was initiated in December 1997 with the enactment of the Electric Service Customer Choice and Rate Relief Act of 1997 (HB 362). HB 362 required a phase-in of retail competition, with larger customers allowed to choose an alternate generation supplier earlier in the transition. Specifically, customers eligible to choose their electric supplier as of October 1, 1999 include industrial and commercial customers with a demand of greater than 4 MW,[1] commercial customers with businesses at ten or more sites with an aggregate coincident peak demand of 9.5 megawatts or greater, and non-residential customers accounting for one-third of the remaining electricity use of their customer class. All other non-residential customers will be allowed to choose a supplier as of December 31, 2000, and all residential customers as of May 1, 2002.[2] There is a mandatory transition period that ends January 1, 2005.[3] The Illinois Commerce Commission (ICC) will oversee the transition to competition in the electric industry.

Services Open to Competition

Generation and metering services. The ICC promulgated rules that permit non-residential customers to choose a meter service provider other than the distribution utility. Three years and six years after the opening of generation to competitive suppliers, the ICC will open investigations to determine whether more unbundling of distribution services is needed (*e.g.*, to allow competition in metering and billing).[4]

Consumer Options

Consumers have two options for service:

(1) They may either remain with the utility as a bundled customer (*i.e.*, receiving generation, transmission and distribution services); or

(2) They may choose to become a delivery services customer (*i.e.*, they only take distribution and transmission services from the utility). Delivery services customers may purchase generation services from another electric utility, from a competitive supplier, or from their own utility using the power purchase option (PPO).[5]

The PPO is a transitional option that is provided by distribution utilities as long as they are recovering stranded costs from customers (*see* Recovery of Stranded Costs/Transition Costs). Under PPO service, a non-residential delivery services customer (such as an industrial customer) can purchase electric power from the utility at a price that reflects wholesale costs. These customers may then assign the power purchased under the PPO to an alternative supplier. Under this option, the suppliers to whom customers have assigned PPO rights are, in effect, purchasing electricity from the utility and selling it to their customers.

Alternative Suppliers Licensed to Provide Service

All suppliers wishing to provide competitive supply service must have a certificate of service authority. In order to receive certification, a supplier must show technical, financial, and managerial capability.[6] A competitive supplier is required to maintain a license or permit bond in the amount of $30,000 if the supplier intends to serve only non-residential customers with maximum demand greater than 1 MW; $150,000 if the supplier intends to serve non-residential customers with annual electric consumption greater than 15,000 kWh; or $300,000 if the supplier wishes to be certified to serve all eligible retail customers.

In 2000, the number of active suppliers in each distribution utility's territory ranged from one for MidAmerican and AmerenUE to eight for ComEd.

Pricing Trends

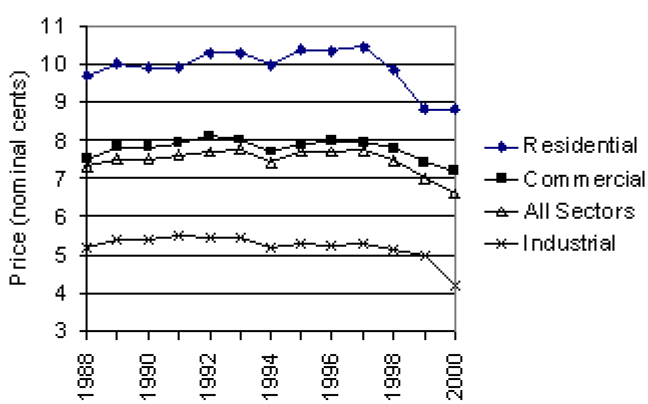
As Table 1 shows, retail prices for the residential sector rose slightly from 1988 to 1997, although prices for the commercial sector remained steady and prices for the industrial sector declined slightly. All three sectors experienced a dip in prices in 1994, and have faced declining prices since 1997. Prices in 2000 were lower than prices in 1988.

Table 1: Average Annual Price per KWh by Sector (nominal cents)

	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
Residential	9.7	10.0	9.9	9.9	10.3	10.3	10.0	10.4	10.3	10.4	9.9	8.8	8.8
Commercial	7.5	7.8	7.8	7.9	8.1	8.0	7.7	7.9	8.0	7.9	7.8	7.4	7.2
Industrial	5.2	5.4	5.4	5.5	5.5	5.5	5.2	5.3	5.2	5.3	5.1	5.0	4.2
All Sectors	7.3	7.5	7.5	7.6	7.7	7.8	7.4	7.7	7.7	7.7	7.5	7.0	6.6

Source: Energy Information Administration

Figure 1. Average Annual Price Per KWh by Sector



Price Changes for Standard Offer (or Regulated) Service

Mandatory residential rate reductions, depend on how the utility's residential rate compares to the residential rate for all large investor owned utilities in the region. There are 6 major utilities in Illinois: Commonwealth Edison (ComEd), Illinois Power, AmerenCIPS, AmerenUE, MidAmerican Energy (MidAmerican), and Central Illinois Light Company (CILCO). Rate reductions were intended to bring residential rates in line with regional rates.[7] Retail rates, less the adjustments, are frozen at 1996 levels until January 1, 2005.

- Residential rates above the Midwest average (ComEd and Illinois Power) were reduced 15% on August 1, 1998, and will be reduced another 5% on May 1, 2002. For ComEd, this final 5% rate reduction will take place instead on October 1, 2001.[8]

- Residential rates below the Midwest average (AmerenCIPS and AmerenUE) were reduced 5% on August 1, 1998, and on October 1, 2000. On October 1, 2002 rates will be reduced either 5% or the percent by which rates exceed the 1999 Midwest average, whichever is less.[9]

- Residential rates for CILCO were reduced 2% on August 1, 1998, an additional 2% on October 1, 2000 and will be reduced a further 1% on October 1, 2002.[10]

Non-residential customers were able to elect "real-time pricing" beginning October 1, 1998. Residential customers were able to elect real-time pricing beginning October 1, 2000.[11] Real time pricing is pricing which varies hour by hour for non-residential customers, and on a periodic basis during the day for residential customers.[12]

Standard Offer Service Provider

Utilities must provide traditional, bundled service for those customers who choose not to shop for a competitive supplier.[13] The standard offer price is the price for bundled service (*i.e.*, service including generation, transmission, and delivery), which was set by the utility's last rate proceeding, less the amount of any rate reduction required in the restructuring law. This rate will be frozen until January 1, 2005.

Recovery of Stranded Costs/Transition Costs

Utilities can collect a competitive transition charge from all customers who choose an alternative supplier to recover stranded generation costs.[14] These charges can be collected from the time the customer chooses an alternative supplier until December 31, 2006. A utility may petition the ICC to extend the collection period to December 31, 2008.[15] ComEd may not petition the ICC to extend the collection period past December 31, 2006.[16] The competitive transition charge will be a cents per kilowatt-hour residual charge calculated by subtracting three factors from the regulated price for bundled service: (a) a mitigation factor (a percentage of the foregone revenue) established by the ICC in accordance with Section 16-102 of the restructuring law; (b) the revenue from delivery services; and (c) the market value of the electricity no longer purchased from the utility.[17]

The market value of electricity will be determined yearly, in accordance with tariffs approved by the ICC, in one of two ways: (a) the utility will calculate market value based on an index of prices at which electricity is bought and sold at exchange or through contracts; or (b) a neutral fact-finder, appointed by the ICC, will review utility contracts and determine an average market price per kWh for electricity sold to each customer class of each utility.[18]

Customer Switching and Eligibility

As of December 31, 2000, all non-residential customers were eligible to choose a competitive supplier. By May 2002, all Illinois customers will be eligible to choose their electric supplier. Electric cooperatives and municipal utilities may choose to allow their customers to choose a competitive supplier, but are not required to do so.[19]

Switching Process

Sign-up Method: In order to switch to a competitive supplier, a customer must sign an agreement with the supplier, who will notify the utility of the change. A utility will only process a enrollment request that comes from a certified competitive supplier.

Restrictions and Minimum Stay Requirements: Customers purchasing power from an alternate supplier are allowed to return to the utility after paying an administrative fee. A utility may require a returning customer with usage less than 15,000 kWh annually to stay with the utility for two years.[20]

Switching Activity

Commercial Sector: All of the utilities in which switching has occurred have seen a steady increase in the number of commercial customers switching to alternative suppliers. In the ComEd region, the percentage of customers and percentage of load switching also increased during the first part of 2000, although these figures began to decline towards the end of 2000. The percentage of customers switched dropped dramatically for all utilities between November 2000 and January 2001. Percent load switched also dropped during this period. This drop was due to the fact that the rate of customer switches did not increase as quickly as the sudden increase in the pool of eligible customers and load caused by the opening of the market to all non-residential customers at the end of 2000. For most of the utilities, approximately 10% or less of their customers switched to other providers, and even at its peak, ComEd saw less than 20% of its customers switching. The utilities' percent load switched varied more widely, ranging from Illinois Power, which had approximately 10% or less load switched, to ComEd, which had more than 40% of load switched during the latter part of 2000. In the service territories of the other utilities, approximately 10-15% of customers had switched from utility bundled service. Forty percent of customers who have switched from utility bundled service have chosen the power purchase option service.[21]

Table 2. Commercial Sector

Number of Customers Served by Alternative Suppliers											
Utility	**Nov-99**	**Jan-00**	**Mar-00**	**May-00**	**Jul-00**	**Sep-00**	**Nov-00**	**Jan-01**	**Mar-01**	**May-01**	**Jul-01**
AmerenCIPs	0	15	86	230	273	512	629	642	773	844	849
ComEd	1,760	3,908	4,668	5,195	6,247	6,706	6,937	8,667	9,987	11,092	12,989
Illinois Power	0	19	41	48	51	340	358	571	716	839	879
MidAmerican Energy	5	62	130	130	130	214	214	227	214	216	216

% of Customers Served by Alternative Suppliers											
Utility	**Nov-99**	**Jan-00**	**Mar-00**	**May-00**	**Jul-00**	**Sep-00**	**Nov-00**	**Jan-01**	**Mar-01**	**May-01**	**Jul-01**
AmerenCIPs	0.0%	0.2%	0.9%	2.5%	3.0%	5.5%	6.6%	1.4%	1.6%	1.8%	1.9%
ComEd	4.9%	10.8%	13.0%	14.4%	17.8%	19.1%	19.8%	2.8%	3.2%	3.5%	4.1%
Illinois Power	0.0%	0.4%	0.8%	0.9%	1.0%	6.4%	6.7%	0.9%	1.2%	1.3%	1.4%
MidAmerican Energy	0.3%	3.3%	6.9%	6.9%	7.0%	11.5%	11.5%	2.2%	2.0%	2.1%	2.1%

Table 2 (cont'd). Commercial Sector

% of Total Load served by Alternative Suppliers											
Utility	Nov-99	Jan-00	Mar-00	May-00	Jul-00	Sep-00	Nov-00	Jan-01	Mar-01	May-01	Jul-01
AmerenCIPS	0.0%	0.4%	7.9%	10.5%	11.3%	27.5%	31.8%	NA	5.7%	6.6%	6.6%
ComEd	15.7%	34.1%	39.6%	48.3%	42.8%	46.3%	47.6%	21.5%	22.1%	22.6%	25.0%
Illinois Power	0.0%	2.2%	3.1%	3.6%	3.8%	10.7%	11.6%	7.4%	9.3%	10.5%	10.7%
MidAmerican Energy	0.2%	7.6%	10.8%	10.8%	15.2%	19.9%	19.9%	6.7%	6.7%	6.8%	6.8%

Notes:
1. ComEd reports its switching data in terms of "small commercial and industrial" and "large commercial and industrial." For purposes of calculating totals, "small commercial and industrial" is assumed to equate "commercial" and "large commercial and industrial " is assumed to equate "industrial."
2. As of Dec. 31, 2000, all non-residential customers became eligible for choice.
3. Customers eligible to switch suppliers may switch either to an alternative supplier or to a unbundled power and energy service offered by utilities called the "Power Purchase Option." Both types of switches are recorded as switches to delivery services.
4. As of July 2001, AmerenUE had a negligible number of customers (less than 20) switch to delivery services. CILCO has not had any switches.

Source: Illinois Commerce Commission

***Industrial Sector*:** With the exception of MidAmerican Energy, the utilities have experienced an increasing number of industrial customers switching to alternative suppliers since November 1999. As in the case of commercial customers, the percentage of eligible industrial customer and load switches dropped during the last part of 2000 as all non-residential customers became eligible for choice, but the degree of change in the industrial sector was not as great as the change in the commercial sector. The percent of load served by alternative suppliers has varied greatly between the various utilities, with ComEd and Illinois Power having more than 40% of load switched and MidAmerican Energy having less than 10% load switched as of May 2001. Illinois Power's percent load switched jumped between May 2000 and July 2000, as it rose from approximately 10% to more than 37%. When ComEd's customers became eligible to choose a supplier, initially more than 60% of the load switched, although this figure has dropped over time.

Table 3. Industrial Sector

Number of Customers Served by Alternative Suppliers											
Utility	Nov-99	Jan-00	Mar-00	May-00	Jul-00	Sep-00	Nov-00	Jan-01	Mar-01	May-01	Jul-01
AmerenCIPs	0	5	21	54	61	77	78	78	78	81	81
ComEd	384	833	983	1,123	560	622	658	702	727	866	830
Illinois Power	2	5	8	9	11	18	26	31	38	38	39
MidAmerican Energy	0	1	1	1	1	1	1	1	1	2	2

% of Customers Served by Alternative Suppliers											
Utility	Nov-99	Jan-00	Mar-00	May-00	Jul-00	Sep-00	Nov-00	Jan-01	Mar-01	May-01	Jul-01
AmerenCIPs	0.0%	0.6%	2.3%	5.9%	6.7%	8.5%	8.6%	16.4%	17.4%	18.4%	18.9%
ComEd	9.6%	0.5%	24.4%	27.9%	66.6%	74.0%	78.2%	47.4%	49.3%	51.1%	57.3%
Illinois Power	1.5%	3.9%	6.2%	6.9%	8.5%	13.9%	20.0%	12.4%	15.2%	15.2%	15.6%
MidAmerican Energy	0.0%	3.6%	3.6%	3.6%	3.5%	3.5%	3.5%	2.0%	2.0%	4.0%	4.0%

Table 3 (cont'd). Industrial Sector

	% of Total Load served by Alternative Suppliers										
Utility	**Nov-99**	**Jan-00**	**Mar-00**	**May-00**	**Jul-00**	**Sep-00**	**Nov-00**	**Jan-01**	**Mar-01**	**May-01**	**Jul-01**
AmerenCIPS	0.0%	5.2%	6.8%	7.3%	7.5%	7.5%	7.5%	9.9%	21.0%	20.9%	21.2%
ComEd	9.4%	27.7%	36.4%	42.7%	62.9%	68.5%	72.1%	47.7%	46.3%	47.3%	51.2%
Illinois Power	2.6%	6.8%	8.9%	9.9%	37.3%	40.8%	46.1%	39.5%	44.5%	46.0%	46.0%
MidAmerican Energy	0.0%	3.9%	3.9%	3.9%	3.2%	3.2%	3.2%	2.9%	2.9%	3.7%	3.7%

Notes:

1. ComEd reports its switching data in terms of "small commercial and industrial" and "large commercial and industrial." For purposes of calculating totals, "small commercial and industrial" is assumed to equate "commercial" and "large commercial and industrial " is assumed to equate "industrial."
2. As of Dec. 31, 2000, all non-residential customers became eligible for choice.
3. Customers eligible to switch suppliers may switch either to an alternative supplier or to a unbundled power and energy service offered by utilities called the "Power Purchase Option." Both types of switches are recorded as switches to delivery services.
4. As of July 20001, neither AmerenUE nor CILCO has had any industrial customers switch to delivery services.

Source: Illinois Commerce Commission

Public Benefits Programs

The restructuring act establishes three public benefits funds:

Low-income: Beginning January 1, 1998, utilities are required to charge all customer accounts an energy assistance charge to provide for the low-income energy assistance fund. Charges will be 40 cents per month for residential customers, $4.00 per month for commercial and small industrial customers, and $300 per month for large industrial customers. Municipal utilities and cooperatives do not have to contribute to this fund; however, if they choose not to contribute, their customers will not receive benefits from the fund. The act also establishes an Energy Assistance Program Design Group to aid in the design of a new low-income energy assistance program for the period beginning January 1, 2003.

Renewable: The renewable energy resources trust fund is established to provide grants and loans and other financial support for the development of renewable resources. The revenue for this fund will come from monthly charges to all customers, regardless of who provides their generation service. Charges are 5 cents for residential customers, 50 cents from non-residential customers whose peak demand is less than 10 MW, and $37.50 from large non-residential customers. Half of these funds will be deposited into the renewable energy resources trust fund; the other half of these collected charges will go towards the coal technology development assistance fund. Municipal utilities and cooperatives are not required to participate in this fund; however, if they choose not to contribute, their customers will not receive benefits from the fund.

Energy Efficiency: The energy efficiency trust fund will provide funding for residential energy efficiency programs including energy efficiency efforts for low-income households, energy efficient window replacement, energy efficient appliance replacement, energy efficient lighting replacement, insulation of buildings and other similar projects. All utilities and competitive suppliers providing electric services to Illinois customers will have to contribute a pro rata share of $3 million annually, based on the company's total kilowatt-hours sold. Municipal utilities and electric cooperatives do not have to contribute to this fund. If they do not contribute, their customers cannot receive benefits from the fund.

Separation of Generation and Transmission

Illinois did not require divestiture or functional separation of utilities, although the ICC is looking into the possibility of requiring functional separation. Utilities may engage in both competitive and non-competitive services without forming a separate affiliate, although many Illinois utilities have transferred ownership of their generation facilities to an affiliate. After January 1, 2003, the ICC may require utilities to separate competitive and non-competitive activities.[22] Of the utilities operating in Illinois, Ameren, Commonwealth Edison, and Illinois Power have spun-off or sold all of their generation assets. Both Illinois Power and Ameren transferred generation assets to an unregulated affiliate. Affiliates still own a high percentage of generation capacity in their parent utility service territories.[23]

State RTO Involvement

The establishment of one or more RTOs is required to facilitate the electric power market. All utilities providing transmission service, who are members of the Mid-American Interconnected Network, have to submit an application to FERC to establish or join an ISO.[24] The major Illinois electric utilities joined the Midwest ISO, although in late 2000, Illinois Power, Commonwealth Edison, and Ameren announced that they wanted to leave the Midwest ISO to join the Alliance RTO. The ICC does not expect an RTO to begin operating in the Midwest before December 15, 2001.[25]

New Plant Construction and Planning

As of September 15, 2000, 6,112 MW of new generation facilities were under construction in Illinois, with 16,419 MW of planned construction that has not yet begun.[26] According to Energy Information Administration data, suppliers in Illinois have planned 17,108 MW of generation capacity additions between 2000 and 2004.[27]

Slamming/Cramming Rules

Before switching a customer, a competitive supplier must obtain verifiable authorization from the customer,[28] in the form of a customer's written authorization of a change in electric service through a letter of agency.[29] Suppliers who switch a customer without his consent are subject to financial penalties, as well as possible revocation of the supplier's certificate of service authority.

Customer Billing

A customer may receive either one bill from the generation supplier, or two bills, one from the utility and one from the generation supplier.[30] During the transition period, a utility may also conduct billing experiments for billing on a consolidated basis to certain groups of customers.[31]

Affiliate Name and Logo Issues

Although joint advertising and marketing by a utility and its affiliate are prohibited, the affiliate may use the corporate name or logo of the utility.

Usage of Customer Information

No customer specific information can be given to a supplier without customer authorization.[32]

Standardized Labeling

***Content*:** Suppliers must give customers information on rates and terms of service, as well as summaries of power sources and emissions information. These summaries must include the known sources of electricity supplied in percentages from each source as well as a pie-chart depicting the percentages. ICC will also determine the format of standardized charts to be provided to consumers to detail emissions information.[33]

***Timing*:** Disclosure statements must be provided to customers quarterly.[34]

Consumer Education

The ICC is required to provide a consumer education program for residential and small commercial customers. This will include information on how the market will function; services provided by and choices available from alternate suppliers and the utility; consumer rights, risks and responsibilities; the legal obligations of the competitive supplier; types of products and services offered in the new market; the meaning of the different components of the electricity bill; and procedures for filing complaints.[35] Additionally, all utilities and competitive suppliers are required to maintain a customer call center.[36] The ICC consumer education efforts include brochures and bill inserts for customers, media and other outreach efforts and a web site which contains an overview of restructuring, a list of eligible suppliers, frequently asked questions and other information. The ICC consumer education program is funded by an annual appropriation from the General Revenue Fund in the state treasury.

Other Consumer Protection Measures

Before providing service for residential and small commercial customers, a competitive supplier must provide a terms of service statement which outlines all charges, the length of the contract, the process for notification regarding changes in terms of service, and a toll-free number. Utilities and competitive suppliers are also required to provide customers at least once a year with information on the average monthly prices paid by the consumer for electricity, as well as the terms and conditions for sales. Alternative suppliers who make claims about the technologies and fuel types used to generate their electricity have to provide documentation substantiating such claims to the ICC and to customers.[37]

Retail Choice in Gas Sales

Although Illinois has not enacted a law opening up the gas market to competition, virtually all of the state's non-residential customers may purchase gas from alternative gas suppliers. Additionally, the ICC recently approved a plan allowing all residential customers of one of the state's largest natural gas utilities, Nicor Gas, to purchase gas from alternative gas suppliers.

Notes

1. Average monthly maximum electrical demand on the electric utility's system during the 6 months with the customer's highest monthly maximum demands in the 12 months ending June 30, 1999.

2. 220 Ill. Comp. Stat. § 5/16-104 (West 2001).

3. *Id*. at § 5/16-102.

4. *Id*. at § 5/16-109.

5. *Id*. at § 5/16-110.

6. *Id*. at § 5/16-115.

7. S.B. 24, amending H.B. 362, enacted June 30, 1999.

8. *Id*.

9. 220 Ill. Comp. Stat § CS 5/16-111 (West 2001).

10. *Id*. at § 5/16-111.

11. *Id*. at § 5/16-107.

12. *Id*. at § 5/16-102.

13. *Id*. at § 5/16-103.

14. *Id*. at § 5/16-108.

15. *Id*. at § 5/16-108.

16. *Id*. at § 5/16-108(f).

17. *Id*. at § 5/16-102.

18. *Id*. at § 5/16-112.

19. *Id*. at § 5/17-200.

20. Comments of the Illinois Commerce Commission, Federal Trade Commission Retail Electricity Study (Apr. 11, 2001) ("ICC Comment"). *See* 220 Ill. Comp. Stat. § 5/16/-103(d).

21. ICC, "Assessment of Retail and Wholesale Market Competition in the Illinois Electric Industry," (Apr. 2001).

22. 220 Ill. Comp. Stat. § 5/16-119A (West 2001).

23. ICC Comment.

24. 220 Ill. Comp. Stat. § 5/16-126 (West 2001).

25. ICC Comment.

26. ICC, Summer 2001 Electric Supply & New Generation, Exhibit 3 (April 19, 2001).

27. Energy Information Administration, Inventory of Nonutility Electric Power Plants in the United States, 1999, Table 6. Energy Information Administration, Inventory of Electric Utility Power Plants in the United States, Table 22.

28. 220 Ill. Comp. Stat. § 5/16-115A (West 2001).

29. 815 Ill. Comp. Stat. § 505/2EE (West 2001).

30. 220 Ill. Comp. Stat. § 5/16-118 (West 2001).

31. *Id*. at § 5/16-106.

32. *Id*. at § 5/16-122.

33. *Id*. at § 5/16-127.

34. *Id*.

35. *Id*. at § 5/16-117.

36. *Id*. at § 5/16-124.

37. *Id*. at § 5/16-115A.

Maine: Overview of Retail Competition Plan and Market Response

Administrator and Start Date

The Maine Public Utilities Commission (PUC) is administering Maine's transition to electric competition. The Maine restructuring law, passed on May 29, 1997, allowed for all customers to choose their electricity supplier beginning March 1, 2000.[1]

Services Open to Competition

Generation only. The restructuring act originally provided for metering and billing to be subject to competition as of March 1, 2003.[2] This provision has since been amended to remove the March 1, 2003 date and to provide the PUC with discretion to allow for billing and metering competition through the adoption of rules.

Consumer Options

Maine consumers have three options. They may choose a new competitive supplier, they may join a buying group (also known as an aggregator), or they may receive standard offer service. A customer will automatically receive standard offer service if he does not choose an alternate supplier or aggregator.[3]

Alternative Suppliers Licensed to Provide Service

All competitive suppliers must be licensed by the PUC in order to serve customers in Maine. In order to receive a license, a competitive supplier must show financial and technical capability.[4] The PUC rules for licensure require a competitive supplier to furnish a surety bond or an irrevocable standby letter of credit for an initial security of $100,000. There will be an annual modification of this requirement which will be 10% of revenues from generation services provided to residential and small commercial customers.[5] Small commercial customers are defined as customers who do not have demand charges.

Maine does not maintain information on the number of suppliers actually providing service to customers.

Pricing Trends

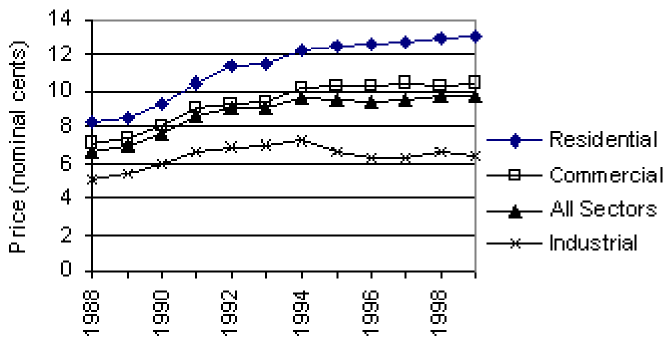
As Table 1 shows, both residential and commercial retail prices increased over the past decade, residential prices rose from approximately 8 to 13 cents per kWh, and commercial prices rose from approximately 7 to 11 cents per kWh. Industrial prices rose through the early 1990's until 1994, and have been relatively constant since then.

Table 1. Average Annual Price per KWh by Sector (nominal cents)

	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
Residential	8.3	8.5	9.3	10.5	11.4	11.4	12.3	12.5	12.6	12.8	13.0	13.1	NA
Commercial	7.1	7.4	8.0	9.1	9.3	9.5	10.2	10.3	10.4	10.4	10.3	10.5	NA
Industrial	5.1	5.4	6.0	6.7	6.9	7.0	7.2	6.7	6.3	6.4	6.6	6.4	NA
All Sectors	6.7	7.0	7.6	8.6	9.1	9.1	9.6	9.5	9.5	9.5	9.8	9.8	NA

Source: Energy Information Administration

Figure 1. Average Annual Price Per KWh by Sector



Price Changes for Standard Offer (or Regulated) Service

Starting in March 2000, residential and small business customers received rate reductions, depending on usage, on their total electric bills.[6] Maine has three investor-owned utilities: Bangor Hydro Electric Company (BHE), Central Maine Power Company (CME), and Maine Public Service Company (MPS).

- Bangor Hydroelectric customers received reductions of approximately 2.5%
- Central Maine Power customers received reductions from 2.5% to 15%
- Maine Public Service customers received reductions of approximately 8%.

