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ADMITTED TO PRACTICE IN:
ARIZONA, COLORADO, MONTANA,
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DISTRICT OF COLUMBIA

January 30, 2009

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ARIZONA CORP. COMM
400 W CONGRESS STE 218 TUCSON AZ 85701

Docket Control
Arizona Corporation Commission
1200 West Washington
Phoenix, Arizona 85007

Re: Generic Proceeding Concerning
Electric Restructuring Issues
Docket No. E-00000A-02-0051
E-00000A-01-0630

To Whom It May Concern:

Enclosed for filing in the above-referenced docket are Comments on behalf of Sempra Energy Solutions LLC, Direct Energy, LLC, Constellation NewEnergy, Inc. and Shell Energy North America (US), L.P.

Please let me know if you have any questions. Thank you for your assistance.

Sincerely,

Angela R. Trujillo

Angela R. Trujillo
Secretary
Lawrence V. Robertson, Jr.

Arizona Corporation Commission
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JAN 30 2009

400 W CONGRESS STE 218 TUCSON AZ 85701

BEFORE THE ARIZONA CORPORATION COMMISSION

IN THE MATTER OF THE GENERIC PROCEEDING CONCERNING ELECTRIC RESTRUCTURING ISSUES	Docket No. E-00000A-02-0051

COMMENTS OF
SEMPRA ENERGY SOLUTIONS LLC,
DIRECT ENERGY, LLC,
CONSTELLATION NEWENERGY, INC. AND
SHELL ENERGY NORTH AMERICA (US), L.P.

January 30, 2009

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TABLE OF CONTENTS

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I. EXECUTIVE SUMMARY

The Arizona Corporation Commission ("ACC") issued Decision No. 70485 on September 3, 2008, which (1) suspended the application of Sempra Energy Solutions LLC for a Certificate of Public Convenience and Necessity ("CC&N") to provide competitive retail electric service and (2) ordered public workshops to address the policy issue of whether retail competition is in the "public interest" and to examine the potential risks and benefits of retail competition. The Commission further ordered the ACC Staff to issue a report by December 31, 2009 based on the workshops that recommends whether retail competition should be implemented in Arizona and, if so, how. The Staff conducted a workshop on November 16, 2008 and requested comments from parties.

Accordingly, Sempra Energy Solutions LLC, Direct Energy, LLC, Constellation NewEnergy, Inc., and Shell Energy North America (US), L.P. jointly submit these comments, which clearly demonstrate that retail electric competition for Arizona is in the "public interest." In fact, retail electric competition is found throughout North America with programs in 15 states, two Canadian provinces and Baja California, Mexico. Moreover, retail competition has been shown to provide substantial benefits wherever it has been introduced, including providing downward pressure on prices, improving competitiveness of businesses, creating demand for renewable products, and providing innovative new products and services to the electric market for all customers, large and small. Further, retail electric competition has achieved this demonstrated success using many different models with each state designing their own programs based on their specific policy goals. Moreover, states with successful retail markets have processes in place that allow for review and modification of the programs and protocols to

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ensure that the programs are refined over time as states adopt new policy goals or seek to enhance the success of their programs.

Arizona's current model is similarly workable. Reinstating competitive retail electric service would require neither a substantive "re-vamping" of the rules nor a time-consuming rulemaking proceeding to examine new utility services. Further, Arizona has designed its rules to minimize risk. The Commission has also established rules for customer switching, utility notification, and the Renewable Energy Standards and Tariff ("REST"), and has addressed utility cost recovery for stranded costs and business systems needed to implement retail competition. In short, Arizona is well positioned to reinstate retail electric competition.

More significantly, as discussed in Appendix A to these comments, the Commission <u>has the existing legal authority</u> to approve the applications for CC&Ns submitted by Sempra Energy Solutions LLC and other prospective competitive retail service providers. Moreover, the Arizona Constitution provides the citizens and businesses of this state with a right to choose their electricity providers and there has been no evidence provided or legislation adopted that would warrant taking away this right.

We urge the Commission to move quickly to: (a) find retail electric competition is in the "public interest;" (b) determine that the current Arizona model is substantively workable for reinstating retail electric competition; (c) lift the suspension on Sempra Energy Solutions LLC's CC&N application, completing the proceeding to decide its merits; and (d) submit such retail electric competition rules as might ultimately be determined to be necessary to the Attorney General for approval.

Nearly three years have passed since Sempra Energy Solutions LLC filed its CC&N application. Further delay will only lead to continued inefficiencies for Arizona's businesses and consumers. Accordingly, we provide herein a reasonable timetable that would

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allow ample public comment and lead to a Staff report to the Commission by June 30, 2009 and a Commission decision in September 2009. If the Commission wishes to consider substantive and procedural modifications to its current competitive retail electric program, these can be evaluated on a parallel track once the CC&Ns are issued and implemented prospectively. Arizona's risks are low, but the potential benefits of moving forward are high. Action is needed now to afford Arizona citizens and customers the products and services they both need and demand to compete in today's global economy.

II. RETAIL ELECTRIC COMPETITION IS IN THE "PUBLIC INTEREST"

Retail electric competition is definitively in the "public interest." Competitive retail electricity markets nationwide have proven that they enhance the competitiveness of local businesses, create demand for renewable and demand response products, and introduce innovative new products and services for the electric market that are available to all customers, large and small. In this section, we first describe the benefits to be gained from retail electric competition in Arizona and then outline the demonstrated record of success that such competition has achieved nationwide. Notably, once retail choice was implemented and became firmly established, no state has later *eliminated* this right for its consumers.[1]

A. Consumers, utilities and the Commission can and will benefit from retail electric competition; no legal barriers exist to moving forward.

1. Consumer perspective

As we heard at the November 16, 2008 Arizona workshop, end-use customers want to choose electric products and services that best meet their business needs. For some customers, that means faster and easier access to renewables; for others, it may mean long-term fixed-price contracts that reduce the risk of price increases in the future; for still others, it

[1] The state of Virginia withdrew retail choice only after a few retail customers had departed utility electric service.

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means the ability to structure a package of products and services that can meet corporate objectives for carbon-neutral sustainability. Today, consumers have choices for virtually every product they buy. The ability to procure telecommunication services competitively, which began after deregulation in 1984, has led to unimagined innovation, including cellular telephones, wireless internet services, and an amazing array of hardware and software that makes information instantly available. Similar innovation has been slowly entering the electricity market as competitive retail markets expand nationwide. Section II.B provides additional detail about the benefits accruing to consumers in states that have deployed retail electric competition.

Benefits are not limited to large customers and in fact, even accrue to smaller customers who elect to stay with utility service. Once the Commission approves one or more CC&N applications, some end-use customers will select competitive retail suppliers that provide the optimal products and services to meet their individual needs. Given the projections for high load growth in Arizona, an increase in the number of suppliers could help to *lower* the projected increase in rates for utility customers, as competition puts *downward* pressure on utility retail rates.

2. Utility perspective:

Because Arizona utilities are currently required to meet significant increases in forecasted demand for electricity, the increase in competition to serve load would create significant benefits for utilities by reducing their needs for capital to (1) construct or procure new generation resources and (2) meet associated credit requirements.

Furthermore, while retail competition raises the possibility of load migration to and from utility service, load migration need not be an insurmountable problem for the utilities, given that specific switching rules apply that provide some market certainty about when and how load migration can occur. Fluctuations in load are a fact of life for utilities, which are already expected to manage their resource portfolios as needed and sell any excess in the wholesale market. In short, load migration is nothing new and should be a component of the utilities' existing forecasting processes in conjunction with other planning factors that are quite normally evaluated and effectively dealt with as part of the utility service.

Another benefit of competition involves Arizona's REST program. As discussed in the next Section, results in other states with retail electric competition have shown that retail choice unleashes consumer demand for renewables and for energy from carbon-neutral resources. That demand should help stimulate the development of renewables in Arizona and the West, which will, in time, provide additional supply for the utilities (and ESPs) to meet the REST requirements.

Finally, the Arizona Independent Scheduling Administrator's Association ("AZISA") stands ready to facilitate retail choice by scheduling power between the ESPs and the utilities. The AZISA system was already tested and found acceptable by Arizona Public Service Company when retail choice first began. Since then, the organization remains in place and is ready to go into full operation.

3. ACC perspective:

The Commission has an unprecedented opportunity before it with the confluence of growing electricity demands in Arizona and enhanced consumer interest in renewable sources. A 2008 report by the NorthBridge Group found that recent experience in the restructured electricity markets and significant experience in other competitive industries suggests that competitive markets are well equipped to address the current multitude of issues in this country.[2]

[2] *Embrace Electric Competition or its Déjà vu All Over Again*, The NorthBridge Group, October 2008, p. 5. Provided in Appendix D herein.

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Retail electric competition would stimulate demand for and development of renewables facilitating REST compliance. Increasing the number and type of retail suppliers would additionally ease the utilities' credit and capital requirements. The entry of diverse suppliers to the retail market would bring innovation and apply downward pressure on prices. Demand response products that meet business needs would be developed and deployed by the competitive market to reduce the growth of peak-load requirements, thereby avoiding construction of some thermal peaking units. And finally, direct competition would force utilities to operate more efficiently and to be more customer-focused and innovative on their own. Consider the U.S. Postal Service for example, which began overnight delivery services only after Federal Express was allowed to provide such competitive services that consumers highly valued. The utilities could be expected to promote their own innovative products and services in response to similar direct competition. Clearly, reinstating retail electric competition in Arizona would provide innumerable benefits.

4. Legal Background:

No legal or regulatory obstacles exist to prevent the Commission from considering and acting upon Sempra Energy Solutions' or any other ESP's CC&N application at this time. First, the Commission's authority to grant these CC&Ns derives from a combination of: (a) Article 15 of the Arizona Constitution and (b) Title 40 of the Arizona Revised Statutes ("A.R.S."). Second, the Commission's authority to prescribe or approve rates for retail electric service provided by ESPs derives from the Commission's authority under Article 15, Section 3 of the Arizona Constitution, which authority is acknowledged and "confirmed" in A.R.S. § 40-202(B). Moreover, the Phelps Dodge decision has not altered the Commission's authority to grant a CC&N to a qualified ESP applicant, thereby authorizing the applicant to provide competitive retail electric services. The Phelps Dodge decision does nothing to prohibit the

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Commission from lawfully approving rates and charges for lawfully certificated ESPs for the provision of competitive retail electric service. In Appendix A, a detailed discussion of the legal background regarding retail electric competition in Arizona is provided, including tables describing the status of Arizona's retail electric competition rules.

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B. Retail electric competition has a demonstrated record of success using a variety of models.

Retail electric competition has been successful in a number of states. Moreover, this success has been achieved through a variety of competitive retail models. Individual states have defined their own retail programs independently, in order to implement programs that best fit the policy goals and objectives for their respective constituencies. These retail programs are not static; states are constantly refining their retail programs to promote competition and enhance their success.

As is evident in the following map, retail competition is flourishing in many states and in initial phases in many others.[3] Contrary to what some parties have claimed in this proceeding, retail competition is not an "experiment" or even a new idea. Rumors abound that retail choice is a "product of the 1990s" whose time has come and gone. That is simply not true.

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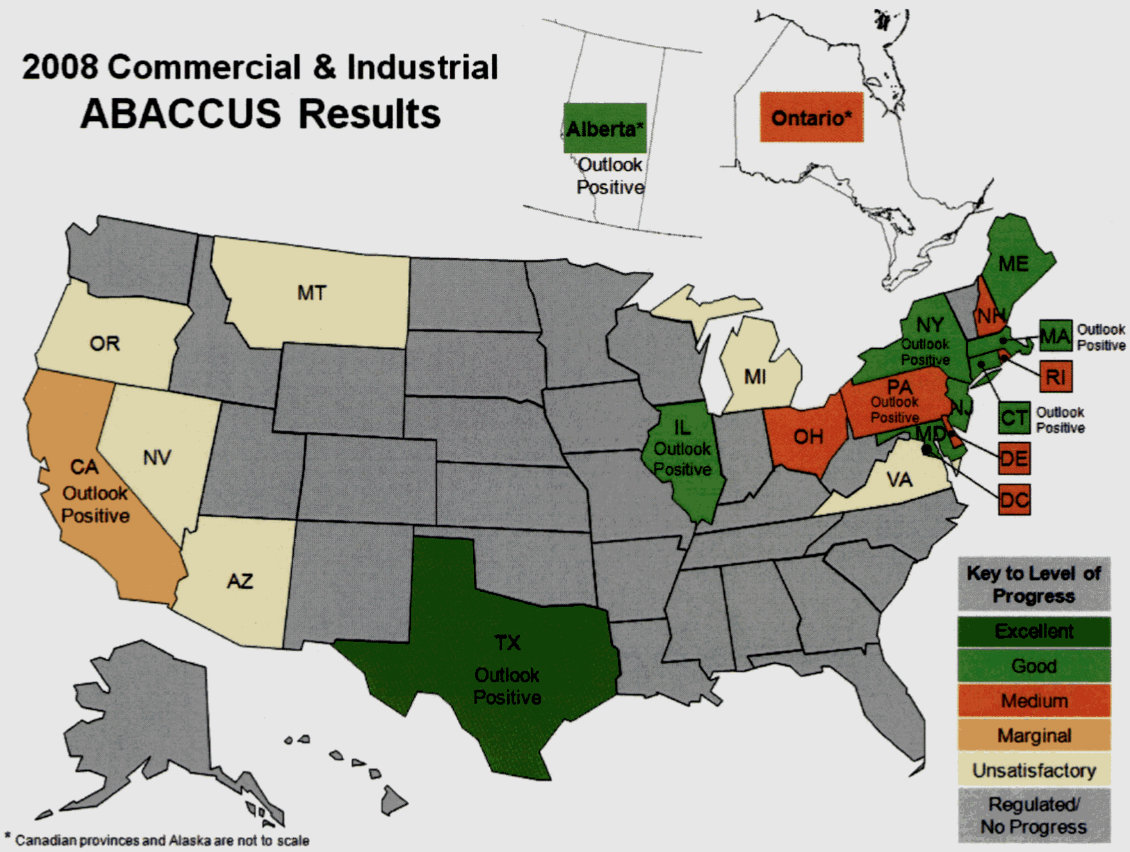
[3] This map and the accompanying report are provided in Appendix B to these comments.



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In fact, retail consumers can choose their electricity providers in many major industrialized states and two Canadian provinces. Indeed, retail choice for electricity supply exists throughout the West -- California, Washington, Oregon, Nevada, Alberta, Canada, and Baja California, Mexico all have some form of retail choice. Rather than embarking on a dangerous "experiment", as parties to this proceeding have claimed, Arizona is actually lagging behind other states -- an approach that could threaten the competitiveness of its businesses in global markets. Retail choice is even more common on the East Coast, where virtually every state north of the Mason-Dixon Line and east of Michigan provides their consumers with retail choice.[4]

[4] Vermont is the only state in this corridor without retail choice.

The range of variations in models of retail electric competition is as large as the number of states offering retail choice. Beginning in 2006, the Energy Retailer Research Consortium conducted an annual assessment of retail choice in the United States and Canada (referred to as the "ABACCUS" report). The report assesses each retail program's design or "model" in a comprehensive review. For example, the researchers evaluated the rules for customer eligibility to select competitive retail supply, the design of "default service"[5] (if available), the ease of selection of a competitive supplier, the status of the wholesale market, including whether retail customers can participate directly in the organized wholesale markets run by Independent System Operators ("ISOs"), and the design of electric service for those served by competitive retail suppliers that have gone out of business, known as "Provider of Last Resort" or "POLR" service. The 2008 study results, provided in Appendices B and C, show a variety retail choice models including those that have POLR or default service and those that do not, programs that have POLR or default service supplied by the utility and those that supply it through the competitive market, models that allow all customers to shop for electricity and those that restrict eligibility, designs that operate within the confines of ISOs and those that have no such organized markets, programs that have required utilities to divest generating assets and those that remain vertically-integrated, and markets with many variations in the type of renewable portfolio standards required for retail suppliers. In short, there are significant variations among competitive retail models. The bottom line, however, is that the states have determined the model that they wish to implement.

Closer to home, Washington, Oregon and California all have some form of retail competition in which the utility distribution company ("UDC") provides default service based on cost-of-service rates, as Sempra Energy Solutions contemplates in its Arizona CC&N

[5] Default service, if provided, represents the service available to customers who elect to remain with utility service and not procure from a competitive retail supplier.

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application. The UDCs in these three western states procure power for their bundled load under the direct supervision of their regulators, and all customer classes, including large commercial customers, can elect utility service or competitive retail providers, subject to each state's switching protocols. Regarding renewables, the Western Electricity Coordinating Council ("WECC") has established the Western Renewable Energy Generation Information System ("WREGIS'), which will be the method by which the Western states can track renewable generation and compliance with renewable portfolio standards or tariffs. California and Oregon have already approved WREGIS tracking. Once the Commission approves the pending ESP CC&Ns, Arizona is well positioned to join the other Western states with retail choice, renewables and WREGIS.

While states have employed a variety of models when implementing retail competition, the success of those markets is unquestioned. The results of the 2008 ABACCUS report for commercial and industrial ("C&I") customers are shown in the map provided above. The researchers found that 15 states and two Canadian provinces have retail choice programs for C&I customers that range from "medium" to "excellent."[6] Moreover, retail competition has spurred an explosion in new product offerings and services that were previously unavailable, and unthinkable, from traditional utilities. These include renewable electricity products, sustainable and carbon-neutral energy packages, numerous demand response offerings and energy efficiency services.[7]

Although some parties have predicted dire outcomes for small customers, the companion 2008 ABACCUS report issued for residential retail choice found similar positive results, with both the Texas and New York programs listed as "excellent." In particular, 44% of

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[6] *Annual Baseline Assessment of Choice in Canada and the United States (ABACCUS) – Commercial and Industrial,* Energy Retailer Research Consortium, December 10, 2008, p. 3. See Appendix B herein.
[7] *Ibid*, p. 15.

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residential consumers in Texas, 16% in New York and 25% in Alberta have elected to shop for electricity from competitive retail suppliers.[8] However, the numbers of retail electricity shoppers alone does not tell the whole story. The report also found that retail choice allowed residential consumers to "vote" directly with their dollars and, consequently, competitive retail suppliers have responded with significant offerings of renewable and "green" products in both Texas and New York.[9] For example, in Texas, more than 26 retail electricity suppliers provide more than 90 different residential products in <u>each</u> utility service area, including a number of "green" products.[10] Clearly, robust retail competition has led to new and innovative product offerings for all customer sizes.

Similarly, a recent study conducted by the NorthBridge Group concluded that, while retail markets are still evolving nationally, data about the numbers of customers switching suppliers are not the relevant statistic. Rather, the success of these markets should be judged by the "new value-added services, market-based pricing and efficient customer consumption decisions that competition encourages."[11] This finding was confirmed in a study of the Texas residential market by Intelometry, which found vigorous competition based on price, product design, customer service and other factors, and concluded that retail electric competition "brought a level of innovation to the Texas market that would not have existed absent competition."[12] In summary, the report found:

> The introduction of retail electricity competition in the Texas electric market in 2002 has brought consumers an array of retail electric service and pricing options for meeting their electricity needs that did not exist previously. Consumers now have the ability to select from one of many 100-percent renewable energy products available in the market, and

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[8] *Annual Baseline Assessment of Choice in Canada and the United States (ABACCUS) – Residential,* Energy Retailer Research Consortium, December 10, 2008, p. 2. See Appendix C herein.
[9] *Ibid*, p. 19.
[10] The NorthBridge Group, *loc. cit.*, p. 4. See Appendix D herein.
[11] *Ibid*, p. 61.
[12] *Texas Retail Competition – Impact on Residential Prices 1995-2008,* Intelometry, December 1, 2008, p. 4. See Appendix E herein.

> [competitive retail suppliers] continue to develop products and offerings to reflect consumer preferences and dynamic market conditions. This competitive market is in stark contrast to the one-size-fits-all paradigm that existed prior to 2002, when residential consumers had no choice in their electric service.[13]

The notion that retail electric competition has led to higher prices for residential consumers was also debunked by the Intelometry report. The report found that, although prices have risen since retail choice began in Texas in 2002, retail electric competition is "not a contributing factor. Other factors, such as the significant increase in natural gas prices since 2002, are responsible."[14] The report further concludes that "retail competition has applied downward pressure on residential electric prices in Texas."[15]

Consumers want to choose their electricity supplier just as they can choose their cell phone company in order to manage their own costs. Even in crisis-scarred California, a recent poll conducted by the California Alliance for Competitive Energy Solutions ("CACES")[16] discovered that 90 percent of those surveyed support the ability to choose electricity suppliers.[17] The overwhelming majority believe they will benefit when companies have to *compete* for their business. In addition, nearly 80 percent of respondents expect retail competition to lead to the development of new energy products and technologies and nearly 60 percent said they would choose an "environmentally responsive source of energy."

In summary, consumers want choice and their varied demands will drive innovation. Consumers in many states in the West and the rest of the country have already benefited from competitive retail markets. Competitive retail electric markets are no longer an

[13] *Ibid*, p. 33.
[14] *Ibid*, p. 3.
[15] *Ibid*, p. 33.
[16] The California Alliance for Competitive Energy Solutions ("CACES") is a coalition of public and private entities that support lifting the suspension of direct access for the electricity market in California.
[17] The July 21, 2008 press release describing the poll results is found on the CACES web site at http://www.ca-aces.org/releases/public%20opinion%20on%20customer%20choice%20release.pdf.

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"experiment," but a vital tool for meeting the business and personal needs of consumers in the 21st century, while achieving significant state policy goals for renewable energy and demand response. Moreover, there is no one "model" for retail choice that "works." Many models "work" and Arizona's current model will work as well. The Commission needs to act quickly to reinstate retail electric competition in Arizona by finding that such competition is in the "public interest," lifting the suspension on Sempra Energy Solutions' CC&N application (and other pending ESP applications), and completing the proceeding for approval of the CC&Ns. While modifications to Arizona's current retail model could assist the Commission in more quickly achieving desired policy goals, any such modifications desired by the Commission can be considered on a parallel path and implemented prospectively after the CC&Ns are approved.

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C. Reinstating Retail Electric Competition in Arizona Will Spur Demand and Development of Renewable Resources and Demand Response Products

As described in Section II.B above, competitive electric retail markets in other states have created an explosion of new products and services for end-use customers, not the least of which provide "green" resources to consumers or reduce electricity demand through demand response and energy efficiency, which postpones or avoids the need for construction of new thermal generation.

For example, Texas opened its retail market to competition in 2002, allowing all customers to choose a non-utility supplier. The ensuing demand there for "green" power, along with the ability to site wind resources, have led to a massive expansion of wind resources. Whereas in 1995, Texas had virtually no wind turbines operating in the state, it produced 4,500

MW by 2007, had 3,600 MW under construction and/or announced and an additional 35,000 MW of planned wind development.[18]

In California, consumer demand for renewables was a major bright spot in the competitive retail market, particularly for residential customers. Prior to the suspension of retail choice and at its peak in mid-2000, more than 215,000 end-use customers in California elected to procure electricity from renewable sources for a total 261.7 million kWh in August of that year.[19] Although retail electric suppliers only garnered about 2% of residential retail load at the peak of California's competitive retail market, most of residential direct access customers elected renewable sources for their electricity needs.[20] To our knowledge, this "green" market, which began when California's market opened in April 1998, was the first one of its kind in the world.

In fact, the ABACCUS report, referenced above and provided in Appendix B, notes that the societal goals of reducing electricity demand and increasing renewable resources are "ideally suited" to be tackled through competitive markets.[21] Businesses are embracing sustainable practices that help them reduce costs, meet consumer demands for "green" companies, and manage business risks in global markets. Seeking products and services in the competitive retail electricity market is a necessary tool for consumers and businesses to meet their needs.

It is also necessary to clarify the role of demand response in competitive markets. Some parties have argued that retail electric competition is unworkable without first implementing utility-run demand response programs. This is not the case. Whereas retail

[18] *ERCOT Texas's Competitive Power Experience: A View from the Outside Looking In*, Analysis Group, October 2008, pps. 46-47.
[19] *Consumer Credit Renewable Resources Account: Report to the Governor and the Legislature,* California Energy Commission, Report # 500-03-008F, April 2003, pps. 4 and 14.
[20] We derived this conclusion from the results provided in the 2003 CEC Report cited above along with data on direct access customers reported by the California Public Utilities Commission and available at: http://www.cpuc.ca.gov/PUC/energy/electric/Electric+Markets/Direct+Access/thru2008.htm.
[21] ABACCUS report, pps. 21-22.

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electric competition began in the United States in 1997, demand response programs have only recently been implemented. As described above, retail competition for all sizes of customers has been implemented successfully in many states – without the need for implementing demand response programs concurrently.[22]

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[22] Demand response seems to be particularly effective in states with organized *wholesale* power markets. Bidding demand response into such markets has been shown to be highly effective for mitigating prices and reducing the potential for wholesale market manipulation by suppliers.

III. RETAIL ELECTRIC COMPETITION DOES NOT POSE ANY "RISKS" TO ARIZONA THAT ARE NOT EITHER OFFSET BY BENEFITS TO BE ACHIEVED THROUGH COMPETITION OR CONTROLLED THROUGH MEASURED REGULATION

The discussion of implied "risks" associated with retail electric competition has been vague at best in this proceeding. From the discussion at the November 16, 2008 workshop, we list the following risks identified by some parties:

- Higher retail prices than would otherwise be expected without retail competition.
- "Cherry picking" of customers.
- Additional utility costs associated with customer switching.
- Stranded cost recovery for utilities.
- Complications for Integrated Resources Planning ("IRP")
- Market upheavals, similar to California's energy crisis in 2000-2001.
- Risks of leaving or staying on utility service.

We address each issue in turn.

Clearly, a major concern is that, somehow, allowing retail electric competition would cause retail prices to rise beyond what they would have otherwise been. As we discussed in Section II.B, however, the most comprehensive study conducted to date, which evaluated one state with retail electric competition, has found that retail competition puts *downward pressure* on retail rates.[23] This logical result was also the norm in every other industry in which competition has been introduced.[24]

Those concerned about "cherry picking," seem to be arguing that all the "high-value" utility customers would depart. We are unsure just what "risk" this imposes on the utility or its remaining customers. Perhaps, there is a concern that the remaining customers would bear higher

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[23] Intelometry Report, p. 33.
[24] The NorthBrideg Group, p. 5.

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rates because utility fixed costs would have to be recovered from a smaller pool of customers. However, as discussed above, when accounting for other variables in the electricity market, higher rates were not attributed to retail electric competition.[25] Moreover, Arizona utilities will have to procure additional resources to meet load growth. Consequently, the remaining retail customers *benefit*, because the utility obligation to procure resources needed to meet the forecast load for the departing customers is eliminated. A regulatory mandate to avoid "cherry picking" would indeed create a perverted result, preventing the very customers who gain the most value from competition from doing so.

Some have argued that retail electric competition in Arizona will impose additional costs on the utilities for billing changes and tracking customer switching. However, these costs are sunk, having already been incurred when the retail markets first opened in Arizona. In addition, the Commission has already addressed utility claims for stranded cost recovery in previous proceedings.

The Commission has a proceeding underway to address IRP for the utilities. Some have argued that retail electric competition would "complicate" IRP and require rule changes. In fact, IRP processes that govern utility procurement practices provide a venue for <u>mitigating or avoiding</u> potential stranding of long-term resources and their fixed costs that might otherwise result from significant utility load variations that may result from retail competition among other factors. For example, Oregon specifically allows its UDCs to recover unexpectedly high stranded costs that are directly attributed to retail load migration. However, the incumbent utilities plan their long- and short-term resource acquisitions and construct resource portfolios in anticipation that certain levels of loads will either depart or re-enter utility service.

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[25] Intelometry Report, pps. 25-33.

As mentioned, a primary objective of utility procurement is to implement a comprehensive method for addressing uncertainties in load forecasting. Uncertainties include natural gas prices, economic conditions, weather, transmission system changes, and federal policy changes. Because customers' electricity demand changes rapidly and sometimes unpredictably, utilities are already in the business of evaluating uncertainties of many kinds and procuring a flexible portfolio of resources that can be unwound (or increased) as needed to reflect known conditions. Departing load is just one more uncertainty to be evaluated and addressed. Therefore, IRPs can easily reflect the results of retail electric competition by adjusting demand forecasts and resource portfolios.

Further, Arizona utility tariff provisions currently in place require one-year notice for a customer to return to utility service. If the customer fails to provide such notice, the customer is required to pay the utility's incremental cost of service. These provisions were designed both to shelter the utility from risk that it would be unable to recover its costs of serving the returning customer and to minimize an incentive for customers to return when utility average costs are lower than prevailing market rates. In addition, these provisions protect the utilities' remaining customers, who stay on existing utility rates, from subsidizing returning customers.

At the November 16th workshop, several parties also mentioned the "scary" events that transpired in California during the 2000-2001 energy crisis. Several also referred to recent high prices in Texas. We must make one point crystal clear. These events were not caused by the presence or operation of retail choice in those markets. Rather, they were reflective of market conditions or flaws in the wholesale markets in those states. Although high prices in wholesale markets inevitably spill into retail markets (as they did most recently in Texas), retail markets were not the source of the events nor did retail markets exacerbate the events.

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Finally, some parties seem to argue that customers have "risk" once they leave the utility, or, conversely, they have "risk" if they stay. First, we note that a customer has absolutely no obligation to leave utility service. We have already explained that there is no evidence customers remaining on utility service would pay higher prices as a result of retail electric competition. However, customers that choose to leave utility service must realize a material benefit to make that move. As with any competitive market, if a competitive retail supplier cannot offer material benefits to retail customers, the supplier will go out of business. The utility suffers little risk from such a supplier exiting the market. If the customer returns to the utility without the required notice, it will pay the utility's incremental cost of the service, leaving the other utility customers unaffected by the return. However, the customer is not <u>required</u> to return to utility service; that customer may choose to obtain service from another competitive retail supplier, thereby minimizing its risk of costs that may it may incur in returning to utility service. In addition, the Commission has required ESPs to post credit support to protect consumers in case the ESP defaults.

In fact, Arizona's current approach to retail electric competition has been designed to protect both the utility and the end-use customers from risk. The Commission has established rules for customer switching, credit support, utility notification, REST, and scheduling power through the AZISA. The Commission has also addressed utility cost recovery for stranded costs and business systems needed to implement retail competition. In summary, Arizona's risks are low, but its potential benefits are high. Some argue that the Commission should "go slow" in restating retail electric competition. We counter that this process has been methodical and that Arizona is now in great danger of lagging significantly behind other states in its competitive framework, disadvantaging businesses that need to compete in today's global economy. We urge the Commission to take action now.

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IV. CONCLUSION

Strong evidence points to the success of retail electric competition nationwide for all customers, large and small. Customers demand retail choice and need it to enhance their own competitiveness in the global market. Moreover, the creativity unleashed through the competitive retail market spurs demand for green products and services, thereby creating real demand for development of renewables (rather than by regulatory fiat). Retail electric competition is clearly in the "public interest."

In these comments, substantial evidence has been provided to document that many different models for retail electric competition can and do work. Retail competition is not an "experiment," but a well-documented success story across the country. In fact, Arizona is surrounded by states with retail competition and risks lagging behind.

Arizona's current rules for retail electric competition are substantively workable and can be used as a starting point for the re-initiation of competition. Once the pending CC&N applications are approved, the Commission can decide whether it wishes to refine those rules prospectively to enhance the success of retail electric competition consistent with established policies to better meet the needs of its constituents.

The Commission has the existing legal authority to approve the applications for CC&Ns submitted by competitive retail electric service providers on a case-by-case basis. As these comments demonstrate, the path to such approval is simple and straightforward. Moreover, the Arizona Constitution provides the citizens and businesses of this state with a right to choose their electricity providers. There has been no evidence provided or legislation adopted that would warrant taking away this right.

As described above, the risks are small and manageable and the benefits of moving forward significant. Accordingly, we urge the Commission to reject the tired and outdated claims of the naysayers and move Arizona toward a more competitive and productive future. Specifically, we respectfully request that the Commission:

1. Move quickly to find retail electric competition in the "public interest" for Arizona and reinstate retail choice based on the current model. Because ample documentation demonstrates substantial benefits from retail electric competition, further delay is unwarranted. In that regard, we propose the following schedule:
   - April 30, 2009 – Issue Staff white paper finding retail electric competition in the public interest and the current Arizona model workable;
   - Early May, 2009 – Hold workshop on Staff white paper;
   - May 20, 2009 – Parties submit comments on Staff white paper;
   - June 1, 2009 – Parties submit reply on Staff white paper;
   - June 30, 2009 – Final Staff white paper issued;
2. September 2009 – ACC decision issued to reinstate retail electric competition by (a) lifting the suspension on Sempra Energy Solutions LLC's CC&N application and (b) setting an expedited timetable for completing the proceeding to consider its merits.
3. Submit such retail electric competition rules as may be determined to be necessary to the Attorney General for approval.

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4. Consider substantive and procedural modifications to the current program for retail electric competition prospectively, as determined to be appropriate by the Commission.

Dated this 29th day of January 2009.

Respectfully submitted,

SEMPRA ENERGY SOLUTIONS LLC,
DIRECT ENERGY, LLC,
CONSTELLATION NEWENERGY, INC. AND
SHELL ENERGY NORTH AMERICA (US), L.P.

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The original and thirteen (13) copies
of the foregoing Comments (and Attachments A-E)
will be filed on January 30, 2009 with:

Docket Control
Arizona Corporation Commission
C/O 400 W. Congress, Suite 221
Tucson, Arizona 85701

In addition, a copy of the foregoing Comments
(and Attachments A-E) is being transmitted electronically
to each party of record.

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APPENDIX A

LEGAL BACKGROUND

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I. The Commission's authority to grant Electric Service Provider ("ESP") Certificates of Convenience and Necessity ("CC&N") derives from a combination of (i) Article 15 of the Arizona Constitution and (ii) Title 40 of the Arizona Revised Statutes.

Article 15, Section 2 defines what constitutes a "public service corporation." Under this definition, an ESP, engaged in the sale at retail of electric generation service, is a "public service corporation" under Arizona law.

A.R.S. § 40-202(B) declares that "it is the public policy of this state that a competitive market shall exist in the sale of electric generation service," and it "confirms" a wide range of powers of the Commission to accomplish the "transition to competition for electric generation service." Such powers include the authority of the Commission to "establish reasonable requirements for certificating and regulating electricity suppliers that are public service corporations." [A.R.S. § 40-202(B)(2)] It is important to note in this regard that A.R.S. § 40-202(B)(2) does not presume to prescribe the nature or extent of such requirements as may be necessary, in order to accomplish the transition to competition. Rather, that is left to the discretion of the Commission, subject to its compliance with applicable Arizona law.

A.R.S. § 40-281(A) provides "a public service corporation shall not begin...service...without having first obtained from the Commission a certificate of public convenience and necessity." It is further important to note that neither A.R.S. § 40-202(B) or A.R.S. § 40-281(A) require the existence of rules or regulations governing the transition to competition as a condition precedent to the legal authority of the Commission to grant an ESP CC&N. Rather, whether and when to grant an ESP CC&N is entirely within the discretion of the Commission, subject to its compliance with applicable Arizona law.

II. The Commission's authority to prescribe or approve rates for retail electric service provided by ESPs derives from the Commission's authority under Article 15, Section 3 of the Arizona Constitution, which authority is acknowledged and "confirmed" in A.R.S. § 40-202(B).

Article 15, Section 3 confers upon the Commission "full power...to prescribe...just and reasonable rates and charges to be made and collected by public service corporations...for service...and reasonable rules, regulations and orders by which such corporations shall be governed in the transaction of business within the state." In exercising such ratemaking authority, the Commission must comply with applicable Arizona law.

III. The Phelps Dodge decision has not altered the Commission's authority to grant an ESP CC&N to a qualified applicant, thereby authorizing the applicant to provide competitive retail electric services.

The Phelps Dodge decision does not stand for the proposition that the Commission cannot grant ESP CC&Ns until a complete set of electric competition rules has been legally promulgated. That issue was not before the Arizona Court of Appeals; and a conclusion to that effect would be inconsistent with applicable Arizona law.

The sole Electric Competition Rule, which was held by the Phelps Dodge decision to be facially invalid, is not indispensable to the ability of the Commission to effectively oversee and regulate retail electric competition, including granting ESP CC&Ns. More specifically, with reference to R14-2-1611(A) [Rates], the court found that any Commission review and approval of ESP rates and charges must comply with the Commission's responsibilities under Article 15, Section 3 and Article 15, Section 14 of the Arizona Constitution. Hence, there is no rule which could legally define in advance, and in the absence of evidence, what constitutes a "just and reasonable" ESP rate or charge, which is what R14-1611(A) had attempted to do. However, the Phelps Dodge decision also specifically found that R14-2-1611(A) could be severed from the remainder of the Electric Competition Rules with regard to the issue of whether the rules were incompatible with the Commission's constitutional responsibilities under the Article 15, Section 3 and Article 15, Section 14.

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> "...we have no difficulty concluding that the rules are independent of R14-2-1611(A) and are enforceable standing alone." [Phelps Dodge at p. 15]

The two (2) Electric Competition Rules, which were held by the Phelps Dodge decision to be invalid because the Commission's promulgation thereof exceeded its authority, also are not essential to the ability of the Commission to effectively oversee and regulate retail electric competition. More specifically, with reference to R14-2-1609(C)-(J) [Transmission and Distribution Access], the Phelps Dodge decision held this rule invaded the managerial prerogative of Affected Utilities to decide how best to open access to their transmission and distribution facilities, in the absence of constitutional or legislative authority for the Commission to do so. [Phelps Dodge at p. 17] However, interim developments in the electric utility industry in Arizona pertaining to the Arizona Independent Scheduling Administrator ("AISA"), as well as a related Commission decision, suggest that the Phelps Dodge decision does not preclude AISA from continuing to perform an important role in relation to retail electric competition. In this regard, in Decision No. 68485, the Commission stated

> "We find that Phelps Dodge had no impact on the continuing economic viability of the AISA, and that it does not reduce the continued public benefit associated with maintaining Commission support of the AISA at its current level of operations. The AISA currently provides the important public benefit of keeping the possibility of retail access available in Arizona to consumers at a minimal cost, by providing potential competitors with the necessary assurance that they will have fair and equitable access to transmission until an RTO is formed and approved by FERC to take over that function." [Decision No. 68485, page 15, lines 5-11]

With reference to R14-2-1615(A) and (C) [Separation of Monopoly and Competitive Services], the Phelps Dodge decision found subsections (A) and (C) were beyond the Commission's plenary ratemaking powers, and without separate statutory authorization, and were thus invalid. However, the court also found that the intended separation of monopoly and

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competitive services could still be achieved through Affected Utilities' compliance with R14-2-1615(B), which was not challenged. More specifically, the court stated:

> "If the Affected Utilities choose to retain competitive assets for a period beyond the prescribed date, or indefinitely, the competitive market is seemingly unaffected, as long as the Affected Utilities abide by R14-2-1615(B), which prohibits them from competing." [Phelps Dodge at p. 18]

Hence, there is no legal or functional need to replace R14-2-1615 (A) and (C) with new regulations.

The electric competition rules, which were invalidated by the Phelps Dodge decision because they were not submitted to the Arizona Attorney General for Certification under the Arizona Administrative Procedure Act ("APA"), also are not indispensable to the ability of the Commission to effectively oversee and regulate retail electric competition, as the following discussion indicates:

a. R14-2-1603 [Certificates of Convenience and Necessity] Given the language of A.R.S. § 40-202(B) and A.R.S. § 40-281(A), the Commission has authority under A.R.S. § 40-281(A) to grant ESP CC&Ns on a case-by-case basis.

b. R14-2-1605 [Competitive Services] The CC&N required for an ESP in order to provide competitive retail electric service, which was required under R14-2-1605, can be obtained pursuant to the Commission's authority under A.R.S. § 40-281(A)].

c. R14-2-1609 [Transmission and Distribution Access] As to subsections (C)-(J), the previous observations regarding the same are equally applicable in this context. As to subsections (A) and (B) of R14-2-1609, the Commission has the power to impose these requirements as a part of its overall constitutional and statutory authority to regulate electric public service corporations, without the necessity of promulgating specific regulations.

d. R14-2-1610 [In-State Reciprocity] While the provisions of these regulations are desirable from the perspective of providing for a complete "level playing" field on which retail electric competition could occur, the reality is that the entities which would be subject to the requirements of these particular provisions are few and their potential impact upon retail electric competition in Arizona would be slight, if not non-existent.

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e. R14-2-1612 [Service Quality, Consumer Protection, Safety and Billing Requirements] These provisions are important to an effective regulatory scheme. However, if the Commission resumes retail electric competition at this time on a case-by-case basis, it could include the relevant provisions from this portion of the Electric Competition Rules as conditions or requirements within its decision granting an ESP CC&N. Alternatively, the Commission could condition the effectiveness of such ESP CC&N upon its receipt of the requisite Arizona Attorney General Certification, which the Commission would promptly undertake to obtain.

f. R14-2-1614 [Administrative Requirements] These provisions to the Electric Competition Rules would contribute to and enhance the overall contemplated regulatory scheme. However, the absence of such provisions would not be fatal to the effective functioning of that regulatory scheme. Moreover, most, if not all, of the actions of the Commission contemplated by these provisions fall within the scope of the Commission's broad regulatory authority under the Arizona Constitution and statutes, and thus do not require these particular provisions as a legal predicate for the Commission to act.

g. R14-2-1617 [Disclosure of Information] The observations made above with regard to R14-2-1612 are equally applicable to this portion of the Electric Competition Rules.

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The Commission can validate those Electric Competition Rules, invalidated by the Phelps Dodge decision for failure to obtain that Arizona Attorney General Certification required by the APA, by promptly submitting the same to the Arizona Attorney General and requesting the requisite certification. In that regard, and with respect to the Commission's legal ability to act promptly, as the Phelps Dodge decision notes:

> "The APA does not require the Commission to conduct any evidentiary hearing before promulgating rules." [Phelps Dodge at p.19]

Hence, the Commission could simply submit the affected Electric Competition Rules to the Arizona Attorney General in their present form and content without the need for further proceedings. Moreover, the Commission can condition the effectiveness of any ESP CC&N it might grant at this juncture upon receipt of the requisite Arizona Attorney General Certification for those Electric Competition Rules, previously invalidated for the lack of such certification.

By way of summary, and in connection with the preceding discussion in this Subsection C, attached hereto as Table A-1 is a table that depicts the current legal status of the Electric Competition Rules in the aftermath of the Phelps Dodge decision. In addition, attached hereto as Table A-2 is a table that depicts what the legal status of the Electric Competition Rules would be, assuming receipt of the requisite certification from the Arizona Attorney General.

IV. The Phelps Dodge decision also does not stand for the proposition that the Commission may not lawfully approve rates and charges for lawfully certificated ESPs for the provision of competitive retail electric service.

The Phelps Dodge decision does not stand for the proposition that the Commission may not lawfully approve rates and charges for lawfully certificated ESPs for the provision of competitive retail electric service. Rather, Phelps Dodge held that, in approving rates and charges for the ESPs which had previously been certificated, the Commission failed to satisfy the requirements of Article 15, Section 14 and Article 15, Section 3 of the Arizona Constitution, incident to an exercise of the Commission's plenary ratemaking powers.

In addition, the Phelps Dodge decision provides specific guidance to the Commission as to what it must do and what it may consider, incident to the establishment of rates and charges for an ESP for the provision of competitive retail electric service. More specifically, with regard to "fair value" rate base [Article 15, Section 14], the court indicated that:

1. The Commission has an affirmative duty to determine "fair value" rate base;
2. The Commission must consider "fair value" rate base in setting rates;
3. The Commission may consider "other information" in setting rates;
4. While the Commission cannot ignore "fair value," it is not required to set rates based on "fair value" rate base in a competitive market.

Furthermore, with regard to "just and reasonable" rates [Article 15, Section 3], the court noted that:

1. The Commission is required to determine and set rates which are "just and reasonable":

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   a. The Commission cannot let market forces alone set such rates; <u>but,</u>
   b. The Commission can consider market forces in setting such rates;
2. The Commission has a duty to discover and remedy potential overreaching and abuse by public service corporations, including Electric Service Providers;
3. The Commission also has a duty to be sure that rates are fair to public service corporations, including Electric Service Providers;
4. When the Commission looks solely to market forces to set rates, it also violates its constitutional duty to consider "fair value" rate base;
5. The Commission may authorize competitive market forces to set rates within an authorized range of rates, as long as that range has been established in a manner that satisfies the "just and reasonable" requirement.

Therefore, one can conclude that the Commission possesses the inherent power to approve rates and charges for ESPs, subject to compliance with Article XV, Sections 3 and 14 of the Arizona Constitution.

V. There are no legal or regulatory obstacles to the ability of the Commission to consider and act upon Sempra Energy Solutions' (or any other ESP's) Application at this time.

As described above, the Commission has the existing authority to approve Applications by ESPs for CC&Ns. Indeed, as these comments demonstrate, the path to such approval is simple and straightforward. Moreover, the Arizona Constitution provides the citizens and businesses of this state with a right to choose their electricity providers. There has been no evidence provided or legislation adopted that would warrant taking this right away. As discussed in the accompanying Comments, any Commission concerns about improving the success of retail competition or ensuring opportunities for ESPs and retail customers to meet Commission policy goals, such as expanded renewable and demand response options, can be addressed in parallel within the factual context of the currently pending retail competition workshop proceeding.

TABLE A-1

CURRENT STATUS OF ELECTRIC COMPETITION RULES

REGULATION	STATUS	REASON(S)
R14-2-1601	Valid	Unchallenged
R14-2-1602	Valid	Not subject to Attorney General Review; w/i ACC ratemaking power
R14-2-1603	Invalid	Subject to Attorney General Review; <u>not</u> w/i ACC ratemaking power
R14-2-1604	Valid	Not challenged
R14-2-1605	Invalid	Subject to Attorney General Review; <u>not</u> w/i ACC ratemaking power
R14-2-1606	Valid	Not challenged
R14-2-1607	Valid	Not challenged
R14-2-1608	Valid	Not challenged
R14-2-1609 (A)-(B)	Invalid	Subject to Attorney General Review; <u>not</u> w/i ACC ratemaking power
R14-2-1609 (C)-(J)	Invalid	Not w/i ACC ratemaking power <u>or</u> ARS 40-252
R14-2-1610	Invalid	Subject to Attorney General Review; <u>not</u> w/i ACC ratemaking power
R14-2-1611 (A)	Invalid	Violates Art. 15, Sec. 3 and Art. 15, Sec. 14 Constitutional Requirements
R14-2-1611 (B)-(F)	Valid	Not challenged
R14-2-1612	Invalid	Subject to Attorney General Review; <u>not</u> w/i ACC ratemaking power
R14-2-1613	Valid	Not subject to Attorney General Review; w/i ACC ratemaking power
R14-2-1614	Invalid	Subject to Attorney General Review; <u>not</u> w/i ACC ratemaking power
R14-2-1615 (A) and (C)	Invalid	<u>Not</u> w/i ACC's plenary ratemaking power, and

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		invade utilities' managerial prerogative
R14-2-1615 (B)	Valid	Not challenged
R14-2-1616	Valid	Not subject to Attorney General Review; w/i ACC ratemaking power
R14-2-1617	Invalid	Subject to Attorney General Review; not w/i ACC ratemaking power

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TABLE A-2

STATUS OF ELECTRIC COMPETITION RULES
ASSUMING RECEIPT OF ATTORNEY GENERAL CERTIFICATION

REGULATION	STATUS	SUBJECT MATTER DESCRIPTION
R14-2-1601	Valid	Definitions
R14-2-1602	Valid	Commencement of Competition
R14-2-1603	Valid	Certificates of Convenience and Necessity
R14-2-1604	Valid	Competitive Phases
R14-2-1605	Valid	Competitive Services
R14-2-1606	Valid	Services Required to be Made Available
R14-2-1607	Valid	Recovery of Stranded Cost of Affected Utilities
R14-2-1608	Valid	System Benefits Charges
R14-2-1610	Valid	In-state Reciprocity
R14-2-1611 (B)-(F)	Valid	Rates
R14-2-1612	Valid	Service Quality, Consumer Protection, Safety, and Billing Requirements
R14-2-1613	Valid	Reporting Requirements
R14-2-1614	Valid	Administrative Requirements
R14-2-1615 (B)	Valid	Separation of Monopoly and Competitive Services
R14-2-1616	Valid	Code of Conduct
R14-2-1617	Valid	Disclosure of Information

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APPENDIX B

ANNUAL BASELINE ASSESSMENT OF CHOICE IN CANADA AND THE UNITED STATES (ABACCUS) – C&I REPORT

Annual Baseline Assessment of Choice in Canada and the United States

Commercial & Industrial
ABACCUS:
An Assessment of Restructured
Electricity Markets

Energy Retailer Research Consortium
December 2008

ERRC

Energy Retailer Research Consortium
A Project of DEFG

C&I

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Acknowledgments

The Energy Retailer Research Consortium is grateful to the ABACCUS Advisory Board for its leadership throughout the study period. ERRC would like to acknowledge the contributions of the numerous regulatory commission staff members who participated in telephone interviews. Any errors in this report are the responsibility of the ERRC Projects Manager.