On March 26, 2001, the PUC issued orders reducing delivery charge rates for non-residential customers of CMP and BHE. From April 15, 2001 through February 28, 2002, delivery rates for non-residential customers will be reduced by 0.8 cents/kWh. These reductions are intended to mitigate increased generation rates.[7]

Standard Offer Service Provider

Standard offer service will be offered until March 1, 2005 to customers who have not chosen a competitive supplier, customers who are between suppliers, and customers whose supplier has terminated service, for whatever reason. Standard offer suppliers will be chosen by the PUC through a bid process. If the PUC does not receive any acceptable bids, it can require the distribution company to arrange for standard offer service for its customers. Marketing affiliates of distribution companies may not provide more than 20% of the standard offer service load in the service territory of the affiliated distribution company, unless required to do so by the PUC.[8]

Standard Offer Bid Process

The restructuring law states that the PUC should seek to ensure that there are at least three standard offer service providers in each distribution company territory. Electric cooperatives will conduct a similar bidding process to the PUC bidding process, but they may conduct this process themselves.[9] A bidder may bid on the total load of predefined customer groups in a service territory, or only a portion of the load. For residential and small commercial customers, the bid must be a fixed cents/kWh price; for medium and large customers, a bidder can bid his preferred pricing structure.[10]

The PUC conducted its first bidding process in 1999 to choose standard offer service providers for the period beginning March 1, 2000. Through this bidding process, the PUC accepted bids for service in all customer classes of the MPS territory, and for the residential/small commercial class of the CMP territory. The PUC rejected the bids and terminated the bid process for the medium and large customer classes of CMP and all classes of BHE because the bids either did not conform to the bid procedures or were unreasonably high. CMP was instead directed to procure power for its medium and large customer classes and BHE was directed to procure standard offer power on the wholesale market. After this first bid process, the PUC proposed amendments to the bidding process to improve the bidding process and increase the likelihood of choosing standard offer providers for all customer classes at reasonable rates.[11]

Amendments to the Standard Offer Service Rule: After the first round of bidding, the PUC amended the rule on the provision of standard offer service in order to give the PUC more flexibility so that there is a greater likelihood that the bid process will result in the selection of a standard offer provider for all customers at reasonable rates. Much of the flexibility comes from not setting out specifics in the rule itself, but leaving them to be specified in the Requests for Bids (RFBs).[12]

A second bidding process took place in the winter of 2000, to determine standard offer providers for the time period beginning March 1, 2001. WPS-ESI was accepted as the standard offer provider for all classes of the Maine Public Service Company territory, for a three-year period. In December 2000, the PUC terminated the formal bid process for CMP and BHE because the bids were inadequate due to price spikes in the northeast wholesale electric market. The PUC instead adopted a two-part alternative selection process, in which the PUC will continue to receive bids from qualified bidders, and CMP and BHE will explore wholesale power arrangements so that they can provide standard offer service for their customers.[13] In August 2001, the PUC rejected BHE's plan to secure standard offer energy and reduce electric rates by 8.4% for small and medium customers and to stabilize standard offer rates at 5.5 cents/kWh through 2006. The PUC rejected BHE's plan because it conflicted with the restructuring law and would create new competitive risks for the company, effectively returning it to the power supply business. In addition, the PUC expects energy prices to drop in the near future and that the market can supply power at lower prices in the next four years. The PUC has issued an RFP for standard-offer energy for the period starting March 2002.[14]

Listed below are the shopping credits for customers in the service territories of the three investor-owned utilities. Several electric cooperatives operate in Maine, and the PUC also established shopping credit rates for each cooperative as well.

Table 2. Shopping Credit Rates (in cents/kWh)

Company	Effective March 1, 2001	Effective March 1, 2002	Effective March1, 2003
Central Maine Power	4.089	N/A[3]	N/A[3]
Bangor Hydro Electric Company	7.3	N/A[3]	N/A[3]
Maine Public Service Company	5.577	5.689	5.802

Notes:
1. These are base rates, subject to an adjustment each month to reflect the actual cost of supply and actual retail sales.
2. Only residential and small non-residential rates are shown. Maine has also adopted shopping credits for medium and large non-residential customers.
3. Rates effective after March 1, 2002 have not yet been determined for either Central Maine Power or Bangor Hydro Electric Company.

Source: Maine PUC

Recovery of Stranded Costs/Transition Costs

Distribution utilities have a reasonable opportunity to recover stranded costs through a stranded cost charge, which is included in the transmission and distribution rates of the distribution utility. Stranded costs eligible for recovery include regulatory assets from generation, the difference between net plant investments associated with the distribution utility's generation assets and the market value of generation assets, and the difference between future contract payments and the market value of the distribution utility's purchased power contracts. Distribution utilities must make mitigation efforts, and they will be allowed recovery of stranded costs comparable to their recovery prior to the start of retail competition. The PUC has calculated stranded costs for all distribution utilities, and may adjust and correct stranded cost estimates and charges at any time. In 2003 and every three years thereafter, the PUC is required to review stranded costs and correct estimates and adjust costs.[15]

Customer Switching and Eligibility

All customers are eligible to choose a competitive electric supplier. The switching statistics show that large industrial customers, and to a certain extent, medium commercial customers, have chosen alternative suppliers. The switching activity for residential customers has been limited.[16]

Switching Process

***Sign-up Method*:** The customer contacts the supplier to sign up for service, after which residential and small commercial customers will receive a terms of service document from the supplier. Before the distribution utility can enroll the customer to receive competitive generation service, it must receive notification from the supplier. For residential and small commercial customers, the supplier will not notify the distribution company of the change in suppliers until after the end of the 5-day rescission period. If a distribution utility receives notification to enroll from more than one competitive supplier, it will carry out the first enrollment received. Changes in supplier will become effective on the customer's next meter reading date.[17]

***Right of Rescission*:** Residential customers have a right of rescission which can be exercised orally, in writing or by electronic means. The rescission will be valid if it is received no later than 8 days after the supplier mails the terms of service document to a customer, or 5 days after the supplier delivers the terms of service personally or by electronic means.[18] Medium and large commercial customers are not afforded right of rescission protections.[19]

***Restrictions and Minimum Stay Requirements*:** A customer can switch to a competitive supplier at any time.[20] Under the original rules, a customer who switched back to standard offer service was required to stay on standard offer service for 12 months. In addition to the 12-month stay rule, which prevents gaming of the system, the PUC has ruled that customers who switch back to standard offer service have to pay an "opt-out fee," equal to two months of generation costs.

Switching Activity

***Residential and Small Commercial Sector*:** In the residential and small commercial sector, all three distribution utilities, as shown in Table 3, experienced an increase in the number of customer switches, but MPS was the only distribution utility with a sizeable number of switches. The number of MPS customers served by alternative suppliers has decreased slightly since February 2001. Although it has seen far more customers switching than the other two distribution utilities, MPS has had at most 10% of its load switch, while the other two distribution utilities have had less than 1% load switched since the inception of customer choice.

Table 3. Residential and Small Commercial Customers

Number of Customers Served by Alternative Suppliers							
Utility	**Jul-00**	**Sep-00**	**Nov-00**	**Jan-01**	**Mar-01**	**May-01**	**Jul-01**
BHE	36	35	36	42	42	65	72
CMP	70	76	110	137	142	163	161
MPS	536	1,375	1,644	1,833	2,022	1,863	1,857
Total	**642**	**1,486**	**1,790**	**2,012**	**2,206**	**2,091**	**2,090**

% of Total Load served by Alternative Suppliers							
Utility	**Jul-00**	**Sep-00**	**Nov-00**	**Jan-01**	**Mar-01**	**May-01**	**Jul-01**
BHE	<1%	<1%	<1%	<1%	<1%	<1%	<1%
CMP	<1%	<1%	<1%	<1%	<1%	<1%	<1%
MPS	2%	7%	10%	9%	10%	10%	9%

Notes:
1. BHE = Bangor Hydro-Electric, CMP = Central Maine Power, MPS = Maine Public Service
2. BHE classifies small commercial customers as commercial customers requiring less than 25 KW, CMP as less than 20 KW, and MPS as less than 50 KW.
3. Prices for standard offer service are based on the bids to supply the service accepted by the Maine Public Utilities Commission. Here we report only the statistics on customers not taking standard offer service.

Source: Maine Public Utility Commission

***Medium Commercial Sector*:** The number of medium commercial customers switching to alternative suppliers increased for all three distribution utilities between July 2000 and May 2001. CMP had the largest number of customers switching. In terms of percent load switched, however, MPS had the highest percentage, with the percent load stabilizing at approximately

6.3% through May 2001, although it has decreased since then. The other two distribution utilities have seen a steady increase in percent load switched between July 2000 and July 2001, although as of July 2001, BHE still had less than 10% load switched and CMP had approximately 20% load switched.

Table 4. Medium Commercial Customers

Number of Customers Served by Alternative Suppliers

Utility	Jul-00	Sep-00	Nov-00	Jan-01	Mar-01	May-01	Jul-01
BHE	29	30	38	46	46	109	107
CMP	403	409	934	921	949	1,575	2,133
MPS	63	95	110	111	114	115	114
Total	**495**	**534**	**1,082**	**1,078**	**1,109**	**1,799**	**2,354**

% of Total Load served by Alternative Suppliers

Utility	Jul-00	Sep-00	Nov-00	Jan-01	Mar-01	May-01	Jul-01
BHE	2%	2%	3%	3%	4%	9%	9%
CMP	6%	6%	10%	15%	15%	24%	29%
MPS	28%	67%	64%	65%	63%	63%	52%

Notes:

1. BHE = Bangor Hydro-Electric, CMP = Central Maine Power, MPS = Maine Public Service
2. BHE classifies small commercial customers as commercial customers requiring less than 25 KW, CMP as less than 20 KW, and MPS as less than 50 KW.
3. Prices for standard offer service are based on the bids to supply the service accepted by the Maine Public Utilities Commission. Here we report only the statistics on customers not taking standard offer service.

Source: Maine Public Utility Commission

***Large Commercial Sector*:** As in the case of medium commercial customers, CMP was the only distribution utility to experience large numbers of large commercial customer switching. The number of CMP customers rose between September and October 2000, stabilized for several months, and then declined during the first part of 2001, only to rise again between March and July 2001. In terms of percent load switched, all three distribution utilities had sizeable figures, and as of July 2001, these figures stood above 50% for CMP and MPS, and approximately 40% for BHE. MPS saw a dramatic increase in percent load switched between July and August 2000, from 3% to 65%.

Table 5. Large Commercial Customers

Number of Customers Served by Alternative Suppliers							
Utility	**Jul-00**	**Sep-00**	**Nov-00**	**Jan-01**	**Mar-01**	**May-01**	**Jul-01**
BHE	6	6	7	6	6	11	13
CMP	116	117	148	145	119	165	185
MPS	3	10	11	11	11	11	11
Total	**125**	**133**	**166**	**162**	**136**	**187**	**209**

% of Total Load served by Alternative Suppliers							
Utility	**Jul-00**	**Sep-00**	**Nov-00**	**Jan-01**	**Mar-01**	**May-01**	**Jul-01**
BHE	47%	43%	29%	29%	22%	38%	41%
CMP	59%	60%	63%	65%	62%	77%	81%
MPS	3%	52%	68%	74%	75%	56%	82%

Notes:
1. BHE = Bangor Hydro-Electric, CMP = Central Maine Power, MPS = Maine Public Service
2. BHE classifies small commercial customers as commercial customers requiring less than 25 KW, CMP as less than 20 KW, and MPS as less than 50 KW.
3. Prices for standard offer service are based on the bids to supply the service accepted by the Maine Public Utilities Commission. Here we report only the statistics on customers not taking standard offer service.

Source: Maine Public Utility Commission

Public Benefits Programs

***Low-income*:** The PUC has established the Electric Lifeline Program (ELP), which will be available to low-income customers statewide. The ELP will assist low-income customers with bill payment by applying a fixed monthly credit to their bills.[21] The ELP will replace all existing distribution utility low-income customer assistance programs beginning on October 1, 2001. Until that time, distribution utilities will continue to implement existing low-income assistance programs.[22] For the year beginning October 1, 2001, each distribution utility will contribute 1.165% of its calendar year 2000 transmission and distribution revenues, for a total ELP cost of $6,600,000. For subsequent years, the PUC will review and evaluate the program to determine whether adjustments need to be made to the funding amount or other program features.[23]

***Renewables*:** Maine has developed a Renewable Resource Research & Development Fund, to which a customer may make a one-time or regular voluntary contribution, in any amount he or she wishes. This fund is designed to establish cleaner, more efficient ways of producing electricity by funding R&D efforts at public higher education institutions in Maine.[24]

***Energy Efficiency*:** Distribution utilities must implement energy conservation programs. These programs will be funded at 1999 levels and charges will be included in transmission and distribution rates. The charges will not be greater than 0.15 cents/kWh and will comprise no less than .5% of the total transmission and distribution revenues of the distribution company. The PUC will consider alternative methods of funding these programs.[25]

Separation of Generation and Transmission

Distribution utilities were required to sell their generation assets by March 1, 2000. After this date, distribution utilities may not own, have financial interest in or control generation or generation assets, unless the PUC decides that it is necessary for the efficient execution of the distribution utility's transmission and distribution obligations. Contracts with qualified facilities and nuclear generation do not have to be divested, although distribution utilities may have to divest their ownership interests in the Maine Yankee Atomic Power company on or after January 1, 2009.[26] Electric cooperatives may only supply electricity within their own service territories. The PUC can limit or prohibit sales by other electricity providers in a electric cooperative's service area if these sales would cause the cooperative to lose its tax-exempt status.[27]

Wholesale Electricity Purchasing and Pricing

On May 1, 1999, the New England ISO implemented a wholesale hourly energy market and new ancillary services markets. The Independent System Operator of New England (ISO-NE) manages the wholesale market, under contract with the New England Power Pool. The new wholesale market is based on bid prices in a spot market. In 1999, only about 8-15% of the daily system load in New England was sold through the new spot market. The remainder was sold through bilateral contracts between suppliers and entities serving retail customers.

State RTO Involvement

Maine distribution utilities belong to the Independent System Operator of New England (ISO-NE). Established in 1997, ISO-NE is responsible for managing energy markets and operating the transmission system in New England.[28]

New Plant Construction and Planning

Maine has more than 1,500 MW of new gas-fired generation which are either operating or about to operate.[29] Developers in New England announced plans to build over 30,000 MW of new generation capacity. Most of these proposed plants will use natural gas and other low emission fuels.[30] These new gas-fired generators are feasible, in part, because new gas pipe-lines have been installed to bring Canadian natural gas supplies to New England. In 1999, 730 MW of new generation capacity were added in New England, with an additional 1,250 MW expected in 2000.[31] According to Energy Administration Data, suppliers in Maine have planned generation capacity additions of 2,466 MW between 2000 and 2004.[32]

Slamming/Cramming Rules

No customer can be switched without his express consent. A switch must be authorized in writing using a letter of authorization, or confirmed by third party verification if done over the phone. If a supplier is found to have switched a customer without his consent, the supplier must refund to the customer any charges paid to the supplier, as well as any expense the customer incurred in switching back to his previous supplier.[33]

Customer Billing

Customer rates were unbundled in January 1999.[34] Under consolidated utility billing, the customer will receive only one bill, as the distribution utility will calculate and issue bills for generation service on behalf of a requesting competitive supplier, in addition to its own billing for transmission and distribution services.

If the supplier chooses to calculate and issue bills for generation service for its own customers, a customer will receive two bills.[35]

Affiliate Name and Logo Issues

Joint advertising and marketing between a distribution company and its affiliate is prohibited.[36] The distribution company and the affiliate cannot give the appearance of speaking on behalf of one another, cannot represent that there is a benefit because of their association, and the distribution company cannot promote the affiliate or its products and services. The affiliation cannot be discussed unless a customer specifically asks. If asked, a customer must be informed that the affiliate is not regulated, that there is no advantage to a customer of the affiliate because of the relationship to the distribution company, and that the customer can choose another supplier, and does not have to choose the affiliate.[37] Maine requires distribution utility affiliates to compensate the distribution utility for the use of the utility name, logo, slogan or other marketing device associated with the distribution utility.[38]

Usage of Customer Information

A competitive supplier may request customer-specific information, including a customer's kWh usage and maximum monthly demands, from a distribution utility. Before requesting such information, the supplier must obtain customer authorization in writing, electronically, or through notification in the terms of service document, which notification must specify that by becoming a customer of the competitive supplier he authorizes the distribution utility to provide customer information to the supplier. The distribution utility must obtain written evidence that the supplier has complied with the customer authorization requirement before it may release customer-specific information to the supplier.[39] A competitive supplier may not release customer-specific information to any other entity without the specific affirmative consent of the customer, by either written authorization or third-party verification.[40]

Standardized Labeling

Competitive electricity providers must provide customers with a uniform disclosure label, and distribution companies must provide standard offer service labels for their customers who will receive standard offer service in their service territory. Maine coordinated the development of labeling rules with other New England states in order to hold down costs for competitive suppliers and to minimize inter-state confusion.[41]

Content: Competitive supplier disclosure labels will include: average price information (which must be the unit price in cents/kWh for generation services only, measured at a customer's meter over an annualized period, regardless of the actual price structure), price variability information, customer service information, and power source data and air emissions characteristics (which must be from the most recent one-year period from which data is available). If there is more than one standard offer provider in a territory, the information on the distribution company's label will be blended to reflect a weighted average of each supplier's price, power sources, and air emissions information.[42]

Timing: Uniform information disclosure labels will be provided to residential and small commercial customers before they begin service with a competitive supplier, at the same time that the supplier provides the customer with the terms of service document. After the initiation of service, labels will be provided quarterly, at a minimum, and upon request.[43] Uniform information disclosure labels will only be provided to medium and large non-residential customers once a year.[44] Standard offer labels must be provided within 6 months after the initiation of standard offer service, and every three months thereafter.[45]

***Standard Offer Service Disclosure*:** In September 2001, the Maine PUC ordered utilities to provide uniform disclosure labels for standard offer service customers. These labels will include pricing information, and fuel source and emissions data compared to the regional average. Medium and large customers will receive standard offer service labels annually, and residential and small business customers will receive labels quarterly. Labels will also be available upon request.[46]

Advertising Restrictions

In all print advertising and marketing materials, the supplier must prominently display the availability of a disclosure label. In non-print materials, the supplier must clearly indicate that a disclosure label is available upon request. Websites of competitive suppliers must have access to the supplier's disclosure label.[47]

Consumer Education

Maine has implemented a consumer education program which was funded by all electric distribution company customers. The consumer education program has spent $1.2 million to raise awareness and understanding of electric industry restructuring through efforts such as advertising, direct, mail, and community outreach. Some of the planned education efforts relating to educating consumers on how to shop for a competitive supplier have been deferred until the market develops further.[48]

Other Consumer Protection Measures

All competitive suppliers must offer customers a minimum service period of 30 days.[49] Competitive suppliers must maintain a "do-not-call" list of customers who request not to receive telemarketing calls from competitive suppliers.[50] Residential and small commercial customers have the right to receive a terms of service document at any time.[51] The terms of service document must include pricing and contract information, as well as any other charge or fee information, and disclosure of the customer's right of recission.[52] Medium and large commercial customers are not afforded terms of service protections.[53]

Retail Choice in Gas Sales

In 1999, unbundled gas service was made available to gas customers, so they could choose their supplier. Most of Maine's 22,000 natural gas customers receive service from Northern Utilities, Inc., although 2 new distribution companies are set to begin service in 1999.[54]

Miscellaneous

All competitive electricity suppliers in Maine, including those providing standard offer service, must provide no less than 30% of their yearly kilowatt-hour sales from "eligible resources."[55] Eligible resources generation facilities include renewable energy sources (including hydroelectric generation), and efficient power sources (*i.e.*, plants that capture the heat or steam produced during generation and use it in heating or industrial purposes). Suppliers cannot average a customer's request for renewable energy with that of other customers who do not choose renewable energy in order to meet the minimum requirement.[56]

Notes

1. Me. Rev. Stat. Ann. Public Utilities 35-A, §3202 (West 2000).

2. *Id.* at §3202.4 as amended by LD 2403 (Act Regarding Electric Metering and Billing Competition, enacted Mar. 30, 2000).

3. Maine PUC, "Everybody's Power Handbook." <www.pucfact.com/handbk.html>

4. Me. Rev. Stat. Ann. Public Utilities 35-A, §3203 (West 2000).

5. Maine PUC, Electric Utility Rules Ch. 305 §2.B.

6. Maine Public Advocate Office Electricity Shopping Guide, "Shopping for Electricity: Advice from Public Advocate Stephen Ward" (Vol. 2, Mar. 2000).

7. Maine PUC, Dockets 97-596, 97-580 (Mar. 26, 2001).

8. Me. Rev. Stat. Ann. Public Utilities 35-A, §3212 (West 2000).

9. *Id.*

10. Maine PUC, "How Standard Offer Service Works in Maine" (Sep. 19, 2000). <janus.state.me.us/mpuc/Electric%20Supplier/stoffer.htm>

11. Maine PUC, Notice of Rulemaking (June 15, 2000); Maine PUC News Release (Nov. 29, 1999).

12. Maine PUC, Order Adopting Rule and Statement of Factual Policy Basis, Amendments to Standard Offer Service Rule (Ch. 301) (Aug. 16, 2000).

13. Maine PUC, "Results of Standard Offer Deliberations." <janus.state.me.us/mpuc/RFB2000/standard_offer_delibs.htm>

14. "Maine PUC Rejects Bangor Hydro's Proposed Rate Decrease." *Electric Power Daily* (Aug. 15, 2001).

15. Me. Rev. Stat. Ann. Public Utilities 35-A, §3208 (2000).

16. Because the suppliers of standard offer service in Maine are not the incumbent distribution utilities or their affiliates, effectively all customers have switched suppliers.

17. Maine PUC, Electric Utility Rules Ch. 322 §7.A.

18. *Id.* at Ch. 305 §4.C.

19. Maine PUC, "UPDATE on Business Consumer Protection" (Spring 2000). <janus.state.me.us/mpuc/electric%20restructuring/update_bus_cons_prot.htm>

20. Maine PUC, "Everybody's Power Handbook." <www.pucfact.com/handbk.html>

21. Maine PUC, Electric Utility Rules Ch. 314 §1.

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23. *Id.* at §4.

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27. *Id.* at §3207.

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41. Comments of the Maine Public Utilities Commission, Federal Trade Commission Retail Electricity Study (Mar. 27, 2001).

42. Maine PUC, Electric Utility Rules Ch. 306 §2.B.

43. *Id.* at §2.E.

44. Maine PUC, "UPDATE on Business Consumer Protection" (Spring 2000). <janus.state.me.us/mpuc/electric%20restructuring/update_bus_cons_prot.htm>

45. Maine PUC, Electric Utility Rules Ch. 306 §2.E.

46. "Maine PUC Orders SOS Disclosure to Customers." *Electric Power Daily* (Sep. 5, 2001).

47. Maine PUC, Electric Utility Rules Ch. 306 §2.F.

48. Comments of the Maine Public Utilities Commission, Federal Trade Commission Retail Electricity Study (Mar. 27, 2001).

49. Maine PUC, Electric Utility Rules Ch. 305 §4.E.

50. *Id.* at §4.I.

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52. Maine PUC, Electric Utility Rules Ch. 306 §2.D.

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Maryland: Overview of Retail Competition Plan and Market Response

Administrator and Start Date

The Maryland Electric Customer Choice and Competition Act (SB 300) was signed April 8, 1999. The Act allowed for a three-year phase-in approach to electric competition, but the Maryland Public Services Commission (PSC) allowed the utilities to start electric competition for all customers on July 1, 2000. The PSC will oversee the opening of the electric market to consumer choice. After the implementation of customer choice, the PSC will no longer regulate generation, supply, and sale of electricity except for setting standard offer prices and reviewing transfers of generation assets.[1]

Services Open to Competition

Generation and billing. Competitive metering begins January 1, 2002 for large customers and April 1, 2002 for all customers.[2]

Consumer Options

Customers may choose to remain with the distribution utility at PSC regulated prices; they may choose a competitive supplier; or they may choose to be aggregated with other customers.

Alternative Suppliers Licensed to Provide Service

All alternative suppliers must be licensed by the PSC, and must show proof of technical and managerial competence, compliance with FERC requirements, and compliance with state and federal environmental laws.[3] A supplier must also give proof of financial integrity.[4] The PSC will assess each competitive supplier's application for a license on a case-by-case basis to determine whether a letter of guarantee, bond, or letter of credit is needed, and in what amount.[5]

Although there are a wide range of licensed suppliers in the four services territories of the investor-owned utilities operating in Maryland, the actual number of alternative suppliers providing services to customers ranges from none to three for residential customers (depending on their location) and up to a maximum of five for industrial customers.

Table 1. Number of Alternative Suppliers Currently Serving Enrolled Customers

Utility Distribution Area	Sep-00	Oct-00	Nov-00	Dec-00	Jan-01	Feb-01	Mar-01	Apr-01	May-01	Jun-01	Jul-01
Residential Customers											
Allegheny Power	0	0	0	0	0	0	0	0	0	0	0
Baltimore Gas and Electric	0	0	1	1	1	1	1	1	1	1	1
Conectiv Power Delivery	0	0	0	0	0	0	0	0	0	0	0
Potomac Electric Power	1	1	2	2	2	2	2	2	3	3	3
Non-Residential Customers											
Allegheny Power	1	2	2	2	2	2	2	2	2	2	2
Baltimore Gas and Electric	1	3	3	4	4	4	4	4	4	4	4
Conectiv Power Delivery	3	3	5	5	5	5	5	3	3	3	3
Potomac Electric Power	2	4	5	5	5	5	5	5	4	4	2

Source: Maryland Public Service Commission

Pricing Trends

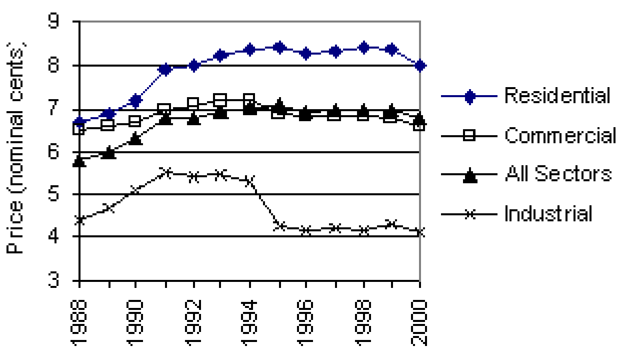
As Table 2 shows, residential retail prices rose throughout the early 1990's, before holding steady at approximately 8.3 to 8.4 cents per kWh. Commercial prices also rose through the early 1990's and after dropping between 1994 and 1995, have held steady at approximately 7 cents per kWh. Industrial prices rose during the late 1980's, reached a plateau during the early 1990's, only to drop between 1994 and 1995 to levels lower than those in 1988. Industrial prices have remained constant since that time at approximately 4 cents per kWh. All sectors saw a decrease in prices between 1999 and 2000.

Table 2. Average Annual Price per kWh by Sector (nominal cents)

	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
Residential	6.7	6.9	7.2	7.9	8.0	8.2	8.4	8.4	8.3	8.3	8.4	8.4	8.0
Commercial	6.5	6.6	6.7	7.0	7.1	7.2	7.2	6.9	6.8	6.9	6.8	6.8	6.6
Industrial	4.4	4.7	5.1	5.5	5.4	5.5	5.3	4.2	4.2	4.2	4.1	4.3	4.1
All Sectors	5.8	6.0	6.3	6.8	6.8	7.0	7.0	7.1	7.0	7.0	7.0	7.0	6.8

Source: Energy Information Administration

Figure 1. Average Annual Price Per KWh by Sector



Price Changes for Standard Offer (or Regulated) Service

Individual distribution utility plans vary, but there will be a cap for all distribution utilities on total rates for at least four years, and distribution utilities must decrease rates 3-7.5% from June 30, 1999 levels for at least four years.[6] If the distribution utility's standard offer price increases, transition charges will decrease by a corresponding amount, so that standard offer customers do not have an overall price increase.[7]

- Allegheny Power residential customers will receive a 7% base rate reduction, as well as capped rates from January 1, 2002 through December 30, 2008. Non-residential customers will have capped rates only from January 1, 2002, through December 31, 2004 and will have a collective revenue reduction of $1.5 million annually through December 31, 2008[8]

- Baltimore Gas & Electric (BGE) residential customers will receive a 6.5% rate reduction and rates frozen for 6 years. Non-residential customers' delivery service rates will be frozen for 4 years.[9]

- Delmarva Power & Light (DPL) (now Conectiv) residential customers will receive a 7.5% rate reduction, and a rate cap until June 30, 2004. Non-residential rates will be capped until June 30, 2003.[10]

- Potomac Electric Power Company (PEPCO) residential customers will receive a 3% rate and the rate will be capped until June 30, 2003.[11] Residential customers are receiving the equivalent of at least an additional 3.9% rate reduction through credits resulting from generation divestiture. Additional rate reductions are also possible through the sharing mechanism for generation procured to provide Standard Offer Service (SOS).

Standard Offer Service Provider

The distribution utility will provide standard offer service until at least 2003 for customers who do not switch electricity suppliers, for customers who cannot choose a supplier, for customers who choose standard offer service, and for customers whose suppliers default on service. A distribution utility can procure the electricity for its standard offer service customers from any supplier, including an affiliate. Individual utility settlements require the utility to be the standard offer service provider for the entire ratecap/freeze period (which varies in length per utility) unless the Commission orders otherwise. Standard offer rates and the respective terms were set in the individual utility settlements and are in effect for the entire ratecap/freeze period.