Table of Contents

Executive Summary

Commercial and industrial customer retail electricity choice has been successful in several North American areas. About a dozen states and Canadian provinces have made progress in restructuring their electricity markets for commercial and industrial (C&I) customers. Numerous competitive service suppliers (retailers) are competing head-to-head for C&I customers. Electricity choice is thriving for these consumers because states and provinces have achieved a balance between the flexibility afforded to large consumers and the minimal regulatory oversight necessary and desirable to build confidence in well-structured C&I markets and draw in many retailers.

A huge variety of electricity products and services is available. The opportunities are nearly limitless. Current offerings allow C&I consumers to choose among the following:

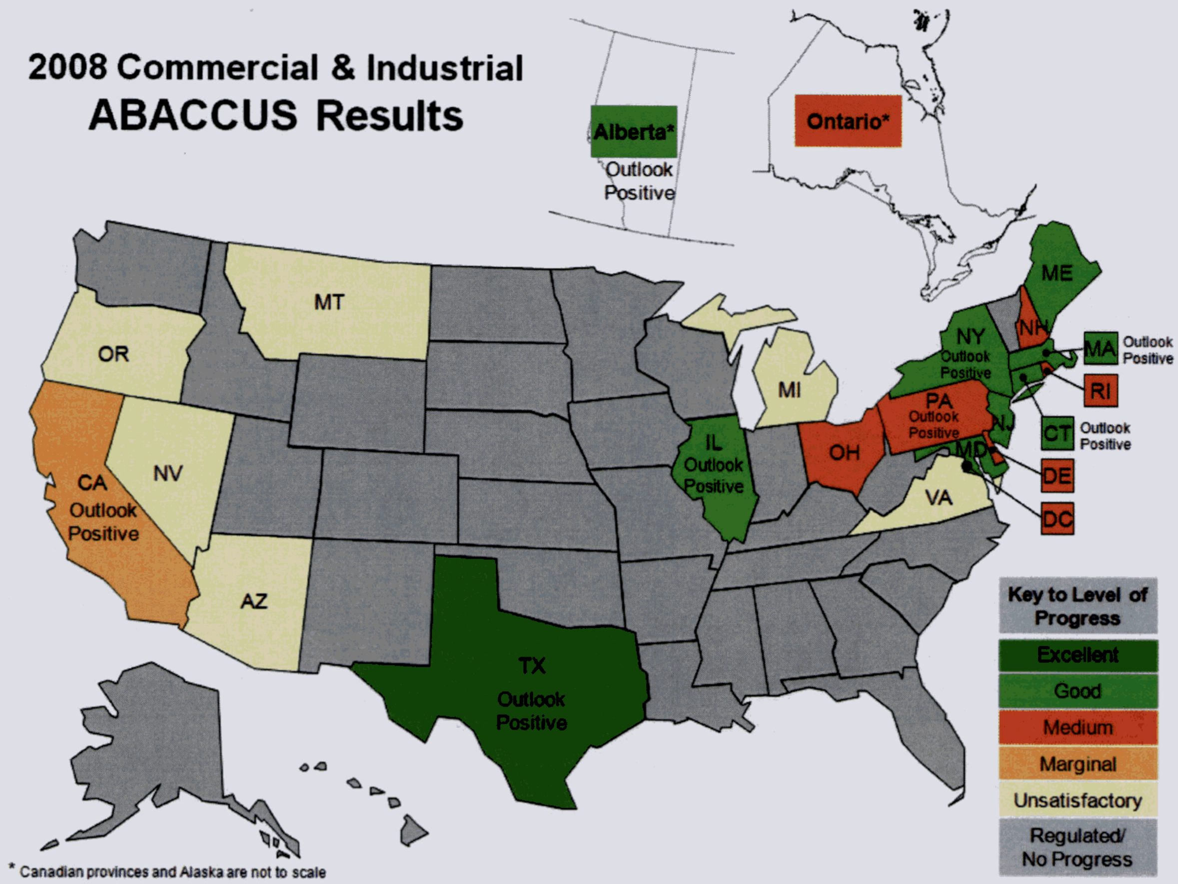
- Power contracts to lock in prices over one or several years
- Power prices indexed to a commodity price that is critical to their operations
- Prices that change hourly so the consumer can assume risk if that serves their business
- Green power that is backed by production from renewable resources
- Sustainable energy paths that are carbon neutral
- Bundled equipment maintenance costs with their electric service
- Retailer-provided services for energy efficiency, and/or energy management devices, usage monitoring and optimization of energy use for their production processes
- Combined heat and power production and contracts for on-site power development
- Demand response opportunities if their operations allow it

Large C&I consumers were the first beneficiaries of retail electricity choice largely because they were already knowledgeable about how to contract for power and associated services. Large consumers must determine how best to manage a variety of inputs into their industrial processes and business operations. Electricity is just one of many important and complex issues that large consumers deal with every day. Business needs vary, facility configurations vary, and management preferences and needs differ. The competitive market is best at satisfying these diverse needs. The old "one-size-fits-all" regulatory model does not serve consumers as well. Competition is a mainstay of the North American economy precisely because competitive service providers respond to consumers who shop. Choosing from among a variety of products, services and suppliers is routine for these consumers and the introduction of retail choice to the electric industry is spurring innovation and efficiency.

"Annual Baseline Assessment of Choice in Canada and the US" (ABACCUS) considers the market structures, business practices and regulatory policies that support retail electricity choice. Two reports are prepared. The Commercial and Industrial ABACCUS is designed to assess each state on its progress in implementing retail competition for large electricity consumers. A companion report, Residential ABACCUS, assesses retail electricity choice for mass market consumers.

The C&I ABACCUS methodology includes twenty-eight important dimensions of service. The facts in each state were assessed, scored, weighted and summed, and states ranked accordingly. The level of progress is then assessed based on qualitative input from a team of advisors. The following five terms have been selected to describe the status of each market: excellent, good, medium, marginal, and unsatisfactory.

Figure ES-1: 2008 Commercial and Industrial ABACCUS Results



More than a decade has passed since the initial US state pilot programs to offer retail choice of power supplier to consumers. A number of states have been very successful in providing the benefits of retail choice to large customers. Several of the states with lower scores have made inappropriate choices and their success with C&I consumers has been limited. These states offer retail choice, but they have had problems with implementation, including restrictions placed on the ability of consumers to choose, or on retailers to offer their products and services. In some instances the design of the default service product has not supported the introduction of competition.

Table ES-1: 2008 Commercial and Industrial ABACCUS Scores and Rank

Jurisdiction	2008 Score†	2008 Rank	2008 Assessment
Texas	75	1	Excellent
New York	57	2	Good
Illinois	56	3	Good
Maryland	53	4	Good
Alberta	49	5	Good
Maine	47	6	Good
Massachusetts	45	7	Good
Connecticut	44	8	Good
New Jersey	44	9	Good
Pennsylvania	42	10	Medium
Delaware	41	11	Medium
District of Columbia	40	12	Medium
Ohio	31	13	Medium
Rhode Island	31	14	Medium
New Hampshire	29	15	Medium
Ontario	28	16	Medium
California*	25	17	Marginal
Virginia*	NA	18	Unsatisfactory
Michigan*	NA	19	Unsatisfactory
Arizona*	NA	20	Unsatisfactory
Oregon*	NA	21	Unsatisfactory
Montana*	NA	22	Unsatisfactory
Nevada*	NA	23	Unsatisfactory

† Scoring is very tough and there is no "grading on a curve." No jurisdiction will ever score 100 because perfect scores for particular ABACCUS elements may not be ideal or even practical in a particular jurisdiction given its history of regulation and restructuring.

** Several states received a qualitative assessment inconsistent with the quantitative score. This is intentional. It is possible to score points with certain reasonable policies, yet limit the success of retail choice as a result of other policies.*

Default service (standard or basic service), refers to a transitional regulated service. Stated plainly, in a few jurisdictions default service was designed to keep rates artificially low throughout the transition to competition, thereby discouraging market entry and competition. A poorly designed default service undermines retail competition. If default service attempts to address all C&I consumers' needs, bundles and spreads risks among all consumers, or is priced below cost, then it is unlikely that retail electricity providers will enter the market. Experience has shown that to encourage the development of a competitive retail market, default service must be a more market reflective rate in the near term, and it must provide opportunities to competitive retailers.

An important factor over which states and provinces have less control is the success of multi-jurisdictional organized markets, that is, electricity markets with regional transmission organizations (RTO) or independent system operators (ISO). Fortunately, federal oversight of multi-jurisdictional organized markets in the US has resulted in enhanced wholesale market competition. For example, in recent orders the Federal Energy Regulatory Commission (FERC) has requested that organized markets enhance the operation of the market monitor and improve demand response programs. Demand response is particularly helpful and useful to large customers as it provides an additional set of options with respect to the reliability of service and the ability to participate in resource and ancillary markets, supplying capacity, energy, operating reserves and regulation, to name a few.

Recommendations

The ABACCUS report recommendations address the full range of issues, and these correspond to the elements that comprise the methodology. These are discussed in more depth in the later part of this report.

> *Recommendation #1: Allow all commercial and industrial customers within the state or province to participate in the competitive retail electricity market.*
>
> *Recommendation #2: Support the implementation of the Federal Energy Regulatory Commission's (FERC) orders to improve the competitiveness of multi-jurisdictional organized markets and to enhance the independence of the market monitor.*
>
> *Recommendation #3: Support access of commercial and industrial customers to demand response and ancillary service markets and to comparable treatment of loads as resources for capacity, energy and ancillary services.*
>
> *Recommendation #4: Establish default service as a transition mechanism only for those C&I customers who are unable to contract for power by themselves. Establish a clear ending date for default service for medium- to small-sized C&I customers.*
>
> *Recommendation #5: Design a default service product that meets only the basic needs of C&I customers. Do not attempt to mimic the variety, scope or breadth of rates or services that are provided by competitive market participants.*
>
> *Recommendation #6: If supply procurement for default service is done through mandated auctions or competitive solicitations, the term lengths should be shortened to an appropriate level for each customer group. This will ensure that appropriate pricing signals are sent to customers to allow them to better select their electric service product and to efficiently manage their energy usage.*
>
> *Recommendation #7: Establish a plan for the complete separation of regulated services from competitive services, and for the application of a strict code of conduct to govern interactions between the regulated utility and its competitive affiliates.*
>
> *Recommendation #8: Establish standards for access to customer information, and for commercial practices and electronic data exchange to lower the transaction costs for market participants.*

Recommendation #9: Establish comprehensive rules for interconnection of distributed generation to the distribution system.

Recommendation #10: Adopt a market-based approach toward achieving goals relating to renewable resources, energy efficiency, demand response and distributed generation.

Introduction

Purpose and Scope

"Annual Baseline Assessment of Choice in Canada and the US" (ABACCUS) gauges progress in the implementation of retail electricity choice. The Commercial and Industrial ABACCUS is a report card on the electric industry's achievements in large customer electricity choice. A companion report focuses on residential customer electricity choice.

The ABACCUS report is intended to achieve the following:

- Identify the market structures, business practices and government policies that increase the likelihood of the success of retail electricity choice
- Identify best regulatory practices for the regulated network portions of the electricity market to support retail electricity choice
- Provide information useful to the US states and Canadian provinces that are implementing retail electricity choice
- Identify potential improvement areas and suggest solutions that US states and Canadian provinces may consider implementing
- Provide information that will enable other US states and Canadian provinces to better consider the market structures, business practices and government policies that provide a good foundation for the future successful implementation of retail electricity choice

Commercial and industrial customers are relatively well informed about the choices for goods and services necessary for industrial production or commerce. Some jurisdictions have achieved success with large customers but do not score well in the Residential ABACCUS because the policies are in need of reform.

ABACCUS Advisory Board

The ABACCUS process began in 2006 with the formation of an Advisory Board and, since that time, has added several new members. The Advisory Board desired a process that would balance the perspectives of retailers with other points of view. An *ad hoc* advisory group was formed to include representatives from some of the larger state regulatory commissions: California, Illinois, Maryland, Massachusetts, Michigan, New York, Pennsylvania and Texas. This advisory group met via conference call between October 2006 and May 2007 to consider which issues (or "elements") would be included in the ABACCUS methodology and to discuss the scoring and weighting of the elements.

The advisory group served an important function – to balance the interests of retailers with the interests of consumers, the general public, and regulatory commissioners. Although retail competition is focused on the successful operation of the restructured marketplace, the ABACCUS Advisory Board recognizes that regulatory commissions play a very important role in market monitoring, the regulation of the monopoly network functions, and in oversight of the transitional period that requires the establishment of new rules and business processes for the facilitation of a competitive retail market.

Outline of the Report

Methodology

The methodology section provides an overview of the Commercial and Industrial ABACCUS methodology. A detailed description appears in Appendix A.

Findings

The findings present a map and table of Commercial and Industrial ABACCUS results. We discuss the states and provinces that have made progress and the states and provinces that are falling behind as a result of their policies and actions relating to resource procurement and adequacy, and default service rate setting. Finally, we discuss the states that have recently closed or are considering closing retail choice, and a state that is considering reopening retail choice.

Recommendations

ABACCUS report recommendations are grouped into five categories: retail market status, wholesale market competition, default service design, facilitation of choice of retailer, and societal goals. The first four of these parallel the topics set forth in the methodology. The final recommendation relates to the increasing tendency of states and provinces to engage in activities relating to energy efficiency and renewable energy resources.

Appendices

Appendix A provides detailed information about the Commercial and Industrial ABACCUS methodology – the 28 elements, their options and scoring. Appendix B provides a write up about each state and province, including a high level summary of ten years of restructuring, switching statistics and data regarding sales and average prices.

Methodology

ABACCUS consistently applies an analytical tool to measure progress in implementing retail choice in North America. The Commercial and Industrial ABACCUS methodology poses about two dozen questions that are considered important to the measurement of progress. Data are collected from US states and Canadian provinces about each question, and points are assigned to various options. More points are assigned to options that would advance retail choice. Weights are assigned to each question to balance the numerous factors that affect the success of retail competition. The weighted average of the scores provides a total score for each jurisdiction. These scores are ranked to show which states have made the greatest progress toward successful implementation of retail electricity choice. ABACCUS is designed to highlight the best policies and the market platform that will provide sustained market performance and long-term consumer value. Qualitative information is then used to assess whether a jurisdiction is improving or falling behind in the implementation of retail choice. Appendix A provides a more detailed description of each element and the scoring methodology.

The Elements

A hallmark of the ABACCUS methodology is the breadth of issues explored. We do not believe that retail electricity choice can be understood in terms of one issue or dimension. The provision of electric service is fairly complex and there are numerous important design issues. In order to understand what is happening in these jurisdictions, we have adopted a methodology for the Commercial and Industrial ABACCUS that gathers facts on 28 issues. The methodology is organized into four general topics: A. Status of Retail Choice, B. Wholesale Competition, C. Default Service, and D. Facilitation of Choice of Retailer.

We relied on a combination of fact checking and interviews in each jurisdiction. This involved a review of the source materials on state and utility Web sites and a telephone interview with staff members at the regulatory commission with responsibility for the implementation and tracking of retail competition.

Status of Retail Choice

ABACCUS first takes a snapshot of each state to determine the percentage of commercial and industrial customers eligible to participate in retail electricity choice. Next, ABACCUS considers the number of active retailers making offers in the state and the percentage of eligible customers on a competitive price. These two measures are outcomes of a successful program and result from other appropriate actions by the state or province. ABACCUS also considers the extent to which the jurisdiction tracks and publishes statistics relating to switching. These elements are labeled A.1 to A.6 in this report.

Table 1: Elements for Status of Retail Choice

No.	C&I Element	Key Question
A.1	Eligibility of C&I Customer Load (%)	What percentage of commercial and industrial load in the state/province is eligible for retail electricity choice?
A.2	Number of Retailers Making Large C&I Offers (#)	How many retailers are active in making offers to large C&I customers?

No.	C&I Element	Key Question
A.3	Number of Retailers Making Medium C&I Offers (#)	How many retailers are active making offers to medium C&I customers?
A.4	Large C&I Customer Load Switching (%)	What percentage of eligible large C&I load has switched?
A.5	Medium C&I Customer Load Switching (%)	What percentage of eligible medium C&I load has switched?
A.6	Publish Market Switching, Migration or Choice Statistics	Does the state/province measure and regularly publish market switching or migration statistics?

Wholesale Competition

Wholesale or bulk market competition can facilitate robust retail electricity choice. Policies to support fully integrated electricity markets include the adoption of advanced market policies and the integration of retail customers into demand response activities. Retail customers who are allowed to participate in wholesale markets make choices that are good for their operations (lowering of costs) and good for the network (participation in markets for ancillary services such as responsive reserves, reduction in price spikes, and reduction in congestion). These elements are labeled B.1 to B.5 in this report.

Table 2: Elements for Wholesale Competition

No.	C&I Element	Key Question
B.1	RTO/ISO Existence	Does the jurisdiction operate its retail choice activities in a RTO/ISO?
B.2	Market Monitor	Is the market monitoring functioning in an independent and transparent manner?
B.3	Reliability Demand Response	Can C&I loads participate in markets for reliability? Is the participation on a level playing field with generation resources?
B.4	Economic Demand Response	Can C&I loads participate in day-ahead and real time markets for energy?
B.5	Ancillary Services	Can C&I loads participate in markets for operating and responsive reserves?

Default Service

Default service refers to the basic or standard rates that are established and periodically adjusted by regulators. Default service has been established as a mechanism to ease the transition from regulated tariffs to competitive electricity prices. The design and implementation of default service is the most significant issue affecting the success of retail choice. If regulators are determined to design default service so as to attempt to address all consumer needs, or price service below market cost, or bundle risks and spread the risk premium to all consumers, then it is unlikely that retail electricity providers will enter the market. That is, default service designed to undermine retail competition can undermine it!

Provider of last resort (POLR) service refers to "safety net" rates for consumers whose supplier goes out of business.

The elements in this topic include: the company that provides default service, how default service is designed, how frequently default service is adjusted to wholesale market prices, what resources are used to supply default service, whether the supplier hedges resources, whether restrictions are placed on customers who wish to leave default service, and whether the default service rate tracks the cost of service. These elements are labeled C.1 to C.8 in this report.

Table 3: Elements for Default Service

No.	C&I Element	Key Question
C.1	Default Service for Large C&I	Is a regulated default service rate offered to large C&I loads as of March 1, 2008? What, if any, size limit has been set? (Above which large customers must contract for market prices.)
C.2	Default Service Cost Tracking Large C&I	With what frequency is large C&I load default service rate realigned to wholesale market costs? (Hourly? Monthly? Etc.)
C.3	Default Service Provider Medium C&I	What type of company (utility; affiliate; retailer) provides default service to medium C&I load (as of March 1, 2008)?
C.4	Default Service Cost Tracking Medium C&I	With what frequency is medium C&I load default service rate realigned to wholesale market costs? (Monthly? Annually? Etc.)
C.5	Default Service Product Options Medium C&I	Is the default service rate for medium C&I load a generic or "plain vanilla" offering? Or are there variations that could be provided in the market?
C.6	Default Service Cost Allocation Medium C&I	Is the default service rate for medium C&I load discounted to include only some costs? Is it capped? Does it reflect the full power costs?
C.7	Default Service Resource Hedging Medium C&I	Is the default service provider allowed to hedge the resource portfolio? Of do the terms of the resource contracts match the terms of the default service?
C.8	Default Service Switching Options Medium C&I	Are consumers restricted in switching away from default service?

Facilitation of Choice of Retailer

Facilitation of choice of retailer refers to the market structures, infrastructure and programs that support retail electricity choice. First, the jurisdiction's policies with regard to electric distribution market structure, functions regulated and types of service provided. We consider the code of conduct and administration of switching. Next we consider uniformity of transaction standards, treatment of distributed generation and ownership of metering information. These elements appear as D.1 to D.9 in this report.

Table 4: Elements for Facilitation of Choice of Retailer

No.	C&I Element	Key Question
D.1	Electric Distribution Utility Structure	Does the jurisdiction have vertically-integrated, functionally separated, or wires-only electric utilities?
D.2	Electric Distribution Utility Regulation	Are the electric distribution utility functions <u>regulated</u> and <u>separated</u> from the competitive market functions on the customer's premises?

No.	C&I Element	Key Question
D.3	Electric Distribution Utility Types of Services	What types of services are provided by the electric distribution utility?
D.4	Competitive Safeguards	Do the electric distribution utilities operate under a code of conduct that governs relations among affiliates and is that code consistently enforced?
D.5	Administration of Switching	Does a central, fully-independent organization handle all customer switching requests?
D.6	Uniformity of Standards	Does the jurisdiction apply uniform standards for the operation of competitive retail markets?
D.7	Transaction Standards	Does the jurisdiction require the use of a standard electronic data exchange (EDI) for business transactions?
D.8	On-site Generation Alternatives	Do C&I customers have interconnection and distribution system access that facilitates the use of DG as an alternative?
D.9	Ownership of Metered Information	Who owns the customer usage data?

The Weighting of the Elements

Each element is assigned a weight that is used to calculate a weighted average score for each jurisdiction. All 28 weights total to 100 percent. There could be significant discussion regarding the most important element and the corresponding weight. However, we have determined that with a large number of elements, the specific weights are less important than if there were just a few data points. Nevertheless, a transparent methodology allows the reader to see what we felt was important.

The following table presents the weights used in 2008 Commercial and Industrial ABACCUS report.

The four general topics are weighted as follows:

A. Status of Retail Choice: 25%

B. Wholesale competition: 16%

C. Default Service: 32%

D. Facilitation of Choice of Retailer: 27%

No.	*Element*	*Weight*
A.1	Eligibility of C&I Customer Load (%)	3%
A.2	Number of Retailers Making Large C&I Offers (#)	4%
A.3	Number of Retailers Making Medium C&I Offers (#)	4%
A.4	Large C&I Customer Load Switching (%)	6%
A.5	Medium C&I Customer Load Switching (%)	6%
A.6	Publish Market Switching, Migration or Choice Statistics	2%
B.1	RTO/ISO Existence	5%
B.2	Market Monitor	3%
B.3	Reliability Demand Response	3%
B.4	Economic Demand Response	3%
B.5	Ancillary Services	2%

No.	Element	Weight
C.1	Default Service for Large C&I	4%
C.2	Default Service Cost Tracking Large C&I	4%
C.3	Default Service Provider Medium C&I	4%
C.4	Default Service Cost Tracking Medium C&I	4%
C.5	Default Service Product Options Medium C&I	4%
C.6	Default Service Cost Allocation Medium C&I	4%
C.7	Default Service Resource Hedging Medium C&I	4%
C.8	Default Service Switching Options Medium C&I	4%
D.1	Electric Distribution Utility Structure	3%
D.2	Electric Distribution Utility Regulation	3%
D.3	Electric Distribution Utility Types of Services	3%
D.4	Competitive Safeguards	3%
D.5	Administration of Switching	3%
D.6	Uniformity of Standards	3%
D.7	Transaction Standards	3%
D.8	On-site Generation Alternatives	3%
D.9	Ownership of Metered Information	3%
	Total	100%

Findings

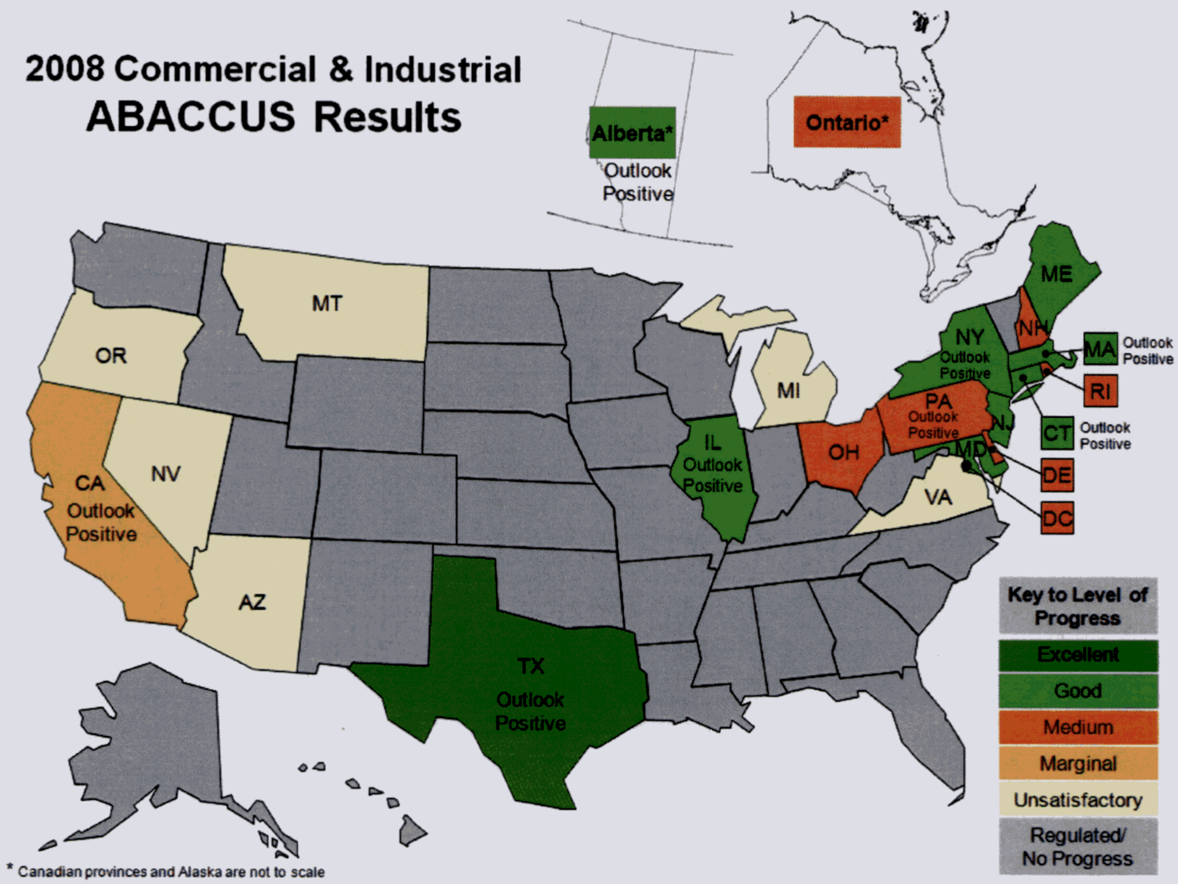
More than a decade has passed since the initial US state pilot programs to offer retail choice of power supplier to consumers. The participation of large energy consumers has been good and has been widely lauded as a success. The purpose of this report is to identify the successes and identify the policy choices that contribute to success in commercial and industrial electricity choice programs.

ABACCUS Sores

Numerous states and Canadian provinces continue to make progress in restructuring the retail electricity market for large customers, addressing problems and moving forward. Market platforms have been designed to allow competitive electricity markets to work effectively.

The ABACCUS map displays the results by converting the scores into five categories: places that have made excellent progress, good progress, medium progress, marginal progress, and states where the progress has been unsatisfactory.

Figure 1: 2008 Commercial and Industrial ABACCUS Results



The C&I ABACCUS considers twenty-eight important dimensions of service. The facts in each state were assessed, scored, weighted and summed, and states were ranked accordingly.

Table 5: Commercial and Industrial ABACCUS Scores and Rank

Jurisdiction	2008 Score†	2008 Rank	2008 Assessment
Texas	75	1	Excellent
New York	57	2	Good
Illinois	56	3	Good
Maryland	53	4	Good
Alberta	49	5	Good
Maine	47	6	Good
Massachusetts	45	7	Good
Connecticut	44	8	Good
New Jersey	44	9	Good
Pennsylvania	42	10	Medium
Delaware	41	11	Medium
District of Columbia	40	12	Medium
Ohio	31	13	Medium
Rhode Island	31	14	Medium
New Hampshire	29	15	Medium
Ontario	28	16	Medium
California*	25	17	Marginal
Virginia*	NA	18	Unsatisfactory
Michigan*	NA	19	Unsatisfactory
Arizona*	NA	20	Unsatisfactory
Oregon*	NA	21	Unsatisfactory
Montana*	NA	22	Unsatisfactory
Nevada*	NA	23	Unsatisfactory

† Scoring is very tough and there is no "grading on a curve." No jurisdiction will ever score 100 because perfect scores for particular ABACCUS elements may not be ideal or even practical in a particular jurisdiction given its history of regulation and restructuring.

** Several states received a qualitative assessment inconsistent with the quantitative score. This is intentional. It is possible to score points with certain reasonable policies, yet limit the success of retail choice as a result of other policies.*

Progress in Selected States and Provinces

About a dozen states and Canadian provinces have made progress in restructuring their electricity markets for commercial and industrial (C&I) customers. Numerous retailers are competing head-to-head for C&I customers. Electricity choice is thriving for the large customer segment in some areas because the states and provinces have achieved a balance between the flexibility afforded to large consumers, and the minimal regulatory oversight necessary and desirable to build confidence in well-structured C&I markets.

A huge variety of electricity products and services is available. The opportunities are nearly limitless. Current offerings allow C&I consumers to choose among the following:

- Power contracts to lock in prices over one or several years
- Power prices indexed to a commodity price that is critical to their operations
- Prices that change hourly so the consumer can assume risk if that serves their business
- Green power that is backed by production from renewable resources
- Sustainable energy paths that are carbon neutral
- Bundled equipment maintenance costs with their electric service
- Retailer-provided services for energy efficiency, and/or energy management devices, usage monitoring and optimization of energy use for their production processes
- Combined heat and power production and contracts for on-site power development
- Demand response opportunities if their operations allow it

Large customers are able to determine how best to manage a variety of inputs into their industrial processes and business operations. Electricity is just one of many important and complex issues that large consumers deal with every day. Business needs and preferences differ, and competitive markets are best at satisfying these diverse needs rather than "one-size-fits-all" regulatory models. Competition is a mainstay of the US economy precisely because retailers respond to consumers who shop. Choosing among a variety of products, services and suppliers is routine for consumers in North America, and the introduction of retail choice to the electric industry is spurring innovation and efficiency. C&I consumers were the first beneficiaries of retail electricity choice largely because these larger customers were already capable of acquiring power and associated services under contracts similar to other business arrangements.

Customer Switching

Customer switching (or migration) rates and customer choice rates of competitive offerings are high in several states because of the large number of retailers, sophistication of the large customers and customized contract offerings. As noted, these data are not strictly comparable, and therefore should be used carefully.

Table 6: Reported Large C&I Customer Switching in Selected Jurisdictions*

New York	74.8%
Texas	72.3%
Maryland	71.1%
Delaware	59.8%
Illinois	50.2%
Massachusetts	49.8%
Connecticut	48.6%
Alberta	45.0%
Maine	36.0%

Table 7: Reported Medium C&I Customer Switching in Selected Jurisdictions*

Illinois	92.6%
Maine	91.8%
Massachusetts	87.3%
New Jersey	82.8%
Alberta	82.0%
Maryland	71.1%
Texas	68.3%
Delaware	59.8%
New York	51.0%
Connecticut	48.6%

** Different jurisdictions use different distinctions for size; therefore, these data are not strictly comparable. Most make a distinction between commercial and industrial customers; a few identify only nonresidential customers; and others have a specified size threshold such as above or below one megawatt. The date of the most recent available data also varies by jurisdiction. These data were checked in October 2008.*

Texas

Texas has made excellent progress toward the achievement of a competitive market for C&I electricity consumers. About 70% of eligible C&I customers receive service from non-incumbent retailers. Texas has several advantages over other states: a state-regulated (intrastate) independent system operator (ISO) with responsibility for reliability, open access transmission, settlement in the energy-only market, managing retail switches and managing renewable energy credit trading. Texas also has policies that promote investments in generation, a healthy economy, a favorable business climate, and consistent regulations. However, it is not these features alone that have resulted in robust electricity choice. Rather, it has been the deliberate policy choices made by the Texas Legislature, the Public Utility Commission of Texas, the ISO (ERCOT, the Electric Reliability Council of Texas), and electricity market participants that have provided a new platform from which competitive services could be offered.

Texas made excellent progress by adopting rules that encouraged numerous power producers and retailers to compete and to offer a variety of services. Texas laws do not give incumbents undue advantage. The Texas "price-to-beat" (default service) ended after five years for C&I customers using less than one megawatt. (Large C&I customer did not have a default service option at any time.) At the end of the transition, C&I consumers on price-to-beat service remained with the retailer on a competitive rate. Today, more than 99% of Texas consumers across all segments who are eligible to choose are served through non-regulated products and services.

New York

In New York, nearly three-quarters of the industrial consumers and over one-half the commercial customers are purchasing power from competitive suppliers. Numerous electric rate offerings from numerous suppliers are available including guaranteed savings programs, fixed and variable prices, and green power. New York benefits from an intrastate independent system operator with advanced policies regarding demand response. These policies allow retail customers to participate directly in the bulk power market and to provide services needed for the operation of the transmission system. New York is fine tuning its market rules including how to place sanctions on retailers who do not follow the rules – a compromise between taking back their license to operate in New York and doing nothing. New York is also working on timelier dispute resolution and training of retailer representatives. New York also has in place an extensive set of programs that encourage energy efficiency, renewable resources and on-site generation, including combined heat and power.

Illinois

The Illinois Commerce Commission has a new Office of Retail Market Development (ORMD). ORMD prepared its first annual report in July 2008 pursuant to the requirements of Section 20-110 of the Illinois Public Utilities Act. There have been new suppliers certified to offer products and services. During the past two years, the commission has determined that larger customers are capable of securing power competitively. Depending on the utility service territory, the default service tariff has been eliminated for customers above a certain size and upon a certain date. The commission has also been addressing the purchase of receivables (to encourage alternative electricity suppliers to serve all consumers), consolidated billing, and referral programs. The ORMD will continue to engage all stakeholders to ensure that the barriers to retail electricity choice are addressed.

Closing or Reopening Markets

Virginia. In 2007, HB 3068 and SB 1416 were signed by Governor Kaine and Virginia suspended retail electricity choice.

Michigan. In Michigan, a bill introduced in December 2007 (HB 5524) has become law and more or less rescinds restructuring. It requires customers who have elected choice in the past to declare within 90 days whether they would continue to receive power from an alternative electric supplier. Customers are required to give notice of a return to regulated service, and pay the higher (for one year) of average rates or market prices at the time of return. New customer would not be eligible for choice and would receive standard tariff service.

California. In May 2007, the California Public Utilities Commission determined that it would investigate the potential to reopen the retail market for direct access. The CPUC has determined in Phase I of Rulemaking 07-05-025 that it does not currently have authority to reinstitute direct access. (Note: The California Department of Water Resources (DWR) still "sells electricity" under existing law, and the CPUC must extricate DWR from that role prior to the reopening of the market. The rulemaking is in the comment phase.) Phase II of Rulemaking 07-05-025 will consider the public policy merits and prerequisites to reopening direct access.

Average Prices

Average electricity prices have been used to compare states and criticize electric restructuring and retail electricity choice. Recent increases in average price in regulated states reveals the folly of a snapshot comparison of prices. Further, this approach is fundamentally flawed in that it assumes that average electricity prices are the most important or only measure of success. Finally, emphasis on average price comparisons reveals a basic misunderstanding of economic value, consumer preferences, and technological advance.

Small consumers traditionally assess the market for electric service by looking at two measures: the price of electricity per kilowatt-hour and the value of the service they receive, including reliability. Simple comparisons of the price of electricity in traditional versus competitive markets are not particularly valuable. It is true that average price comparisons are simple to understand and price increases can garner headlines. Both regulated and restructured states have seen price increases. However, a regulatory mindset is focused on percent rate requests and cents per kilowatt-hour. Unfortunately, the cents-per-kilowatt-hour mindset is holding back progress. This mindset squashes reforms that could lower costs and increase the value of energy services to consumers, both today and over the long-term.

Decades of average price reductions occurred during periods of rapid electrification and supply-side technological change in the mid-twentieth century. This period was marked by power plant engineers who designed and companies that constructed larger, lower cost-per-unit generating units. This period ended in the 1970s, but the supply-side mindset persists. Unfortunately, not enough utilities, regulators and consumers moved quickly enough to adopt a better cost reduction paradigm. As a result, average prices per unit have increased for several decades. Some federal and state policy makers in the 1970's recognized the power of energy efficiency and demand-side technological innovation, but new energy policies were not sustained or comprehensive. Energy efficiency and demand response have only recently become national policy and there is still much work to do. Now, all kinds of retailers and energy service providers are poised to deliver energy efficiency, demand response, renewable energy resources, financial and risk management products and smart grid choices that will transform the electric industry and move the policy debate away from cents per kilowatt-hour comparisons.

Let us examine the old debate. Where electricity costs were the highest, states considered restructuring to apply market forces where regulation had failed. For a variety of reasons, this did not lead to immediate average price reductions in some areas. In regulated states, it has been possible to shift costs from one time period to another, delaying the bad news. In many instances, this approach is catching up with those who advocate more regulation. Wholesale price increases have affected all market participants, not merely restructured states. But is it valid to compare one state's average electricity price with another's? Are average prices even a compelling measure of success?

It is generally agreed that large commercial and industrial consumers have benefited from the introduction of retail electricity competition. One way to measure robust C/I customer competition is in terms of the amount of load switching from the default service provider to a competitive retailer. C/I customers have signed favorable power contracts, benefited from price reductions, and benefited from new products and services that help them manage risk and energy costs. Large C/I customers are comfortable managing risks and input costs in this manner. The ability to procure energy to match a customer's fiscal budget cycle and to hedge that cost by fixing it, has been as important as absolute price. Control over price volatility is equal to the level of the price for risk adverse customers. Other C/I customers, whose energy budget is a smaller percentage of their cost of doing business, may choose a more volatile pricing product. Utilities and regulated default service providers that have routine fuel factor adjustments have the ability to shift the risk of price changes to customers who have little opportunity to hedge such price. A key advantage of retail choice is that customers can procure energy in a manner that best fits their risk profile.

Larger C/I customers are able to manage energy costs as a part of the overall business plan. Industrial operations with storage capability and production line flexibility may participate in demand response markets, for example. This may require the installation of new on-site equipment and may be part of a significant re-engineering of their industrial process. The absolute level of energy cost is merely one of many costs which are managed. The C/I customer loads can provide capacity and energy resources in organized wholesale markets and receive compensation for peak capacity, operating reserves and regulation service. Management of these cost and revenue streams is complex and assistance is provided by energy service specialists and retailers. Many C/I customers have also installed new equipment on-site to increase power quality and reliability. Overall, large electricity customers are comfortable with the ability to choose. The competitive market allows access to specialized products and services in a timely fashion. Market allocation of resources ensures efficiency and equity.

Smaller consumers have demonstrated a preference for green power. Customers have chosen to be EPA LEED certified and one way of doing so is to procure 20% of consumption as green or to acquire the equivalent in Renewable Energy Credits. Competitive packages can bundle such credits with other energy products to satisfy these customers' desires. Small consumers are also expressing a growing appreciation for energy-efficient appliances and devices, green building technologies, and actions to protect the environment. The beauty of the competitive market is the ability of retailers to respond rapidly to these stated or measured preferences. Retailers are able to bundle new energy services and products with non-energy offers and are willing to bear the full financial risk of their experiments. This entrepreneurialism is extremely valuable, and is a hallmark of competitive markets.

Technological change has been rapid and extremely valuable in industries that are exposed to market forces. The electric industry is poised to combine new infrastructure investments (such as advanced meters, communications and control) with the entrepreneurship of mass-market retailers. In the future, consumers may be able to lower their total energy costs, increase their reliability and control, reduce their impact on the environment, and increase the value of electric services in their lives. We have only just begun the changes that will transform the electric industry and the way consumers interact with their appliances and devices.

The search for the right combination of services and products is unlikely to come through regulation. Regulation is constrained by the outdated concept of focusing on the average cost of a unit of electricity. Anyone who has purchased a flashlight battery or recharged a cell phone may be aware of a value of electricity not based on minimizing cents per kilowatt-hour. (That is, whether they are aware of it or not, they value the convenience and mobility offered by these devices, and they pay extremely high costs per kilowatt-hour to obtain that value!) The need for change and reform is great and competitive markets can provide the best means of achieving enhanced value and reduced cost.

Recommendations

The methodology for the Commercial and Industrial ABACCUS (Appendix A) defines an analytical framework and scoring system that reflects the policy direction in which each US state or Canadian province ought to move to improve the likelihood of success in retail competition. While many states have achieved success with C&I retail electricity choice, there are policy choices that could enhance these markets. While considering the realities in each jurisdiction, the ABACCUS Advisory Board believes there are overarching public policy choices that should be considered.

Retail Market Status

Customers must be eligible to participate in retail markets. Several states have yet to open all areas to retail electric choice. Therefore, they limit the ability of commercial and industrial within those service territories to opt out of the local rates and regulatory decisions.

> *Recommendation #1: Allow all commercial and industrial customers within the state or province to participate in the competitive retail electricity market.*

Wholesale Market Competition

Effective wholesale markets are a key component of a well functioning retail market. Full access to organized wholesale markets (RTOs and ISOs) will allow retail power suppliers to manage physical and financial risk for commercial and industrial customers. Through scale economies and a deep understanding of both the wholesale markets and a C&I customers' needs, a retailer can provide differentiated and customized risk management services that individual customers can choose which are generally not available through regulation. Large C&I customers can take action on their own behalf to develop the contracts that match their operations and ability to manage risk.

Policies to support fully integrated electricity markets include the integration of large retail customers into demand response activities. Retail customer participation in wholesale markets is good for the C&I customers who choose to participate (lowering of costs) and good for the network (reduce price spikes and congestion; provide resource adequacy).

> *Recommendation #2: Support the implementation of the Federal Energy Regulatory Commission's (FERC) orders to improve the competitiveness of multi-jurisdictional organized markets and to enhance the independence of the market monitor.*

> *Recommendation #3: Support access of commercial and industrial customers to demand response and ancillary service markets and to comparable treatment of loads as resources for capacity, energy and ancillary services.*

Default Service Design

Default service refers to basic retail rates established to provide a transition from regulated rate making to market-based electricity prices and contracts. The design and implementation of default service is a significant single issue affecting the success of retail choice. We offer this caution: If regulators are determined to design default service so as to attempt to address all C&I consumers' needs, set prices artificially below cost, or bundle risks and spread that risk premium to all consumers, then it is unlikely that retail electricity providers will enter the retail electricity market. A poorly designed default service program can undermine retail competition because it will attempt to provide the services that a robust market can and will provide.

There are a number of actions that a state can take to reduce the impediments of default service to competitive retail markets. Key among these is the movement of default service to a more market reflective rate in the near term. Short term prices are more efficient, and allow consumers to better respond to price changes. Short term prices exclude the premiums associated with long term fixed prices. For consumers who desire a longer-term fixed price product, retailers are likely to offer such products. The incorporation of a risk premium in default service, with forced repayment of that premium by all consumers, defeats a purpose of retail choice. Competitive markets can provide a range of products and services from which consumers may choose. Default service that operates in opposition to our recommendations is likely one that mimics regulated ratemaking and does not provide services that are consistent with a transition to retail competition.

Recommendation #4: Establish default service as a transition mechanism only for those C&I customers who are unable to contract for power by themselves. Establish a clear ending date for default service for medium- to small-sized C&I customers.

Recommendation #5: Design a default service product that meets only the basic needs of C&I customers. Do not attempt to mimic the variety, scope or breadth of rates or services that are provided by competitive market participants.

Recommendation #6: If supply procurement for default service is done through mandated auctions or competitive solicitations, the term lengths should be shortened to an appropriate level for each customer group. This will ensure that appropriate pricing signals are sent to customers to allow them to better select their electric service product and to efficiently manage their energy usage.

Facilitation of the Choice of Retailer

Each state may adopt policies and programs to facilitate the choice of retailer. The options include laws regarding electric distribution utility structure, utility and utility affiliate code of conduct, rules governing billing and metering, and rules that require the standardization of business transactions among all utilities and market participants.

Recommendation #7: Establish a plan for the complete separation of regulated services from competitive services, and for the application of a strict code of conduct to govern interactions between the regulated utility and its competitive affiliates.

Recommendation #8: Establish standards for access to customer information, and for commercial practices and electronic data exchange to lower the transaction costs for market participants.

Recommendation #9: Establish comprehensive rules for interconnection of distributed generation to the distribution system.

Societal Goals

With new interest in climate change, there is renewed interest in energy efficiency, renewable energy resources, demand response and small-scale power production/distributed generation. C&I customers are also interested in sustainable business practices because their customers and investors are interested in sustainability.

States and provinces employ a variety of mechanisms to achieve new goals for energy efficiency, renewable resources, demand response and the promotion of on-site power generation. Some states have taken a command and control approach through standards and codes. Others have used market-based incentives to encourage businesses to offer new technologies and services. It is worth noting at the outset that goods and services provided on the customer premises – including these alternative energy options – are ideally suited for competitive markets. Most people are used to using competitive markets to purchase, operate and maintain their electricity-consuming devices and equipment for their business operations and industrial processes.

Government action in the pursuit of certain societal goals should bear in mind that the actions of individual consumers are necessary to the achievement of energy efficiency on the customer premises. It behooves government to make sure that the implementation of its goals is pursued in a way that takes full advantage of the market mechanisms. The day-to-day interactions among C&I consumers and retailers is one important avenue to bring new technologies to a broad audience.

> *Recommendation #10: Adopt a market-based approach toward achieving goals relating to renewable resources, energy efficiency, demand response and distributed generation.*

Conclusions

Commercial and industrial customer electricity choice has been successful in delivering strong customer benefits in several jurisdictions. About a dozen states and provinces have achieved a significant level of competitiveness as measured by the ABACCUS methodology. The other states and provinces of North America have an opportunity to take stock of the progress made with C&I retail choice during the past decade, and to replicate the successes which have occurred in several states and provinces by adopting programs and policies that enhance competitive markets.

The ABACCUS report recommendations are consistent with the provision of lower cost, more reliable service through the creation and support of an appropriate market platform.

ABACCUS Sponsors

Energy Retailer Research Consortium

The Energy Retailer Research Consortium (ERRC) is an independent research consortium that supports retail energy choice. Membership is open to energy retailers and marketers, energy service companies, products vendors, and the manufacturers of retail energy devices and infrastructure technologies. ERRC studies retail energy market performance, business models and infrastructure investments that enhance the delivery of products and services. The ABACCUS report is sponsored by the members of ERRC.