Table 3. Residential and Industrial Shopping Credit Rates (in cents/kWh):

Date	Allegheny		BGE		DPL (Conectiv)		PEPCO	
	Res.	Ind.	Res.	Ind.	Res.	Ind.	Res.	Ind.
2000-2001	4.34	3.58	4.11	4.11	4.92	4.8028	4.99	4.7
2001-2002	4.47	3.67	4.22	N/A	4.92	4.8066	4.99	4.7
2002-2003	4.47	3.67	4.33	N/A	4.92	4.8103	4.99	4.7
2003-2004	4.47	3.67	N/A	N/A	4.92	N/A	4.99	4.7

Source: PSC, Maryland Electric Customer Choice FAQ <www.psc.state.md.us/psc/electric/FAQ/overall.htm>

Recovery of Stranded Costs/Transition Costs

Distribution utilities will be given a fair opportunity to recover all "prudently incurred and verifiable" net transition costs, subject to full mitigation.[12] Transition costs eligible for recovery include those that would be recoverable under rate-of-return regulation, but are not recoverable in a restructured electric market and costs that result from the creation of customer choice.[13] Stranded costs will be recovered through a competitive transition charge, and may be recovered over different lengths of time for each distribution utility. The PSC will determine the amount of recoverable transition costs, as well as the amount of the charge to be levied to customers. Distribution utilities may also apply to the PSC to recover some or all transition costs through transition bonds. The BGE settlement provided for an annual true-up of transition charges for non-residential customers.

Not all distribution utilities are implementing a transition charge:[14]

- Allegheny Power has no transition charge for any customers.

- BGE's residential customers will pay a 0.8 cents/kWh charge in the first year, and decreasing rates over the next 5 years. The charge for the final year, from June 2005 to May 2006, will be0.264cents/kWh.

Non-residential customers will pay rates which range from 0.100 cents/kWh to 1.500 cents/kWh over the same 6 year period. Non-residential BGE customers have options for the length of time they pay the transition charge, and they also may choose to make a lump sum payment instead of the transition charge.

- DPL has no charge for its residential class, although $8 million will be collected from non-residential classes over three years.

- PEPCO, which has divested its generation assets voluntarily, is currently disbursing $188.6 million in divestiture sharing credits to its Maryland distribution customers. Additional sharing credits are the subject of current litigation.

Customer Switching and Eligibility

Most customers are eligible to choose their electric supplier as of July 1, 2000. Some electric cooperative customers will be able to choose an electric supplier in 2001; Choptank and Southern Maryland cooperative customers will be able to choose by July 1, 2001 in accordance with their restructuring settlements. Municipal utilities may decide whether or not they want to participate.[15]

Switching Process

***Sign-up Method*:** A customer can contract to change electric suppliers (1) in writing, which requires a signature; (2) by phone, which requires a follow-up mailing; or (3) on the Internet, which requires proof of identity. After a customer has reached an agreement with the competitive supplier, the supplier must send to the customer information which includes notice of enrollment, a description of billing options, the due date and mailing address for payments, information about customer service and the dispute process, and a notice of the customer's 10-day cancellation right.

***Right of Rescission*:** A customer has 10 days to cancel his switch to a competitive supplier if he changes his mind.

***Restrictions and Minimum Stay Requirements*:** A customer may switch to a new supplier at any time, subject to the regulations of his contract with his current supplier. A customer may also return to standard offer service at any time, although customers who voluntarily return to standard offer service may have to remain with the distribution utility for a certain period of time, to prevent gaming.[16] Minimum stay requirements have been adopted as a part of the restructuring orders for AP, BGE and PEPCO. DPL has a 6 month minimum stay. BGE customers who leave standard offer service and voluntarily return are subject to a minimum stay of one year or the remaining time that BGE offers the standard offer service, whichever is less. PEPCO customers who return to standard offer service of their own initiative will have to remain on that service for one year or until PEPCO stops offering standard offer service, whichever is less.[17]

Switching Activity

***Residential Sector*:** Most of the distribution utilities have seen little or no switching activity by their residential customers as Table 4 shows. The only distribution utility with an appreciable number of residential customers switching has been PEPCO, which has divested its generation assets. PEPCO has seen an increasing number of switches since September 2000. Even for PEPCO, however, the number of customers and load switching as a percentage of the customer base has been small, with less than 10% of residential customers and load switching.

Table 4. Residential Customers

Number of Customers Served by Alternative Suppliers											
Utility	**Sep-00**	**Oct-00**	**Nov-00**	**Dec-00**	**Jan-01**	**Feb-01**	**Mar-01**	**Apr-01**	**May-01**	**Jun-01**	**Jul-01**
Allegheny Power	-	-	-	-	-	-	-	-	-	-	-
Baltimore Gas and Electric	-	-	2	5	13	15	21	21	21	19	17
Conectiv Power Delivery	-	-	-	-	-	-	-	-	-	-	-
Potomac Electric Power	360	3,044	6,599	10,687	10,960	12,179	17,682	24,657	31,654	39,052	42,526
Total	**360**	**3,044**	**6,601**	**10,692**	**10,973**	**12,194**	**17,703**	**24,678**	**31,675**	**39,071**	**42,543**

% of Customers Served by Alternative Suppliers											
Utility	**Sep-00**	**Oct-00**	**Nov-00**	**Dec-00**	**Jan-01**	**Feb-01**	**Mar-01**	**Apr-01**	**May-01**	**Jun-01**	**Jul-01**
Allegheny Power	-	-	-	-	-	-	-	-	-	-	-
Baltimore Gas and Electric	-	-	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Conectiv Power Delivery	-	-	-	-	-	-	-	-	-	-	-
Potomac Electric Power	0.1%	0.7%	1.5%	2.4%	2.5%	2.8%	4.0%	5.6%	7.2%	8.9%	9.6%
Total	**0.0%**	**0.2%**	**0.4%**	**0.6%**	**0.6%**	**0.7%**	**1.0%**	**1.3%**	**1.7%**	**2.1%**	**2.3%**

% of Total Load served by Alternative Suppliers											
Utility	**Sep-00**	**Oct-00**	**Nov-00**	**Dec-00**	**Jan-01**	**Feb-01**	**Mar-01**	**Apr-01**	**May-01**	**Jun-01**	**Jul-01**
Allegheny Power	-	-	-	-	-	-	-	-	-	-	-
Baltimore Gas and Electric	-	-	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Conectiv Power Delivery	-	-	-	-	-	-	-	-	-	-	-
Potomac Electric Power	0.0%	0.1%	1.1%	2.4%	2.8%	2.8%	3.1%	4.4%	6.6%	8.2%	10.5%
Total	**0.0%**	**0.0%**	**0.3%**	**0.7%**	**0.7%**	**0.7%**	**0.8%**	**1.2%**	**1.8%**	**2.1%**	**2.7%**

Source: Maryland Public Service Commission

***Non-residential Sector*:** None of the distribution utilities have seen a great number of their non-residential customers switching to alternative suppliers. Initially the numbers of customers switching grew every month, but since December 2000, this number has held steady or declined slightly for all of the distribution utilities, with the exception of PEPCO, which has seen its customers continue to switch to other suppliers. This pattern of customer switches is also reflected in the percentage of customers switching, as well as percent of load switched. Although non-residential customers in Maryland face a greater variety of suppliers from which to choose than residential customers, as with residential customers, non-residential customers making the switch comprise only a small portion of the distribution utilities' customer and load base.

Table 5. Non-Residential Customers

Number of Customers Served by Alternative Suppliers											
Utility	**Sep-00**	**Oct-00**	**Nov-00**	**Dec-00**	**Jan-01**	**Feb-01**	**Mar-01**	**Apr-01**	**May-01**	**Jun-01**	**Jul-01**
Allegheny Power	23	31	36	38	38	38	38	38	38	12	2
Baltimore Gas and Electric	108	118	163	392	392	389	388	386	382	293	277
Conectiv Power Delivery	19	19	30	38	38	25	25	20	7	6	6
Potomac Electric Power	12	12	1,983	2,037	2,044	2,296	2,980	3,170	3,457	3,751	5,540
Total	**162**	**180**	**2,212**	**2,505**	**2,512**	**2,748**	**3,431**	**3,614**	**3,974**	**4,062**	**5,825**

% of Customers Served by Alternative Suppliers											
Utility	**Sep-00**	**Oct-00**	**Nov-00**	**Dec-00**	**Jan-01**	**Feb-01**	**Mar-01**	**Apr-01**	**May-01**	**Jun-01**	**Jul-01**
Allegheny Power	0.1%	0.1%	0.1%	0.2%	0.2%	0.1%	0.1%	0.1%	0.1%	0.0%	0.0%
Baltimore Gas and Electric	0.1%	0.1%	0.1%	0.3%	0.3%	0.3%	0.3%	0.3%	0.3%	0.3%	0.2%
Conectiv Power Delivery	0.1%	0.1%	0.1%	0.2%	0.2%	0.1%	0.1%	0.1%	0.0%	0.0%	0.0%
Potomac Electric Power	0.0%	0.0%	4.3%	4.4%	4.4%	5.0%	6.5%	6.9%	7.6%	8.1%	11.9%
Total	**0.1%**	**0.1%**	**1.1%**	**1.2%**	**1.2%**	**1.3%**	**1.6%**	**1.7%**	**1.9%**	**1.9%**	**2.8%**

% of Total Load served by Alternative Suppliers											
Utility	**Sep-00**	**Oct-00**	**Nov-00**	**Dec-00**	**Jan-01**	**Feb-01**	**Mar-01**	**Apr-01**	**May-01**	**Jun-01**	**Jul-01**
Allegheny Power	0.2%	0.3%	0.4%	0.4%	0.5%	0.4%	0.5%	0.4%	0.3%	0.1%	0.0%
Baltimore Gas and Electric	0.3%	0.4%	0.5%	1.1%	1.0%	1.0%	1.0%	1.0%	1.0%	0.7%	1.2%
Conectiv Power Delivery	1.8%	1.8%	3.5%	4.9%	4.9%	2.6%	2.6%	0.7%	0.4%	0.4%	0.4%
Potomac Electric Power	3.4%	3.4%	4.2%	9.5%	11.9%	11.9%	12.8%	19.0%	21.7%	22.1%	23.3%
Total	**1.2%**	**1.2%**	**1.6%**	**3.3%**	**3.9%**	**3.7%**	**3.9%**	**5.1%**	**5.6%**	**5.4%**	**5.9%**

Source: Maryland Public Service Commission

Public Benefits Programs

Funds for a Universal Service Program will be collected from all customers, and may not be assessed on a per kilowatt-hour basis.[18]

Low-income: The Universal Service Program will aid customers at or below 150% of the poverty level, providing bill assistance, weatherization assistance, and helping to pay past unpaid bills.[19] For the first three years, the fund will collect $34 million per year; for the fourth year and each year thereafter, the amount of the fund will be determined by the PSC subject to approval by the legislature.[20] The residential charge for universal service will be approximately 41 cents per month. Non-residential customers will pay a charge based on the amount of their total electric bill; charges range from $.41 to 4,500 per month.[21]

Renewables: Distribution utilities will continue to provide at least the same percentage of electricity from renewable energy resources.[22] There will also be a per kilowatt-hour environmental surcharge, which will be collected until June 30, 2005. The amount of the environmental surcharge cannot exceed the lesser of 0.15 mill/kWh or $1,000 per month.[23]

Separation of Generation and Transmission

Divestiture of generation assets was not required, but functional, operational, structural or legal separation of regulated and non-regulated businesses or non-regulated affiliates was required by July 1, 2000.[24] Distribution utilities must provide a code of conduct to prevent their regulated service customers from subsidizing services of unregulated businesses.[25] A distribution utility can transfer any of its generation facilities or assets to an affiliate, if it desires.[26] Power generation affiliates can only sell power on the wholesale market, except for standard offer service suppliers. Retail sales affiliates may only buy power from the wholesale market.

- Allegheny Power and Baltimore Gas & Electric transferred their generation assets to affiliates as of July 1, 2000.
- Delmarva Power & Light is divesting some of its generation assets to a third party, the remainder was transferred to an affiliate as of July 1, 2000.
- PEPCO has divested most of its generation assets to a third party.[27]

State RTO Involvement

The interstate transmission grid in Maryland is controlled by PJM Interconnection, an independent system operator (ISO) that includes Pennsylvania, New Jersey, Maryland, Delaware, the District of Columbia, and parts of Virginia. PJM is responsible for the operation of the region's wholesale electric market, ensuring that there are enough generation supplies to meet the region's electric demand.

New Plant Construction and Planning

Since 1997, PJM has received proposed construction plans for 5,000 MW of generation to be installed by 2002.[28] According to the Maryland Public Service Commission's Ten-Year Plan (2000-2009), there are seven generating facilities under review for construction in Maryland that would add nearly 2,800 MW of additional generation capacity between 2001 and early 2003.

Slamming/Cramming Rules

Slamming is prohibited. The PSC requires a signature on all mailed, newspaper and door-to-door contracts. All competitive suppliers who contract using the internet must ensure that the contracts are made by the persons claiming to make them. Telephone contracts are only allowed if all contract terms and conditions are disclosed to the customer over the phone, if the customer's contract agreement is verified by an independent third party, if the customer receives a complete written contract two days from the initial agreement with the supplier, and if the consumer has a 10 day right of rescission from the date of the receipt of the written contract.[29]

Customer Billing

A customer will either receive a consolidated bill from either the supplier or the distribution utility, or two separate bills, one from the supplier, and one from the distribution utility.[30]

Affiliate Name and Logo Issues

Affiliates must pay royalties for the use of the common name and logo. An affiliate must also use a disclaimer stating that the affiliate is not the same company as the distribution utility, and that its products and services are not regulated by the PSC. All joint marketing, promotions, and advertising are prohibited.[31]

Usage of Customer Information

Customer information cannot be released without a customer's consent, except for bill collection and credit rating purposes.[32] Customer lists containing names, addresses, and telephone numbers of customers may be sold to competitive suppliers. If a distribution utility intends to release such a list, it must inform its customers, and advise customers of their opportunity to prevent disclosure of their identifying information.[33]

Standardized Labeling

***Content*:** Distribution utilities and competitive suppliers must provide customers with a uniform set of information on fuel mix and emissions. When actual data is unavailable, a regional average may be used. Once the information is available, labels have to include comparison of emissions and fuel mix to the regional average.[34]

***Timing*:** Labels must be provided to customers every six months.[35]

Advertising Restrictions

Marketing advertisements must include, in a clear and conspicuous position, and in plain and easy to understand language, precise rates for services offered, and must state that the rate shown is for generation services only and that the total electric rate will be higher. If an offer compares the competitive supplier's price to the rate the customer will pay for standard offer service, this rate must be based on the official "price-to-compare" (i.e. the price per kWh for a typical heating and non-heating customer in a distribution utility service territory). Advertisements must also include the time of day the advertised rate will be in effect, the minimum contract duration necessary to obtain the advertised rate, any fees and charges, and the supplier's Maryland license number. Solicitations must include all of the information required for marketing advertisements, as well as the terms and conditions of the contract, including description of service, unit price (if this is not a flat rate, it must be on a cents/kWh basis), a notice that generation service, and not transmission and distribution service, is being offered, and the duration of the agreement.[36] These marketing and solicitation disclosures apply only to residential customers, although if suppliers market to industrial and commercial customers in general media they must make clear that the offer is only for such customers.[37]

Consumer Education

The PSC began a $6 million consumer education program in April 2000 to educate customers about electric retail choice. This program is to continue for 3 years but will be funded at $3 million for years 2 and 3. Each distribution utility also must inform its customers about changes in the electric industry. Competitive suppliers must provide adequate and accurate information to consumers.[38]

Other Consumer Protection Measures

Competitive suppliers must provide a notice in their marketing materials that they are licensed to provide service in Maryland. If a customer requests to be taken off of a telemarketer's list, the telemarketer cannot call that customer again.[39]

Retail Choice in Gas Sales

As of February 2000, over 95% of residential customers may choose their natural gas supplier. All commercial and industrial customers may choose their supplier. Statewide, 17.9% of eligible residential customers bought their gas from a supplier as of June, 2001.[40]

Notes

1. Md. Code Ann., Pub. Util. Comp., §7-509 (2000).

2. *Id.* at §7-511.

3. *Id.* at §7-507.b.

4. *Id.* at §7-507.c.

5. PSC Supplier Authorization Procedures (Mar. 17, 2000).

6. Md. Code Ann., Pub. Util. Comp., §7-505.d (2000).

7. PSC, Maryland Electric Choice FAQ. <www.psc.state.md.us/psc/electric/FAQ/overall.htm>

8. PSC, Introduction to Allegheny Power Compliance Plan. <www.psc.state.md.us/psc/electric/ComplianceFilings/Allegheny.htm>

9. PSC, BGE Compliance Plan. <www.psc.state.md.us/psc/electric/ComplianceFilings/BGE.htm>

10. PSC, Utility and Customer Group FAQs. <www.psc.state.md.us/electric/utilityquestions.htm>

11. PSC, PEPCO Amendment to Proposed Settlement Agreement and Phase II Settlement Agreement, <www.psc.state.md.us/psc/home.htm>.

12. Md. Code Ann., Pub. Util. Comp., §7-513 (2000).

13. *Id.* at §7-501.p.

14. PSC, Maryland Electric Customer Choice FAQ. <www.psc.state.md.us/psc/electric/FAQ/overall.htm>

15. PSC, A Consumer Guide to Electric Choice. <www.md-electric-info.com/pdf/md-consumerguide.pdf>

16. PSC, A Consumer Guide to Electric Choice. <www.md-electric-info.com/pdf/md-consumerguide.pdf>

17. PSC Order 75949 (Aug. 24, 2000).

18. Md. Code Ann., Pub. Util. Comp., §7-512.1 (2000).

19. PSC, A Consumer Guide to Electric Choice <www.md-electric-info.com/pdf/md-consumerguide.pdf>.

20. Md. Code Ann., Pub. Util. Comp., §7-512.1 (2000).

21. PSC, Maryland Electric Customer Choice FAQ <www.psc.state.md.us/psc/electric/FAQ/overall.htm>.

22. Md. Code Ann., Pub. Util. Comp., §7-516 (2000).

23. *Id.* at §7-203.

24. *Id.* at §7-505.b(10).

25. *Id.* at §7-505.b(13).

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28. PJM Interconnection, 1997-2006 PJM Transmission Adequacy Assessment <http://www.pjm.com/transmission/trans_exp_plan/downloads/assessment.pdf>.

29. PSC Order 75949 (Aug. 24, 2000).

30. PSC, A Consumer Guide To Electric Choice <www.md-electric-info.com/pdf/md-consumerguide.pdf>.

31. PSC Order 76292 (July 1, 2000).

32. Md. Code Ann., Pub. Util. Comp., §7-505.b (2000).

33. PSC Order 76110 (Apr. 25, 2000).

34. PSC Order 76241. See section below on advertising restrictions for supplier requirements to disclose pricing information to customers.

35. Md. Code Ann., Pub. Util. Comp., §7-505.b (2000).

36. PSC Order 75949 (Aug. 24, 2000).

37. PSC Order 76110 (Apr. 25, 2000).

38. Md. Code Ann., Pub. Util. Comp., §7-505.f (2000).

39. PSC, A Consumer Guide to Electric Choice <www.md-electric-info.com/pdf/md-consumerguide.pdf>.

40. PSC, Gas Choice Enrollment Report <www.psc.state.md.us/psc/gas/gasenrollmentrpt.htm>.

Massachusetts: Overview of Retail Competition Plan and Market Response

Administrator and Start Date

Electricity Restructuring in Massachusetts was initiated and is administered by the Department of Telecommunications and Energy (DTE). Retail competition began March 1, 1998, in accordance with the restructuring legislation enacted November 25, 1997.

Services Open to Competition

Generation only. Metering and billing are provided by the distribution utility. The 1998 law required that DTE examine opening metering, billing, and information services to competition. In January 2001, DTE recommended that metering and billing not be opened to competition yet, as customers would not receive any substantial savings. After wholesale and retail markets are more mature, particularly after February 2005, the DTE may decide to introduce competitive metering. The DTE is also looking into encouraging advanced metering options for distribution companies.[1]

Consumer Options

Consumers may choose from among standard offer service, default service, service through an aggregator, or service from a competitive supplier. Standard offer service will be provided until 2005 for consumers who have not chosen a competitive power supplier. At this time, customers who have not chosen a competitive supplier will automatically receive default service from the utility. Massachusetts differentiates between standard offer service and default service. In most cases, a customer who leaves standard offer service cannot return. There are limited exceptions, however, including customers who qualify for low-income rates, who can return to standard office service at any time, and customers who choose aggregator service, who have 180 days from the time they join the aggregator to switch back to standard offer service. All customers are eligible for default service at any time, and may remain on default service indefinitely. Default service is provided by the distribution utility to customers who are not receiving power from any of the other three options, for whatever reason. By choosing aggregator service, the customer becomes a member of a group in order to get bulk discounts on electricity. Aggregators serve homes, businesses, and entire communities.

Alternative Suppliers Licensed to Provide Service

All competitive suppliers must be licensed to provide service to customers in Massachusetts.[2] Licensing regulations require a supplier to show technical and financial capability.[3] Massachusetts does not maintain information on the number of suppliers actually providing service to customers.

Pricing Trends

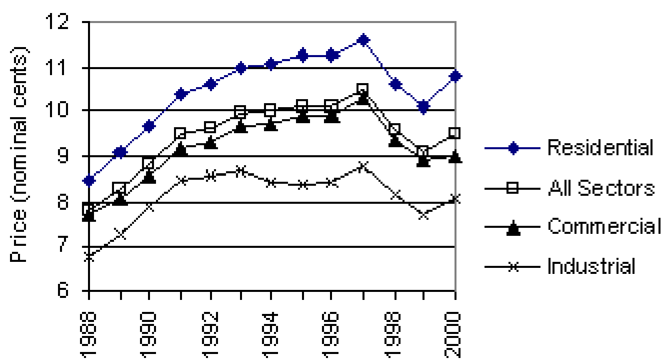
As Table 1 shows, prices for the residential and commercial sectors rose between 1988 and 1997, then declined between 1997 and 1999, in light of the mandatory retail rate reductions. Prices for the industrial sectors rose throughout the first part of the decade, then held steady until 1997, when they began to fall.

Table 1. Average Annual Price per KWh by Sector (nominal cents)

	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
Residential	8.5	9.1	9.7	10.4	10.6	11.0	11.1	11.3	11.3	11.6	10.6	10.1	10.8
Commercial	7.7	8.1	8.6	9.2	9.3	9.7	9.8	9.9	9.9	10.3	9.4	8.9	9.0
Industrial	6.8	7.3	7.9	8.5	8.6	8.7	8.5	8.4	8.4	8.8	8.2	7.7	8.1
All Sectors	7.8	8.3	8.8	9.5	9.7	10.0	10.0	10.1	10.1	10.5	9.6	9.1	9.5

Source: Energy Information Administration

Figure 1. Average Annual Price Per KWh by Sector



Price Changes for Standard Offer (or Regulated) Service

Massachusetts set a minimum 10% reduction of the entire bill for all customers receiving standard offer service. On September 1, 1999, the reduction increased to at least 15% to adjust for inflation. These standard rate reductions apply to all distribution utilities.[4] Distribution utilities are authorized to use securitization to meet the second rate reduction effective September 1, 1999.[5]

Standard Offer Service Provider

- Standard offer service will be provided until 2005 for customers who have not chosen a competitive supplier. It will be offered by the distribution utility, at rates which are set in advance and which will increase until 2005, when standard offer service will cease.[6]

- Default service will be offered to customers who are not receiving standard offer service or service from a competitive supplier or aggregator, and to standard offer customers after 2005. The price for default service is variable and changes based on the market price for electricity. Distribution companies must procure electricity for default generation service through competitive bidding, although the DTE also may authorize a competitive supplier to supply default service.[7]

In 2000, the DTE ordered default service rates to be decoupled from standard offer rates, and directed distribution utilities to offer a fixed-price, six month default service. This service will be obtained by bids in the wholesale market. Although residential customers on default service will automatically receive this fixed rate, they also have the option to choose a month-to-month variable price for default service. Commercial and industrial customers will receive the month-to-month variable price. New default service prices, which are higher than standard offer rates, were effective January 1, 2001.

Table 2. Shopping Credit Rates for Standard Offer Service (residential rates in cents/kWh)

Date	Boston Edison	Cambridge Electric	Commonwealth Electric	Fitchburg Gas & Electric	Massachusetts Electric	Western Mass Electric
1998	3.2	2.8	2.8	2.8	3.2	2.8
1999	3.69	3.5	3.5	3.5	3.707	3.1
2000	4.5	3.8	3.8	3.8	3.8	4.557
Jan.-Jun. 2001	6.215	5.121	5.121	5.121	5.401	7.258
Jul.-Dec. 2001	7.445	6.351	6.351	6.351	6.631	7.258

Source: DTE

Table 3. Default Service Pricing (fixed rates in cents/kWh):

Company	Time Period	Residential	Commercial	Industrial
Boston Edison	January-June 2001	7.032	7.032	7.032
	July-December 2001	8.743	9.035	8.664
Cambridge	January-June 2001	6.671	6.671	6.671
	July-December 2001	8.333	8.622	8.23
Commonwealth	January-June 2001	6.985	6.985	6.985
	July-December 2001	8.651	8.956	8.511
Fitchburg	January-May 2001	8.013	7.981	7.723
	June-December 2001	9.128	9.113	8.787
Massachusetts	Dec. 2000-April 2001	6.37	6.493	5.36
	May-October 2001	9.213	9.556	9.054
Western Mass.	February-June 2001	7.938	7.908	7.834
	July-December 2001	8.53	8.55	8.41
	January-June 2002	7.57	7.57	7.63

Source: DTE

Recovery of Stranded Costs/Transition Costs

The restructuring legislation provided for the recovery of stranded costs through a non-bypassable charge to all customers.[8] This charge will be capped by the DTE, and the DTE will determine, on a case-by-case basis, the time period for recovery.[9] Stranded costs eligible for recovery include generation-related assets, nuclear shutdown and decommissioning assets, regulatory assets, and purchased power contracts. DTE may also include certain employee costs, although employee costs can only be recovered through 2005.[10] In order to recover transition costs, the distribution utility was required to divest all non-nuclear generation assets by August 1, 1999, as well as develop a plan to mitigate stranded costs to the greatest extent possible.[11] The DTE will review and reconcile transition costs by March 1, 2000, and not less than every 18 months thereafter.[12] At the end of each year, each distribution utility submits a filing to the DTE reporting the reconciliation of its annual revenue and costs, as well as providing the standard offer service rates and transition charges for the upcoming year. Transition charges were adjusted in 1999.[13] Securitization of stranded costs is allowed.

Transition/Stranded Costs

Initial statewide stranded costs totaled approximately $9.7 billion.[14]

Table 4. Stranded Costs

Company	Total Stranded Costs	Net Stranded Cost
Boston Edison	$3,234,079	$2,706,781
Cambridge Electric	$189,854	$143,913
Commonwealth Electric	$1,256,204	$931,386
Massachusetts Electric	$3,389,251	$1,440,595
Eastern Edison	$591,207	$530,165
FG & E	$91,327	$74,960
Western Mass. Electric	$967,809	$788,332

Note: Net Stranded Cost is the amount of the Total Stranded Costs reduced by the value of divestitures.
Source: DOER 1998 Market Monitor, September 1999

Customer Switching and Eligibility

All customers of Massachusetts distribution utilities were eligible for retail access as of March 1, 1998.[15] Certain non-profit, community-owned municipal utilities are exempt from most provisions of the Commonwealth's restructuring law.[16]

Switching Process

***Sign-up Method*:** The supplier must first receive authorization from the customer to switch service, either through a letter of authorization, third-party telephone verification, or the completion of a toll-free telephone call initiated by the customer. After receiving customer authorization, the supplier must send an information disclosure packet to the customer, which describes the terms of the contract, and the fuel mix and environmental characteristics of the generation portfolio. If the customer does not choose to terminate his choice, the supplier initiates generation service by contacting the distribution utility and informing it that the supplier will provide generation service on the next meter read date.[17]

Right of Rescission: After the customer receives the information disclosure packet from the supplier, he has three days in which he can decide to terminate his choice of supplier without penalty.[18]

Switching Activity

***Residential Sector*:** The number of residential customer switches has been negligible. The vast majority of residential customers have remained with their distribution utilities, and after more than two years of customer choice, less than 1% of residential customers and load have switched to alternative suppliers.

Table 5. Residential Sector

Number of Customers Served by Alternative Suppliers

Apr-99	Jul-99	Oct-99	Jan-00	Apr-00	Jul-00	Oct-00	Jan-01	Apr-01	Jul-01
1,278	1,831	1,854	1,944	2,041	2,439	2,793	3,028	1,017	1057

% of Customers Served by Alternative Suppliers

Apr-99	Jul-99	Oct-99	Jan-00	Apr-00	Jul-00	Oct-00	Jan-01	Apr-01	Jul-01
< 1%	<1%	< 1%	<1%	< 1%	<1%	< 1%	<1%	< 1%	<1%

% of Total Load served by Alternative Suppliers

Apr-99	Jul-99	Oct-99	Jan-00	Apr-00	Jul-00	Oct-00	Jan-01	Apr-01	Jul-01
< 1%	<1%	< 1%	<1%	< 1%	< 1%	< 1%	<1%	< 1%	<1%

Source: Massachusetts Division of Energy Resources

***Commercial Sector*:** The number of commercial customers served by alternative suppliers also has been very small. As with residential customers, the number of commercial customers and load served by alternative suppliers has been only a small portion of the total commercial customer and load base, with about 5% or less of customers and load switching.

Table 6. Commercial Customers

Number of Customers Served by Alternative Suppliers

Customer Class	Apr-99	Jul-99	Oct-99	Jan-00	Apr-00	Jul-00	Oct-00	Jan-01	Apr-01	Jul-01
Small	2,647	3,836	3,917	4,240	2,394	1,412	1,401	1,417	765	876
Medium	868	1,461	1,505	1,796	1,422	748	702	773	569	462

% of Customers Served by Alternative Suppliers

Customer Class	Apr-99	Jul-99	Oct-99	Jan-00	Apr-00	Jul-00	Oct-00	Jan-01	Apr-01	Jul-01
Small	1.2%	1.6%	1.7%	1.8%	1.0%	0.6%	0.6%	0.6%	0.3%	0.4%
Medium	1.7%	3.0%	3.0%	3.7%	2.8%	1.6%	1.5%	1.6%	1.2%	1.0%

% of Total Load served by Alternative Suppliers

Customer Class	Apr-99	Jul-99	Oct-99	Jan-00	Apr-00	Jul-00	Oct-00	Jan-01	Apr-01	Jul-01
Small	1.1%	1.7%	1.9%	3.1%	1.1%	0.6%	0.6%	0.6%	0.3%	0.4%
Medium	2.6%	4.3%	4.5%	5.1%	3.6%	2.0%	2.1%	2.1%	1.8%	1.5%

Note: Massachusetts does not distinguish between commercial and industrial customers, but divides all non-residential customers into three categories: small, medium, and large. For purposes of this report, commercial customers are considered to be small and medium non-residential customers, where small non-residential customers are customers with average monthly usage of less than or equal to 3,000 kWh and medium non-residential customers are customers with average monthly usage of greater than 3,000 kWh but less than or equal to 120,000 kWh.
Source: Massachusetts Division of Energy Resources

***Industrial Sector*:** The number of industrial customers switching to competitive suppliers increased until the end of 1999, when they began to decline. By July 2001, the number of customers served by alternative suppliers had dropped to levels similar to those in April 1999. The changes in the number of customers switched has also been reflected in the percentage of customer and load switched. Industrial customers making the switch comprised a larger portion of the customer base than was the case in the residential and commercial sectors, ranging from approximately 5% to 13% of total industrial customers, and between 9% to 20% of total industrial load.

Table 7. Industrial Customers

Number of Customers Served by Alternative Suppliers									
Apr-99	Jul-99	Oct-99	Jan-00	Apr-00	Jul-00	Oct-00	Jan-01	Apr-01	Jul-01
387	640	666	668	573	423	439	448	333	427

% of Customers Served by Alternative Suppliers									
Apr-99	Jul-99	Oct-99	Jan-00	Apr-00	Jul-00	Oct-00	Jan-01	Apr-01	Jul-01
7.5%	12.9%	11.8%	13.2%	9.9%	7.7%	7.2%	7.8%	5.5%	6.7%

% of Total Load served by Alternative Suppliers									
Apr-99	Jul-99	Oct-99	Jan-00	Apr-00	Jul-00	Oct-00	Jan-01	Apr-01	Jul-01
9.6%	22.2%	20.0%	24.9%	18.3%	14.8%	12.4%	15.4%	9.1%	12.3%

Note: The industrial sector represent customers which Massachusetts places in the "large commercial and industrial" customer class, and consists of commercial and industrial customers with average monthly usage of greater than 120,000 kWh.
Source: Massachusetts Division of Energy Resources

Public Benefits Programs

***Low-income*:** Low income customers are allowed to switch back to standard offer service at any time.[19] In addition to the 10% bill-reduction, low income customers receive an additional 25-35% discount on their bill. The cost of discount rates to low income customers will be included in the rates charged to all other distribution utility customers.[20]

***Renewables*:** Massachusetts has established a renewable energy fund, financed via a system benefits charge, paid by customers of distribution utilities. This fund will be used to create initiatives to promote the use, availability and affordability of renewable energy. The fund for renewable energy projects will be collected beginning March 1998; this charge will vary until 2003 when it will be set at one-half of one mill per kWh.[21]

***Energy Efficiency*:** For five years beginning March 1998, distribution utilities have to collect a per kilowatt-hour charge from all customers to fund energy efficiency activities. The charge will begin at 3.3 mills in 1998 and decrease to 2.5 mills in 2002.[22]

Separation of Generation and Transmission

The Massachusetts restructuring law required distribution utilities to divest their generation facilities, either by sale or by transfer to an affiliated company.[23] If a distribution utility opted to transfer its generation assets to an affiliate, the two companies had to be strictly separated,[24] and distribution utilities will not be permitted to sell electricity at retail except to provide their customers with standard offer service.[25] Each of the distribution companies divested their assets to only one company.

Wholesale Electricity Purchasing and Pricing

On May 1, 1999, the New England ISO implemented a wholesale hourly energy market and new ancillary services markets. The Independent System Operator of New England (ISO-NE) manages the wholesale market, under contract with the New England Power Pool. The new wholesale market is based on bid prices in a spot market. In 1999, only approximately 8-15% of the daily system load in New England was sold through the new spot market. The rest was sold through bilateral contracts between suppliers and entities serving retail customers.

State RTO Involvement

Massachusetts is a member of the Independent System Operator of New England. Established in 1997, ISO-NE is responsible for managing energy markets and operating the transmission system in New England.[26]

New Plant Construction and Planning

Developers in New England announced plans to build over 30,000 MW of new generation capacity. Most of these proposed plants will use natural gas and other low emission fuels.[27] In 1999, 730 MW of new generation capacity were added in New England, with an additional 1,250 MW expected in 2000.[28] According to Energy Information Administration data, suppliers in Massachusetts have planned 5,648 MW of generation capacity additions between 2000 and 2004.[29]

Slamming/Cramming Rules

A supplier may not switch a customer without a customer's prior authorization, either in the form of the customer's written consent (i.e. "Letter of Authorization") or a customer oral statement to an independent third party.[30]

If it is determined that a customer was switched without his consent, the supplier must refund the difference between what the customer would have paid his previous supplier and the charges he paid to the supplier who switched his service. The supplier must also refund any reasonable expenses the consumer had to pay in switching back to his previous supplier, as well as refund to the previous supplier the revenue the previous supplier would have received from the customer if he had not been switched. In addition, the switching supplier will be subject to civil penalties, and may be prohibited from selling electricity for up to one year.[31]

Customer Billing

All customer bills must show unbundled rates. A customer will either receive one bill from the distribution utility for all electric charges, or two bills, one from the distribution utility for distribution-related charges, and one from the generation supplier for generation charges.[32] In accordance with its December 9, 2000 report on the investigation of metering, meter maintenance and testing, customer billing and information services,[33] the DTE opened a proceeding on May 9, 2001 to investigate offering consumers the option of receiving a single bill from the alternative generation supplier.[34]

Affiliate Name and Logo Issues

An affiliate may use a distribution utility's name and logo if it uses a disclaimer which notifies the customer that the affiliate is not the same as the regulated distribution utility and assures him that he does not have to buy from the affiliate to continue to receive quality services. Additionally, a distribution utility cannot give any appearance of speaking on behalf of the affiliate, cannot engage in joint advertising or marketing programs, or market any product or service offered by the affiliate.[35]

Usage of Customer Information

The distribution utility cannot release proprietary customer information to the affiliate without written consent of the customer. Historical usage information will be provided to a supplier who has received customer authorization to initiate service.[36]

Standardized Labeling

In May 1998, Massachusetts began a consumer education program showing the labels that disclose the price of electricity, generation sources, and air emission contents. Beginning in September 1998 a standardized disclosure label was required for both competitive power suppliers and for distribution companies providing standard offer or default service.

***Contents*:** The disclosure label must include average price or price variability information, a description of the power sources used in generation, air emissions characteristics, labor practices characteristics, and a toll-free number for customer service.[37] Competitive suppliers must also prepare a terms of service statement which includes information on pricing, contract, and billing procedures.[38]

***Timing*:** Disclosure labels and terms of service must be provided to the customer before commencing service and then provided quarterly once service has started. They must also be provided upon the request of a customer.[39]

Advertising Restrictions

All advertisements have to comply with state and federal advertising regulations. On printed or Internet materials, the electricity rate to be charged must be shown in bold print. In television or radio announcements, the rate must be stated in clear and deliberate speech. In any written marketing materials, there must be a prominent statement that a retail customer may obtain an information disclosure label upon request. Non-print media must also indicate clearly that a retail customer may obtain an information disclosure label upon request. Suppliers who do not comply with these regulations or who provide inaccurate information may be subject to license suspension, revocation or non-renewal.[40]

Consumer Education

The Division of Energy Resources will undertake measures to ensure consumer education about their rights and choices under electricity restructuring and to provide customers with a reliable basis for the comparison of products and services so they can make informed choices about their electric service.[41]

Retail Choice in Gas Sales

Gas distribution companies have offered non-residential customers a choice of suppliers since 1993. Massachusetts has partially implemented comprehensive unbundling programs for its residential gas customers, and there are several residential pilot programs underway.[42]

Notes

1. D.T.E., 00-41 Legislative Report (Dec. 29, 2000).

2. Mass. Gen. Law ch. 164, §1F(1) (2001).

3. Mass. Regs. Code tit. 220, §11.05(2) (2001).

4. Mass. Gen. Law ch. 164, §1B(b) (2001).

5. *Id.* at §1G(c)(2).

6. *Id.* at §1B(b).

7. *Id.* at §1B(d).

8. *Id.* at §1G(a).

9. *Id.* at §1G(e).

10. *Id.* at §1G(b).

11. *Id.* at §1G(c).

12. *Id.* at §1A(a).

13. Massachusetts Division of Energy Resources (DOER), Market Monitor 1999 (Feb. 2001).

14. DOER, 1998 Market Monitor (Sep. 1999).

15. Mass. Gen. Law ch. 164, §1A (2001).

16. "The Power is Yours!", Massachusetts Department of Energy Resources Consumer Information Site, "Changes to the Industry." <www.state.ma.us/ thepower/ text_version/ change.htm>

17. Electric Restructuring in Massachusetts, Summary. <www.state.ma.us/ dpu/ restruct/ competition/ index.htm#BACKGROUND>

18. Mass. Regs. Code tit. 220, §11.04 (4)(d) (2001).

19. Mass. Gen. Law ch. 164, §1F(4)(iii) (2001).

20. *Id.* at §1F(4)(i).

21. Mass. Gen. Law ch. 25A, §11F (2001).

22. Mass. Gen. Law ch. 25, §19 (2001).

23. Mass. Gen. Law ch. 164, §1A(b)(2) (2001).

24. *Id.* at §1A(c).

25. *Id.* at §1A(b)(1).

26. Comments of the Maine Public Advocate, Federal Trade Commission Retail Electricity Study (Apr. 10, 2001).

27. DOER, 1998 Market Monitor: Electric Industry Restructuring, Executive Summary (Sep.1999).

28. DOER, Market Monitor 1999 (Feb. 2001).

29. Energy Information Administration, Inventory of Nonutility Electric Power Plants in the United States, 1999, Table 6. Energy Information Administration, Inventory of Electric Utility Power Plants in the United States, Table 22.

30. Mass. Gen. Law ch. 164, §1F(8)(a) (2001), *see also* regulations at Mass. Regs. Code tit. 220, §11.04 (4) (2001).

31. Mass. Gen. Law ch. 164, §1F(8)(c) (2001); *see also* Mass. Regs. Code tit. 220, §11.07(3)(b, c) (2001).

32. Mass. Gen. Law ch. 164, §1D (2001).

33. D.T.E., Docket No. 00-41 Legislative Report (Dec. 29, 2000).

34. D.T.E., Docket No. 01-28 (Phase II) (May 9, 2001).

35. Mass. Regs. Code tit. 220, §12.03 (2001).

36. *Id.* at §11.04(12).

37. *Id.* at §11.06(2)

38. *Id.* at §11.06(3).

39. *Id.* at §11.06(4).

40. *Id.* at §11.06(6).

41. Mass. Gen. Law ch. 25A, §11D.

42. Energy Information Administration, Retail Unbundling - Massachusetts. <www.eia.doe.gov/ oil_gas/ natural_gas/ restructure/ state/ ma.html>

Michigan: Overview of Retail Competition Plan and Market Response

Administrator and Start Date

In January 1998, the Michigan Public Service Commission (PSC) issued orders to complete action on a basic framework for electricity restructuring in Michigan. In April 1998, Consumers Energy (CE) and Detroit Edison (DE), Michigan's two largest utilities filed restructuring plans to implement retail competition. In March 1999, the PSC adopted the implementation plans, which provided for 2.5% of CE and DE customers to choose their electric supplier by September 1999, with four additional 2.5% blocks of customers thereafter until January 1, 2002, when all customers will be able to choose their electric supplier.

In June 1999, the Michigan Supreme Court ruled that the PSC did not have the authority to mandate restructuring. DE and CE, however, voluntarily decided to abide by the PSC restructuring plans to implement customer choice. The Customer Choice and Reliability Act (PA 141) (the Act) for electric restructuring in Michigan was enacted on June 3, 2000.[1] All of the PSC's previous orders relating to restructuring are in compliance with the Act, and are enforceable, including the orders which confirmed DE and CE's commitments to voluntarily implement customer choice.[2]

Services Open to Competition

Generation only.

Consumer Options

There are currently four retail competition program providing for customer choice in Michigan. They are intended as trials or transitions until full retail access is provided on January 1, 2002. The Consumers Energy Direct Access (DA) Program and the Detroit Edison Experimental Retail Access Program (ERAP) were the first electric choice programs in Michigan, serving 135 MW and 90 MW of load, respectively. Although there are still customers receiving power from competitive suppliers under these programs, new customers who wish to participate in electric choice must participate under one of the following two programs:[3]

(1) Detroit Edison Electric Choice Program (ECP): ECP was established by the Act and subsequent PSC orders. It provides for a phase-in period, during which 1125 MW (12.5% of DE's peak load) is the maximum amount of load to be served by competitive suppliers. Capacity allocations were awarded through a bid process, in which parties bid for the amount of a transition charge (per kWh) they were willing to pay through December 31, 2001 toward the recovery of stranded costs. There were 5 bid cycles of 225 MW each.

(2) Consumers Energy Electric Customer Choice Program (ECC): ECC is similar to DE's ECP. During the phase-in period, 750 MW (12.5% of CE's peak load) is available for customer choice. Capacity allocations were made in a similar bid process to DE's, also with 5 bid cycles.

Alternative Suppliers Licensed to Provide Service

All suppliers who wish to serve Michigan customers must receive certification from the PSC. Certification includes the determination that the supplier is financially capable. The PSC may require a supplier to post a bond or letter of credit or other financial guarantee of not less than $40,000 if it decides this is in the public interest.[4] As of February 2001, when the MPSC's most recent annual report was published, only three of the ten licensed suppliers in Michigan were serving retail customers.[5] Because retail competition is not yet fully implemented, these statistics may not be representative of long-term trends.

Pricing Trends

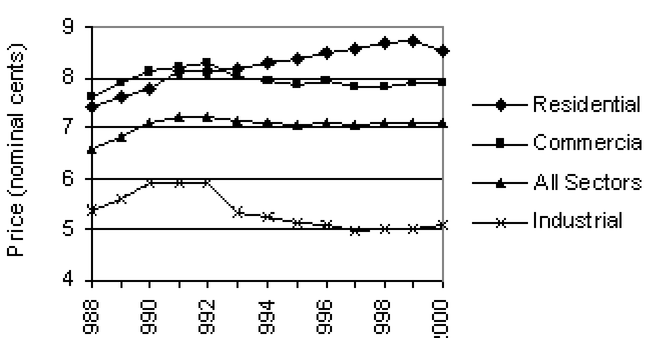
As shown in Table 1, prices in the industrial and commercial sectors rose between 1988 and 1992, only to begin declining after 1992. Prices fell the most between 1992 and 1993. Commercial prices have held steady since 1993, while industrial prices continued to decline until 1997. Residential prices rose throughout the past decade. Commercial prices were higher than residential prices between 1988 and 1992, but fell below residential prices beginning in 1993.

Table 1. Average Annual Price per KWh by Sector (nominal cents)

	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
Residential	7.4	7.6	7.8	8.1	8.1	8.2	8.3	8.3	8.5	8.6	8.7	8.7	8.5
Commercial	7.6	7.9	8.1	8.2	8.3	8.0	7.9	7.9	7.9	7.8	7.8	7.9	7.9
Industrial	5.4	5.6	5.9	5.9	5.9	5.3	5.3	5.1	5.1	5.0	5.0	5	5.1
All Sectors	6.6	6.8	7.1	7.2	7.2	7.1	7.1	7.1	7.1	7.0	7.1	7.1	7.1

Source: Energy Information Administration

Figure 1. Average Annual Price Per KWh by Sector



Price Changes for Standard Offer (or Regulated) Service

All residential customers of DE and CE received a 5% rate reduction on June 5, 2001, which will remain in place until December 31, 2003. After December 31, 2003, rates will not be increased until either December 31, 2013 or until the PSC determines that the distribution utility controls less than 30 percent of a particular market (market power test)[6] and has expanded available transmission capacity by 2,000 MW over such capacity in place as of January 1, 2000,[7] whichever is earlier.

Standard Offer Service Provider

Customers who return to distribution utility service or who do not choose a supplier will receive service from the distribution utility at the rates determined by the PSC, as before restructuring. These rates are subject to the 5% rate reduction described above, and will be capped until December 31, 2013 or until the PSC determines that the distribution utility meets the market test and has completed transmission expansions, whichever is earlier.[8] The distribution utility will also provide electric generation standby service for open access customers until December 31, 2001, or until the date described above, whichever is later. The pricing for this service will be determined by the PSC using market indices.[9]

Recovery of Stranded Costs/Transition Costs

Distribution utilities are allowed full recovery of net stranded costs and implementation costs as determined by the PSC.[10] The PSC may use various methods to determine stranded costs, including evaluating the relationship of the market value to the net book value of generation assets and purchased power contracts, and evaluating the net stranded costs based on the market price of power in relation to prices assumed by the PSC in prior orders. The PSC will undertake an annual review and true-up of stranded cost charges.[11] A transition charge, made up of stranded costs and implementation costs, will be added to the bill of a customer who chooses a competitive supplier.[12] The MPSC established a bidding process for the rights to open retail access, under which the participants (customers, aggregators and suppliers) submitted bids reflecting the amount in cents per kWh they were willing to pay towards competitive transition charges. This bidding process allowed customers to actively participate in a market-based mechanism for setting the transition charge (see discussion of the bidding process in the Customer Switching section below). Beginning January 1, 2002, the MPSC will set a uniform transition charge for each distribution utility.[13]

A utility may also apply to recover certain qualified costs (*i.e.*, regulatory assets, adjusted by investment tax credits, plus costs the distribution utility would be unlikely to recover in a competitive market, including retail open access implementation costs) through a securitization bond. These costs can be recovered over a period not exceeding 15 years.[14]

Customer Switching and Eligibility

Currently customer participation in electric retail choice is only available to customers of DE and CE, through a bidding process. All customers will be eligible to choose their retail supplier as of January 1, 2002. Utilities other than DE and CE are expected to formulate proposals to submit to the PSC to implement customer choice for their customers no later than 2002.

Bidding Process:[15]

Participants: Customers who wished to participate in retail open access prior to January 1, 2001, were selected through bidding process. Anyone could participate in the bidding process, but the minimum capacity to be bid was 1 MW; this is the minimum load that can be dispatched on the Michigan transmission system. Large customers (greater than 1 MW demand) could participate directly in the bidding process, while smaller customers could participate by establishing a relationship with a competitive supplier who bid on their behalf. Smaller customers could also join an aggregator in order to meet the bid minimum.

Bidding: Participants in the bidding process submitted bids reflecting the amount in cents per kWh they were willing to pay towards competitive transition charges. The highest bidders were awarded capacity until all available capacity was awarded. In order to ensure that smaller customers had an opportunity to participate, the PSC set aside a portion of each bidding cycle for aggregators of small customers. In Detroit Edison's territory, 6 MW was set aside, and 4 MW was set aside in Consumers Energy's territory.

Cooperatives are not required to allow customer choice in their territory until January 1, 2005, although customers with load greater than 1 MW should have the opportunity to choose a supplier by January 1, 2002.[16] The governing body of municipal utilities will decide whether its customers will have retail choice, and it has jurisdiction over rates, stranded costs and terms and conditions of a customer choice program.[17]

Switching Process

***Restrictions and Minimum Stay Requirements*:** Currently there are no restrictions on switching suppliers, except as provided for in the terms and conditions of a customers contract with the competitive supplier. A customer can return to his distribution utility at any time, in accordance with the terms of service of his supplier, but he has to remain with the distribution utility for at least 12 months. The distribution utility may charge a PSC approved fee to switch a customer from one supplier to another.[18]

Public Benefits Programs

***Low-income and Energy Efficiency*:** If securitization savings are greater than the amount needed for the 5% rate reductions, then for 6 years, all of the excess savings, up to 2% of the distribution utility's commercial and industrial revenues will be allocated to the low-income and energy efficiency fund.[19] This provision is expected to produce a fund of approximately $50 million annually.

***Renewables*:** The PSC will establish a program for consumer information on renewable energy sources, to promote their use and to encourage the development of new renewables facilities.[20]

Separation of Generation and Transmission

Michigan distribution utilities are not required to sell plants. They are allowed to maintain the generating plants needed to serve firm retail load and a reasonable reserve margin.[21] If the PSC determines that a distribution utility has control of 30% or more of the capacity available to serve a relevant market, the distribution utility must either divest part of its generation capacity; sell its generation capacity under contract to a non-retail purchaser for a term of at least 5 years; or transfer its generation capacity to an independent brokering trustee, that has no affiliation to the distribution utility and has complete control over marketing, pricing, and terms of capacity, for a term of at least 5 years.[22]

A distribution utility or competitive supplier that provides both regulated and unregulated services must do so through structural or functional separation. A distribution utility must offer unregulated services through an affiliate or division, which must be entirely separate from the business of the regulated distribution utility.[23]

State RTO Involvement

Each investor owned distribution utility must either join a FERC-approved, multi-state independent transmission organization or divest its interest in its transmission facilities.[24] There is not currently a single ISO covering the entire Midwest region.[25]

New Plant Construction and Planning

Since the Act was enacted, four new plants have begun construction. There are 16 plants that are currently in the construction or planning stages, expected to provide well over 8,000 MW capacity by 2004.[26] According to Energy Information Administration data, suppliers in Michigan have planned 3,579 MW of generation capacity additions between 2000 and 2004.[27]

Slamming/Cramming Rules

A customer cannot be switched to a supplier without his express consent.[28] A competitive supplier that switches a customer without his consent is subject to penalties including fines which range from $20,000 for the first offense up to $70,000 for a second and any subsequent offenses knowingly made in violation of the switching regulations. Other penalties for slamming include the refund to the customer of any charges in excess of what the customer would have paid his authorized supplier, reimbursement of the authorized supplier of the amount that it should have been paid, and refund to the customer of charges for any unauthorized services. In addition, a portion between 10% to 50% of the fine will be paid directly to the customer, and the supplier is subject to possible revocation of its license to provide service. Competitive suppliers will not be subject to penalties for unintentional and bona fide (e.g., clerical, calculation, computer malfunction, programming or printing) errors.[29]

Customer Billing

No later than one year after the Act is passed, distribution utilities must file plans with the PSC to unbundle their industrial and commercial rate schedules. The PSC may also order distribution utilities to unbundle residential rates, although residential rates may be expressed in terms of percentages.[30] Billing will be done either by the supplier or by the local distribution company.[31]

Affiliate Name and Logo Issues

Distribution utilities and their affiliates cannot engage in joint advertising, marketing, or other promotional activities. The distribution utility cannot give the appearance of speaking on behalf of its affiliate, nor can the affiliate give the appearance of speaking on behalf of its distribution utility.[32] An affiliate of a distribution utility may not use its logo without providing a disclaimer, in a clearly visible and readable position, which states that the affiliate and its services are not regulated by the MPSC.[33]

Usage of Customer Information

Customer specific information cannot be provided to any entity without written customer approval. This information cannot be provided to affiliates unless it is also offered at the same time, in the same manner, to all competitors.[34]

Standardized Labeling

Suppliers will have to provide customers with standardized information beginning January 1, 2002:[35]

***Content*:** Suppliers will provide information on average fuel mix, average emissions, and average high level nuclear waste of the electricity products purchased by a consumer. Suppliers will also have to provide the regional average fuel mix and emissions profile.

***Timing*:** This information will be provided no more than twice annually, and will be included on the customer's bill with a bill insert, on customer contracts, or, for cooperatives, in periodicals issued by an association of rural electric cooperatives.

Consumer Education

The Act provides for the PSC to set up a fund for carrying out a consumer education program to inform customers of the changes in the provision in electric service, inform customers of alternative supplier requirements, and help customers make informed choices about electric service.[36] The consumer education program is proposed to begin in the third quarter of 2001 and to be funded through a small charge to all customers.[37]

Retail Choice in Gas Sales

The Michigan PSC has approved pilot programs to allow for customer choice in Michigan for natural gas customers. On October 13, 2000, the PSC adopted terms and conditions for providing permanent natural gas customer choice programs.[38]

Notes

1. Energy Information Administration, Status of State Electric Industry Restructuring <www.eia.doe.gov/cneaf/electricity/chg_str/regmap.html>; MPSC History of Electric Restructuring in Michigan <cis.state.mi.us/mpsc/electric/restruct/history.htm>.

2. Mich. Comp. Laws §460.10a.5 (2001).

3. MPSC, "Status of Electric Competition in Michigan" (Feb. 1, 2001).

4. Mich. Comp. Laws §460.10q (2001).

5. MPSC, "Status of Electric Competition in Michigan" (Feb. 1, 2001).

6. The market power test is a determination of whether a distribution utility controls less than 30% of a particular market. *See id.* at §460.10f (2001).

7. *See Id.* at §460.10v (2001).

8. *Id.* at §460.10a.12 (2001).

9. *Id.* at §460.10b.4,5 (2001).

10. *Id.* at §460.10a.1 (2001).

11. *Id.* at §460.10a.9,10 (2001).

12. MPSC Frequently Asked Questions about Michigan Electric Utility Restructuring. <cis.state.mi.us/mpsc/electric/restruct/faq/faq.htm>

13. Comments of the Michigan Public Service Commission, Federal Trade Commission Retail Electricity Study (April 13, 2001).

14. Mich. Comp. Laws §460.10h-k (2001).

15. MPSC Frequently Asked Questions about Michigan Electric Utility Restructuring. <cis.state.mi.us/mpsc/electric/restruct/faq/faq.htm>

16. Mich. Comp. Laws §460.10x (2001).

17. *Id.* at §460.10y (2001).