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Appendix A – Commercial and Industrial ABACCUS Methodology

Background

The ABACCUS report relies on the consistent application of a methodology to gauge progress in the implementation of retail electricity choice. The Commercial & Industrial ABACCUS provides a report card for each jurisdiction on the achievements in electricity choice for large customers. The important issues selected for analysis in the ABACCUS methodology are referred to as elements. Data are collected to assess each element in each jurisdiction. A ranking of jurisdictions by ABACCUS score provides an overall sense of which US states and Canadian provinces have done a good job at designing a platform for successful retail transactions. ABACCUS is designed to highlight the best policies and the market platform that will provide sustained market performance and long-term consumer value.

The ABACCUS report is intended to achieve the following:

- Identify the market structures, business practices and government policies that increase the likelihood of the success of retail electricity choice
- Identify best regulatory practices for the regulated network portions of the electricity market to support retail electricity choice
- Provide information useful to the US states and Canadian provinces that are implementing retail electricity choice
- Identify potential improvement areas and suggest solutions that US states and Canadian provinces may consider implementing
- Provide information that will enable other US states and Canadian provinces to better consider the market structures, business practices and government policies that provide a good foundation for the future successful implementation of retail electricity choice

The Commercial & Industrial ABACCUS methodology considers the issues or elements of importance to large customer retail electricity choice and sets forth reasonable options or paths that each jurisdiction might select. Data are collected from each affected state and province, and points are assigned to the different options, depending upon the degree to which an option helps or hinders retail choice. Weights are then assigned to each issue or element to balance the numerous factors that affect the success of retail competition. A weighted average of score is calculated for each jurisdiction. These values are ranked to show which states have made the greatest progress toward successful implementation of retail electricity choice.

Unless otherwise noted, all references to "electricity customer" or "consumer" or "customer" means commercial or industrial electricity consumers in the relevant jurisdiction. There is no universal definition for "small," "medium" and "large" C&I consumers. For the purposes of this report, however, we apply the following definitions:

- Medium C&I includes consumers with loads of approximately 50 to 200 kW
- Large C&I includes consumers with loads of greater than 200 kW

(Note that in certain jurisdictions "large" might not begin until 500 kW or higher.) The key point is this: The smallest C&I customers, those that use no more than 10 to 20 kW at peak, are not included in this

Commercial/Industrial ABACCUS Topic A: Retail Market Status				
No.	**C&I Element**	**Key Question**	**Options**	**Notes**
A.4	Large C&I Customer Load Switching (%)	What percentage of eligible large C&I <u>load</u> has switched?	Number (0 to 100%) – Percentage of eligible large C&I customer load that has switched from the incumbent or default service	Use the published switching statistics or calculate by subtracting the percent of large C&I load on default service from 100%. Default service or standard offer service is a regulated rate or tariff if the regulator in the jurisdiction approves the rate or rate formula. It does not matter if the default service is competitively acquired in the bulk power market.
A.5	Medium C&I Customer Load Switching (%)	What percentage of eligible medium C&I <u>load</u> has switched?	Number (0 to 100%) – Percentage of eligible medium C&I customer load that has switched from the incumbent or default service	Use the published switching statistics or calculate by subtracting the percent of medium C&I load on default service from 100%.
A.6	Publish Market Switching, Migration or Choice Statistics	Does the state/province measure and regularly publish market switching or migration statistics?	• Does not collect (NoTrack) • Collects but does not routinely publish (Track) • Collects and publishes quarterly statistics or its monthly statistics are delayed by a quarter or more (Quarter) • Collects and publishes up-to-date statistics monthly (Month) • Publishes monthly and actively promotes dissemination (Promote) • Publishes monthly, actively promotes dissemination, and uses the result as a measure of success for the agency or a goal for the jurisdiction (Success)	Jurisdictions that regularly promote the statistics demonstrate a level of engagement with the issues.

Topic B: Wholesale Competition

Effective wholesale (bulk power) market competition is essential for robust retail electricity choice. Large C&I customers have sophistication and the ability to interact with the bulk power market if they are permitted to do so. This choice gives them a range of options that affect their exposure to risk. The wholesale market structure and rules defines what large customers can and cannot do within the market. Market structure determines the customers' level of access to other market participants.

Effective supply-side market policies are only one-half of an effective wholesale market. ("Supply-side efficiency is the sound of one hand clapping" is on point.) The full development of robust wholesale competition requires the integration of both demand and supply. Power suppliers must offer a range of contract options that satisfy the needs of retailers and retail customers with respect to risk management over an appropriate planning horizon. Many of the largest C&I customers will interact directly with the bulk power market. This leads to the full integration of retail and wholesale markets to ensure the success of competitive electricity markets. The wholesale market platform must consider customer loads as something to be managed by customers or their designated representatives: retailers and specialized energy service companies.

The C&I ABACCUS methodology takes into account:

- Structure of the wholesale market platform
- Market monitoring
- Contract flexibility
- Participation of loads in reliability markets
- Participation of loads in economic markets
- Participation of loads in ancillary service markets

Commercial/Industrial ABACCUS Topic B: Wholesale Market Structure				
No.	**C&I Element**	**Key Question**	**Options**	**Notes**
B.1	RTO/ISO Existence	Does the jurisdiction operate its retail choice activities in a RTO/ISO?	• No functional RTO or ISO in the jurisdiction (No) • Jurisdiction is served by an RTO/ISO (Yes)	
B.2	Market Monitor	Is the market monitoring functioning in an independent and transparent manner?	• No RTO/ISO • No independent market monitor • Weak market monitor functions with a lack of independence • Market monitor experiences some problems with independence and effectiveness • Effective and independent market monitor	Each jurisdiction is tagged with the name of the RTO/ISO (or "none") and the assessment is based on the functions performed by the market monitor.

Commercial/Industrial ABACCUS Topic B: Wholesale Market Structure				
No.	**C&I Element**	**Key Question**	**Options**	**Notes**
B.3	Reliability Demand Response	Can C&I loads participate in markets for reliability? Is the participation on a level playing field with generation resources?	• C&I loads cannot participate in reliability DR and cannot receive the same market price as a generator, not a deflated amount • C&I loads can participate fully in reliability DR	Consider the features of the DR program that open or restrict load participation.
B.4	Economic Demand Response	Can C&I loads participate in day-ahead and real time markets for energy?	• C&I loads cannot participate in economic DR • C&I loads can participate fully in economic DR	
B.5	Ancillary Services	Can C&I loads participate in markets for operating and responsive reserves?	• C&I loads cannot participate in ancillary service markets • C&I loads can participate fully in ancillary service markets	

Topic C: Default Service (Standard Offer)

Default service, standard offer service, and basic service are names given to regulated electricity service products in restructured electricity markets. When used effectively, default service provides a transition service for small customers as the market matures. The length of the transition varies, and some jurisdictions do not create default service products for large C&I customers, recognizing that large customers are sophisticated and able to arrange immediately for competitive electric service.

Medium sized and smaller customers require a transition. In the C&I ABACCUS, we focus on default service for medium-sized C&I customers, testing whether the design of default service supports the transition to competition. As we discussed, a utility has acted like a risk insurer through average ratemaking and going to market for an aggregated class. As retailers shop for individual C&I customers their own risk profile will drive the pricing, and risk management tools need to be put in place during the transition.

The C&I ABACCUS methodology takes into account:

- Large C&I customer default service – its existence and costing
- Medium C&I customer default service

Commercial/Industrial ABACCUS Topic C: Default Service (Standard Offer)				
No.	**C&I Element**	**Key Question**	**Options**	**Notes**

Commercial/Industrial ABACCUS Topic C: Default Service (Standard Offer)				
No.	**C&I Element**	**Key Question**	**Options**	**Notes**
C.1	Default Service for Large C&I	Is a regulated default service rate offered to large C&I loads as of March 1, 2008? What, if any, size limit has been set? (Above which large customers must contract for market prices.)	• Yes, all large C&I customers are eligible to receive regulated default service (All) • Yes, certain C&I customers above 1 MW peak load are eligible to receive service (Few) • No, default service is only available to customers below 1 MW (1000kw) • No default service is only available to customers below 500 kW (500kw) • No default service is only available to customers below ~200 kW (200kw) • Less than 5% of C&I customer load receives default service (Minor)	Jurisdictions that provide default service to the largest C&I customers are misunderstanding the purpose of default service. The largest customers do not need a transitional period.
C.2	Default Service Cost Tracking Large C&I	With what frequency is large C&I load default service rate realigned to wholesale market costs? (Hourly? Monthly? Etc.)	• Default service rate is realigned to market prices only occur through a formal regulatory proceeding with no set minimum frequency of change (Regulated) • Power contracts exceed one year (Multiyear) • Annually (Annual) • Six Monthly (Half) • Quarterly (Quarter) • Mix of spot and short term contracts not to exceed one year (Mix) • Monthly (Month) • Default service tracks costs on a hourly basis (Hour) • Less than 5% of C&I customer load receives default service (Minor)	This is the same approach as used in the Residential ABACCUS methodology but focused on default service for the larger C&I
C.3	Default Service Provider Medium C&I	What type of company (utility; affiliate; retailer) provides default service to medium C&I load (as of March 1, 2008)?	• Local electric distribution company (Utility) • Affiliate of the local distribution company (Affiliate) • Non-utility competitive retailer (Retailer) • Less than 5% of C&I customer load receives default service (Minor)	This is the same approach as used in the Residential ABACCUS methodology but focused on default service for the medium C&I

Commercial/Industrial ABACCUS Topic C: Default Service (Standard Offer)				
No.	**C&I Element**	**Key Question**	**Options**	**Notes**
C.4	Default Service Cost Tracking <u>Medium</u> C&I	With what frequency is medium C&I load default service rate realigned to wholesale market costs? (Monthly? Annually? Etc.)	• Default service rate is realigned to market prices only occur through a formal regulatory proceeding with no set minimum frequency of change (Regulated) • Power contracts exceed one year (Multiyear) • Annually (Annual) • Six Monthly (Half) • Quarterly (Quarter) • Mix of spot and short term contracts not to exceed one year (Mix) • Monthly (Month) • Default service tracks costs on a hourly basis (Hour) • Less than 5% of C&I customer load receives default service (Minor)	This is the same approach as used in the Residential ABACCUS methodology but focused on default service for the medium C&I
C.5	Default Service Product Options <u>Medium</u> C&I	Is the default service rate for medium C&I load a generic or "plain vanilla" offering? Or are there variations that could be provided in the market?	• Includes new product offerings that retail markets could provide (Range) • Includes multiple product options that closely track the historical tariff offerings to similar consumers (Multiple) • One product ("plain vanilla") offering (One) • Less than 5% of C&I customer load receives default service (Minor)	This is the same approach as used in the Residential ABACCUS methodology but focused on default service for the medium C&I
C.6	Default Service Cost Allocation <u>Medium</u> C&I	Is the default service rate for medium C&I load discounted to include only some costs? Is it capped? Does it reflect the full power costs?	• Default provider rates are capped at a level below the cost of wholesale power (Capped) • Default provider rates do not fully reflect wholesale power costs, and the residual is allocated to a wires charge (WhlslPart) • Default provider rates reflects wholesale power costs, but do not provide a "gross margin" and do not allocate "competitive elements" (WhlslOnly) • Default provider rates reflects wholesale power costs, and provide allocation of "competitive elements" of distribution rate (e.g., bad debt) (WhlslAlloc) • Default provider rates reflect wholesale power costs, and provide "gross margin" for default provider (WhlslGM) • Default provider rates reflect wholesale power costs, and provide "gross margin" for default provider, and provide allocation of "competitive elements" of distribution rate (e.g., bad debt) (WhlslBoth) • Less than 5% of C&I customer load receives default service (Minor)	This is the same approach as used in the Residential ABACCUS methodology but focused on default service for the medium C&I

Commercial/Industrial ABACCUS Topic C: Default Service (Standard Offer)				
No.	**C&I Element**	**Key Question**	**Options**	**Notes**
C.7	Default Service Resource Hedging <u>Medium</u> C&I	Is the default service provider allowed to hedge the resource portfolio? Of do the terms of the resource contracts match the terms of the default service?	• Default provider uses its own resource supply (Own) • The default provide is allowed to hedge the resource portfolio or to "ladder" the terms for periods longer than the term of the default provider product (Hedge) • The term of resource purchases matches the term of the default provider product (hour to hour, month to month, etc.) (Match) • Less than 5% of C&I customer load receives default service (Minor)	This is the same approach as used in the Residential ABACCUS methodology but focused on default service for the medium C&I
C.8	Default Service Switching Options <u>Medium</u> C&I	Are consumers restricted in switching away from default service?	• No opportunity to leave default service (Restrict) • Periodic window; greater than one year (Multiyear) • Annual window of opportunity to leave; exit and/or switching fees apply (AnnualFee) • Annual window of opportunity to leave; no exit or switching fees (Annual) • Monthly opportunity to leave; exit and/or switching fees apply (MonthFee) • Monthly opportunity to leave; no exit or switching fees apply (Month) • Leave at any time; no exit or switching fees; the switch typically begins at the date of the next regular meter read (Open) • Less than 5% of C&I customer load receives default service (Minor)	This is the same approach as used in the Residential ABACCUS methodology but focused on default service for the medium C&I

Topic D: Facilitation of Choice of Retailer

Facilitation of choice of retailer refers to the market structures, infrastructure and programs that support retail electricity choice.

A key addition, as compared to the Residential ABACCUS methodology, is the treatment of on-site generation. DG/CHP can serve as an alternative to power purchases from the grid, and therefore can provide a cap to the prices paid for power if a customer has easy access to DG technologies, fuels and the use of the distribution system.

Facilitation of choice of retailer includes the following:

- Electric distribution system structure
- Electric distribution utility services and regulation
- Competitive safeguards and a code of conduct
- Administration of switching

- Uniformity of standards; transaction standards
- Distributed generation policies (including interconnection)

Commercial/Industrial ABACCUS Topic D: Facilitation of Choice of Retailer				
No.	**C&I Element**	**Key Question**	**Options**	**Notes**
D.1	Electric Distribution Utility Structure	Does the jurisdiction have vertically-integrated, functionally separated, or wires-only electric utilities?	• Vertically integrated utilities provide electric distribution service (Integrated) • ~½ integrated utilities and ~½ functionally separated utilities (PartInteg) • Functionally separated utilities provide electric distribution service (Separated) • ~½ functionally separated utilities and ~½ wires only utilities (PartWires) • Wires only electric distribution utilities in competitive regions (WiresOnly)	
D.2	Electric Distribution Utility Regulation	Are the electric distribution utility functions <u>regulated</u> and <u>separated</u> from the competitive market functions on the customer's premises?	• Electric distribution utilities provide competitive services on customer premises which are not regulated or separated from wires functions (Unsupervised) • Electric distribution utilities provide competitive services on customer premises which are fully regulated (Regulated) • Electric distribution utilities provide competitive services on customer premises which are fully regulated and fully separated (Separated) • Electric distribution utilities provide wires related services only service (WiresOnly)	What costs and risks do retailers face if the local distribution utility is able to offer value added services that are not regulated? This element helps to determine whether the jurisdiction separates regulated services from competitive services.
D.3	Electric Distribution Utility Types of Services	What types of services are provided by the electric distribution utility?	• Wires service plus metering, billing, value-added services and default service (All) • Wires service plus metering, billing, and value-added services (Value) • Wires service plus metering and billing (Billing) • Wires service plus metering (Metering) • Wires service only (WiresOnly)	This element helps to determine where the jurisdiction draws a line between regulated services and competitive services. What "value added" services provided by the utility are the most detrimental to the success of retail choice?

Commercial/Industrial ABACCUS Topic D: Facilitation of Choice of Retailer				
No.	**C&I Element**	**Key Question**	**Options**	**Notes**
D.4	Competitive Safeguards	Do the electric distribution utilities operate under a code of conduct that governs relations among affiliates and is that code consistently enforced?	• Integrated utilities (no code or restriction their sharing of information) (Integrated) • Weak code of conduct (Weak) • Strong code of conduct (full "arm's length" separation of affiliated consistently enforced) (Strong) • Wires (delivery) service only throughout the jurisdiction (that is, no affiliates) (WiresOnly)	This element applies to the portions of the jurisdiction where functional separation occurs.
D.5	Administration of Switching	Does a central, fully-independent organization handle all customer switching requests?	• Administered by each electric distribution utility (Utility) • Administered by more than one entity in the jurisdiction (Multiple) • Administered by one independent entity across the entire jurisdiction (One)	
D.6	Uniformity of Standards	Does the jurisdiction apply uniform standards for the operation of competitive retail markets?	• Standard vary by utility • Uniform standards throughout the jurisdiction • NAESB consensus standards	
D.7	Transaction Standards	Does the jurisdiction require the use of a standard electronic data exchange (EDI) for business transactions?	• Utility specific processing (Utility) • Standard customer information set throughout jurisdiction (StdInfo) • Standard Electronic Data Interchange (EDI) for all transactions (StdEDI)	

report. The issues faced by retailers that target these small C&I customers tend to be similar to issues addressed in the Residential ABACCUS report.

Twenty-seven elements are organized into four topics: (A) Status of Retail Choice, (B) Wholesale Competition, (C) Default Service, and (D) Facilitation of Choice of Retailer. A table is provided for each element. The tables list each discrete option (data entry) and the points assigned to each option. For convenience, options are assigned points on a zero- to ten-point scale.

Topic A: Retail Market Status

"Status of Retail Choice" refers to the essential statistics regarding customer load eligibility, number of retail providers, and switching/migration. The C&I ABACCUS takes into account:

- The percentage of C&I load eligible to participate in retail electricity choice
- The number of retailers actively making offers of C&I customers of various sizes
- The percentage of eligible customer load that is not on a regulated rate (a proxy for switching or migration statistics)
- The extent to which the jurisdiction tracks and publishes switching/migration statistics

Commercial/Industrial ABACCUS Topic A: Retail Market Status				
No.	**C&I Element**	**Key Question**	**Options**	**Notes**
A.1	Eligibility of C&I Customer Load (%)	What percentage of commercial and industrial load in the state/province is eligible for retail electricity choice?	Number (0 to 100%) – Percentage of C&I load in the jurisdiction eligible to choose a retailer	Less than 100% if portions of the jurisdiction of are ineligible, or if certain utility types (municipal utilities or electric cooperatives) are not required to offer choice and have not "opted in."
A.2	Number of Retailers Making Large C&I Offers (#)	How many retailers are active in making offers to large C&I customers?	Number (0 to large #) – Number of retailers in the jurisdiction actively making offers to large C&I customers	Determining how many retailers are active requires a judgment call. "Active" is almost always a number less than "registered," "licensed," or "certified."
A.3	Number of Retailers Making Medium C&I Offers (#)	How many retailers are active making offers to medium C&I customers?	Number (0 to large #) – Number of retailers in the jurisdiction actively making offers to medium C&I customers	Determining how many retailers are active requires a judgment call. "Active" is almost always a number less than "registered," "licensed," or "certified."

Commercial/Industrial ABACCUS Topic D: Facilitation of Choice of Retailer				
No.	**C&I Element**	**Key Question**	**Options**	**Notes**
D.8	On-site Generation Alternatives	Do C&I customers have interconnection and distribution system access that facilitates the use of DG as an alternative?	• Jurisdiction does not have DG interconnection rules and procedures for all utilities and/or the jurisdiction allows utilities discretion (inconsistencies within the state/province) (Limited) • Fair interconnection rules but a few restrictive DG policies remain (Fair) • Fair interconnection and fair policies plus incentive payments or portfolio standards that encourage DG (Incentive) • Fair interconnection and policies plus incentives/portfolio standards to encourage DG, plus power export allowed on the distribution system (Full)	Use independent rating of distributed generation interconnection rules, standby pricing tariffs, and related pro-DG policies to rate each state
D.9	Ownership of Metered Information	Who owns the customer usage data?	• Utility • Unclear • Retailer • Customer	

Appendix B - Restructuring in States/Provinces

Appendix B provides a summary of the key events in restructuring during the past decade for each state and province, basic switching statistics, and a chart with sales and average prices. This appendix appears in both the residential ABACCUS report and commercial and industrial ABACCUS report.

A short description provides a high-level overview of the major restructuring legislation and decisions that have shaped retail choice in each jurisdiction during the past ten years. The information is based on regulatory commission and utility Web sites and press releases, interviews with individual staff members at regulatory commissions, and comments from the ABACCUS Advisory Board.

Switching (migration) statistics provide a snapshot of the status of retail choice. Switching refers to customers and loads that have moved from a regulated default service (standard offer service) to a competitive contract or price. The most recently available data are provided based on data available on regulatory commission Web sites. The tables present switching data in terms of percent of eligible residential customers, and percent of nonresidential load. Depending on the jurisdiction, "load" is either reported in terms of non-coincident customer class peak demand or megawatt-hours sales. Where available, such data are displayed at the electric distribution utility service area level as well as the aggregate state/province level.

Switching statistics are one way to assess the success of retail choice. However, switching statistics are just one of many inputs into the ABACCUS model (see Appendix A). It is also worth mentioning that the switching statistics may not indicate multiple customer switches ("churn"), or customers who may select a competitive contract or pricing plan from the default service provider (for example, were the default service provider is allowed to offer both regulated and competitive prices).

Two charts present residential and industrial electricity sales (bars) and average residential and industrial prices (dots) for the period 1990 to 2006 based on DOE Energy Information Administration statistics. In a few instances, sales data are presented for combined commercial and industrial customers because reclassification during the period from "industrial" to "commercial" made the industrial data alone misleading. Note that average price data are derived from revenues divided by sales. The 1990 to 2006 data are annual averages presented in real dollars (2006 dollars), while the last two data points are monthly data that represent June 2007 and June 2008 in current year dollars.

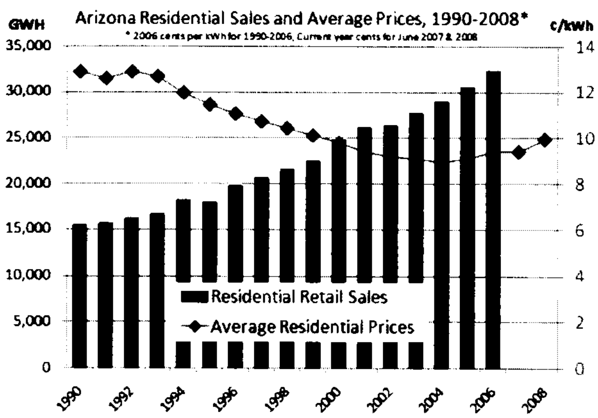
Arizona

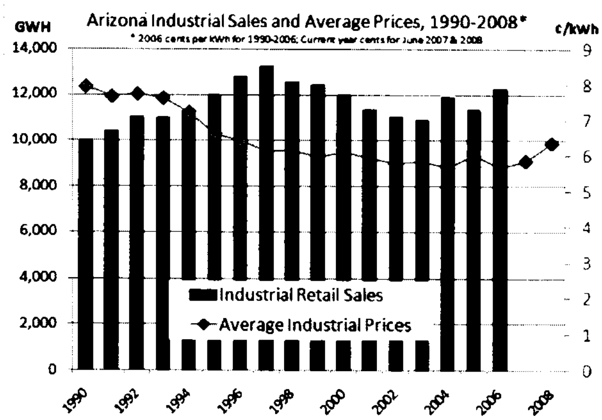
Legislation (HB 2663) was enacted in 1998. The Arizona Corporation Commission (ACC) rules required generation divestiture (transfer to a utility affiliate) and mandated a rate cut. Retail choice was phased-in, with about 90% of electric customers eligible for retail choice by January 2001. By June 2001, all competitors had pulled out of the market due to the way the shopping credit was established. Wholesale market prices rose, but the low credit subtracted from the retail rate for the energy service provider to compete was not increased. Switching halted and all customers were returned to the incumbents.