18. MPSC Frequently Asked Questions about Michigan Electric Utility Restructuring. <cis.state.mi.us/mpsc/electric/restruct/faq/faq.htm>

19. Mich. Comp. Laws §460.10d.6 (2001).

20. *Id.* at §460.10r.6 (2001).

21. MPSC, "Status of Electric Competition in Michigan" (Feb. 1, 2001).

22. Mich. Comp. Laws §460.10f.1 (2001).

23. MPSC, Code of Conduct §II (Dec. 4, 2000).

24. Mich. Comp. Laws §460.10w (2001).

25. MPSC, "Status of Electric Competition in Michigan" (Feb. 1, 2001).

26. *Id*.

27. Energy Information Administration, Inventory of Nonutility Electric Power Plants in the United States, 1999, Table 6. Energy Information Administration, Inventory of Electric Utility Power Plants in the United States, Table 22.

28. Mich. Comp. Laws §460.10a.3 (2001).

29. *Id*. at §460.10c.3 (2001).

30. *Id*. at §460.10b.2 (2001).

31. MPSC Frequently Asked Questions about Michigan Electric Utility Restructuring. <cis.state.mi.us/mpsc/electric/restruct/faq/faq.htm>

32. MPSC, Code of Conduct §II.H (Dec. 4, 2000).

33. *Id*. at §II.K,L (Dec. 4, 2000).

34. *Id*. at §II.A,B (Dec. 4, 2000).

35. Mich. Comp. Laws §460.10r.3,4 (2001).

36. *Id*. at §460.10r.2 (2001).

37. Comments of the Michigan Public Service Commission, Federal Trade Commission Retail Electricity Study (April 13, 2001).

38. MPSC <cis.state.mi.us/mpsc/gas/choice.htm>; MPSC Order No. U-12550 (Oct. 13, 2000).

New Jersey: Overview of Retail Competition Plan and Market Response

Administrator and Start Date

The New Jersey Electric Discount and Energy Competition Act (the Act) provided for retail choice to begin August 1, 1999, but the New Jersey Board of Public Utilities (BPU) delayed the start date to November 14, 1999 to give utilities more time to modify their computer systems to interact with competitive retail suppliers in order to ease customer switching.

Services Open to Competition

Generation only. One year after the start of competition, the BPU may examine whether to open up additional customer services, such as metering and billing.[1]

Alternative Suppliers Licensed to Provide Service

New Jersey licensing standards provide that before receiving licensure, new suppliers must show financial integrity and maintain a surety bond of $250,000 for an initial license. For a renewed license, suppliers will have to maintain a bond at a level determined by the BPU.[2] Competitive suppliers must renew their licenses annually.[3] New Jersey does not maintain information on the number of suppliers actually providing service to customers.

Pricing Trends

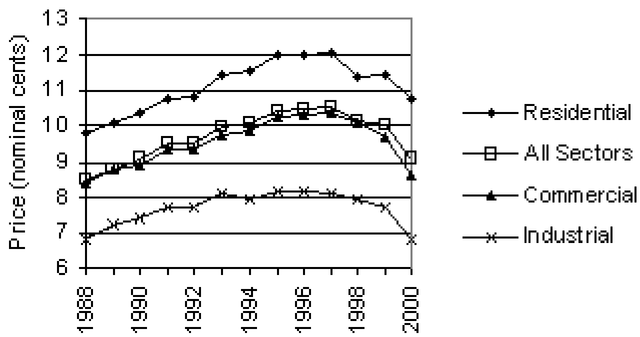
As Table 1 shows, prices in all three sectors rose throughout the early part of the decade, reaching their peak in 1997. While prices have fallen since then, they are still higher (in nominal terms) than average prices in 1988, with the exception of industrial prices, which, at 6.8 cents per KWh, were the same in 1988 as in 2000.

Table 1. Average Annual Price per kWh by Sector (nominal cents)

	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
Residential	9.8	10.1	10.4	10.8	10.9	11.4	11.5	12.0	12.0	12.1	11.4	11.4	10.8
Commercial	8.4	8.8	8.9	9.3	9.3	9.7	9.8	10.2	10.3	10.4	10.1	9.7	8.6
Industrial	6.8	7.2	7.4	7.7	7.7	8.1	7.9	8.2	8.2	8.1	7.9	7.7	6.8
All Sectors	8.5	8.8	9.1	9.5	9.5	10.0	10.1	10.4	10.5	10.5	10.2	10	9.1

Source: Energy Information Administration

Figure 1. Average Annual Price Per KWh by Sector



Price Changes for Standard Offer (or Regulated) Service

All customer classes were granted an initial 5% rate reduction with an additional reduction of at least 5% over the next three years. This entails a reduction of at least 10% from April 1997 levels. The price reductions were from the distribution portion of the customer's bill, so that even those customers that switched to a new supplier obtained the price reductions. Price reductions must be maintained for 4 years after the start of competition.[4]

Standard Offer Service Provider

Generation service will be provided by the distribution company for three years following the opening of retail competition.[5] Through standard offer service, all customer classes are eligible for basic generation service.[6] Non-residential customers who return to standard offer service are generally required to remain with that service for one year.[7] Electricity supply for standard offer service will be purchased at market prices and the charges to customers will be regulated by the BPU, based on the cost to the distribution utility of providing the service.[8] For the four-year transition period from August 1, 1999 through July 31, 2003, the price for standard offer service was pre-set, and decreases slightly over the transition period.[9] No later than three years after the beginning of competition, the BPU must decide whether to allow competitive suppliers to provide standard offer service.[10]

Beginning August 1, 2002, some distribution utilities are required to bid-out provider of last resort service. The BPU has not yet determined the procedures and parameters of the bid-out.[11] Electricity for standard offer service may be bought from public utility holding company affiliates, if this is required for reasons of reliability or other extraordinary reasons. If power is bought from the affiliate, purchase prices may not exceed market prices or must be procured under competitive bid, and net revenues have to be used to offset market transition charges or distribution rates.[12] Distribution utilities that have divested their generation assets are procuring generation for standard offer service through a combination of spot market purchases, bilateral contracts, and buy-back contracts, as well as non-utility generation contract commitments. More than 98% of all customers are receiving standard offer service.[13]

Table 2. Shopping Credit Rates
(average of all customer class rate schedules, in cents/kWh)

Date	Conectiv	GPU	PSE&G	Rockland
1999	5.65	5.14	4.95	4.46
2000	5.7	5.27	5.03	4.489
2001	5.75	5.31	5.06	4.518
2002	5.8	5.36	5.1	4.545
2003	5.85	5.4	5.1	N/A

Source: Electric Company Summary Orders/EIA Monthly Restructuring Status Update

Recovery of Stranded Costs/Transition Costs

For distribution companies to recover stranded costs, they must meet the mandatory rate reduction and show that they have taken steps to reduce stranded costs.[14] For distribution utilities that divested their generation assets, the stranded cost calculation was based on the net stranded costs after divestiture.[15] Stranded costs eligible for recovery include generation-related, purchased power contracts, and restructuring related costs.[16] The BPU will determine the recoverable amount of stranded costs, and distribution utilities will recover most stranded costs over a maximum of 8 years, through a market transition charge (MTC), although under certain conditions, the MTC term can be extended for greater than 8 years.[17] All customers will be assessed this charge, except for off-grid customers who are exempt from exit fees.

Generally, customers who have existing on-site generation facilities do not have to pay the MTC, transition bond charges, or societal benefits charges, unless they deliver power to other consumers using the distribution utility's transmission and distribution system. Customers who build new on-site generation facilities that reduce the utility's supply needs to less than 92.5% of pre-competition levels, will have to pay the charges.[18]

An electric distribution utility may also issue transition bonds to finance approved stranded costs. Consumers will be assessed a non-bypassable fixed charge to recover the costs of any transition bonds. The New Jersey restructuring legislation permits securitization of stranded costs.[19]

Table 3. Transition/Stranded Costs

Company	Allowable Stranded Cost Recovery
Conectiv	$800 million
GPU	$400 million
PSE&G	$2.9 billion, of which $2.4 billion is securitized
Rockland	$Unknown

Source: Electric Company Summary Orders/EIA Monthly Restructuring Status Update

Customer Switching and Eligibility

All customers are eligible to switch to an alternative generation supplier. Electric cooperatives and the municipal utilities are exempt from having to implement retail choice, unless they choose to serve customers outside of their franchise area.[20] Although existing public power systems are not subject to the Act, the local government entity can require a cooperative or municipal utility to implement retail choice.[21] None of the cooperatives and municipal utilities in New Jersey has implemented retail choice.

Switching Process[22]

***Sign-up Method*:** After a consumer has made the decision to switch electric suppliers, verified by a signed contract or other BPU-approved process,[23] the alternative supplier will notify the distribution company about the decision to switch. Following notification, the distribution company and generation supplier will initiate the changeover. Within 24 hours of notification, the distribution company will send the customer a confirmation letter which indicates the customer's choice of supplier and gives a date when the customer will be switched.

***Right of Rescission*:** From the date of the confirmation letter, a customer has 14 days to terminate the switch. If the customer does not respond to the confirmation letter, his electric supplier will be changed.

***Restrictions and Minimum Stay Requirements*:** Customers can switch suppliers or return to their distribution company at any time, in accordance with the terms and conditions of their service agreement with their supplier or distribution company. A customer may not be charged a fee for switching suppliers.

Switching Activity

***Residential Sector*:** The number of residential customers served by alternative suppliers has declined since December 2000 for all of the distribution utilities, with the exception of RECO, which had only two customer switches during the entire period. Despite the number of customer switches, the number of customer and load switches as a percentage of the customer and load base has been small. Conectiv, which, of the four distribution utilities, has seen the greatest percentage of customers and load switching, nevertheless only had, at the most, approximately 6% of its customers and load switch to alternative suppliers. The percentage of customer and load switching has also declined over time.

Table 4. Residential Customers

Number of Customers Served by Alternative Suppliers					
Utility	**Dec-00**	**Jan-01**	**Feb-01**	**Mar-01**	**Apr-01**
Conectiv	24,942	24,369	19,633	14,902	6,767
GPU	9,214	9,196	4,136	2,198	1,626
PSEG	32,487	31,324	31,324	26,699	26,699
RECO	2	2	2	2	2
Total	**66,645**	**64,891**	**55,095**	**43,801**	**35,094**

Table 4 (cont'd). Residential Customers

% of Customers Served by Alternative Suppliers					
Utility	**Dec-00**	**Jan-01**	**Feb-01**	**Mar-01**	**Apr-01**
Conectiv	5.7%	5.6%	4.5%	3.4%	1.5%
GPU	1.0%	1.0%	0.5%	0.2%	0.2%
PSEG	1.9%	1.8%	1.8%	1.5%	1.5%
RECO	0.0%	0.0%	0.0%	0.0%	0.0%
Total	**2.1%**	**2.1%**	**1.8%**	**1.4%**	**1.1%**

% of Total Load served by Alternative Suppliers					
Utility	**Dec-00**	**Jan-01**	**Feb-01**	**Mar-01**	**Apr-01**
Conectiv	6.0%	5.9%	4.7%	3.5%	1.5%
GPU	1.3%	1.3%	0.6%	0.3%	0.2%
PSEG	1.9%	1.7%	1.7%	1.5%	1.5%
RECO	0.0%	0.0%	0.0%	0.0%	0.0%
Total	**2.2%**	**2.1%**	**1.7%**	**1.4%**	**1.1%**

Notes:
1. GPU = General Public Utilities Corporation, PSEG = Public Service Electric & Gas Company, RECO = Rockland Electric Company.
2. Although retail choice began in November 1999, data detailing switches by sector and utility has only been available since December 2000.

Source: New Jersey Board of Public Utilities

***Non-Residential Sector*:** As with the residential sector, the number of non-residential customers served by alternative suppliers declined between December 2000 and April 2001 for all of the distribution utilities. For each distribution utility, a greater percentage of non-residential customers and load switched to alternative suppliers than was the case with residential suppliers. At the peak of switching activity, two of the distribution utilities had approximately 10% of their customers switch, most of the distribution utilities had approximately 15% or more load switching, and Conectiv had more than 25% of its load switching. But just as the number of customer switches declined between December 2000 and April 2001, so too did the percentage of customer and load switching decline.

Table 5. Non-Residential Customers

Number of Customers Served by Alternative Suppliers					
Utility	**Dec-00**	**Jan-01**	**Feb-01**	**Mar-01**	**Apr-01**
Conectiv	6,364	6,221	4,221	1,266	656
GPU	6,609	6,497	5,229	4,869	1,219
PSEG	22,241	20,377	20,377	12,133	12,133
RECO	13	13	13	12	12
Total	**35,227**	**33,108**	**29,840**	**18,280**	**14,020**

Table 5 (cont'd). Non-Residential Customers

% of Customers Served by Alternative Suppliers					
Utility	**Dec-00**	**Jan-01**	**Feb-01**	**Mar-01**	**Apr-01**
Conectiv	10.4%	10.1%	6.9%	2.1%	1.1%
GPU	6.0%	5.9%	4.8%	4.4%	1.1%
PSEG	9.6%	8.8%	8.8%	5.2%	5.2%
RECO	0.2%	0.2%	0.2%	0.1%	0.1%
Total	**8.6%**	**8.1%**	**7.3%**	**4.4%**	**3.4%**

% of Total Load served by Alternative Suppliers					
Utility	**Dec-00**	**Jan-01**	**Feb-01**	**Mar-01**	**Apr-01**
Conectiv	25.5%	21.0%	16.3%	9.7%	6.9%
GPU	16.5%	13.9%	12.1%	10.7%	5.5%
PSEG	14.8%	12.5%	12.5%	9.5%	9.5%
RECO	1.2%	1.2%	1.2%	1.2%	1.2%
Total	**16.3%**	**13.7%**	**12.6%**	**9.7%**	**8.0%**

Notes:
1. GPU = General Public Utilities Corporation, PSEG = Public Service Electric & Gas Company, RECO = Rockland Electric Company.
2. Although retail choice began in November 1999, data detailing switches by sector and utility has only been available since December 2000.

Source: New Jersey Board of Public Utilities

Public Benefits Programs

Low-income: Energy assistance programs will still provide financial assistance even if customers in these programs choose a competitive supplier. These energy assistance programs provide customers with assistance on energy bills or protection from power shut-offs because of non-payment. Costs for these programs will be recovered through the societal benefits charge, which will also cover the cost of nuclear decommissioning, cleanup of manufactured gas plant sites, demand-side management programs, and consumer education.[24]

Renewables and Energy Efficiency: The BPU has established a monthly fund, which amounts to $2 to $4 for residential customers, to finance energy efficiency, renewable energy, and energy conservation projects. The BPU approved, on March 1, 2001, $358 million, over three years, for renewable and energy efficiency programs.[25]

Separation of Generation and Transmission

The Act does not mandate divestiture, though the BPU may require a distribution utility to functionally separate its generation assets to the distribution utility's holding company or a related competitive business segment. BPU may also order divestiture to an unaffiliated entity if there are market concentration concerns.[26] Electric distribution utilities had three options: divestiture, structural separation or functional separation. Of the four major distribution utilities in New Jersey, two divested nearly all of their generation, one divested most (but not all) of its generation, and the fourth transferred its generation assets to an unregulated affiliate.[27] Electric distribution utilities are not required to purchase energy needs through the spot market or a power exchange.[28] In August 2000, PSE&G transferred approximately 10,200 MW of its electric generating facilities to PSEG Power, LLC, an unregulated power generation affiliate. The BPU approved the sale of Rockland Utility's generation assets to Southern Energy Affiliates in June 1999.[29]

State RTO Involvement

The interstate transmission grid in New Jersey is controlled by PJM Interconnection, an independent system operator (ISO) that includes Pennsylvania, New Jersey, Maryland, Delaware, the District of Columbia, and parts of Virginia. PJM is responsible for the operation of the region's wholesale electric market, ensuring that there are enough generation supplies to meet the region's electric demand.

New Plant Construction and Planning

Since 1997, PJM has received proposed construction plans for 5000 MW of generation to be installed by 2002.[30] According to Energy Information Administration data, suppliers in New Jersey have planned 3,715 MW of generation capacity additions between 2000 and 2004.[31]

Slamming/Cramming Rules

Until September 1, 2000, a customer could not be switched without his express written consent. Currently, a customer may sign up with a supplier through the mail, online, or in person. In order to prevent slamming, the distribution company must send the customer a confirmation to verify their choice of supplier. Customers have 14 days to cancel the selection of a supplier, for any reason.[32] An order for change in electric service from a licensed supplier must be an Electric Data Interchange (EDI) transaction, and it will not be considered authorized unless the customer has approved it through a signed contract or other verification. Separate verification is required for electric and gas services.[33] If a customer authorizes a switch to a new supplier, the new supplier must notify the customer of the change within 30 days.[34] If a customer is slammed, he is only required to pay what he would have paid his authorized supplier. There are severe penalties against companies that engage in slamming, including possible revocation of licensure.[35]

Customer Billing

Electric distribution utilities are required to unbundle costs for services. These costs may be re-bundled on residential customer bills, but for commercial and industrial customers, costs will be shown separately.[36] A customer can elect to receive one bill from the distribution company, one bill from the alternative supplier, or two bills, one from the distribution company and one from the supplier.[37]

Customers will receive a "shopping credit" on their electric bill. The shopping credit is also known as the "price to compare" and is the amount on a customer's bill that will be credited to the customer if he chooses an alternate supplier and does not receive basic generation service from the distribution utility.[38]

Affiliate Name and Logo Issues

An affiliate of a distribution company may use the distribution utility's name or logo as long it provides a disclaimer that indicates that the holding company or affiliate is not the same company as the distribution utility and that it is not regulated by the BPU. The disclaimer must also state that the customer does not have to buy from the affiliate in order to get reliable and quality regulated services from the distribution utility. Distribution utilities may not engage in joint advertising or marketing programs with their holding companies or affiliates.[39]

Usage of Customer Information

Neither power suppliers nor distribution companies can disclose proprietary information, including historical payment and energy usage information without the written consent of the customer. Any third party who receives such information can only use it in order to provide continued electric service to the customer.[40]

Standardized Labeling

All suppliers are required to provide an environmental label for customer review.[41]

***Content*:** The label shows which fuel sources are used for the electricity, the amount of air pollution caused by generation, and how much the supplier has supported energy efficiency measures. Suppliers who have made claims that their electricity is better for the environment are required to disclose their generation source and fuel mix in the environmental label for their product. If a supplier does not make any environmental claims, it can use a regional default label.[42] There are three types of labels:[43]

1. Default label–The default label is used by new suppliers and shows historic averages for the Pennsylvania/New Jersey/Maryland region instead of information about the specific electricity product. The default label will be replaced by an historical label after 18 months.

2. Claim label–A claim label may also be used by a new generation supplier. The claim label shows the characteristics the generation supplier intends to provide. After 12 months, the supplier must submit documentation to the BPU showing that the claim was met.

3. Historical label–An historical label must be used by existing suppliers. It shows actual data from the past 12 months.

***Timing*:** Generation suppliers are required to include this label in their marketing materials, and distribution companies will include the label in their spring and fall billing statements.

Advertising Restrictions

Advertising material must contain the average price per kWh the supplier intends to offer the customer, the projected savings, and the period of time over which the price is valid. This information must also be included in contracts. Advertising material must also show the price per kWh offered by the local distribution utility for basic generation service, which is known as the "price to compare," the license number of the competitive supplier, the service territory in which the supplier is offering the advertised prices, and whether the supplier offers budget billing. A supplier must clearly state in all marketing and advertising materials that switching to a supplier is not mandatory.[44] If a competitive supplier offers customers optional services, it must clearly state in advertising materials that these services are provided at an additional charge, which is not reflected in the cost per kilowatt-hour or the percentage savings. Additionally, all electronic, radio, and television advertisements must include a telephone number that the customer can call to request information about the average price per kilowatt-hour and the environmental characteristics of services.[45]

Consumer Education

The New Jersey restructuring law requires a comprehensive, multi-lingual consumer education program.[46] The BPU, along with state electric and gas distribution utilities, developed a consumer education program which included a statewide media campaign, as well as a local campaign administered by each distribution utility in its service territory. The consumer education program is funded via the societal benefits charge.[47]

Other Consumer Protection Measures

Customer contracts must explicitly state the terms of the contract, disclose the price per kWh for generation, separately identify prices for services other than electric and natural gas supply, and give a statement of residential customer rights.[48]

A customer must receive 30 days' notice that a supplier is going to terminate his service; additionally, the supplier must make the customer aware of the conditions under which his service may be terminated. If a customer receives gas and electric supply from the same supplier, failure of payment for one service cannot result in termination of the other service, unless this is explicitly permitted by the contract.[49]

Retail Choice in Gas Sales

Starting in 1995 and prior to electric restructuring, all commercial and industrial customers were able to choose their natural gas supplier. Beginning in January 1997, the BPU approved residential gas pilot programs. Since January 1, 2000, residential customers also have retail open access in natural gas.[50]

Miscellaneous

Beginning January 1, 2001, one-half of one percent of the electricity sold in New Jersey by each competitive supplier or basic generation service provider must come from Class I renewable resources, which include wind, solar, fuel cells, ocean energy, landfill methane, geothermal, and sustainable grown biomass. This percentage will be increased to one percent by January 1, 2006, and then increased by one-half percent each year to 4 percent by January 1, 2012.[51]

Notes

1. N.J. Stat. Ann. §48:3-54.6.a (2001)

2. BPU, Interim Licensing and Registration Standards §4.e.

3. Comments of the New Jersey Division of the Ratepayer Advocate, Federal Trade Commission Retail Electricity Study (April 3, 2001) (NJ Ratepayer Comments) at 4.

4. N.J. Stat. Ann. §48:3-52.4.d and j (2001).

5. N.J. Stat. Ann. §48:3-57.9.a (2001).

6. *Id.* at §48:3-51.3.

7. NJ Ratepayer Comments at 7.

8. N.J. Stat. Ann. §48:3-57.9.a (2001).

9. NJ Ratepayer Comments at 8.

10. N.J. Stat. Ann. §48:3-57.9.c (2001).

11. NJ Ratepayer Comments at 7.

12. N.J. Stat. Ann. §48:3-57.9.b (2001).

13. NJ Ratepayer Comments at 7.

14. N.J. Stat. Ann. §48:3-61.13.f (2001).

15. NJ Ratepayer Comments at 9.

16. N.J. Stat. Ann. §48:3-61.13.a (2001).

17. *Id.* at §48:3-61.13.i.

18. *Id.* at §48:3-61.28.

19. *Id.* at §48:3-61.14.

20. *Id.* at §48:3-88.39.b.

21. *Id.* at §48:3-88.39.a.

22. BPU Publication: New Jersey Energy Choice, Step 6–Sign Up. <www.njenergychoice.com/electric/res/step6.html>

23. Until September 1, 2000, a customer could not be switched without his express written consent. Since then, customers have also been able to sign-up online. BPU Publication: New Jersey Energy Choice,

"New Program Allows Consumers to Switch Energy Suppliers Over the Internet" (Aug. 7, 2000). <www.njenergychoice.com/press/7aug00.html>

24. N.J. Stat. Ann. §48:3-60.12.a (2001).

25. BPU, Comprehensive Resource Analysis (2001) <http://www.bpu.state.nj.us>.

26. *Id.* at §48:3-59.11.a.

27. NJ Ratepayer Comments at 9.

28. Testimony of Herbert H. Tate, President of the New Jersey Board of Utilities, Before the Senate Economic Growth, Agriculture and Tourism Committee, (Feb. 7, 2001).

29. Rockland Utilities Divestiture Approval (June 24, 1999).

30. 1997-2006 PJM Transmission Adequacy Assessment.

31. Energy Information Administration, Inventory of Nonutility Electric Power Plants in the United States, 1999, Table 6. Energy Information Administration, Inventory of Electric Utility Power Plants in the United States, Table 22.

32. New Jersey Energy Choice, "New Program Allows Consumers to Switch Energy Suppliers Over the Internet" (Aug. 07, 2000). <www.njenergychoice.com/press/7aug00.html>

33. BPU, Interim Anti-Slamming Standards (May 12, 1999).

34. N.J. Stat. Ann. §48:3-86.37.c (2001).

35. *Id.* at §48:3-86.37.e.

36. *Id.* at §48:3-52.4.a.

37. The ability of a customer to receive one bill from his alternative supplier is not yet fully implemented. *See* BPU, Amended Order Approving Stipulation with Conditions and Modifications, Docket No. EX99090676 (Dec. 22, 2000).

38. N.J. Stat. Ann. §48:3-51.3 (2001).

39. Affiliate Relations, Fair Competition and Accounting Standards and Related Reporting Requirements; N.J. Stat. Ann. §48:3-53.5.6 (2001).

40. *Id.* at §48:3-85.36.b.

41. *Id.* at §48:3-87.38.

42. NJ Ratepayer Comments at 5.

43. New Jersey Energy Choice–Step 5: How to Compare Environmental Factors and Choose Clean Power <www.njenergychoice.com/electric/res/step5.html>

44. BPU, Interim Retail Choice Consumer Protection Standards §1.4.

45. *Id.* at §1.3.

46. N.J. Stat. Ann. §48:3-85.36.d (2001).

47. NJ Ratepayer Comments at 2.

48. BPU, Interim Retail Choice Consumer Protection Standards, §1.6.b.

49. *Id.* at §1.10.

50. Energy Information Administration, Energy Unbundling – New Jersey <www.eia.doe.gov/oil_gas/natural_gas/restructure/state/nj.html>

51. N.J. Stat. Ann. §48:3-87.38.d (2001).

New York: Overview of Retail Competition Plan and Market Response

Administrator and Start Date

The New York Public Service Commission (PSC) has implemented retail choice through a series of orders and opinions. New York has no supporting restructuring legislation. Because the PSC has phased in restructuring through PSC-approved utility restructuring plans over a three year period, each utility had a different timetable to transition to retail competition based on customer usage. As of July 2001, all customers in the territories of Central Hudson Gas and Electric (Central Hudson), Consolidated Edison (ConEd), Orange and Rockland Utilities (O&R), New York State Electric and Gas (NYSE&G), Niagara Mohawk Power (Niagara), and Rochester Gas and Electric (RG&E) are eligible to choose a competitive supplier.

Services Open to Competition

Generation, metering and billing. As of June 1999, metering services were made competitive for large customers (greater than 50 kW). Distribution companies were required to file unbundled metering tariffs in October 1999 and calculate a "backout" credit for customers that choose a different meter service provider. The PSC's competitive metering and meter reading rules allow both customers who choose a competitive supplier and customers who remain with the distribution utility to choose competitive metering services. Customers who choose competitive metering services must procure both meter and meter data services competitively. Distribution utilities will continue as the providers of last resort for metering and meter data services.[1]

Alternative Suppliers Licensed to Provide Service

New York does not maintain public information on the number of suppliers actually providing service to customers.

Pricing Trends

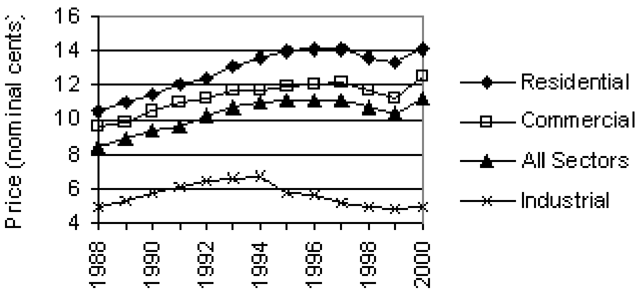
As shown in Table 1, prices in all three sectors rose throughout the first part of the decade. Retail prices in the industrial sector began declining after 1994, while prices began to decline in the commercial and residential sectors after 1997. All three sectors saw an increase in prices between 1999 and 2000, and by 2000 residential prices were approximately 14 cents per kWh, commercial prices were at 12.5 cents per KWh, and industrial prices were approximately 5 cents per kWh.

Table 1. Average Annual Price per KWh by Sector (nominal cents)

	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
Residential	10.5	10.9	11.4	12.0	12.4	13.2	13.6	13.9	14.0	14.1	13.7	13.3	14.1
Commercial	9.6	9.9	10.5	10.9	11.2	11.7	11.7	11.9	12.1	12.1	11.6	11.2	12.5
Industrial	4.9	5.3	5.8	6.2	6.5	6.7	6.8	5.8	5.6	5.2	5.0	4.8	4.9
All Sectors	8.5	8.9	9.4	9.6	10.2	10.7	10.9	11.1	11.1	11.1	10.7	10.4	11.2

Source: Energy Information Administration

Figure 1. Average Annual Price Per KWh by Sector



Price Changes for Standard Offer (or Regulated) Service

Each distribution utility's restructuring plan laid out different rate reduction plans:

- Central Hudson basic electric rates were frozen at 1993 levels through June 30, 2001, for all customers. In addition, large industrial customers who chose to remain with Central Hudson for their generation services received 5% per year rate reductions until mid-2001.

- Con Edison industrial customers received a 25% immediate rate decrease, which would remain fixed for five years. All other customers received a 10% rate decrease, phased in over five years.

- Orange and Rockland residential customers received a 4% decrease in rates during 1995 and 1996, while industrial and commercial customers received rate reductions of 4-14%. On December 1, 1997 and on December 1, 1998, residential rates were reduced an additional 1%. Large industrial customer rates were reduced by approximately 8.5% on December 1, 1997.

- Rochester Gas and Electric residential and small commercial customers received a 7.5% rate decrease. Other commercial and most industrial customers received an 8% decrease. Large industrial customers received an 11.2% decrease. All decreases are being phased in over 5 years.

- New York State Electric and Gas industrial and large commercial customers (greater than 500 kW capacity) received a 5% per year rate decrease, for five years. Residential and small commercial and industrial customers have had their rates frozen at current levels for two years, bills reduced 1% in the third year of the plan, and a total decrease of 5% by the fifth year of the plan. Industrial and commercial customers who are not eligible for the 5% decrease received financial incentives for load growth to encourage business expansion.

- Niagara Mohawk customers received an overall rate decrease of an average of 4.3%. Residential and commercial customers were to have a 3.2% decrease phased in over three years. Industrial customers were to have decreases of approximately 13%. In addition, Niagara Mohawk rates for electricity and delivery were set until September 1, 2001. In 2001 and 2002, Niagara Mohawk was allowed to request limited rate increases for distribution services, and prices for some of the electricity sold to all customers will fluctuate with changes in market prices.

Standard Offer Service Provider

The PSC is reviewing options for standard offer service. Until the PSC makes a ruling otherwise, the distribution companies will provide regulated service for customers who do not choose a competitive supplier or who return to full service from the distribution company.[2]

Recovery of Stranded Costs/Transition Costs

Distribution utilities will have a reasonable opportunity to recover stranded costs through a non-bypassable distribution charge. Distribution utilities must use creative means to reduce the amount of stranded costs before they are considered for recovery. Stranded cost calculations and timing of recovery will be determined on a case-by-case basis for each distribution utility.[3]

Customer Switching and Eligibility

All customers are eligible to choose a competitive electricity supplier, in accordance with the distribution utility phase-in plans.

Switching Process

***Sign-up Method*:** A customer who wishes to switch to a competitive supplier informs his distribution utility of his intent to switch. The competitive supplier must provide a notice to the distribution utility of requested switches at least 10 days prior to the requested switch date (either the customer's regular meter reading date or a requested special meter reading date). The distribution utility must acknowledge receipt of switch notices within 5 days. After a distribution utility receives switch notices, it will send customers a verification of their choice of electric supplier. If the competitive supplier shown in the verification letter is incorrect, or shows a switch that the customer has not authorized, the customer must contact the distribution utility to correct the error. An authorized switch will occur either on the regularly scheduled meter reading date or the special meter reading date, whichever is sooner. Most distribution utilities charge a fee for a customer to begin service on a special meter reading date.

***Restrictions and Minimum Stay Requirements*:** The PSC does not allow restrictions on frequency of customer switches, except for restrictions which may result from the notice period requirement, or are specified in customer contracts with competitive suppliers, or which may result from distribution company requirements for bundled service (i.e. service which includes generation supply). If a customer chooses to voluntarily return to generation service from his distribution utility, he may be required to remain with this service for a minimum period of time, not to exceed 12 months, though this requirement will not apply to customers who are involuntarily returned to generation service from the distribution utility. A distribution utility may not charge a customer for switching from its generation supply service, and there may be no charges for involuntary switches. Involuntary switches are those not initiated by the customer, for example if the competitive supplier goes out of business, assigns its customers to another supplier or decides to no longer serve a customer. There will be no charge for the first voluntary switch (i.e. a switch initiated by the customer) from one competitive supplier to another or a switch back to the distribution utility during the first twelve months of a customer's participation in retail access. Thereafter, a switching fee of up to $10 can be charged for all other voluntary switches. Most distribution utilities charge a switching fee of $10 for any voluntary switches after the first voluntary switch. Niagara Mohawk, however, does not currently charge for additional switches.

Switching Activity

Residential Sector: Since the end of 1999, most of the utilities have seen an increase in the number of residential customers served by alternative suppliers, although the rate of increase has not always been steady. In terms of percentages, however, not many customers have switched. Although the percentage of customers switching has risen over time, less than 4% of the total customer base had switched to alternative suppliers as of April 2001.

Table 2. Residential Sector

Number of Customers Served by Alternative Suppliers									
Utility	**Apr-99**	**Jul-99**	**Oct-99**	**Jan-00**	**Apr-00**	**Jul-00**	**Oct-00**	**Jan-01**	**Apr-01**
CHG&E	160	162	160	130	134	134	133	132	128
Con Ed	49,032	62,779	57,851	54,259	49,412	46,021	68,701	79,008	75,182
NMPC	57	195	623	4,932	34,996	33,429	47,907	44,159	42,469
NYSEG	4,539	4,398	20,136	27,013	26,711	25,999	24,973	24,150	23,225
O&R	419	0	979	4,162	5,933	9,836	12,688	13,710	22,009
RG&E	88	82	295	2,414	8,665	11,448	20,794	30,849	31,460
Total	**54,295**	**67,616**	**80,044**	**92,910**	**125,851**	**126,867**	**175,196**	**192,008**	**194,473**

% of Customers Served by Alternative Suppliers									
Utility				**Jan-00**	**Apr-00**	**Jul-00**	**Oct-00**	**Jan-01**	**Apr-01**
Total				**1.7%**	**2.3%**	**2.3%**	**3.2%**	**3.5%**	**3.5%**

Notes:

1. CHG&E = Central Hudson Gas & Electric Corp. Con Ed = Consolidated Edison Company of New York, NMPC = Niagara Mohawk Power Corp., NYSEG = New York State Electric & Gas Corp., O&R = Orange and Rockland Utilities, Inc., RG&E = Rochester Gas & Electric Corp.
2. New York reports total energy switched in a given month, but does not report total energy delivered by the distribution company in each month, therefore it is not possible to compute percent load switched.
3. While New York has reported the number of customers switching since February 1999, it has only reported the percentage of customers switching since December 1999.

Source: New York State Public Service Commission

Non-residential Sector: Most of the utilities experienced an increase in the number of non-residential customers served by alternate suppliers between April 1999 and January 2000, after which time the numbers held steady. Of the six utilities, two of them, Central Hudson Gas & Electric and Consolidated Edison, have seen declining numbers of customers served by alternative suppliers, while the other four have seen increasing numbers. In terms of percentage of customers switched, the general trend, as with residential customers, has been that of increasing percentage of customers switching. Even while increasing, however, the percentage of non-residential customers switching to alternative suppliers has remained low, ranging from 4.7% in January 2000 to 5.3% in April 2001.

Table 3. Non-Residential Sector

Number of Customers Served by Alternative Suppliers									
Utility	**Apr-99**	**Jul-99**	**Oct-99**	**Jan-00**	**Apr-00**	**Jul-00**	**Oct-00**	**Jan-01**	**Apr-01**
CHG&E	302	304	324	283	287	249	257	214	104
Con Ed	17,563	17,447	16,612	15,941	14,260	13,040	13,905	13,680	13,658
NMPC	16	32	4,449	7,925	8,765	8,705	8,549	8,767	5,587
NYSEG	911	871	2,900	4,785	5,502	5,247	5,807	5,780	8,743
O&R	1,349	96	1,829	2,324	3,885	3,398	3,888	4,178	4,451
RG&E	1,157	1,561	2,725	4,074	4,649	5,010	3,056	7,908	7,948
Total	**21,298**	**20,311**	**28,839**	**35,332**	**37,348**	**35,649**	**35,462**	**40,527**	**40,491**

% of Customers Served by Alternative Suppliers									
Utility				**Jan-00**	**Apr-00**	**Jul-00**	**Oct-00**	**Jan-01**	**Apr-01**
Total				**4.7%**	**5.0%**	**4.7%**	**4.7%**	**5.3%**	**5.3%**

Notes:
1. CHG&E = Central Hudson Gas & Electric Corp. Con Ed = Consolidated Edison Company of New York, NMPC = Niagara Mohawk Power Corp., NYSEG = New York State Electric & Gas Corp., O&R = Orange and Rockland Utilities, Inc., RG&E = Rochester Gas & Electric Corp.
2. New York reports total energy switched in a given month, but does not report total energy delivered by the distribution company in each month, therefore it is not possible to compute percent load switched.
3. While New York has reported the number of customers switching since February 1999, it has only reported the percentage of customers switching since December 1999.

Source: New York State Public Service Commission

Public Benefits Programs

The PSC established a System Benefits Charge (SBC) in May 1996. During the transition to full retail access, and possibly afterwards, the SBC will fund energy efficiency programs, research and development projects, environmental protection efforts, and efforts on behalf of low-income distribution utility customers.[4] The SBC was to be collected over an initial three-year period beginning July 1, 1998, with monthly rates ranging from .613 mill/kWh to 1.01 mill/kWh for each distribution utility, for an average of .86 mill/kWh. A total of $234.3 million was expected to be collected through the SBC. On January 26, 2001, the SBC issued an order which extended the period for the collection of the SBC until July 31, 2006, with $150 million collected annually through an increased monthly rate of 1.56 mills/kWh for all distribution utilities.[5]

Separation of Generation and Transmission

The PSC encouraged total divestiture of generation, and has instructed distribution utilities to separate generation and energy service functions from transmission and distribution systems.[6] Each distribution utility company's restructuring agreement sets out different requirements for separation of generation and transmission:[7]

- Central Hudson was required to separate transmission and distribution from generation before mid-2001. Central Hudson established a holding company and sold its fossil generation plants, though it may bid for the plants through an unregulated affiliate.

- Con Edison was to auction off at least 50% of its electric plants in New York City by the end of 2002; however, the settlement agreement with the PSC was modified and all plants, with two exceptions, have been sold to unaffiliated entities of Con Edison.

- Under a merger agreement with Con Edison, Orange and Rockland (O&R) was to become a wholly-owned subsidiary of Con Edison, though O&R was to continue to offer both the sale and delivery of electricity, and billing and metering services. O&R was to auction off its generating plants and has done so. There were financial incentives for O&R to sell them by May 1, 1999.

- Rochester Gas & Electric was to separate its electric operations into a regulated electricity supply company, a regulated transmission and distribution company, a power generating company, and an unregulated energy supplier. It has done so.

- New York State Electric & Gas was to auction off its coal-fired generation plants by August 1, 1999. The new owners will compete in the competitive market.

- Niagara Mohawk was to auction off its fossil fuel and hydro plants. Niagara Mohawk plans also to divest its nuclear generation assets.

State RTO Involvement

New York distribution utilities belong to the New York ISO, formed in 1998. The New York ISO exercises operational control over most of New York's transmission systems, administers the ISO transmission tariff, and operates the New York Open Access Same Time Information System (OASIS).[8]

Slamming/Cramming Rules

In order for a switch to be valid, a competitive supplier must receive authorization from a customer, the documentation of which must be retained for 6 years. Agreement can be in the form of either a written agreement signed by the customer, a written statement by an independent third party that witnessed or heard a verbal commitment by the customer, a tape recording of the customer's verbal commitment made by the competitive supplier, or an electronic transmittal that can be shown to have originated with the customer.

If a competitive supplier switches a customer without his consent, it will be fully responsible for all wrongful charges paid by the customer, and for the costs incurred by the distribution utility. A competitive supplier who switches a customer without his consent may also have his eligibility to serve customers in New York terminated, and there may be a financial penalty.[9]

Customer Billing

In March 2000, the PSC issued an order allowing for customer choice in billing.[10] Most customers who have switched suppliers are currently receiving two bills: one from the distribution company for delivery services, and one from the competitive supplier for generation, although some customers of some distribution utilities have a single-bill option based on distribution utility arrangements with the competitive suppliers. In April 2001, the PSC issued orders that will help provide for efficient single-billing options for all customers. This includes an initial set of standards for electronic data interchange, which will make it easier to process requests to switch customers and to transfer customer data. Distribution utility companies were also directed to incorporate the PSC's uniform billing business practices into their operating procedures.[11]

Affiliate Name and Logo Issues

The PSC does not have generic standards for distribution utility and affiliate relations, although each distribution utility's restructuring plan included standards of conduct. There are no restrictions on affiliate use of name, logo, or trademarks. An affiliate may identify its relationship to the distribution utility or holding company. The distribution utility and affiliate may not give the impression that they speak for one another.[12]

Usage of Customer Information

Historical customer data will be provided by distribution companies to customers or their authorized designees. All historical data that a competitive supplier receives from the distribution company must be kept confidential, unless authorized for release by the customer. A distribution company cannot disclose customer information to competitive suppliers if the customer has notified the distribution company in writing that he does not authorize release. Thereafter, customer information can only be released to a competitive supplier with the customer's written authorization.[13]

Standardized Labeling

All competitive suppliers and distribution utilities must provide periodic environmental disclosure statements to their current and prospective retail electricity customers. Disclosures will occur in a uniform manner established by the PSC.[14] Until the first marketer labels are developed, the PSC will issue historic statewide fuel mix and emissions data for use by marketers as a basis for comparison with their products.[15]

***Content*:** Disclosures must include the average fuel mix and average emissions rates for its generation sources. Companies will use actual data to calculate a rolling annual average of aggregate quarterly fuel mix, and emissions factors will be based on annual data. Air emissions will be shown relative to the New York State average. Data will be updated quarterly.

***Timing*:** Labels must be given to prospective customers as part of the disclosure statement prior to a contract offer. Disclosure information must accompany customer bills; it may either be printed on the bill or included with the bill as a bill insert.

Other Consumer Protection Measures

In January 1999, the PSC adopted uniform business practice rules, which set minimum standards for exchange of customer information, customer billing procedures, protections against slamming, and dispute resolution procedures.[16] Companies wishing to provide competitive electric service must meet financial security requirements. Competitive suppliers will also have to provide customers with specific and limited protections, which include an adequate disclosure statement, sufficient notice of supply contract termination, and sufficient procedures to ensure a smooth transition between suppliers, including slamming protections.[17]

Retail Choice in Gas Sales

On March 14, 1996, the PSC approved plans allowing for retail choice in gas sales for all customers. As of March 2001, 5.7% of New York residential customers were participating in the gas customer choice program.[18]

Miscellaneous

In September 2001, the New York governor signed legislation which reduces the sting time to six months for modifications to plants that reduce emissions by 75%.[19]

Notes

1. NYPSC Case 00-E-0165 – In the Matter of Competitive Metering and Case 94-E-0952 – In the Matter of Competitive Opportunities Regarding Electric Service (Feb. 26, 2001).

2. NYPSC Opinion 96-12, Opinion and Order Regarding Competitive Opportunities for Electric Service (May 20, 1996).

3. *Id.*

4. New York State Public Service Commission, "System Benefits Charge (SBC)." <www.dps.state.ny.us/sbc.htm>

5. NYPSC Order Continuing and Expanding the System Benefits Charge for Public Benefit Programs (Jan. 26, 2001).

6. NYPSC Opinion 96-12, Opinion and Order Regarding Competitive Opportunities for Electric Service (May 20, 1996).

7. PSC Publication: PSC Rate and Restructuring Plan Fact Sheets. <www.dps.state.ny.us/energyarch.htm#facts>

8. NYISO Frequently Asked Questions. <www.nyiso.com/faqs.html>

9. New York Public Service Commission, Case 98-M-1343, Uniform Retail Access Business Practices, Appendix A, "Slamming Prevention Process" (April 14, 1999). <www.dps.state.ny.us/doc5743_appendix_a.pdf> For information on the acceptance of uniform retail access business practices in New York *see* <www.dps.state.ny.us/ubr.htm>

10. New York Public Service Commission, Customer Billing Arrangements. <www.dps.state.ny.us/cba.htm>

11. Public Service Commission Press Release, "PSC Approves Data Exchange Standards, Uniform Billing Practices for Energy Providers," April 25, 2001. <www.dps.state.ny.us/fileroom/doc9654.pdf> *See also* <www.dps.state.ny.us/AppA51501.pdf>

12. Since most generation has been divested, this issue is less significant in New York.

13. New York Public Service Commission, Case 98-M-1343, Uniform Retail Access Business Practices, Appendix A, "Customer Information" (April 14, 1999). <www.dps.state.ny.us/doc5743_appendix_a.pdf> For information on the acceptance of uniform retail access business practices in New York *see* <www.dps.state.ny.us/ubr.htm>

14. NYPSC Opinion 98-19, Opinion and Order Adopting Environmental Disclosure Requirements and Establishing a Tracking Mechanism (Dec. 15, 1998).

15.NYPSC, Historical Fuel Mix and Emissions Data <www.dps.state.ny.us/fuelmix.htm>

16. NYPSC, Uniform Retail Access Business Practices <www.dps.state.ny.us/ubr.htm> On April 14, 1999 the PSC issued an order modifying portions of the Uniform Business Practices, which are set forth in

Appendix A of that order. *Id.* The modified Uniform Business Practices can be found at <www.dps.state.ny.us/doc5743_appendix_a.pdf> *See* <www.dps.state.ny.us/AppA51501.pdf> for new Consolidated Billing Practices.

17. NYPSC Opinion 97-5, Opinion and Order Establishing Regulatory Policies for the Provision of Retail Energy Services (May 19, 1997). *See* <www.dps.state.ny.us/escoapp.htm> for the competitive supplier Retail Access Eligibility Application, which outlines these requirements in more detail.

18. Energy Information Administration, Status of Natural Gas Restructuring Programs, March 2000. <www.eia.doe.gov/oil_gas/natural_gas/restructure/state/ny.html>; New York State Department of Public Service Gas Retail Access Migration Summary Report (March 2001). <www.dps.state.ny.us/Gas_Migration.htm>

19. "New York Governor Signs Bill to Hasten Siting Process." *Electric Power Daily* (Sep. 4, 2001).

Ohio: Overview of Retail Competition Plan and Market Response

Administrator and Start Date

Ohio's restructuring legislation, SB 3, which was signed into law July 6, 1999, allows for Ohio customers to choose their electric supplier beginning January 1, 2001. The Public Utilities Commission of Ohio (PUCO) will oversee the transition to retail competition (the "market development period"). This period ends no later than December 31, 2005.

Services Open to Competition

Generation only. PUCO will initiate a proceeding prior to March 31, 2003 to determine the feasibility of competition in ancillary, metering, billing, and collection services.[1] Some distribution utilities, however, have voluntarily opened these services up to competition as of January 1, 2001.

Consumer Options

On August 9, 2001, PUCO approved rules allowing the formation of aggregation groups by local governments. The rules require the local government aggregators to gain a majority in support of aggregation and to adopt and ordinance authorizing aggregation. Approximately 100 local governments in Ohio have formed or joined aggregation groups.[2]

Alternative Suppliers Licensed to Provide Service

Table 2 (attached at the end of this summary) lists the alternative suppliers licensed to serve customers. Of the 42 suppliers licensed to provide service to customers in Ohio, as of September 17, 2001 11 are actively serving commercial and industrial customers, and 2 are actively serving residential customers.

Competitive suppliers must be licensed, and provide a financial guarantee sufficient to protect customers and distribution companies from default.

Pricing Trends

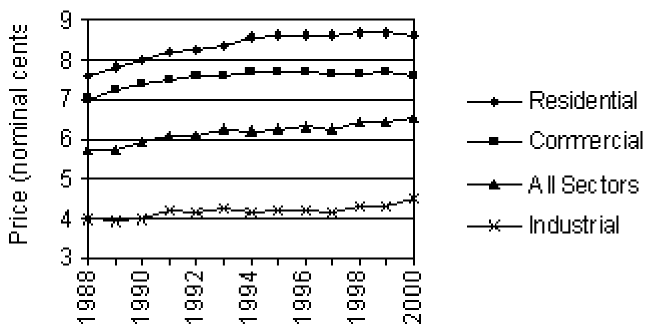
As shown in Table 1, retail prices in the industrial sector rose throughout the past decade. Prices also rose throughout the decade in the residential sector, although the rate of increase declined during the latter part of the decade. Prices in the commercial sector rose until 1994, after which time they held steady. While the difference between commercial and residential prices has been one cent or less throughout the decade, industrial prices have generally been about half as high as residential prices.

Table 1. Average Annual Price per KWh by Sector (nominal cents)

	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
Residential	7.6	7.8	8	8.2	8.24	8.36	8.56	8.6	8.6	8.63	8.7	8.7	8.6
Commercial	7	7.2	7.4	7.5	7.57	7.59	7.72	7.68	7.71	7.67	7.67	7.7	7.6
Industrial	4	3.9	4	4.2	4.14	4.25	4.14	4.17	4.21	4.16	4.3	4.3	4.5
All Sectors	5.7	5.7	5.9	6.1	6.06	6.22	6.19	6.24	6.3	6.25	6.38	6.4	6.5

Source: Energy Information Administration

Figure 1. Average Annual Price Per KWh by Sector



Price Changes for Standard Offer (or Regulated) Service

Prices must be unbundled, but they can be repackaged on a bundled basis to meet consumer preferences.[3] Residential customers received a five percent rate reduction applied to unbundled generation services beginning January 1, 2001.[4] The PUCO may alter or remove the five percent rate reduction after January 1, 2001 if it determines that the rate reduction has unduly discouraged market entry by competitors. Delivery rates (*i.e.*, the sum of transmission and distribution rates) are frozen for at least five years.[5]

Standard Offer Service Provider

The incumbent distribution utility will provide standard offer service for customers who do not choose an alternate supplier, as well as for those customers whose suppliers default on service. During the market development period, standard offer service will be provided at prices in accordance with PUCO approved rates of the distribution utility's unbundled generation service component.[6] After the market development period, standard offer service will be provided at market rates which may be obtained through competitive bidding by the distribution utility. Beginning in 2002, a customer who voluntarily returns to his distribution utility for standard offer service will be required to remain with the distribution utility through the following April if he returns to service between May and September or be subject to a "come-and-go" rate approved by the PUCO.

Market Support Generation: As part of the restructuring settlement with Ohio's largest distribution utility (FirstEnergy), the utility developed a market support generation program, where suppliers are able to purchase generation from the utility at discounted wholesale rates, and then resell it to customers. This stipulated agreement approved by the PUCO requires FirstEnergy's subsidiaries to set aside at least 1,120 MW (approximately 20%) of its generation capacity for this program, 300 MW of which is set aside exclusively for residential load. This capacity was available to suppliers on a first come, first serve basis, and it is fully subscribed.

Shopping Credit Rates

SB 3 requires the PUCO to set shopping incentives by customer class that induce, at a minimum, 20 percent load switching by customer class by no later than December 21, 2003. This 20 percent is a desired target. Although there is no penalty associated with non-achievement, incentives and credits can be adjusted by the PUCO to encourage further customer switching activity.

Recovery of Stranded Costs/Transition Costs

Stranded costs eligible for recovery include net costs related to generation service that are unrecoverable in the competitive market, employee assistance costs, and regulatory assets.[7] During the market development period, the distribution utility can recover PUCO-approved stranded costs through customers receiving the standard offer rate, as well as through a per kilowatt-hour charge for customers who choose an alternate supplier.[8] Generation related assets can be recovered from January 1, 2001 through December 31, 2005. Regulatory assets can be recovered from January 1, 2001 through December 31, 2010. The PUCO can review transition costs annually, and adjust charges as necessary.[9]

Customer Switching and Eligibility

All customers are eligible to choose their supplier as of January 1, 2001. Cooperatives can opt-in to the retail choice program at any time, and use their own discretion as to whether to declare ancillary services, metering, billing, and collection to be competitive or non-competitive. To encourage consumer aggregation, municipalities may adopt an ordinance that aggregates all residents within its boundaries and changes their generation supplier to one with which the municipality has negotiated a supplier agreement. Consumers are automatically enrolled unless they "opt out" of the program.

Switching Process

***Sign-up Method*:** A customer who wishes to switch to a competitive supplier can agree to change his service in one of three ways: by contract (for face-to-face or mail enrollment); by an audio recording (for telephone enrollment); or by input on a supplier's web site (for electronic enrollment). Before entering into a contract, the competitive supplier must provide the customer with enrollment documents which include pricing information, terms and conditions of service, dollar amounts of all recurring and non-recurring charges (including fees for early contract termination), the resource mix and environmental characteristics of the power, and the duration of the contract. After receiving the customer's agreement to switch suppliers, the supplier will contact the distribution utility within 3-5 days after enrollment. The distribution utility will then mail confirmation to the customer.

***Right of Rescission*:** The customer has 7 days from the postmark on the confirmation of his switch in suppliers to change his mind and cancel his contract.

Public Benefits Programs:

***Low-income*:** A universal service fund to provide funding for the low-income customer assistance programs and for the consumer education program was established under SB 3. This program is administered by the Director of Development.[10]

***Energy Efficiency*:** The Director of Development also established an energy efficiency and weatherization program for customers on the percentage-of-income-payment-plan program,[11] as well as an education program for consumers eligible for low-income assistance programs.[12] The state also established a fund to provide for the energy efficiency revolving loan program, which provides financial assistance to improve energy efficiency in a cost-efficient manner.[13]

Separation of Generation and Transmission

A distribution utility can offer both competitive and non-competitive services only if it has formed separate affiliates and meets the accounting requirements determined by PUCO.[14] Distribution utilities must file an application with PUCO for approval of a proposed corporate separation plan. (See State RTO Involvement below). During an interim period, an electric distribution utility with "good cause" can choose an interim functional separation plan instead of a structural separation plan. This plan, however, must progress to full structural separation.

State RTO Involvement

By December 31, 2003, all distribution utilities and cooperatives must transfer control of their transmission systems to an independent third party transmission entity.[15]

New Plant Construction and Planning

There is a total potential of 19,000 MW of new generation planned in Ohio above the 1998 level. The Ohio Power Siting Board has certificated over 10,000 MW and of this total, 2,110 MW of new generation is operational.[16]

Slamming/Cramming Rules

Rules are currently being considered by the PUCO. A customer cannot be switched to an alternate supplier without his consent. If a customer signs up with a competitive supplier through mail, facsimile or direct solicitation, his authorization will be obtained by a written signature on the contract. If a customer signs up by telephone, the competitive supplier must make a recording of the telephone call which verifies the customer's request to enroll with the competitive supplier. If a customer signs up through the Internet, his authorization will be obtained by encrypted customer input.

Competitive suppliers that do not comply with the customer enrollment provisions are subject to penalties, including fines, suspension, recission or revocation of licensure, recission of the customer contract, and restitution of damages to the customer.

Customer Billing

A customer will either receive one bill from the distribution company, or two bills, one from the supplier and one from the distribution company. The supplier will determine which billing format is used.

Affiliate Name and Logo Issues

Joint advertising and marketing are allowed. An affiliate may use the name and logo of its parent distribution utility, but it has to detail the means by which it will guard against anti-competitive and unreasonable sales practices.

Usage of Customer Information

Distribution utilities have to provide name, address, and usage information on a list of consumers eligible to choose their electric supplier. Distribution utilities must provide information to customers at least four times per year about how to remove oneself from the list. A distribution utility cannot provide any proprietary customer information (*e.g.*, customer load profiles or billing histories) to an affiliate without the prior authorization of the customer.

Standardized Labeling

***Content*:** Each supplier must provide a customer with information on the generation mix and environmental characteristics of his power. Environmental disclosure labels will be in a standardized format to facilitate comparisons by consumers.

***Timing*:** Label information must be distributed to customers at least four times per year.[17]

Consumer Education

A statewide consumer education program will be funded at a level of $16 million in 2001, and $17 million from 2002-2005. The program is two-pronged, calling for a statewide campaign and a service territory-specific campaign. The PUCO with the Ohio Consumers' Counsel oversee the consumer education effort.