Citing market immaturity, Arizona Public Service Company (APS) asked the ACC to overturn the rules that compelled it to obtain power from the competitive market. APS proposed that the power needs be met through 2015 from the parent company, Pinnacle West Capital Corp., and the competitive generation affiliate. In making a determination, the ACC issued Decision No. 65154 (Track A) in September 2002, and ordering APS and Tucson Electric Power Company (TEPCO) to cancel any plans to divest interest in any generating assets. The ACC also stayed the requirement that 100% of power purchased for Standard Offer Service be acquired from the competitive market. Without an RTO in the western US, and with the problems in California markets, the ACC was not willing to wait for markets to function properly.

In March 2004, Arizona Court of Appeals ruled that the ACC's decision to require electric utilities to divest their generation assets was unconstitutional because the ACC was trying to control rates, not utilities, and had not proven the case for divestiture. By October 2004, restructuring was placed on hold.

Sempra has argued (Docket No. E-03964-06-0168) that it is fit to serve as a competitive energy service provider and it has requested reinstatement. In a recent order, the ACC has determined that certain other findings are still needed. It has ordered the ACC's Utilities Division to conduct public workshops to address the underlying policy issue of whether retail competition is in the public interest and to examine the potential risks and benefits of retail competition. By December 31, 2009, a report based on the workshops must include the staff recommendation as to whether or not retail competition should be implemented, and if so, how such implementation should proceed.





California

The California Public Utilities Commission (CPUC) issued reports in 1993 (Yellow Book) and 1994 (Blue Book) that addressed regulation and restructuring. In September 1996, Assembly Bill 1890 was enacted to start retail access January 1998 (delayed to April 1998). Approximately 14% of load was served by competitive energy service providers by 2000. California experienced setbacks with its wholesale markets that affected retail prices and resource availability. Because of supply shortages, wholesale market prices were very extremely volatile. San Diego Gas & Electric Company had completed its stranded cost recovery in 1999, and could therefore pass wholesale prices to retail customers. In contrast, Pacific Gas and Electric Company (PG&E) and Southern California Edison Company (SCE) paid high wholesale prices, but incurred significant debt because they were not allowed pass high wholesale prices to retail customers.

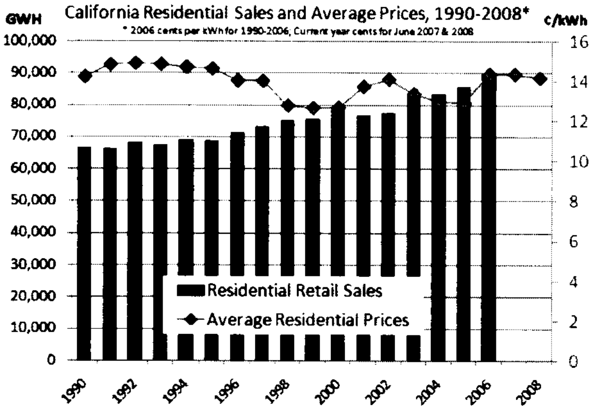
In January 2001, PG&E filed for bankruptcy protection. Subsequently, the State of California Department of Water Resources (DWR) purchased power on behalf of the utilities. (Authorized by emergency legislation AB 1X, February 1, 2001, this state procurement lasted until 2003.) In March 2001, the Federal Regulatory Energy Commission ordered suppliers to make refunds to utilities. On June 18, 2001, FERC voted to impose price controls on wholesale electricity prices for California and ten other Western states.

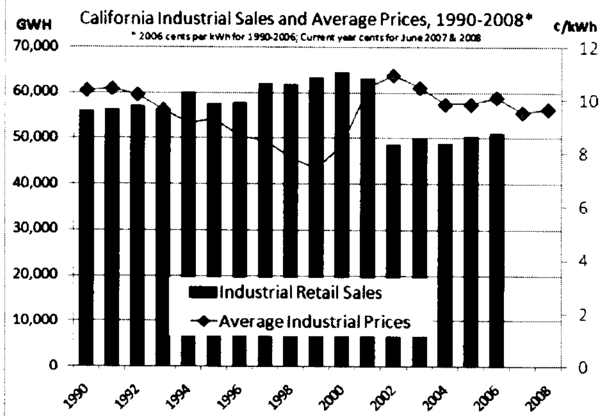
On September 20, 2001, in Decision 01-09-060, the retail access provisions of AB 1890 were suspended by the CPUC. Direct access contracts signed before September 20 were allowed to continue until their expiration. These direct access customers were charged Cost Responsibility Surcharges for costs incurred by the State and utilities during the energy crisis (Decision 02-11-022). As of February 2008, there were 18,700 residential direct access customers (0.2%) in California. In 2002, AB 117 passed to amend the Utilities Code to allow community choice aggregation with an "opt out" provision. In April 2007 the CPUC authorized the first community choice aggregation application.

In May 2007, CPUC determined that it would investigate the potential to reopen the retail market for direct access (Rulemaking 07-05-025). The CPUC has determined that it does not currently have authority to reinstitute direct access. (Phase I of the proceeding focused on legal issues. Since power is supplied when delivered to a retail customer, the DWR is still "supplying power" under the Water Code §80110. DWR still holds power contracts, has title, and receives payment. Although DWR no longer has contracting authority, it still administers contracts and "sells electricity" under existing contracts, therefore, the CPUC must extricate DWR from that role prior to the opening of the direct access market.) In a February 28, 2008 press release, CPUC President Peevey stated: "The suspension of choice cannot be lifted until DWR no longer supplies power through the contracts that were signed during the energy crisis. Accordingly, the CPUC can and should evaluate the merits of ways to extricate DWR from its current role as supplier of energy under those existing contracts. After that the CPUC can proceed to the question of whether and how to reinstate Direct Access." Phase II of R.07-05-025, scheduled for the fall of 2008, will consider the public policy merits and prerequisites to reopening direct access.

California has been very active during the past several years with resource adequacy, energy efficiency incentive programs, energy efficiency codes and standards, demand response programs and renewable resources. In 2006, California enacted comprehensive legislation to address climate change. AB32, the California Global Warming Solutions Act of 2006, requires the California Air Resources Board to adopt, monitor and enforce regulations. SB 1368, Emission Performance Standards, prohibits any load serving entity and any local publicly-owned electric utility from entering into a long-term financial commitment for base load generation that does not comply with an emission performance standard of 1,100 lbs CO2 per MWh.

California Percent of Customer Switching July 2008	Percent of Residential Customers	Percent of Small Commercial (<20 kW) Sales (MWH)	Percent of Medium Commercial (20 - 500 kW) Sales (MWH)	Percent of Industrial (> 500 kW) Sales (MWH)	Percent of Agricultural Sales (MWH)	Percent of State Sales (MWH)
State Total	0.2%	0.8%	11.7%	23.9%	1.2%	9.08%





Connecticut

The Act Concerning Electric Restructuring (HB 5005) was signed into law April 1998. The law required divestiture of nuclear assets, required participation in an ISO, functional unbundling, a renewable portfolio standard, a 10% rate deduction, and a rate cap until 2000. The utilities filed divestiture plans and there was some uncertainty with respect to the amount of stranded costs. Few competitive retailers entered the state. The Department of Public Utility Control (DPUC) set restrictions on switching back to standard offer service – a 12 month switching moratorium was instituted.

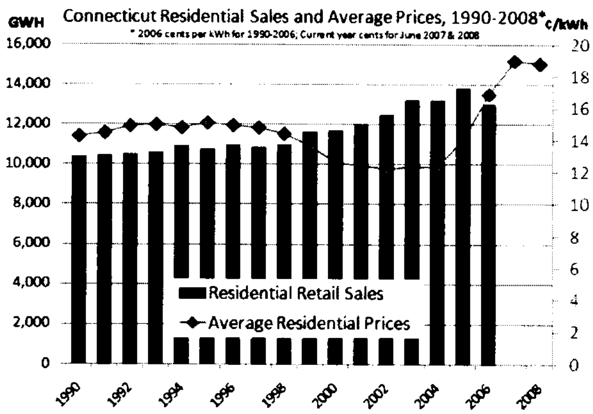
Rate caps ended and rates increased in 2004-05. In June 2006, DPUC passed regulations requiring Connecticut utilities to hold multiple auctions for standard offer power supply.

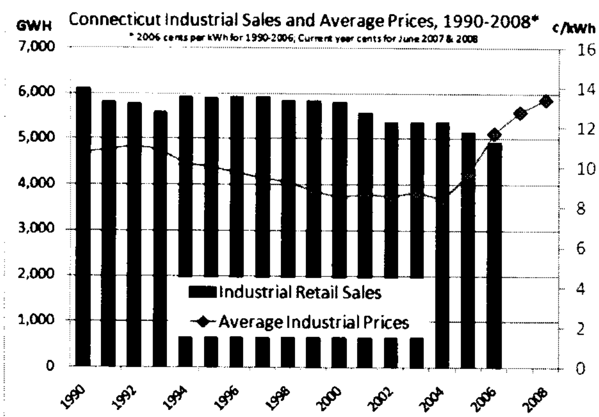
In June 2004 Connecticut passed a public act concerning climate change. In February 2007 the governor proposed a new state department of energy to work on energy policy and renewable resources. The state has a three-tier resource portfolio standard that includes renewable resources and energy efficiency. There is also an emphasis on distributed generation to address capacity needs in the southwestern corner of the state. April 18, 2008, Governor Rell signed the Governors' Declaration on Climate Change, joining 17 states to urge federal-state cooperation and federal support.

In 2007 the Connecticut General Assembly passed legislation allowing utilities (which had been divested of generation after the 1998 restructuring bill) to construct regulated peaking units. In March 2008, Connecticut Power and Light (CP&L) filed for permission to build four 50 MW units and two 32.5 MW units to come in service in 2010. In late January 2008, CL&P rates were approved by the DPUC in Docket Nos. 07-07-01 and 03-07-02RE10.

Connecticut Percent of Customer Switching September 2008	Percent of Residential Customers	Percent of Commercial/ Industrial Sales (MWh)
Connecticut Light & Power	5.9%	46.9%
United Illuminating	7.9%	55.3%

State Total	6.6%	48.6%





Delaware

In March 1999, Delaware enacted legislation (HB 10) mandating electric restructuring and a rate cut of 7.5% for most electric customers. Larger customers of Connectiv Power were eligible for choice October 1999, medium customers January 2000, and all residential and commercial customers became eligible October 2000.

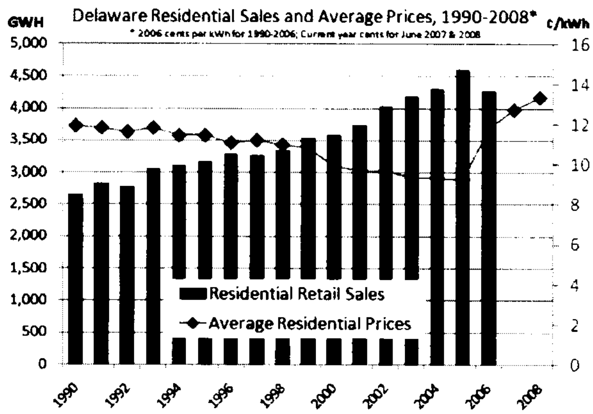
In April 2001, Delaware Electric Cooperative's customers became eligible for the choice plan. Rate caps were lifted for Delaware Electric Cooperative in March 2005 and rate increased 8%.

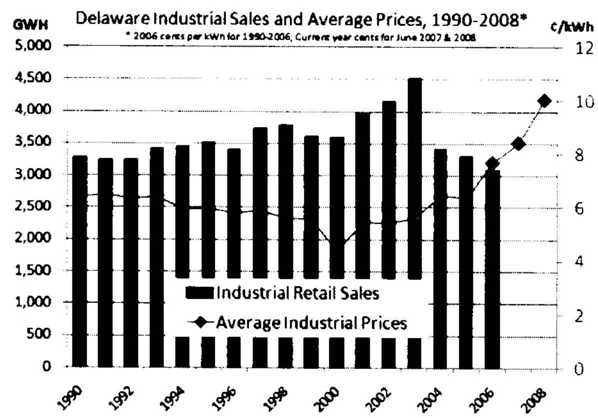
In 2003, the PEPCO/Connectiv (now Delmarva Power & Light Company) merger settlement increased rates about 1%, but extended the rate freeze for Delmarva Power customers until May 2006. In October 2004, the Commission opened PSC Docket No. 04-391 to determine which company would provide standard offer service (SOS) in Delmarva Power service territory after May 2006. Delmarva Power was selected. The Request for Proposal process is nearly complete and a technical consultant report was received in March 2008. It is expected that residential rate will increase about 2% as a result of increases in the blocks of power selected. (One third of the power need is acquired annually to reduce price volatility.)

The Electric Utility Retail Customer Supply Act of 2006 requires Delmarva Power to file a proposal for long-term supply contracts. On December 4, 2007, the Commission entered PSC Order No. 7318 to propose and take comments on Integrated Resource Planning regulations. Written comments were filed in February 2008.

Delaware Percent of Customer Switching July 2008	Percent of Residential Customers	Percent of Nonresidential Load (MW)

State Total	2.8%	59.8%





District of Columbia

The District of Columbia Public Service Commission (DCPSC) issued Order Nos. 11576 (December 1999) and 11796 (September 2000) to allow all residential and commercial customers to choose an alternative electric supplier effective January 2001. Potomac Electric Power Company (PEPCO) is the sole electric distribution company. At the end of 1999, PEPCO made a decision to divest itself of generating units. A Code of Conduct working group was created in 2000 to work on competitive safeguards, with an interim decision to adopt Maryland's Code of Conduct, and a longer-term effort to develop a DC-specific Code of Conduct. DCPSC orders issued in 2001 addressed customer education, new electric supplier tariffs, and interim customer aggregation standards.

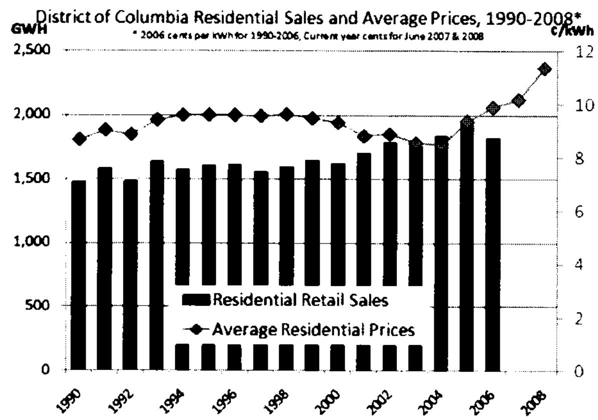
In 2002, the DCPSC issued an order and report on a Municipal Aggregation Program. The DCPSC also approved the PEPCO/Connectiv merger subject to conditions. Divestiture resulted in a sharing of proceedings with customers. (The typical household received $80.42 of divestiture sharing credits in 2002.) PEPCO has moved toward a holding company structure.

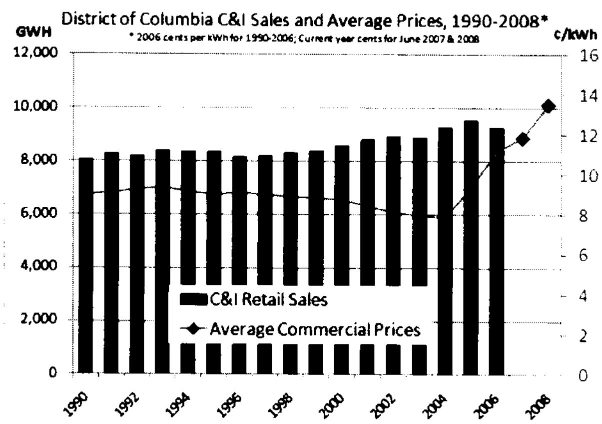
In 2003-04, the DCPSC examined the standard offer service (SOS) process (Order Nos. 12655 and 13118), including whether PEPCO should continue to provide SOS because its obligation to serve was set to expire at the end of 2004. A new process was adopted that relied on to a greater degree on wholesale market prices. In March 2006, PEPCO filed for rates increases for SOS of about 10% to 12%. In July 2006, the DCPSC issued Order No. 14006 to adopted improvements in the procurement process for SOS, and to consider the benefits of a portfolio approach.

A Renewable Energy Portfolio Standard Act was enacted in 2005 which will require suppliers to acquire 11% of their energy from renewable resources by 2022. The DCPSC has increased the amount of information available to customers regarding energy efficiency.

During the peak period for switching (between September 2002 and December 2003), residential customer switching was between 10.2% and 11.9% in DC. As of March 2008, only 1.0% of residential customers in DC were served by competitive suppliers. All other residential customers were on PEPCO's SOS tariff.

District of Columbia Percent Switching August 2008	Percent of Residential Customers	Percent of Nonresidential Customers*
District Total	1.0%	19.8%
* Statistics are provided based on number of nonresidential customers, not the peak MW or MWH sales.		





Illinois

In December 1997 and again in September 1999, the Illinois Public Utilities Act was amended (P.A. 90-0561, Electric Service Customer Choice and Rate Relief Law of 1997, HB 362). Large customers were allowed to choose their supplier in 1999, and other nonresidential customers were allowed to choose in 2000. The initial decision to give residential retail choice (in 2002) was moved up to a late-1999 to late-2000 phase in. The amendments also mandated rate cuts of 15% in 1998 and 5% in 2001. Other provisions promoted cogeneration and allocated $250 million to special environmental initiatives and to an energy efficiency fund. Rates were capped until 2005, providing relatively little incentive for mass market customers to switch. In 2002, the Illinois General Assembly extended the rate cap to January 1, 2007 (P.A. 92-357).

In late 2002, the Illinois Commerce Commission (ICC) eliminated the regulated rate for customers above three megawatts. As of the end of 2006, nearly 28,000 commercial and industrial customers have chosen to take delivery service from a retail electric service provider other than the utility, totaling approximately 28,500 GWH for that year. ("Summary of Annual Reports Filed by Electric Utilities Regarding the Transition to a Competitive Electric Industry: Required by Electric Service Customer Choice and Rate Relief Law of 1997", May 2007 (220 ILCS5/16-130)(1999)).

In 2007, Public Act 095-0481 (Illinois Power Agency Act) created the Illinois Power Agency (IPA) and amended the Illinois Public Utilities Act to return certain rates to 2006 levels. The IPA is responsible for overseeing the procurement of power and energy for retail customers who receive fixed-price bundled service from electric utilities with 100,000 or more customers (220 ILCS 5/16-111.5(a)(2007)). The IPA is to prepare a plan, by August 15 of each year, to procure the necessary energy and power in the following year (220 ILCS 5/16-111.5(b)(2007)).

The Illinois Power Agency Act also declared services in ComEd and Ameren whose peak demand is above 400 kW to be competitive as of August 2007 (220 ILCS 5/16-113(f)). ComEd customers who have peak demand above 400 kW are allowed to take bundled service until June 2008. ComEd customers who have peak demand between 100 kW and 400 kW are allowed to take bundled service until June 2010. Ameren customers with peak demand is above 1 MW are able to take bundled service until June 1, 2008, and customers with peak demand between 400 kW and 1 MW can take bundled service until June 1, 2010. Electric utilities are able to obtain determinations of competition for the customers who have peak demand between 100 kW and 400 kW if they can demonstrate that at least 33% of the customer's in the service area are eligible to take service from an alternative retail electric supplier and that at a least three alternative retail electric suppliers provide comparable service (220 ILCS 5/16-113(g)(2007)).

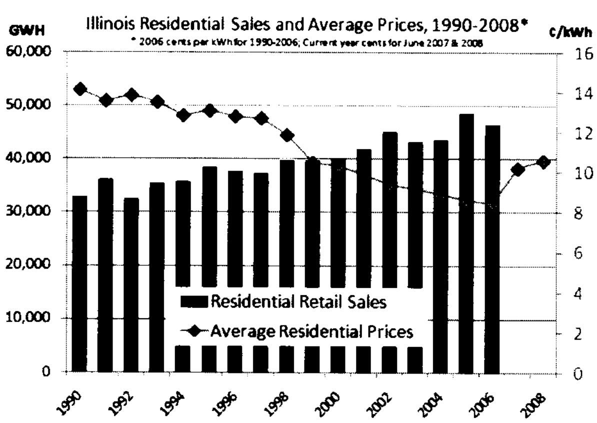
The ICC cannot make a determination of competition for residential customers, with peak demand less than 100 kW, until after July 1, 2012 (220 ILCS 5/16-113(h) (2007)). The Illinois Power Agency Act also set energy efficiency and demand response goals for Illinois utilities (220 ILCS 5/12-103)(2007).

In April 2008, utilities in Illinois started offering net-metering (83 IL. Admin. Code Part 465) to eligible customers, that is, to retail customers who own or operate a solar, wind, or other eligible renewable electrical generating facility with a rated capacity of two MW or less. In addition, the ICC has initiated a rulemaking (Docket No. 06-0525) that will set standards for interconnection of direct generation to the distribution network (83 IL. Admin. Code Part 466).

The Illinois Office of Retail Market Development (ORMD) prepared its first annual report in July 2008 pursuant to the requirements of Section 20-110 of the Illinois Public Utilities Act.

Illinois Percent Switching August 2008	Percent of Residential Customers	Percent of Small C&I Load (< 1 MW)	Percent Large C&I Load (> 1 MW)	Percent Total Load (MW)
Central Illinois Light Company (AmerenCILCO)	0.0%	44.0%	69.4%	38.8%
Central Illinois Public Service (AmerenCIPS)	0.0%	30.8%	98.5%	43.7%
Illinois Power Company (AmerenIP)	0.0%	36.4%	97.5%	48.9%
Commonwealth Edison Company	0.0%	54.4%	92.4%	48.4%
MidAmerican Energy Company	0.0%	0.0%	0.0%	0.0%
Mt. Carmel	0.0%	0.0%	0.0%	0.0%

State Total	0.0%	50.2%	92.6%	47.9%



Maine

In May 1997, the Maine Legislature passed Directive 1804 to require divestiture of utility generation assets and initiate retail choice in March 2000. The Legislature imposed a 33% market share cap on investor-owned utilities in their old service areas, and instituted a renewable energy portfolio requirement of 30% (including hydroelectric power). Maine's law (Title 35-A, Chapter 32: Electric Industry Restructuring), allows retail consumers to purchase electricity supply from licensed competitive electricity providers, and requires customers not served competitively to accept standard offer electricity regulated by the Maine Public Utilities Commission (MPUC).

The MPUC has considered bids for resources to serve default customers. In 1999, the MPUC rejected bids and reissued a request in 2000 under amended rules in an attempt to attract more bidders. The MPUC set standard offer rates and ordered Central Maine Power to provide standard offer service from March 2000 to March 2002 for medium and large nonresidential customers. The MPUC also approved a transmission/distribution rate scheme for restructuring submitted by Maine Public Service Company (in far northern Maine, and isolated on the grid) that separated MPS's revenue requirements into a transmission component under FERC jurisdiction and a distribution component under MPUC jurisdiction.

The MPUC revisited standard offer service in 2002. To further connect the standard offer to market prices, the MPUC shortened the time period for its current medium and large standard offer categories to six months. That is, the winning bid sets the standard offer at start of the six-month period, with prices changing each month. In December 2002, the MPUC reported to the legislature that retail access had been a success for commercial and industrial customers in Maine, and that some residential customers had switched to renewable resource suppliers. At that time, 47% of the electricity in Maine was bought from competitive suppliers—the highest percentage in the nation. The MPUC stated that until retail markets mature, the legislature must keep standard offer service in place beyond the scheduled termination date of March 2005.