Other Consumer Protection Measures

The PUCO has created rules to prohibit unfair or deceptive acts in the marketing and sale of retail service, including rules on contract disclosure, switching providers, minimum content of customer bills, and procedures for disconnection and service termination.[18]

Retail Choice in Gas Sales

Industrial customers have been able to choose their gas supplier since the 1970s. Retail choice has been extended to certain residential and small commercial customers since 1997, through programs by Columbia Gas of Ohio, Cincinnati Gas and Electric, and East Ohio Gas Company.[19]

Table 2. Licensed Suppliers/Aggregators (as of September 17, 2001)

Company	Date Licensed	Retail Service Class
Advantage Energy, Inc.	11/16/2000	Not Active
AEP Ohio Commercial & Industrial Retail Company, d/b/a AEP Plus	12/14/2000	Not Active
Allegheny Energy Supply Company	11/06/2000	C, I
Alliance Energy Services Partnership	11/18/2000	Not Active
Amerada Hess Corporation	11/24/2000	Not Active
American PowerNet Services L.P.	03/08/2001	Not Active
Affiliated Power Purchasers International, LLC, d/b/a APPI	02/18/2001	Not Active
eVulkan, d/b/a beMANY	10/27/2000	Not Active
Biomass Group, LLC	01/01/2001	Not Active
Bob Schmitt Electrical Aggregator, LLC	12/18/2000	Not Active
Buckeye Energy Brokers, Inc.	10/22/2000	Not Active
Cincergy Solutions Holding Company d/b/a Cinergy Solutions	04/19/2001	Not Active
Clinton Energy Management Services	11/18/2000	Not Active
Commonwealth Energy Corporation d/b/a Electric AMERICA	06/10/2001	Not Active
U.S. Power & Gas, Inc., d/b/a Consumer Sales Solutions	01/04/2001	Not Active
Dominion Energy Direct Sales, Inc., d/b/a Dominion Evantage	12/16/2000	Not Active
Dominion Retail, Inc.	10/30/2000	Not Active
DPL Energy Resources, Inc.	12/08/2000	Not Active
DTE Energy Marketing, Inc.	12/03/2000	Not Active
Dynegy Energy Services	07/01/2001	Not Active
Eagle Energy, LLC	04/20/2001	Not Active
Energy America, LLC	11/16/2000	Not Active
Energy.com Corp.	12/15/2000	Not Active
Enron Energy Services, Inc.	11/16/2000	C, I
Enron Power Marketing, Inc.	11/18/2000	Not Active
Unicom Energy Inc., d/b/a Exelon Energy	10/30/2000	C, I
FirstEnergy Services Corp.	11/03/2000	R, C, I
Green Mountain Energy Company	02/11/2001	Members Only
K2 Energy Advisors, LLC	02/10/2001	Not Active
MidAmerican Energy Company	10/30/2000	Not Active
AEP Ohio Retail Energy, LLC, d/b/a Mutual Energy	12/15/2000	Not Active
National City Corporation	01/18/2001	Not Active

Table 2 (cont'd). Licensed Suppliers/Aggregators (as of September 17, 2001)

Company	Date Licensed	Retail Service Class
New Energy Inc.	10/22/2000	C, I
The New Power Company	11/19/2000	R, C, I
Nicor Energy	11/20/2000	C, I
Ohio Farm Bureau Development Corp.	11/06/2000	Members Only
OMA Service Corporation	01/04/2001	Not Active
AES Power Direct, LLC, d/b/a Power Direct	10/20/2000	C, I
The Proctor and Gamble Distributing Company, d/b/a Procter and Gamble	12/18/2000	Not Active
Sempra Energy Solutions	01/19/2001	Not Active
Shell Energy Services Company, LLC, d/b/a Shell Energy	11/02/2000	C, I
Strategic Energy, LLC	10/27/2000	C, I
Utilimax.com, Inc.	01/04/2001	Not Active
WPS Energy Services, Inc.	11/06/2000	C, I

Note: R = residential, C = commercial, I = industrial
Source: PUCO

Notes

1. Ohio Rev. Code Ann. §4928.4 (2001).

2. PUCO Case No. 002394-EL-ORD. In the Matter of the Commission's Promulgation of Rules for Competitive and Noncompetitive Retail Electric Service Standards Regarding Governmental Aggregation Service Pursuant to Chapter 4928, Revised Code (Aug. 9, 2001). *See also* "Ohio Adopts Government Aggregation Rules." *Electric Power Daily* (Aug. 13, 2001).

3. *Id.* at § 4928.7.

4. *Id.* at § 4928.40.

5. *Id.* at § 4928.34.

6. *Id.* at § 4928.14

7. *Id.* at § 4928.39.

8. *Id.* at §4928.37.

9. *Id.* at §4928.40.

10. *Id.* at § 4928.51.

11. *Id.* at § 4928.55.

12. *Id.* at § 4928.56.

13. *Id.* at §§ 4928.61-62.

14. *Id.* at § 4928.17.

15. *Id.* at § 4928.12.

16. PUCO, Electric Restructuring: Differences Between California and Ohio (Apr. 2001). <www.puc.state.oh.us/Consumer/Electric/ohiovscalif.html>

17. Ohio Rev. Code Ann.,§4928.10 (2001).

18. *Id.* at §4928.10.

19. PUCO The Basics: How the Natural Gas Industry Works. <www.puc.state.oh.us/Consumer/NaturalGas/thebasics.html>

Pennsylvania: Overview of Retail Competition Plan and Market Response

Administrator and Start Date

The Electricity Generation Customer Choice and Competition Act was enacted December 3, 1996. The Pennsylvania Electric Choice Pilot Program began in the fall of 1997, with 230,000 customers participating. These customers were able to begin shopping for their electric generation supplier beginning September 1, 1998, and those who chose their supplier by November 1, 1998 began receiving power from their designated supplier in January 1999.[1] On January 2, 1999, two-thirds of Pennsylvania customers were eligible to choose their electricity supplier, and as of January 2, 2000, electric choice was fully implemented in nearly all of Pennsylvania.[2] Retail competition is administered by the Pennsylvania Public Utility Commission (PUC).

Services Open to Competition

Generation. Generally the distribution company will provide metering and billing services, although there are some areas in Pennsylvania in which the supplier may provide these services.[3] Pennsylvania has developed rules to allow licensed generation suppliers to provide metering and billing services to retail customers in some territories.[4]

Alternative Suppliers Licensed to Provide Service

Competitive suppliers must be licensed by the PUC to provide service to Pennsylvania customers.[5] All suppliers must be bonded or have other security to ensure financial responsibility.[6] The initial security level will be $250,000, and it will be reviewed annually thereafter and may be modified so that it equals 10% of the supplier's gross receipts.[7] Pennsylvania does not formally maintain information on the number of licensed suppliers actually providing service to customers.

Pricing Trends

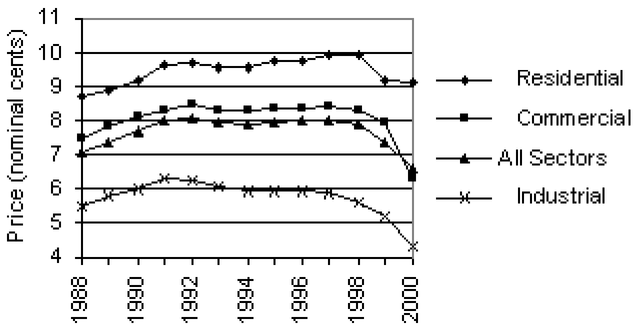
As shown in Table 1, prices in Pennsylvania rose steadily in all three customer classes between 1988 and 1991-1992, then held relatively constant until the latter part of the decade, when they began to decline. With the exception of residential prices, average retail prices for 2000 were lower than prices in 1988.

Table 1. Average Annual Price per KWh by Sector (nominal cents)

	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
Residential	8.7	8.9	9.2	9.6	9.7	9.6	9.6	9.7	9.7	9.9	9.9	9.2	9.1
Commercial	7.5	7.8	8.1	8.3	8.5	8.3	8.3	8.3	8.3	8.4	8.3	7.9	6.3
Industrial	5.5	5.8	6.0	6.3	6.2	6.0	5.9	5.9	5.9	5.9	5.6	5.2	4.3
All Sectors	7.1	7.4	7.7	8.0	8.0	7.9	7.9	7.9	8.0	8.0	7.9	7.4	6.6

Source: Energy Information Administration

Figure 1. Average Annual Price Per KWh by Sector



Price Changes for Standard Offer (or Regulated) Service

There are statutory caps on electric distribution utility rates: rates for standard offer service (*i.e.*, service for customers who do not choose a generation supplier) and non-generation service are capped at January 1, 1997 levels until July 1, 2001; rates for generation, including transition charges, are capped at January 1, 1997 levels until January 1, 2006.[8] In some distribution utility service areas, generation caps are in place until 2008-2011. Many distribution utilities have also extended distribution rate caps until 2003-2005. Pennsylvania did not require rate reductions, although several distribution utilities agreed to reduce rates in the first year of retail choice. These reductions were to be lowered and phased out over a two to three year period.[9]

Overall rate reductions for the first year ranged up to 8% for the major utilities operating in Pennsylvania.[10]

Shopping credit rates are shown below in Table 2. These are the rates that a customer will pay for generation if he receives generation service from the utility rather than a competitive supplier. Shopping credit rates increase over time.

Table 2. Shopping Credit Rates (in cents/kWh)

Date	Dusquene	MetEd	Penelec	PPL	Penn Power	West Penn	PECO
1999	4	3.757	3.73	3.73	3.7259	3.12	N/A
2000	4.22	3.868	3.84	3.83	3.8448	3.23	5.56
2001	4.31	3.973	3.948	3.94	3.9717	3.28	5.67
2002	4.4	4.078	4.052	4.4	4.0892	3.33	N/A
2003	4.5	4.182	4.153	4.5	4.1947	3.38	N/A
2004	4.61	4.281	4.251	4.61	4.2945	3.43	N/A
2005	4.75	4.377	4.346	4.61	4.3809	3.47	N/A
2006	N/A	4.469	4.438	4.61	5.085	N/A	N/A
2007	N/A	4.557	5.279	4.61	5.085	N/A	N/A
2008	N/A	4.635	5.279	N/A	N/A	N/A	N/A
2009	N/A	4.711	N/A	N/A	N/A	N/A	N/A

Note: Shopping Credit Rates for Allegheny Power are not available.
Source: Company Restructuring Orders and Tables

Standard Offer Service Provider

The distribution company will provide standard offer service for customers who do not choose a competitive supplier, for those who are unable to obtain service from a competitive supplier, or for customers whose suppliers do not deliver service. Distribution utilities must offer standard offer service as long as the distribution utility is collecting transition charges or until 100% of its customers have electric choice.[11] In June 2000, the PUC issued a change in the provision of standard offer service, in order to prevent "gaming" of the system by customers who were returning to their distribution utility. During a period when market prices rose, standard offer rates remained stable. This caused customers to be either returned to default service by their suppliers or to return themselves to default service. Many distribution utilities require customers to remain with the distribution utility for a 12-month period after switching back to provider of last resort service. The PUC has permitted this practice and encouraged the distribution utilities to offer customers a second option of staying with the distribution utility for a shorter period, but paying a market-based generation rate.[12] The 12-month requirement generally only applies to industrial and commercial customers.

Competitive Default Service

Some distribution utilities have arranged for competitive bidding to supply the generation services portion of standard offer service for customers who do not affirmatively choose an alternative supplier. This option is known as Competitive Default Service (CDS). The PUC has approved additional consumer protections for the initial phase-in of CDS, including bidder qualifications, established creditworthiness, and bond limits. The PUC will also review the CDS annually to ensure that it is still benefitting consumers.[13]

- Duquesne plans to supply standard offer service by importing power from the wholesale market. It does not participate in CDS.

- GPU (MetEd and Penelec) attempted to competitively bid standard offer service for 20% of customers who had not chosen alternate suppliers in 2000. Under the restructuring settlement, the amount of generation services that will be competitively bid will increase by 20 percent each year.

- PECO has awarded a standard offer service contract for 20% of its customers to The New Power Company. Additionally, 50,000 PECO customers were assigned to Green Mountain Energy, Inc. PECO customers assigned to the competitive default service have received a two-percent discount on standard offer service. The competitive default provider will also provide no less than two percent of its competitive default service supply from renewable resources and will increase the use of renewable resources by one-half of a percent annually.[14]

- PPL will seek competitive bids for a portion of its standard offer service starting in 2002.

- West Penn Power attempted unsuccessfully to competitively bid a portion of its standard offer service in 2000.

Recovery of Stranded Costs/Transition Costs

Stranded costs are administratively determined by the PUC on a case-by-case basis. Utilities were not required to establish market-based valuation by selling generation assets. Stranded costs will be fully recoverable through a non-bypassable charge to all consumers, collectible for up to nine years, unless the PUC orders an alternative payment period.[15] The PUC will annually review the transition charges for each distribution utility and, if necessary, adjust the charge for over or under recovery.[16] Stranded costs eligible for recovery include regulatory assets, decommissioning costs, cost obligations under contracts with non-utility generation projects, and generation related costs. The PUC will also consider mitigation efforts. Distribution companies have the duty to mitigate generation related transition or stranded costs as much as possible.[17] A distribution utility may also apply to the PUC for a qualified rate order to recover some or all of its transition costs. If the transition bonds approved by a qualified rate order are approved by the PUC, the distribution utility will collect the charges for the bonds through customer bills, and either the distribution utility's rates for electric service, or its transition charges will be reduced.[18] Tables 3 and 4, below, portray the stranded costs and competitive transition charges for each utility.

Cooperatives can collect a transition surcharge from those customers that choose an alternate supplier. They can also request a review of this surcharge by the PUC.[19]

Table 3. Transition/Stranded Costs

Company	Allowable Stranded Cost Recovery	Length of Recovery
Allegheny Power	$670 million	10 years
Duquesne Light	$1,331 million	7 years
GPU Energy (Met Ed.)	$975 million	10 years
GPU Energy (Penelec)	$858 million	8 years
PECO	$5,024 million	8 ½ years
Pennsylvania Power and Light	$2,864 million	9 years
Pennsylvania Power Company	$234 million	9 years
West Penn Power Company	$524 million	7 years

Source: Company Restructuring Orders and Tables

Table 4. Competition Transition Charges (in cents/kWh)

Date	Dusquene	MetEd	Penelec	PPL	Penn Power	West Penn
1999	2.58	1.678	1.549	1.78	1.35911	0.72
2000	2.5	1.567	1.439	1.68	1.24024	0.67
2001	2.4	1.462	1.331	1.57	1.11333	0.62
2002	2.31	1.357	1.227	1.45	0.99584	0.56
2003	2.21	1.253	1.126	1.33	0.8903	0.51
2004	2.11	1.154	1.028	1.2	0.79053	0.47
2005	1.97	1.058	0.933	1.06	0.70406	0.42
2006	N/A	0.966	0.841	0.91	N/A	N/A
2007	N/A	0.878	N/A	0.79	N/A	N/A
2008	N/A	0.8	N/A	N/A	N/A	N/A
2009	N/A	0.724	N/A	N/A	N/A	N/A

Note: Competition Transition Charges for Allegheny Power and PECO are not available.
Source: Company Restructuring Orders and Tables

Customer Switching and Eligibility

As of January 2001, all customers are eligible to choose a competitive supplier. Electric cooperatives were obligated by statute to open for competition on the same schedule as the regulated utilities.[20] The cooperative decided to implement retail choice January 1, 1999, although as of December 2000, no alternative suppliers had signed up to provide generation service in the cooperatives' territories.

Switching Process

It generally takes about 45 days for a switch to occur after a customer has notified a supplier of his intent to switch.[21]

***Sign-up*:** In order to implement a switch, the supplier must first get direct oral or written authorization from the customer.[22] Many suppliers accept telephone and internet authorizations.[23] After it receives authorization from the customer, the supplier sends to the customer its terms of agreement. The customer can cancel his choice within three business days of receiving the terms of agreement.[24] If the customer does not cancel his choice, the new supplier then sends the switch request to the distribution company, who will send the customer a confirmation letter which notifies the customer of the switch request.[25]

***Right of Rescission*:** Pennsylvania customers have 10 days from receipt of a confirmation letter from their distribution utility to indicate whether the switch to an alternative suppliers is unauthorized.[26]

***Restrictions and Minimum Stay Requirements*:** Customers can switch suppliers at any time, although they are advised to check their supply agreement for any penalties which may apply.

Switching Activity

***Residential Sector*:** The number of residential customers served by competitive suppliers has held relatively constant. Duquesne Light experienced the largest movement of customers to alternative suppliers. These trends were also reflected in the percentage of customers switched and the percentage of customer load switched. Many of the utilities saw less than 10% of their customers switch to alternative suppliers, although PECO had approximately 13% switch and Duquesne had approximately 33% switch by July 2001. In July 2001, all utilities saw a dramatic decrease in the number of customers served by an alternative supplier.

Table 5. Residential Sector

Number of Residential Customers served by Alternative Supplier										
Company	**Apr-99**	**Jul-99**	**Oct-99**	**Jan-00**	**Apr-00**	**Jul-00**	**Oct-00**	**Jan-01**	**Apr-01**	**Jul-01**
Allegheny Power	7,822	8,243	7,978	7,574	6,656	3,492	3,168	3,107	2,152	1,502
Duquesne Light	68,762	74,906	100,152	116,442	133,715	154,153	174,790	176,488	175,160	171,230
GPU Energy	34,886	37,415	45,226	46,728	46,114	37,911	43,544	43,093	35,973	4,262
PECO Energy	172,342	200,442	194,707	201,874	206,171	213,416	204,887	218,850	214,171	169,601
Penn Power	8,100	7,715	7,840	7,941	8,211	8,423	8,359	8,243	8,377	1,503
PP&L	22,233	25,704	25,323	25,613	26,651	24,897	22,474	22,286	17,278	2,725
Total	**316,367**	**356,865**	**383,557**	**408,414**	**429,670**	**444,154**	**459,029**	**473,852**	**454,818**	**350,914**

Table 5 (cont'd). Residential Sector

% of Residential Customers served by Alternative Supplier

Company	Apr-99	Jul-99	Oct-99	Jan-00	Apr-00	Jul-00	Oct-00	Jan-01	Apr-01	Jul-01
Allegheny Power	1.4%	1.4%	1.4%	1.3%	1.1%	0.6%	0.5%	0.5%	0.4%	0.3%
Duquesne Light	13.1%	14.3%	19.1%	22.2%	25.5%	29.4%	33.3%	33.6%	33.4%	32.6%
GPU Energy	3.8%	4.1%	4.9%	5.1%	5.0%	4.1%	4.7%	9.7%	3.9%	0.5%
PECO Energy	12.8%	14.9%	14.5%	14.9%	15.3%	15.8%	15.2%	16.2%	15.6%	12.3%
Penn Power	6.2%	5.9%	6.0%	6.0%	6.3%	6.4%	6.3%	6.2%	6.3%	1.1%
PP&L	2.0%	2.3%	2.3%	2.3%	2.4%	2.3%	2.0%	2.0%	1.6%	0.2%
Total	**6.8%**	**7.6%**	**8.3%**	**8.7%**	**9.1%**	**9.6%**	**9.7%**	**11.2%**	**9.8%**	**7.3%**

% of Residential Customer Load served by Alternative Supplier

Company	Apr-99	Jul-99	Oct-99	Jan-00	Apr-00	Jul-00	Oct-00	Jan-01	Apr-01	Jul-01
Allegheny Power	1.4%	1.6%	1.5%	1.5%	1.2%	0.7%	0.6%	0.6%	0.4%	0.2%
Duquesne Light	13.1%	14.2%	17.8%	21.5%	24.7%	28.4%	32.1%	31.8%	34.8%	34.0%
GPU Energy	5.7%	4.9%	5.9%	6.7%	6.6%	5.4%	6.2%	5.8%	4.8%	0.5%
PECO Energy	14.5%	16.4%	17.1%	17.5%	17.4%	17.8%	16.9%	18.2%	17.3%	13.7%
Penn Power	6.3%	6.2%	6.0%	6.1%	6.3%	6.5%	6.4%	6.4%	6.5%	1.2%
PP&L	2.5%	2.8%	2.8%	2.8%	2.8%	2.3%	2.4%	2.4%	1.8%	0.2%

Notes:
1. PECO figures exclude residential customers assigned to competitive discount services.
2. Small local utilities are included in the totals, but are not listed separately.

Source: Pennsylvania Public Utility Commission

Commercial Sector: As with the case of residential customers, the number of commercial customers served by alternative suppliers remained relatively constant between 1999 and April 2001 for most of the utilities. The number of commercial customers served by competitive suppliers fell in the spring of 2001 as consumers taking services under CDC are not included in these figures. In July 2001, the commercial sector, like the residential sector, saw a dramatic decline in the number of customers receiving services from a competitive supplier. All of the utilities, other than PECO, have seen approximately 15% or less of their commercial customers switch to alternative suppliers. The percentage of PECO customers switching rose throughout 1999 and 2000, peaking at approximately 33% in January 2001. With the exception of Penn Power, all of the utilities saw a greater percentage of their load switch than their customers switch, with percent load switched going as high as almost 60%, as was the case for GPU in the early part of 2000.

Table 6. Commercial Sector

Number of Commercial Customers served by Alternative Supplier

Company	Apr-99	Jul-99	Oct-99	Jan-00	Apr-00	Jul-00	Oct-00	Jan-01	Apr-01	Jul-01
Allegheny Power	3,894	4,153	5,072	511	5,277	2,648	2,502	2,648	1,343	98
Duquesne Light	6,915	7,875	8,699	10,000	9,571	3,178	9,449	9,129	7,964	5,698
GPU Energy	16,520	18,831	19,733	20,218	19,080	12,297	12,636	12,193	10,478	517
PECO Energy	31,753	36,231	37,583	37,789	43,649	44,504	47,393	49,052	41,045	7,474
Penn Power	1,172	1,321	1,560	1,844	1,842	427	426	1,321	1,192	80
PP&L	15,093	17,877	18,478	19,026	21,603	18,373	17,053	17,136	15,327	2,588
Total	**75,463**	**86,473**	**91,312**	**94,188**	**101,153**	**81,527**	**89,534**	**91,551**	**77,421**	**16,479**

% of Commercial Customers served by Alternative Supplier

Company	Apr-99	Jul-99	Oct-99	Jan-00	Apr-00	Jul-00	Oct-00	Jan-01	Apr-01	Jul-01
Allegheny Power	4.8%	5.2%	6.3%	6.3%	6.2%	3.1%	2.9%	3.1%	1.6%	0.1%
Duquesne Light	12.1%	13.8%	15.2%	17.5%	16.7%	5.5%	16.5%	15.9%	13.9%	10.2%
GPU Energy	13.0%	14.8%	15.5%	15.9%	15.0%	9.7%	10.0%	9.6%	8.0%	0.4%
PECO Energy	21.9%	25.0%	26.3%	25.8%	29.7%	30.2%	32.1%	33.3%	27.5%	5.0%
Penn Power	6.8%	7.7%	9.0%	10.6%	10.7%	2.4%	2.4%	7.5%	6.7%	0.4%
PP&L	10.2%	12.0%	12.4%	12.7%	14.5%	12.3%	11.4%	11.5%	10.3%	1.7%
Total	**13.0%**	**14.9%**	**15.7%**	**16.1%**	**17.1%**	**13.8%**	**15.1%**	**15.5%**	**13.0%**	**3.14%**

% of Commercial Customer Load served by Alternative Supplier

Company	Apr-99	Jul-99	Oct-99	Jan-00	Apr-00	Jul-00	Oct-00	Jan-01	Apr-01	Jul-01
Allegheny Power	20.5%	18.4%	21.7%	20.1%	23.6%	9.4%	6.6%	7.2%	3.5%	0.2%
Duquesne Light	36.7%	31.2%	34.5%	41.3%	41.0%	4.0%	35.4%	25.9%	23.1%	10.0%
GPU Energy	50.9%	48.6%	52.1%	58.2%	58.8%	37.4%	38.0%	39.8%	26.9%	1.8%
PECO Energy	34.9%	38.3%	39.2%	39.1%	44.7%	43.9%	45.6%	46.1%	38.7%	6.0%
Penn Power	12.0%	10.9%	17.0%	20.4%	20.7%	4.8%	4.8%	6.0%	5.3%	0.4%
PP&L	30.3%	31.8%	32.8%	33.3%	37.8%	27.9%	26.8%	27.4%	21.0%	3.2%

Note: Small local utilities are included in the totals, but are not listed separately.
Source: Pennsylvania Public Utility Commission

***Industrial Sector*:** The number of industrial customers served by alternative suppliers rose slowly throughout 1999 and early 2000 for most of the utilities, and held steady until July 2001. Since then switching has dropped substantially. The movement in the percent of customers switched mirror those for the number of customers switched. Many of the utilities had a sizeable percent of their customer base switch to alternative suppliers. For example, in April 2000, at the peak of switching activity, PP&L, which, of the utilities with any industrial switches, had retained the greatest percentage of its customers, nevertheless had more than 10% of its customers served by alternative suppliers, and PECO had more than 60% of its customers switch.

Table 7. Industrial Sector

Number of Industrial Customers served by Alternative Supplier										
Company	**Apr-99**	**Jul-99**	**Oct-99**	**Jan-00**	**Apr-00**	**Jul-00**	**Oct-00**	**Jan-01**	**Apr-01**	**Jul-01**
Allegheny Power	29	26	26	27	25	9	9	9	9	0
Duquesne Light	206	155	233	262	256	47	340	312	271	157
GPU Energy	1,418	1,567	1,616	1,615	1,602	789	812	776	666	57
PECO Energy	1,832	1,892	1,902	1,891	2,025	1,440	1,474	1,493	1,052	150
Penn Power	63	64	70	83	77	20	21	46	44	8
PP&L	509	548	555	578	637	469	447	453	312	84
Total	**4,057**	**4,252**	**4,402**	**4,456**	**4,622**	**2,774**	**3,103**	**3,089**	**2,354**	**456**

% of Industrial Customers served by Alternative Supplier										
Company	**Apr-99**	**Jul-99**	**Oct-99**	**Jan-00**	**Apr-00**	**Jul-00**	**Oct-00**	**Jan-01**	**Apr-01**	**Jul-01**
Allegheny Power	35.4%	31.7%	31.7%	32.9%	23.6%	8.5%	8.6%	8.6%	8.7%	0.0%
Duquesne Light	13.4%	10.1%	15.1%	17.0%	16.4%	3.0%	21.8%	20.0%	17.3%	10.2%
GPU Energy	28.4%	31.3%	32.3%	32.3%	32.0%	15.8%	16.2%	15.5%	14.3%	1.2%
PECO Energy	55.9%	57.7%	58.6%	58.3%	62.3%	44.3%	45.4%	46.0%	32.8%	4.7%
Penn Power	28.1%	28.6%	31.5%	36.7%	34.7%	8.8%	9.3%	20.4%	19.6%	3.6%
PP&L	9.4%	10.2%	10.3%	10.7%	11.8%	8.7%	8.3%	8.4%	5.8%	1.6%

% of Industrial Customer Load served by Alternative Supplier										
Company	**Apr-99**	**Jul-99**	**Oct-99**	**Jan-00**	**Apr-00**	**Jul-00**	**Oct-00**	**Jan-01**	**Apr-01**	**Jul-01**
Allegheny Power	24.4%	21.1%	18.5%	21.1%	30.0%	6.2%	6.8%	6.6%	5.8%	0.0%
Duquesne Light	7.8%	5.7%	11.6%	13.4%	13.2%	0.5%	17.2%	18.0%	17.1%	5.7%
GPU Energy	76.4%	71.5%	73.1%	67.3%	69.2%	45.4%	46.7%	50.9%	39.5%	11.3%
PECO Energy	52.5%	55.0%	55.4%	58.7%	63.5%	39.8%	40.6%	42.3%	27.0%	7.0%
Penn Power	37.0%	37.5%	41.8%	49.2%	45.4%	12.0%	12.4%	17.5%	16.9%	3.1%
PP&L	39.9%	41.9%	40.4%	42.1%	63.6%	37.7%	33.5%	34.3%	18.4%	4.9%

Note: Small local utilities are included in the totals, but are not listed separately.
Source: Pennsylvania Public Utility Commission

Public Benefits Programs

Investor-owned utilities are required to fund universal service and energy conservation programs through a non-bypassable, competitively neutral charge that fully recovers costs.[27] Each distribution utility had to submit a comprehensive universal service and energy conservation program to the PUC as part of its restructuring filing.[28] For most distribution utilities, the charge for universal service and energy conservation programs will be a cents/kWh charge to all residential customers, which will be separately identified for cost accounting purposes, but included in the distribution rates on a customer's bill.[29] For Duquesne Light Company, the charge for universal service and energy conservation programs will be on a cents/kWh basis to all classes based on the allocation in the current base rate proceeding.[30]

Separation of Generation and Transmission

Generation must be separated from transmission and distribution, but distribution utilities are not required to divest facilities or reorganize corporate structure.[31] However, several utilities have voluntarily divested generation assets.

Generation Sales

- Duquesne Light Company and GPU (MetEd and Penelec) have divested most of their generation assets.[32] Duquesne sold its generating assets to Orion Power Holdings, Inc. in April 2000.

- PECO's generation assets have been transferred to PECO Energy Generation, a subsidiary of PECO.

- PPL transferred its generation assets and liabilities to several limited liability corporations.

- West Penn sold its generation assets to AE Supply.[33]

State RTO Involvement

The restructuring legislation directs the PUC to encourage interstate power pools to enhance competition and to complement restructuring. The transmission grid in much of Pennsylvania is controlled by PJM Interconnection, an independent system operator (ISO) that includes Pennsylvania, New Jersey, Maryland, Delaware, the District of Columbia, and parts of Virginia. PJM is responsible for the operation of the region's wholesale electric market, ensuring that there are enough generation supplies to meet the region's electric demand. To meet electric load in the PJM region, PJM coordinates with member companies and uses bilateral contracts and the spot market to secure power.[34] In March 2001, Allegheny Power and PJM filed with FERC a request to expand PJM by forming PJM-West. The filing calls for implementation by January 1, 2002.[35]

New Plant Construction and Planning

Over 6,000 MW of new generation capacity are currently being constructed or added as facility improvements in Pennsylvania.[36] According to Energy Information Administration data, suppliers in Pennsylvania have planned 11,273.1 MW of generation capacity additions between 2000 and 2004.[37]

Slamming/Cramming Rules

In order to switch a customer's service, a supplier must receive direct oral or written confirmation from the customer.[38] The preventative measures against slamming provide that the chosen supplier must send the terms of agreement to the customer in writing. A customer may cancel an agreement for any reason within three days. If a distribution company receives notification of a change in supplier, it will send the customer a confirmation letter, to which the customer has 10 days to respond. If the information in the confirmation letter is incorrect, and reflects an unauthorized change, the customer will be restored to his previous service without penalty.[39] Penalties for competitive suppliers who switch customers without authorization include fines and possible revocation of licensure.

Customer Billing

Unbundling is required to separate charges for generation, transmission and distribution. Distribution utilities are required to unbundle their bills sufficiently that customers can determine the basis for all charges. Customers will either receive a single bill from the distribution company or two bills, one from the generation supplier and one from the distribution company. In some areas, the alternative supplier will be able to issue one bill for generation and other electric service charges.[40] Customers who receive Competitive Default Service may choose to receive a single bill from the competitive default service provider, who must then provide all "customer care" services.

Affiliate Name and Logo Issues

Affiliates may use the name and logo of their parent distribution utility only if they include a disclaimer which states that the affiliate is not the same company as the distribution utility, its prices are not regulated by the PUC, and that the customer is not required to purchase services from the affiliate to continue to receive the same quality of service from the regulated distribution utility. If the affiliate is using the distribution utility's name and logo in its advertising or marketing through the radio, television, or other electronic media, the affiliate must include the same disclaimers at the conclusion of the advertisement.[41]

Usage of Customer Information

A customer can restrict the disclosure of his telephone number and his historical billing data. A distribution utility or supplier who intends to supply a third-party with this information must provide a customer with the means of restricting the release of this information, either through a signed form, orally, or electronically.[42] Customer information cannot be given preferentially by a distribution utility to its affiliate.[43] During the initial-phase in period of electric restructuring, a customer's name, address, telephone number, rate class, account number and load data were given to competitive suppliers as a result of the customer's enrollment into the electric choice program. The customer had the option of restricting the release of his telephone number and load data to suppliers. After this initial phase-in period, to assure that customers retain the ability to restrict disclosure of certain information to suppliers, the PUC directed distribution utilities to send forms to customers to give them the opportunity to restrict the release of load data, or of all information (name, address, rate class, and account number). Telephone numbers would not be released to suppliers under any circumstances.[44]

Standardized Labeling

Pennsylvania has no mandated labeling requirements,[45] but does have advertising disclosure requirements.

Advertising Restrictions

All distribution companies, electricity suppliers, marketers, aggregators, and brokers must provide accurate information to the consumer so he can compare prices and services on a uniform basis and make informed decisions as to his electric service.[46] Marketing materials which offer consumers terms of acceptance must include a table showing the price per kWh for usage levels of 500, 1000, and 2000 kWh of electricity per month. If variable price service is offered, these prices must factor in all costs and be an average price per kWh. Materials must also note the effective date of the prices.[47] If a competitive supplier markets its generation as having special characteristics, it must substantiate such claims, and a supplier must inform the customer of the availability of the annual licensing report if a customer makes a reasonable request for information about generation sources.[48]

Consumer Education

Each distribution company must provide a consumer education program during the transition period to familiarize customers with changes in the electric utility industry.[49] The Pennsylvania consumer education program is funded by all customers through distribution utility competitive transition charges. The program comprises statewide, grassroots, and distribution utility programs to raise awareness and provide information about electricity restructuring. The program explains consumer protections, addresses safety and reliability concerns, and actively encourages customers to shop for a competitive supplier. Pennsylvania has developed a web site to provide consumers with an additional source of information on electric restructuring and how to shop for a supplier.[50]

Other Consumer Protection Measures

Pennsylvania has implemented consumer protection measures in the areas of information disclosure (suppliers have to provide customers with adequate and accurate information that allows them to compare prices and services on a uniform basis), reliability, universal service, and quality of service.[51]

Retail Choice in Gas Sales

In accordance with the Natural Gas Choice and Competition Act, passed June 17, 1999, Pennsylvania has begun to implement comprehensive unbundling for its natural gas customers.[52]

Notes

1. News Brief from the Office of Governor Tom Ridge (June 26, 1998). <sites.state.pa.us/PA_Exec/Governor/News_Briefs/vol3is9.html>

2. Pennsylvania PUC Publication: Pennsylvania Electric Choice, Q&A. <www.electrichoice.com/public/qa.html>

3. Pennsylvania PUC Publication: Pennsylvania Electric Choice, How to Shop Guide. <www.electrichoice.com/public/guide.html>

4. Comments of the Pennsylvania Utility Commission, Federal Trade Commission Retail Electricity Study (April 9, 2001).

5. 66 Pa. Cons. Stat. §2809.A (2001).

6. *Id.* at §2809.C.

7. 52 Pa. Code §54.40 (2001).

8. 66 Pa. Cons. Stat. §2804.4 (2001).

9. Comments of the Pennsylvania Utility Commission, Federal Trade Commission Retail Electricity Study (April 9, 2001).

10. Ahmed Kaloko, Ph.D., Chief Economist, Pennsylvania Public Utility Commission, "Power 99–California & Pennsylvania Retail Market Development."

11. 66 Pa. Cons. Stat. §2807.E (2001).

12. Comments of the Pennsylvania Utility Commission, Federal Trade Commission Retail Electricity Study (April 9, 2001).

13. *Id.*

14. *Id.*

15. 66 Pa. Cons. Stat. §2808.A, B (2001).

16. *Id.* at §2808.F

17. *Id.* at §2808.C.

18. *Id.* at §2808.E, *see also id.* at §2812.

19. *Id.* at §7407, 7408.

20. 15 Pa. Cons. Stat. Ch. 73 (2001).

21. Pennsylvania PUC Publication: Pennsylvania Electric Choice, Frequently Asked Questions. <www.electrichoice.com/public/frequent.html>

22. Pennsylvania PUC Publication: Pennsylvania Electric Choice, Shopping Guide. <www.electrichoice.com/public/guide.html>

23. Comments of the Pennsylvania Utility Commission, Federal Trade Commission Retail Electricity Study (April 9, 2001).

24. Pennsylvania PUC Publication: Pennsylvania Electric Choice, Shopping Guide. <www.electrichoice.com/public/guide.html>

25. Comments of the Pennsylvania Utility Commission, Federal Trade Commission Retail Electricity Study (April 9, 2001).

26. *Id.*

27. 66 Pa. Cons. Stat. §2804.9 (2001).

28. *Id.* at §2804.15.

29. Pennsylvania PUC, Company Restructuring Orders. <puc.paonline.com/electric/competition/Restructuring/restructuring_orders.asp>

30. Duquesne Light Restructuring Plan (Docket R-00974104). <puc.paonline.com/electric/competition/Restructuring/restructuring_orders.asp>

31. 66 Pa. Cons. Stat. §2804.5 (2001).

32. Ahmed Kaloko, Ph.D., Chief Economist, Pennsylvania Public Utility Commission, "Power 99–California & Pennsylvania Retail Market Development."

33. Pennsylvania Public Utility Commission, Bureau of Conservation, Economics, and Energy Planning, "Electric Power Outlook for Pennsylvania: 1999-2004" (July 2000).

34. Pennsylvania Public Utility Commission, Bureau of Conservation, Economics, and Energy Planning, "Electric Power Outlook for Pennsylvania: 1999-2004" (July 2000).

35. PJM Interconnection Press Release, "Allegheny Power and PJM File with FERC to Create PJM West" (Mar. 15, 2001). <www.pjm.com/about/news/news_articles/2001/20010315_ap_pjm_file_with_ferc.pdf>

36. Comments of the Pennsylvania Utility Commission, Federal Trade Commission Retail Electricity Study (April 9, 2001).

37. Energy Information Administration, Inventory of Nonutility Electric Power Plants in the United States, 1999, Table 6. Energy Information Administration, Inventory of Electric Utility Power Plants in the United States, Table 22.

38. Comments of the Pennsylvania Utility Commission, Federal Trade Commission Retail Electricity Study (April 9, 2001).

39. Pennsylvania PUC Publication: Pennsylvania Electric Choice, Frequently Asked Questions. <www.electrichoice.com/public/frequent.html>

40. Pennsylvania PUC Publication: Pennsylvania Electric Choice, How to Shop Guide. <www.electrichoice.com/public/guide.html>

41. 52 Pa. Code, §54.122.10 (2001).

42. *Id.* at §54.8.

43. *Id.* at §54.122.2.

44. Comments of the Pennsylvania Utility Commission, Federal Trade Commission Retail Electricity Study (April 9, 2001).

45. *Id.*

46. 66 Pa. Cons. Stat. §2807.D (2001).

47. 52 Pa. Code, §54.7 (2001).

48. Comments of the Pennsylvania Utility Commission, Federal Trade Commission Retail Electricity Study (April 9, 2001).

49. 66 Pa. Cons. Stat. §2807.D (2001)

50. Comments of the Pennsylvania Utility Commission, Federal Trade Commission Retail Electricity Study (April 9, 2001).

51. *Id.*

52. Energy Information Administration, Retail Unbundling – Pennsylvania. <www.eia.doe.gov/oil_gas/natural_gas/restructure/state/pa.html>

Texas: Overview of Retail Competition Plan and Market Response

Administrator and Start Date

The Texas restructuring bill was signed June 18, 1999. The Public Utility Commission of Texas (PUC) will administer the transition to retail competition, which is scheduled to begin with a pilot program starting June 1, 2001. During the pilot program, five percent of customers will be able to choose their competitive supplier. Retail competition for all customers will begin January 1, 2002.[1] Competition will not be open in areas served by municipal utilities and electric cooperatives, unless the governing body of the city or cooperative opts in to retail competition.

Services Open to Competition

Generation and billing (retail sales). Competitive metering for commercial and industrial customers will begin January 1, 2004. Metering for residential customers will be regulated until September 1, 2004 or until 40% of customers have switched to an competitive supplier, whichever is later.[2]

Consumer Options

After January 1, 2002, customers will have the option of choosing a competitive supplier, choosing an aggregator, and, in the case of residential and small commercial customers, choosing standard offer service. Customers participating in the pilot program have the option of choosing a competitive supplier or an aggregator.[3]

Alternative Suppliers Licensed to Provide Service

In order to be licensed to provide service in Texas, competitive suppliers must meet financial creditworthiness and technical standards.[4]

Pricing Trends

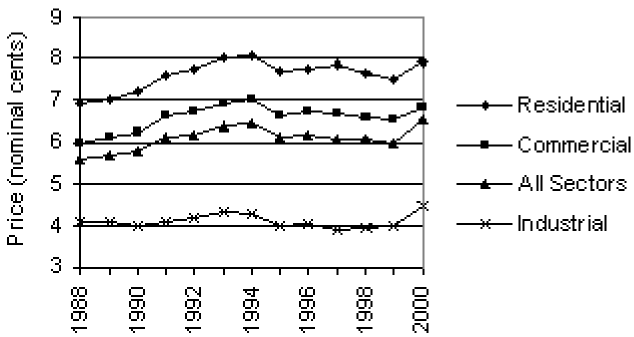
As Table 1 shows, all three customer sectors experienced increasing prices during the first part of the 1990's. After peaking between 1993 and 1994, these prices declined slightly, and then held steady until 2000, when they increased to levels comparable to those during the 1993-1994 period.

Table 1. Average Annual Price per KWh by Sector (nominal cents)

	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
Residential	6.9	7.0	7.2	7.6	7.7	8.0	8.1	7.7	7.8	7.8	7.7	7.5	7.9
Commercial	6.0	6.1	6.2	6.6	6.7	6.9	7.0	6.6	6.7	6.7	6.6	6.5	6.8
Industrial	4.1	4.1	4.0	4.1	4.2	4.3	4.3	4.0	4.0	3.9	3.9	4.0	4.5
All Sectors	5.6	5.7	5.8	6.1	6.2	6.4	6.4	6.1	6.2	6.1	6.1	6.0	6.5

Source: Energy Information Administration

Figure 1. Average Annual Price Per KWh by Sector



Price Changes for Standard Offer (or Regulated) Service

Distribution utility rates are frozen at September 1, 1999 levels until January 1, 2002.[5] On January 1, 2002, rates for residential and small commercial customers will be reduced approximately 6% from January 1, 1999 levels and then frozen until January 1, 2007, or until 40% of residential or small commercial customers have chosen a competitive supplier. The January 1, 2002 reduced rate is called the "price to beat."[6] It is subject to adjustment twice per year, to reflect changes in fuel costs.

Standard Offer Service Provider

Until December 31, 2001, standard offer service will be provided by the distribution utility. When competition for all customers begins on January 1, 2002, standard offer customers will be transferred to the retail affiliate of the distribution utility. The affiliates, as are independent retail suppliers, are termed "retail electric providers (REP)." Prices for standard service will be fixed at the "price to beat." The PUC will designate a REP to be the provider of last resort for customers whose supplier goes out of business or terminates service to a customer. The standard offer service provider will offer this service at a fixed, non-discountable rate approved by the PUC.[7]

Standard offer service customers have been divided into three classes: residential, small non-residential, and large non-residential. The standard offer service provider will supply customers in any or all of these three classes who either request standard offer service or are assigned to standard offer service because they are not receiving service from a REP, for any reason. The rates for standard offer service will be established through a competitive bid process. A bidder for standard offer service may bid for any customer class, or for more than one class. An affiliate of a distribution utility cannot bid to be the standard offer service provider in the distribution utility's service territory during the period when the price to beat is in effect.[8]

Recovery of Stranded Costs/Transition Costs

Distribution utilities can recover all of their net non-mitigated stranded costs through a transition charge. The PUC will determine the amount of stranded costs eligible for recovery, which will include uneconomic generation related assets, and purchased power contracts. Before January 1, 2001, distribution utilities will be allowed to securitize 100% of their regulatory assets, and up to 75% of estimated stranded costs to be recovered over a period not exceeding 15 years.[9] The PUC will make an initial determination of the amount of stranded costs eligible for recovery in setting the rates for delivery of electricity, which will be effective beginning in 2002. Two years after the beginning of competition, the PUC will hold a hearing to make a final determination of stranded costs, and may modify charges to correct stranded cost recovery if it finds that the distribution utility is recovering too much or not enough. Following the true-up of stranded costs in 2004, any remaining stranded costs may be securitized.[10]

Customer Switching and Eligibility

During the pilot program, 5% of customers will be eligible to choose a competitive supplier. Residential customers will be able to choose on a first come, first serve basis, until the 5% threshold is reached. If more than 5% of non-residential customers sign up for the pilot program, a lottery will be conducted to determine who will be eligible to participate. Municipal utilities and cooperatives do not have to allow their customers to choose a supplier, but they can voluntarily participate in the customer choice program.[11] Texas has residential service obligation, under which an REP which serves at least 300 MW of load must serve residential customers. The REP will pay a penalty if it does not meet a requirement that not less than 5% of sales be residential sales.[12]

Switching Process[13]

***Sign-up Method*:** A customer who decides to switch suppliers does not have to notify his distribution utility; once he has decided to switch, he informs the competitive supplier, which will inform the distribution utility. After he contacts the competitive supplier, the competitive supplier will mail the customer the terms of service.

***Right of Rescission*:** The customer has 7 days from the date of the postmark on the terms of service in which to cancel his choice. There is a 3-day cancellation period for Internet transactions .

***Restrictions and Minimum Stay Requirements*:** A customer can switch suppliers at any time subject to the terms of his contract with the competitive supplier. There are no switching fees unless a customer requests a special meter reading.

Public Benefits Programs

The legislation provides for a non-bypassable per kilowatt-hour systems benefit charge. This charge will provide funds for low-income customer protection, consumer education programs, and for property tax losses in school districts. The systems benefit charge will not exceed 50 cents per megawatt hour, except for the period from January 1, 2002 through December 31, 2006 when the PUC may set the charge at an amount not exceeding 65 cents per megawatt hour in order to collect enough revenue for a 10% rate reduction for low-income customers. The charge will be allocated based on the number of kilowatt hours used by a customer.[14] All customers must have access to energy efficiency alternatives.[15]

Separation of Generation and Transmission

By January 1, 2002, utilities are required to separate their business activities into three units: a wholesale electric power generation company, a retail electricity company (a "REP"), and a transmission and distribution company. This separation can take place either through the sale of assets to a third party, or by the creation of separate non-affiliated companies or separate affiliated companies owned by a common holding company.[16] After the beginning of retail competition, a distribution utility may not sell electricity or participate in the market for electricity except to procure electricity to serve its own needs.[17] Wholesale electric power generation companies that are affiliated with a distribution utility are required to auction off 15% of their installed generation capacity,[18] and no wholesale generator can own more than 20% of the installed capacity that can be sold in a region.[19] REP affiliates of transmission and distribution utilities cannot offer competitive rates to residential and small commercial customers in the territory of the distribution utility, except as the standard offer provider, until 40% of the residential and small business load in the territory is buying electricity from competitive suppliers.[20]

State RTO Involvement

Each power region has to establish one or more PUC-certified ISOs, to ensure the reliability of the regional power network.[21] Most of Texas (approximately 85%) is in the Electric Reliability Council of Texas (ERCOT), which began operations as an ISO in 1996, and is not regulated by the Federal Energy Regulatory Commission.[22] The Texas PUC has primary oversight over ERCOT, with the exception of Central Power and Light Company and West Texas Utilities Company, who are primarily regulated by FERC.[23]

New Plant Construction and Planning

Since 1995, 27 new plants have been built in Texas, with a combined capacity of over 9,300 MW. There are an additional 27 plants under construction, which will add 14,000 MW of capacity in the next three years, as well as 31 plants that have been announced for future construction.[24] There are also plans for 2,000 MW of new renewable capacity by 2009.[25] According to Energy Information Administration data, suppliers in Texas have planned 33,445.9 MW of generation capacity additions between 2000 and 2004.[26]

Slamming/Cramming Rules

A customer cannot be switched to a supplier without his permission. To verify that a switch has been made, the supplier must verify the customer's choice to switch. Verification must include a confirmation of the customer's billing name, address, and electric service identifier or account number to be used in making the switch; confirmation of the appropriate verification data; confirmation of the customers decision to switch to the new competitive supplier; and confirmation of the customer's designation of the new competitive supplier as his agent for the switch.[27] Written authorization of a customer's choice to switch to a competitive supplier must use a letter of agency signed by the customer.

To authorize a switch by telephone, the supplier must comply with all verification requirements, and authorization will be verified by an audio recording done by the supplier or by third-party verification. If a customer enrolls over the Internet, the transaction must be encrypted, the terms of service must be available on the supplier's website, the supplier must meet verification requirements, and it must adhere to state and federal guidelines governing the use of electronic signatures. Door-to-door sales (including personal solicitations at malls, fairs, etc.) must meet verification requirements, must provide the customer with disclosures and information about the right of rescission and the representative must wear identification which clearly states the name of the competitive supplier. Additionally, the representative must state that he is not a representative of the distribution utility and must avoid the impression that he represents the distribution utility or the standard offer service provider.[28]

If a competitive supplier switches a customer without authorization, it will have to pay the charges for returning a customer to his original supplier, pay the original supplier the amount it would have received had the customer not been switched, refund any amounts paid by the customer, and cancel any unpaid charges.[29]

The Texas law calls for the creation of an independent organization to confirm customer switches (known as the "customer registration function"). This independent organization will notify customers of a switch after it receives notification from the REP. The customer will be able to cancel any unauthorized switch. ERCOT will provide this function for both the ERCOT region and the non-ERCOT areas of Texas.[30]

Customer Billing

Most customers will receive only one bill from their REP. Customers of cooperatives and municipal utilities which have elected to participate in customer choice will have the option of receiving two bills, one from the competitive supplier, and one from the cooperative or municipal utility, or they may receive only one bill from the cooperative or municipal utility.[31]

Affiliate Name and Logo Issues

Until September 1, 2005, an affiliate cannot use the name and logo of the parent distribution utility unless it provides on business cards and in advertisements to existing and potential residential and small commercial customers in the distribution utility's service area, a disclaimer which informs the customer that the affiliate is not the same company as the distribution utility, that the affiliate is not regulated, and that the customer has no obligation to buy services from the affiliate.[32] Joint advertising and marketing are prohibited.[33]

Usage of Customer Information

Distribution utilities are required to include customer name, address, and usage information on a list of eligible customers given to competitive suppliers. Distribution utilities will provide their customers with information on how to remove their name from this list.[34]

Standardized Labeling

***Content*:** A competitive supplier is required to provide a customer with an electricity facts label which includes disclosures on pricing, contract terms, fuel mix, air emissions and wastes, and renewable energy claims. This information will be provided on a standardized label designed by the PUC.

***Timing*:** Beginning July 1, 2002, the electricity facts label must be distributed to customers with their January and July billings.[35] The electricity facts label is also included in the terms of service document given to customers before they switch suppliers.

Advertising Restrictions

All advertising and marketing materials, other than print or radio, that make claims about price, cost competitiveness, or environmental quality have to include an electricity facts label, or include a statement which gives a number to call and a website (if available) where the customer can obtain information which will allow him to compare the supplier's offer with other offers. Television or radio advertisements making claims about price, cost competitiveness, or environmental quality must also include a statement which gives a number to call and a website (if available) where the customer can obtain information which will allow him to compare the supplier's offer with other offers. Customers who contact the supplier through this information will be sent a terms of service document, which includes the electricity facts label.[36]

Consumer Education

The legislation directs the PUC to establish a consumer education program.[37]

Other Consumer Protection Measures

Customers who do not wish to receive telephone solicitations can be placed on a "do not call" list.[38] Additionally, a competitive supplier must provide a customer with a "Your Rights as a Customer" disclosure which summarizes the standard consumer protections. This disclosure will be distributed annually.[39] A competitive supplier cannot disconnect service for non-payment during extreme hot or cold weather, and competitive suppliers also have to provide deferred payment plans during these times.[40]

Retail Choice in Gas Sales

Texas has no retail choice programs for residential and small commercial natural gas customers. Large commercial and industrial customers have had options other than service from their local distribution company for many years. In 2001 approximately 50% of large commercial customers, and 70% of industrial customers bought natural gas from companies other than the local distribution company.[41]

Miscellaneous

The electric restructuring bill included many environmental protections, including that 50% of new generating capacity must come from natural gas, and that a percentage of electricity sold in Texas must come from renewable resources. The bill requires 50% reductions in nitrous oxide emissions and 25% reduction in sulphur dioxide emissions from power plants that were grandfathered when air permits were introduced under the Federal Clean Air Act. There reductions must be achieved by 2003 by retrofitting or shutting down the grandfathered units. In addition, distribution utilities that upgrade older generation facilities to meet emissions standards may recover the costs from retrofitting as stranded costs.[42] The PUC will implement additional measures to encourage natural gas generation,[43] and set procedures to reach the goal of 2000 MW of renewable capacity by January 1, 2009.[44] The PUC has adopted a renewable energy credit trading program to encourage cost-effective new renewable generation facilities.

Notes

1. Tex. Util. Code Ann. §39.102 (2001).

2. *Id.* at §39.107.

3. PUC Publication: Texas Electric Choice, Electricity Information-FAQ's. <www.powertochoose.org/residential/electricinfo/faq.html>

4. Tex. Util. Code Ann. §39.352-355 (2001).

5. *Id.* at §39.052.

6. *Id.* at §39.202

7. *Id.* at §39.106.

8. PUC Sub. Rules §25.43.

9. Tex. Util. Code Ann. §39.201, 252 (2001).

10. *Id.* at §39.262(c) (2001).

11. PUC Publication, Texas Electric Choice, Electricity Information-FAQ's. <www.powertochoose.org/residential/electricinfo/faq.html>

12. Comments of the Public Utility Commission of Texas, Federal Trade Commission Retail Electricity Study (May 1, 2001).

13. PUC Publication, Texas Electric Choice, Electricity Information-FAQ's. <www.powertochoose.org/residential/electricinfo/faq.html>

14. Tex. Util. Code Ann. §39.903 (2001).

15. *Id.* at §39.905.

16. *Id.* at §39.051.

17. *Id.* at §39.105.

18. *Id.* at §39.153

19. *Id.* at §39.154.

20. PUC Publication, Electric Competition-Fostering Competition. <www.puc.state.tx.us/ocp/competition/fostering.cfm>

21. PUC Publication, Electric Competition-Customer Choice. <www.puc.state.tx.us/ocp/competition/cchoice.cfm>

22. ERCOT, "The Market Guide: A Guide to How the Electric Reliability Council of Texas (ERCOT) Facilitates the Competitive Power Market," (Feb. 22, 2001).

23. Comments of the Public Utility Commission of Texas, Federal Trade Commission Retail Electricity Study (May 1, 2001).

24. *Id.*

25. PUC Publication, Electric Competition-Renewable Energy. <www.puc.state.tx.us/ocp/competition/renewe.cfm>

26. Energy Information Administration, Inventory of Nonutility Electric Power Plants in the United States, 1999, Table 6. Energy Information Administration, Inventory of Electric Utility Power Plants in the United States, Table 22.

27. PUC Sub. Rules §25.474.e.

28. PUC Sub. Rules §25.474.f.

29. PUC Sub. Rules §25.474.n.

30. Comments of the Public Utility Commission of Texas, Federal Trade Commission Retail Electricity Study (May 1, 2001).

31. PUC Publication, Electric Competition-Frequently Asked Questions. <www.puc.state.tx.us/ocp/competition/ecfaq.cfm>

32. Tex. Util. Code Ann. §39.157.d.5 (2001).

33. *Id.* at §39.157.d.6.

34. PUC Publication, Texas Electric Choice, Electricity Information-FAQ's. <www.powertochoose.org/residential/electricinfo/faq.html>

35. PUC Sub. Rules §25.475.e.

36. PUC Sub. Rules §25.475.b.

37. Tex. Util. Code Ann. §39.902 (2001).

38. *Id.* at §39.1025.

39. PUC Sub. Rules §25.475.f.

40. Tex. Util. Code Ann. §39.101.h (2001).

41. Energy Information Administration, *Natural Gas Monthly*, Table 25 – "Percentage of Total Deliveries Represented by Onsystem Sales, by State, 1999-2001."

42. PUC Publication, Electric Competition-Cleaning Up Air Pollution in Texas. <www.puc.state.tx.us/ocp/competition/airpol.cfm>

43. Tex. Util. Code Ann. §39.904 (2001).

44. *Id.*