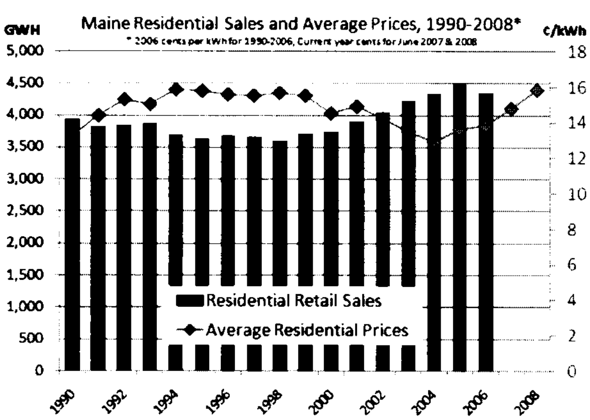
In late 2004, an auction produced standard offer rates with a nearly 30% increase in the generation price due to conditions in the wholesale market. In more recent auctions, the MPUC goes to the market each year for one-third of the load in a three-year contract. In January 2008, the MPUC accepted a one-year contract for one-third of the load at Central Maine Power and Bangor Hydro-Electric. As a result, in

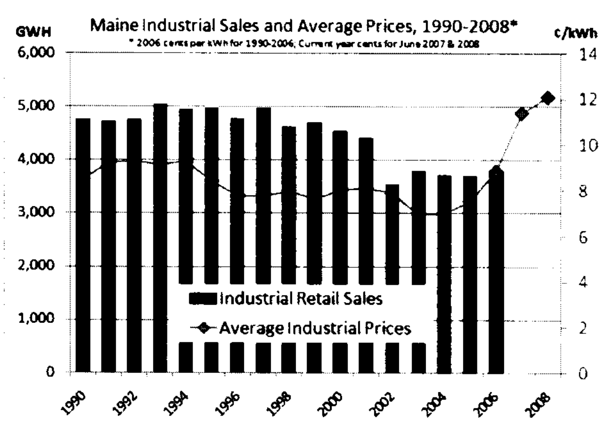
2009, there will be a need to replace two-thirds of the load (the 2006 and 2008 contracts). Standard offer rates have increased between 2% and 3% for each of the past two years for these two utilities, weighing together the net effect of power costs and decreases in stranded costs.

MPS with approximately 5% of the state's load is directly connected to the New Brunswick system, and is connected to the New England Power Pool through New Brunswick. There is only one competitive supplier serving the MPS service territory, and MPS is filing an application in 2008 for new transmission facilities to better connect with the rest of the state. Cost allocation for the investment will be an issue.

In addition to the 30% RPS requirement, Maine requires "new renewable resources" to be 1% of the portfolio in 2008 (and growing by 1% a year). In 2007, Maine created an Energy Conservation Board to assist the MPUC with energy conservation as it relates to carbon dioxide reductions.

Maine Percent Switching July 2008	Percent of Residential and Small Commercial Customers	Percent of Medium C&I Load	Percent Large C&I Load	Percent Total Load
Bangor-Hydro Electric	0.6%	39.6%	76.0%	31.1%
Central Maine Power	0.9%	36.5%	92.9%	38.2%
Maine Public Service	0.4%	24.1%	71.4%	26.4%
State Total	0.8%	36.0%	91.8%	36.6%





Maryland

In April 1999, Maryland adopted the Electric Customer Choice and Competition Act of 1999 (SB300 and HB703). The bill mandated retail access and a rate reduction. Customers of the investor-owned utilities became eligible for choice in July 2000, and customers of electric cooperatives became eligible at the end of 2001. Five municipal utilities remain locally controlled and are not required to offer retail choice.

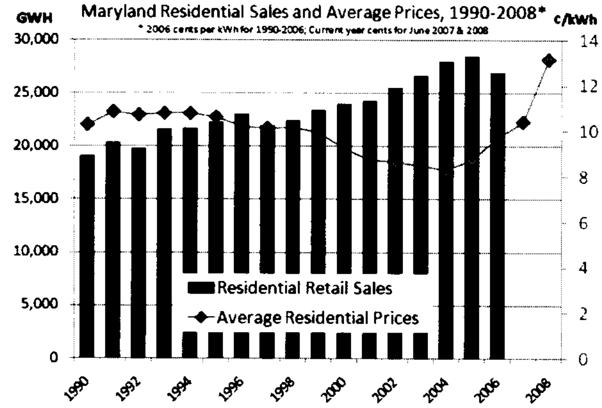
Standard offer service design and rate levels have been a point of contention. The initial standard offer service remained in effect until July 1, 2003. A subsequent case (Case No. 8908) determined that standard offer service would remain in effect to 2004 to 2008. During this period, utilities, as the default service providers, acquired 1, 2, and 3-year power contracts to meet the needs of residential customers. Commercial customers received a more variable price, and large customers received hourly pricing over a one-year period. If numerous customers remained with standard offer service, the utilities applied an alternative price of service – the PJM hourly price.

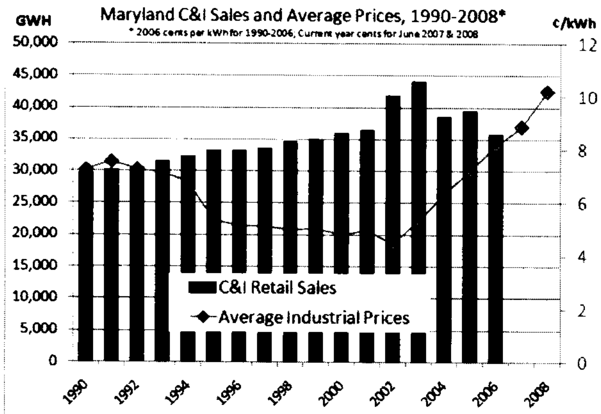
Rate caps were scheduled to expire, but the anticipated price increases resulted in numerous alternative rate mitigation proposals. For example, in anticipation of 72% rate increases in the Baltimore Gas and Electric (BGE) service territory, the legislature considered bills in 2005 and 2006 to limit the immediate increase to 5% to 25%, with future recovery of deferred costs through a new transition charge. In Case No. 9056, the Maryland Public Service Commission determined that everyone other than the smallest commercial customers would be moved to quarterly bidding and quarterly pricing. In Case No. 9064, residential customers were changed from to a two-year bidding framework, with one-fourth of the load bid every six months. In the BGE service territory, a Rate Stabilization Charge will collect a set amount over the next 10 years.

Maryland is pursuing climate change and energy efficiency issues. A significant portion of the revenues derived from a carbon auction in 2008 will be dedicated to energy efficiency activities and will be administered by the Maryland Energy Administration. Although advanced metering has not penetrated mass markets in Maryland, demand response remains important with approximately 1,000 MW of direct load control programs using smart switches, smart thermostats and radio frequency signals in PJM. State officials continue to work on reliability and resource adequacy issues, including the need for power plant construction in the state.

Residential customer switching in Maryland is 2.9 %, with a range from 0.0% to 5.8 % in the four distribution utility service areas.

Maryland Percent Switching September 2008	Percent of Residential Customers	Percent of Commercial and Industrial Load (MW)	Percent of Total Load (MW)
Allegheny Power	0.0%	63.1%	29.5%
Baltimore Gas and Electric	2.6%	72.1%	38.5%
Delmarva Power & Light	0.8%	63.5%	30.7%
Potomac Electric Power	5.9%	73.8%	42.6%
State Total	3.0%	71.1%	38.1%





Massachusetts

In November 1997, the state legislature enacted HB 5117 to restructure the electric power industry, granting rate cuts of 10% at first, and another 5% after 18 months, with full recovery of stranded costs over a 10-year transition period. In March 1998, the Massachusetts Department of Telecommunications & Energy (now known as the Department of Public Utilities) issued final decisions and regulations to open the electricity market to retail competition. The law included a provision for a systems benefits charge, and Massachusetts has adopted advanced plans for energy efficiency and renewable energy.

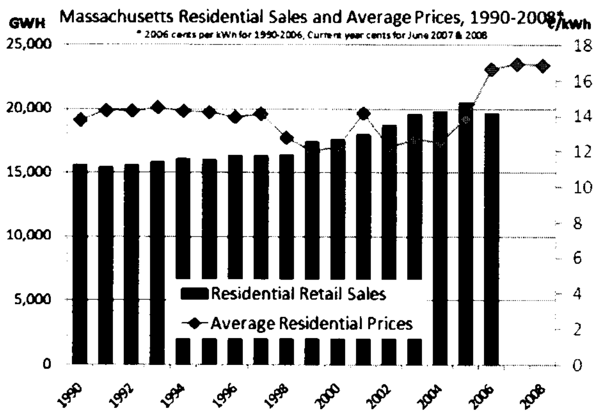
Generation service became competitive, but transmission, distribution and customer services remained regulated monopoly services. Standard offer service was created as a transitional service for existing electricity customers. The standard offer set at 2.8 cents with a trajectory to rise to 5.2 cents per kWh in 2005 (projected to be above market in 2005). These were administratively determined numbers (not market based) and included fuel triggers to increase if necessary.

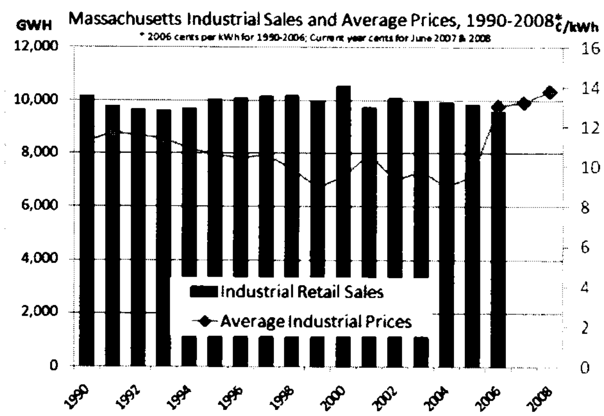
When markets opened, the 2.8 cents per kWh standard offer service rate was too low for competitors, stifling competition until the standard offer service rate was scheduled to rise in 1999. Utilities divested themselves of generation and natural gas plants were constructed. In 2000, standard offer rates were increased in response to market price increases.

In 2005, standard offer service expired. These customers were transferred to default service which had been designed for customers who were new to the system but not selected a competitive service provider. (In Massachusetts, "standard offer" and "default service" have distinct meanings.) Default service for smaller customers relies on twice a year procurement of 50% of the load for one-year terms. Default service for larger customers is procured four times a year, 100% of load at a time.

Aggregation is active on Cape Cod (eastern MA) with the Cape Light Compact serving a significant number of customers. Cape Light accounts for approximately one-half of the residential customer switching in Massachusetts. Customers who do not wish to participate can opt out of the aggregation program.

Massachusetts Percent Switching May 2008	Percent of Residential Customers	Percent of Small C&I Load (MW)	Percent of Medium C&I Load (MW)	Percent of Large C&I Load (MW)	Percent of Total Load (MW)
State Total	11.2%	33.9%	49.8%	87.3%	52.8%





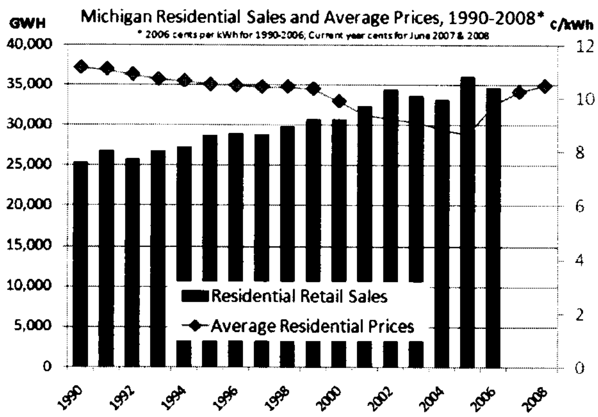
Michigan

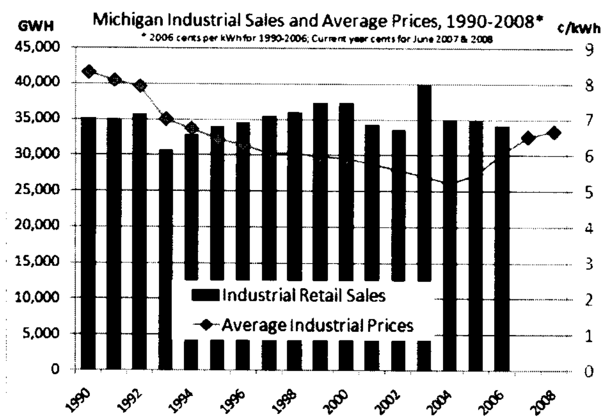
The Michigan Public Service Commission (MPSC) initially ordered retail choice pilot programs in 1998 and 1999. Michigan's Customer Choice and Electricity Reliability Act (2000 PA 141), enacted June 2000, introduced competition into the electric industry by offering Michigan customers the opportunity to choose to purchase their electric generation services from an alternative electric supplier (AES). While access for a few large customers began in 1999, all large customers (loads of greater than 1 MW) of Detroit Edison, Consumers Energy, and the electric cooperatives obtained retail access in January 2001. In December 2001, the MPSC issued nine orders to advance Michigan's competitive electric environment. Among the decisions: Detroit Edison and Consumers Energy could not change their depreciation accrual rates and practices until January 2006; rules would be drafted for service quality and reliability standards for electric distribution systems; standards were adopted for the disclosure of customer information, fuel mix and environmental characteristics; and net stranded costs for utilities were determined. Rate cuts were mandated for some default service tariffs.

Michigan is first state to have independent transmission company ownership of virtually all its high-voltage transmission facilities. Trans-Elect owns Consumers Energy's 5,400 miles of transmission, and Kohlberg Kravis Roberts and Trimaran Capital Partners own DTE Energy's (Detroit Edison) 3,000 miles of transmission.

On October 6, 2008, Governor Granholm signed a pair of bills. HB 5524 amends the Customer Choice and Electricity Reliability Act, and SB 231 addresses energy planning and renewable energy. HB 5524 was introduced in December 2007 and requires customers to declare within 90 days whether they would continue to receive power from an alternative electric supplier. Upon selection of this option, customers would be required to give notice to return to regulated service, and would pay the higher of average rates or market prices at the time of return for one year. Other customers would receive on standard tariff service. New customer would not be eligible for choice and would receive standard tariff service. The proposed legislation would also limit the market share of non-incumbent suppliers to 10% of sales.

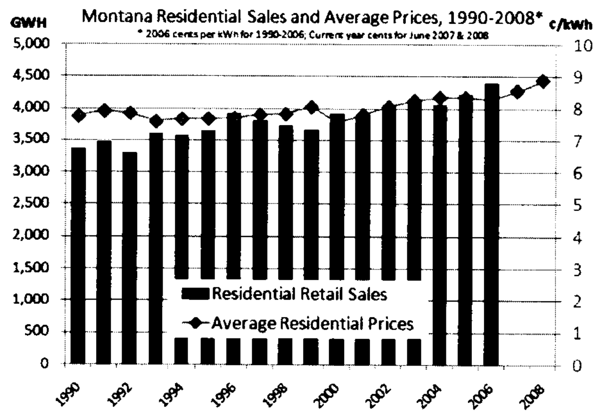
Michigan Percent Switching November 2007	Percent of Residential Customers	Percent of Commercial Load	Percent of Industrial Load
Consumers Energy	0%	3.9%	7.8%
Detroit Edison	0%	8.6%	5.1%
State Total	0%	6.8%	6.3%

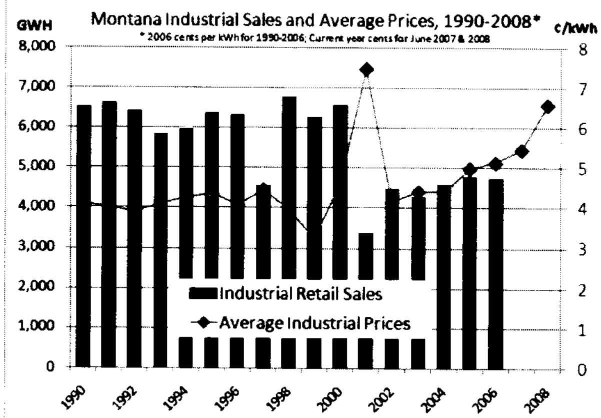




Montana

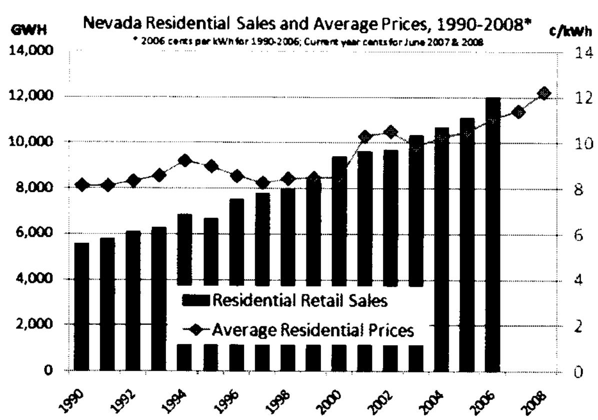
In May 1997, Montana enacted SB 390 that gave larger consumers the ability to choose their power supplier in 1998. Under the Act, electricity suppliers must file an application and obtain a license from the Montana Public Service Commission (MPSC) before offering electricity for sale to retail customers. The PSC decided in 2000 to delay full customer choice until 2004. Montana's investor-owned utility voluntarily divested its generation in December, 1999, and acquired default supply through competitive bidding. Legislation in 1999 (SB 406) allowed residential and small business customers to combine their buying power by forming a cooperative. The law exempts electricity suppliers from laws that prohibit cooperatives from expanding into cities of more than 3,500 persons. A standard information facts label is required for sales to residential and small commercial customers. The MPSC web site provides consumer protection information. Additional legislation in 2001 (HB 474) altered the existing legislation and extended the transition period to July 2007. Rates were increased and the PSC was criticized for not exerting enough control over the market participants. Every two years, Northwestern Energy must submit a plan detailing how it will secure electricity. The utility remains the default service provider and the MPSC conducts proceedings to consider the utility's Electricity Supply Procurement Plan.

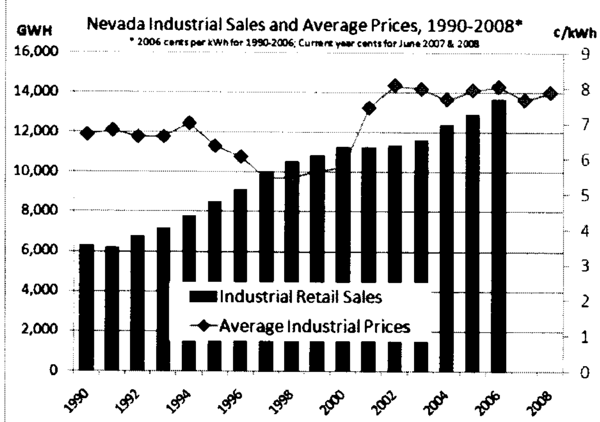




Nevada

In July 1997, Assembly Bill 366 was enacted adopting retail access. Larger customers became eligible in 2000. A settlement from a challenge by the Nevada utilities to the state's electric restructuring statue resulted in an agreement that the companies would not seek stranded cost recovery. In October 2000, the governor delayed implementation of the choice plan for residential customers until September 2001. In March 2001, the governor issued the Nevada Energy Protection Plan, a strategy to provide energy reliability, consumer protection, and long-term rate stability. In April 2001, AB 369 rejected retail access for small customers, returned utilities to regulation, and barred the sale of power plants before July 2003. Electric utility deregulation was halted because of high demand, low supply, and unstable prices.

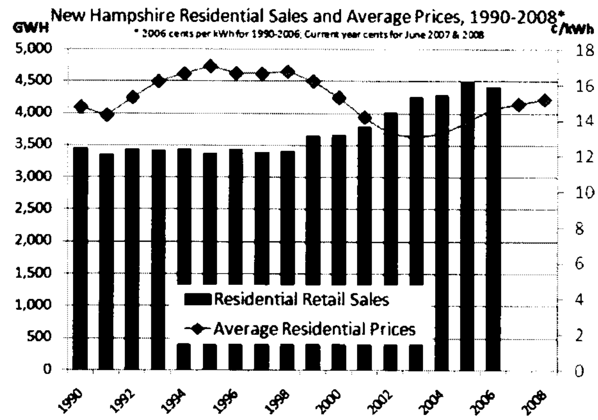


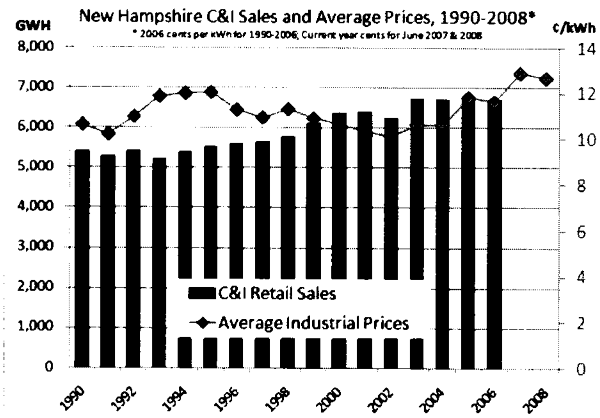


New Hampshire

In May 1996, legislation (HB 1392) was enacted for retail choice: statute RSA 374-F. In July 1998, Granite State Electric opened its retail load to competition. Litigation in state and federal courts tied up implementation for Public Service New Hampshire (PSNH). Additional legislation (SB 472) passed in May 2000 breaking the deadlock with PSNH. PSNH did not implement customer choice until May 2001.

Legislation mandated rate reductions and divestiture of generation. The other three electric distribution utilities restructured in between 1998 and 2002. Competitive suppliers are welcome to provide service in restructured areas, but most residential customers receive Transition (default) Service. The focus in recent years in New Hampshire has been on the development of comprehensive energy efficiency programs and the effective use of a system benefits charge of 3 mills per kilowatt-hour.





New Jersey

In February 1999, New Jersey adopted the Electric Discount and Energy Competition Act (EDECA) (AB 10/SB 5) which authorized the New Jersey Board of Public Utilities (NJBPU) to permit competition in the electric and gas marketplace, allowed electric utilities to divest themselves of electric generation assets, allowed securitization of stranded cost recovery that could be collected through a non-bypassable wires charge, provided an immediate rate reduction of 5% (10% by year four) and established a social benefits charge for the collection of monies for demand-side management programs. Utilities were allowed to use deferred accounting for expenses that were not collected under the rate cap. All customers in New Jersey can purchase their electricity from a third party supplier rather than the local utility company. Shopping credits, the rates against which outside suppliers must compete, were set at about 5 to 6 cents per kWh, depending on the rate class and utility.

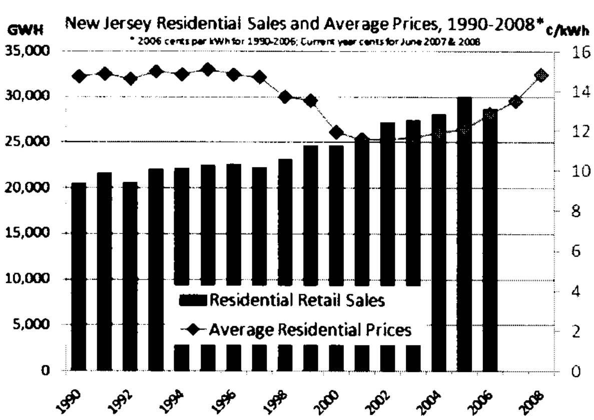
In December 2000, the NJ Supreme Court upheld a decision upholding the NJBPU restructuring and securitization orders for PSE&G. By 2002, the difference between the market cost of electricity and the mandated rates, known as "deferred balances," had grown to approximately $1 billion, largely because competition in New Jersey had not occurred as anticipated. A task force on deferred balances was convened by the governor.

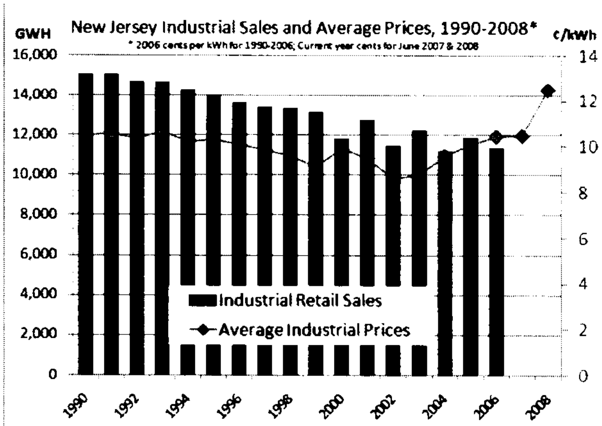
Under EDECA, there was a requirement for a provider of last resource for basic generation service (BGS). BGS has been provided by the electric utilities since 2002-03. In February 2006, rate increases of 12% to 13.7% were announced as a result of the 2006 auction for BGS. The 2008 auction covers hourly-priced service for Commercial and Industrial Energy Pricing (CIEP) Customers for one year beginning June 1, 2008. The fixed price customer auction for is for a supply period of three years, with one-third of each utility's total load requirements acquired each year. The winning fixed price contracts averaged 11.15 to 12.05 cents per kWh. These supplies replace the 2005 contracts and will result in residential customer price increases of 11.5% to 17.3% in the various service areas.

The social benefits charge includes incentives for energy efficiency programs and renewable resource programs. The state adopted a renewable portfolio standard that includes a solar set aside (2.12% solar capacity by 2020). New Jersey has almost 55 MW of solar capacity and uses Solar Renewable Energy Certificate (SREC) trading to help finance solar projects. In 2007, New Jersey adopted the Global Warming Response Act (A3301) which set greenhouse gas emissions targets. The state has programs implemented by investor-owned utilities that are transitioning to third-party program management.

New Jersey Percent Switching March 2008*	Percent of Residential Customers	Percent of Nonresidential Load (MW)	Percent of Commercial and Industrial Energy Pricing (CIEP) Customer Load (MW)
Atlantic City Electric Company	0%	12.6%	99.8%
Jersey Central Power & Light (JCP&L)	0%	10.0%	83.6%
Public Service Electric and Gas Company (PSE&G)	0%	15.3%	80.4%
Rockland Electric Company	0%	6.6%	66.2%
State Total	0%	13.0%	82.8%

* Most recent nonresidential data reported is for June to September 2007.





New York

The New York Public Service Commission (not the state legislature) ordered restructuring of the electric utilities in May 1996. The NYPSC implemented a plan for restructuring by approving utility plans in 1997 and 1998. The entire market is now open. Residential consumers can elect to receive service through the regulated tariff of the local electric distribution company, or through an aggregation program, or directly from a competitive retailer known in New York as energy service company (ESCO). Switching rates appear in the table below. Although New York does not use the term "default service," a majority of residential consumers receive electric service through the regulated tariff of the local electric distribution utility.

The NYPSC played a key role in the development of national uniform business practices. The NYPSC approved standards governing the electronic exchange of routine business information and data among electricity and natural gas service providers in New York in June 2001. The NYPSC also issued an order to establish uniform retail access billing and payment processing practices that facilitates a single bill option for customers.

In 2002, New York made important progress in enhancing retail competition in the areas of customer protection, information disclosure, and demand responsiveness. Under a 2002 law, the customers of ESCO receive the same protections as those of the utilities. The ESCOs lobbied for these provisions because they now have a greater chance of getting payment from customers, and customers have equal protection from all ESCOs and utilities. Electricity consumers now receive information in electric bills about the types of generating fuels and related air emissions. These steps encourage green power offerings in New York. ESCOs are participating in demand response programs. Electricity use curtailment competes directly with generation during periods of high electricity consumption.

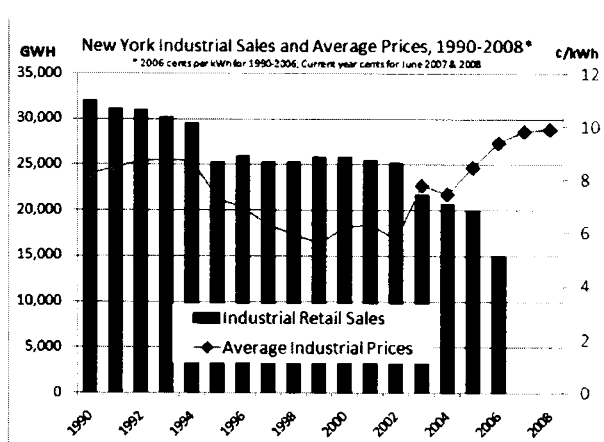
Competitive electric metering and electric meter data services are permitted in New York for certain customers. New York is considering the deployment of an advanced metering infrastructure to realize the State's energy policy goals for time-differentiated pricing and energy efficiency.

In May 2007, the NYPSC initiated a proceeding (Case 07-M-0548) to investigate an Energy Efficiency Portfolio Standard (similar to a renewable resources portfolio standard) to advance the Governor's goal of 15% reduction in electricity use by 2015. The existing systems benefit charge is used, in part, to fund energy efficiency incentive programs administered by the New York State Energy Research and Development Administration (NYSERDA). The NYPSC will determine how additional energy efficiency activities will be administered in the future.

The New York PSC is fine tuning its market rules and is considering a requirement for a consumer disclosure statement, timelier dispute resolution and training of retailer representatives.

New York Percent Switching August 2008	Percent of Residential Customers	Percent of Small Nonresidential Load (MWH)	Percent of Large Nonresidential Load (MWH)	Percent of Total Load (MWH)
Central Hudson	3.9%	23.3%	85.5%	31.5%
Consolidated Edison	17.2%	46.9%	90.4%	44.8%
National Grid (Niagara Mohawk)	13.1%	61.7%	71.8%	46.3%

New York State Electric & Gas	14.4%	51.9%	59.9%	41.7%
Orange & Rockland Utilities	27.9%	49.8%	28.7%	36.5%
Rochester Gas & Electric	18.8%	62.7%	73.5%	53.0%
State Total	15.6%	51.0%	74.8%	44.3%
Does not include Long Island Power Authority and municipalities that purchase from the New York Power Authority.				



Ohio

Legislation (SB 3) was enacted in July 1999 to allow retail customers to choose energy suppliers as of January 2001. The goal was to achieve retail competition with respect to the generation component of electric service. The law required a 5% residential rate reductions and a rate freeze for 5 years to allow a transition to competitive markets. The legislation contained consumer protections, environmental provisions, and labor protections; empowered the Ohio Public Utility Commission (PUCO) to determine the amount and recovery period for stranded costs; required that property taxes utilities paid would be replaced with an excise tax on consumer bills; and required that utilities to spend $30 million over six years on consumer education programs. Utility plans were approved in 2000 and choice began January 2001.

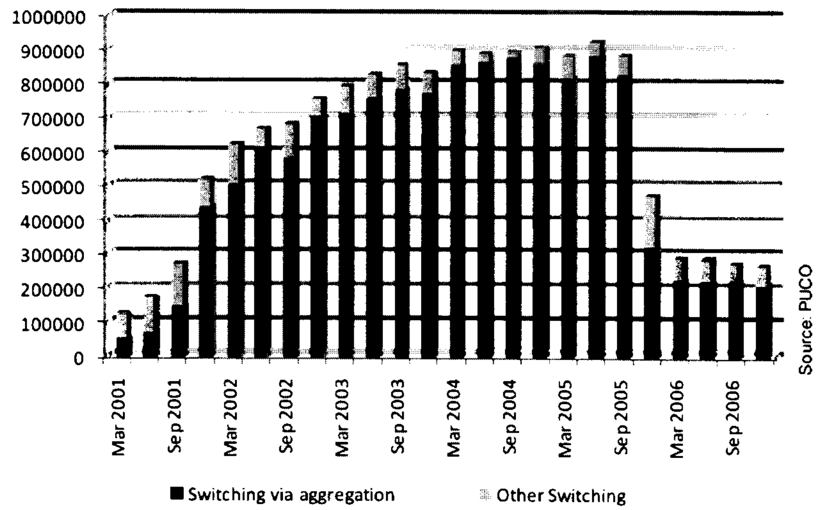
Ohio's law allowed communities to aggregate and strengthen their bargaining power in establishing electricity prices. Under aggregation, residents received a postcard in the mail notifying them of their new electricity choice, and those who choose to "opt out" and continue buying power from their current supplier had 21 days to act. Ohio was a model for aggregation with over 800,000 consumers receiving power in that manner in 2004-5.

During the five year "market development period," First Energy utilities offered relatively economical power (market support generation) that helped to encourage market entry by competitive suppliers. As the end of the five-year transition approached, the PUCO was concerned that the market had not developed sufficiently to quickly move to market based rates. PUCO adopted "rate stabilization plans" of three to five years duration for each utility, which went into effect in 2006. The "shopping credits" were inadequate to encourage sustained retail competition.

In April 2008, Ohio modified its restructuring law to address Governor Strickland's plan to protect retail electricity consumers from "rate shock" due to market forces. SB 221 requires electric distribution utilities to provide consumers with a standard service offer (SSO) that either relies on an "electric security plan" (ESP; a proposed standard service offer), or an SSO based on a "market rate offer" (MRO) that is determined through competitive bidding. Both approaches may be in effect during a transition period using a blended rate. If the utility elects the "electric security plan," then the utility may construct and place the investment costs of a power plant into rate base. Such generating units must forever remain under the "electric security plan" option; that is, in service to Ohioans under the SSO. If however the utility elects the "market rate offer" approach, then the market rate offer will be phased in over a period of years until it comprises 100% of the SSO. In the intervening years, "electric security plan" rates will make up a decreasing proportion of the blended SSO. The "market rate offer" approach is irrevocable – the utility cannot later elect to build power plants. Further, the competitive bidding process is subject to PUCO oversight and approval of the least cost bidder. The utility may recovery prudently incurred costs of fuel, purchased power, costs for energy and capacity, and purchases from affiliates.

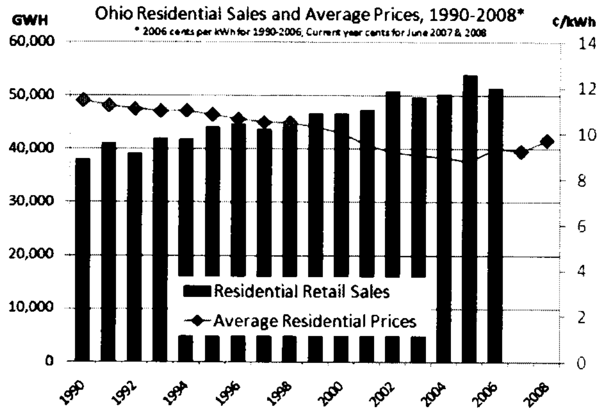
Retail choice is preserved under SB221 with specified safeguards, such as prohibiting the inclusion of generation costs in unbundled distribution rates. (Section 4928.02(H) of the law state, "[It is the policy of this state to] Ensure effective competition in the provision of retail electric service by avoiding anticompetitive subsidies flowing from a noncompetitive retail electric service to a competitive retail electric service or to a product or service other than retail electric service, and vice versa, including by prohibiting the recovery of any generation-related costs through distribution or transmission rates; ...") Section 4905.31 addresses "special arrangements" and allows large customers (over 700,000 kWh per year or part of a national chain) to file with the PUCO a request for a preferential deal outside any tariff. This provides large customers with leverage that they did not have before. Special arrangements can also be made between utilities, to allow a joint program or purchase, so long as the PUCO approves it.

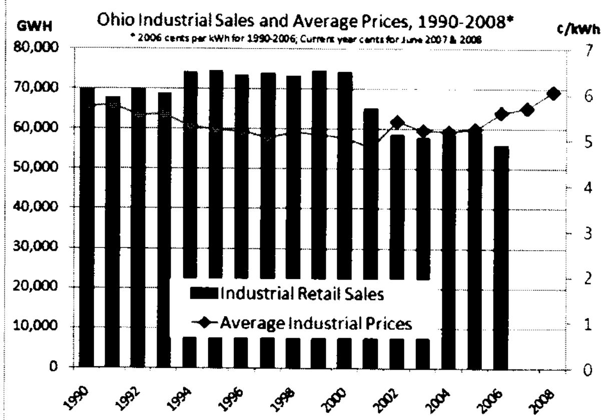
Figure 3: Number of Residential Customer Switches in Ohio 2001 - 2006



Source: Ohio PUC, "Ohio Retail Electric Choice Programs Report of Market Activity, July 2005 – December 2006," 2007.

Ohio Percent Switching June 2008	Percent of Residential Customers	Percent of Commercial Sales (MWH)	Percent of Industrial Sales (MWH)	Percent of Total Sales (MWH)
Cleveland Electric Illuminating Company	8.4%	16.9%	11.2%	12.1%
Duke Energy Ohio	1.7%	9.0%	0.3%	3.5%
Columbus Southern Power Company	0%	1.7%	0%	0.7%
Dayton Power and Light Company	0%	11.4%	58.6%	23.4%
Ohio Edison Company	17.1%	23.4%	15.7%	18.0%
Ohio Power Company	0%	0%	0%	0%
Toledo Edison Company	10.9%	33.8%	1.8%	12.7%
State Total	6.1%	13.0%	9.9%	9.8%





Oregon

In late 1997 Portland General Electric proposed a pilot project to allow customers to select a generation supplier. A few months later, PacifiCorp proposed a pilot that would allow customers to select from a portfolio of pricing and resource options. These pilots set the stage for SB 1149, the restructuring bill, enacted in July 1999. SB 1149 offered energy supplier choice to nonresidential customers by October 2001. Residential customers would be offered a portfolio of options including green power. In August 2001, two new bills amended the restructuring law (delaying the implementation date to March 2002 for nonresidential customers) and gave the Oregon PUC new powers to balance the interests of utility shareholder with electric customers. (NOTE ADD REF TO 3% systems benefit charge)

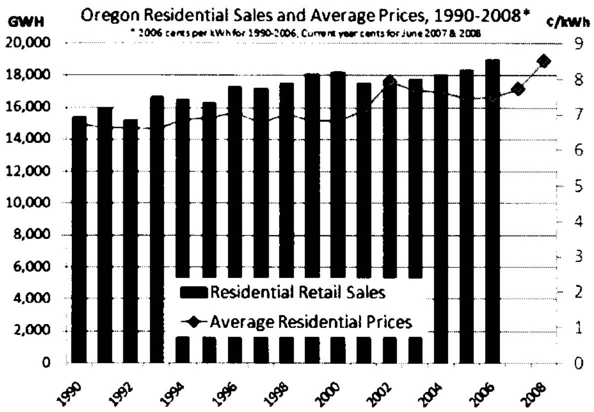
Under the portfolio approach, residential customers can choose among renewable energy pricing plans that rely on existing geothermal and wind sources, or contribute to salmon habitat restoration, or purchase new wind resources. As of April 2008, approximately 7.9% of residential customers in Oregon were served through one of these options (106,366 of these options have been selected, with some double counting as one customer selects more than one option).

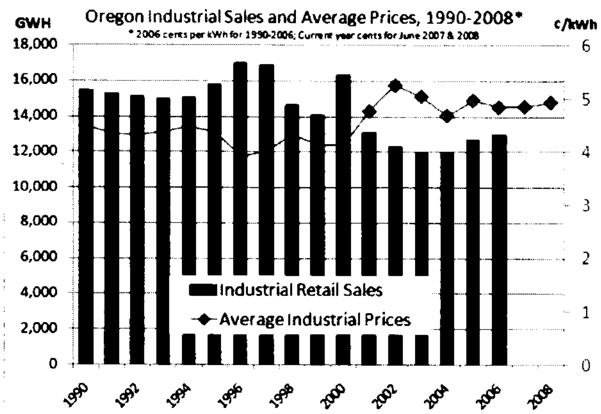
The Oregon PUC has conducted rate cases for both major utilities to resolve default service and stranded cost issues, and put in place programs for codes of conduct. At first, the transition charge was variable, and large customers were required to commit to not return to standard offer service for five years. There were also limitations with respect to when switching could occur. As a result, no switching occurred at first. By late 2002, the transition charge had been stabilized. As of April 2008, 12% of nonresidential load had switched to competitive suppliers. Direct access-eligible (nonresidential) customers may choose service from an alternative electric service supplier for 1, 3, 4, in some cases a 5 year period.

Oregon is engaged in a consideration of climate change issues. Under a proposed rule, utilities would be required to handle CO2 risk by examining values that range from zero dollars to $40 per ton.

Oregon Percent Switching October 2008	Percent of Residential Customers	Percent of Nonresidential Load

Portland General Electric	0%	20.1%
PP&L (PacifiCorp)	0%	0.7%
State Total	0%	12.0%





Pennsylvania

The Electricity Generation Customer Choice and Competition Act (HB 1509) was enacted in December 1996. A pilot phase began in late 1997, and then a phase-in allowed one-third of consumers to join each year. Different utilities received different treatment with respect to initial rate decreases and the size of stranded cost recovery and competitive transition charge. A shopping credit was advertised to allow customers to compare competitive rates with the "price to compare" or "shopping credit."

After several years the Pennsylvania Public Utility Commission (PUC) approved a change in default service rates because some consumers were "gaming the system" by returning to the utility rate for the summer when competitive prices typically rose, making default service rates more attractive. Under the revised system utilities were able to impose switching restrictions and exit fees (a market based penalty called the "generation rate adjustment").

Competitive Default Service was authorized for 2001 for PECO Energy customers and allowed customers to be assigned to a new supplier, New Power Company. PECO retained the customers after this non-utility provider left the state. Several other utilities had similar experiences with price caps in place. In March 2002, Duquesne Light became the first Pennsylvania utility to send bills without a competitive transition charge. Duquesne was no longer subject to the rate cap. Shopping credits rise as the CTC decreases, and thus customers have a greater opportunity to find suppliers who can sell below the default service price.

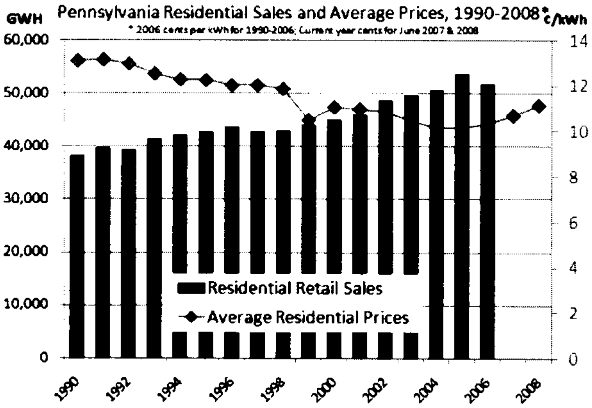
Most residential customers are protected by rate caps through 2010. Utilities and the PUC are getting ready for that day. The Pennsylvania Office of the Consumer Advocate stated in a February 1, 2007 press release that, "we not wait until 2010 and then roll the dice in a single wholesale market auction ... It is also essential that customers not have to rely solely on volatile short term and spot market prices ... we should be taking steps as soon as possible to secure stable, reliable, and least cost resources, including new renewable energy resources as well as conservation and energy efficiency, to meet consumers' future needs."

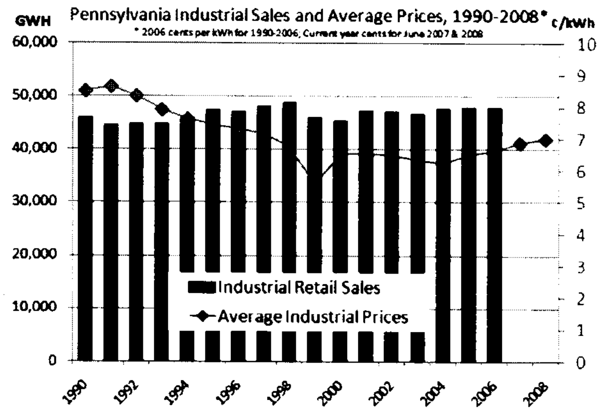
Under a new plan, Penn Power is purchasing one and two year power contracts for default service that will be effective through 2011. Penn Power's rate caps ended in 2006. The PUC is holding hearings on PPL Electric's Rate Stabilization Plan and the PPL Electric rate cap will come off in January 2010. Residential customer switching is very low in five of seven utility service areas. Switching in Duquesne Light exceeds 22% and nearly 10% of Penn Power residential customers have switched because prices are no longer capped. The average switching rate for residential customers is 2.8%.

Load serving entities are required to satisfy the state's Alternative Energy Portfolio Standard which will rise to 18% of load over time. While the state as a whole is not using advanced metering, the PPL Electric service area has 100% penetration of AMI which could support competitive offers in the future. Pennsylvania is not currently part of a climate change initiative, however, the governor is planning to address energy efficiency and the environment in the near future, and energy efficiency and demand response are addressed in pending legislation. Pennsylvania has recently committed $5 million dollars for consumer education, including education relating to retail choice and conservation of energy.

New legislative initiatives require utility service providers to buy power through a mix of short- and long-term contracts. The PUC will have oversight to ensure that there is no market manipulation. There is a new focus on renewable energy industries and programs to conserve and use power more efficiently.

Pennsylvania Percent Switching in Utility Distribution Regions July 2008	Percent of Residential Customers	Percent of Commercial Load (MW)	Percent of Industrial Load (MW)	Percent of Total Load (MW)
Allegheny Power (central & west)	0%	0%	0%	0%
Duquesne Light (Pittsburgh/west)	22.0%	50.3%	88.5%	48.8%
MetEd/Penelec (formerly GPU)	0%	0%	3.9%	1.0%
PECO Energy (Philadelphia/southeast)	0.2%	7.4%	0.1%	2.2%
Penn Power (west)	8.4%	44.9%	97.4%	53.6%
PPL Electric (central & east)	0%	0.1%	0.1%	0.1%
UGI (Scranton/Wilkes Barre)	0%	0%	0%	0%
State Total	2.8%	--	--	--

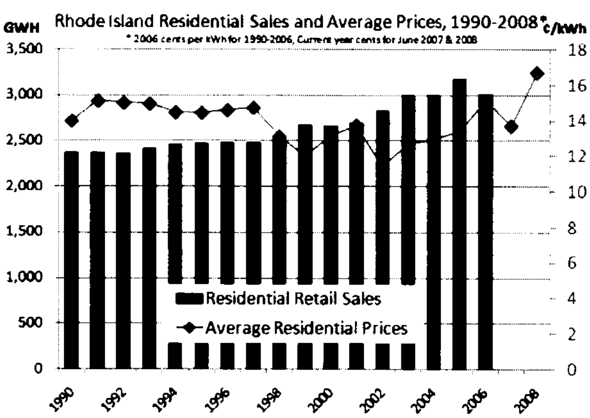


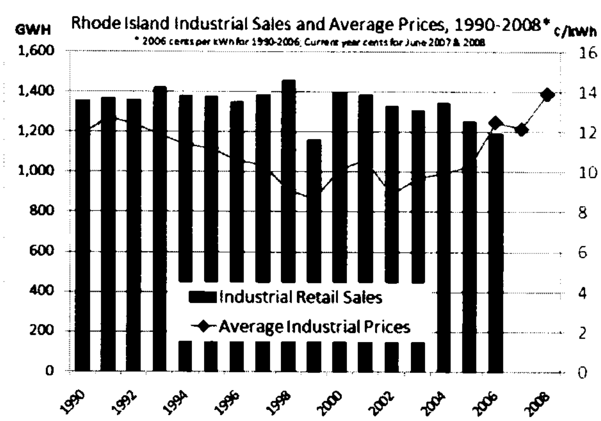


Rhode Island

In August 1996, legislation (HB 8124) passed, and Rhode Island became the first state to begin phase-in of statewide retail wheeling in July 1997 for industrial customers. Residential consumers were guaranteed retail access by July 1998. Very few customers switched because of the low standard offer service rate. SB 881, enacted May 2001, enabled non-residential customers enrolled in last resort service the option to return to standard offer service. These customers are required to sign a 2-year agreement prohibiting self-generation during non-emergency conditions and prohibiting remarketing of purchased electricity.

Rhode Island Percent Switching June 2008	Percent of All Customers	Percent of All Load
State Total	0.6%	15.3%





Texas

Texas developed a strong independent power industry in the 1980s. The implementation of PURPA under Texas law resulted in rapid cogeneration project development. The open-access transmission regime that began in 1996 is operated by the Electric Reliability Council of Texas (ERCOT), subject to the jurisdiction of the Public Utility Commission of Texas (PUCT). Legislation for retail choice was enacted in 1999 (SB 7), which set out to initiate competition with a pilot project in mid 2001, to be followed with a mandatory 6% rate cut and full customer choice implementation in January 2002. During 2001 pilot project enrollment, commercial and industrial classes exceeded the 5% participation limit, resulting in a lottery to determine which customers would be eligible. The pilot project started in the summer of 2001. Full retail choice began on January 1, 2002 for customers of investor-owned utilities within the ERCOT region of Texas. During the first eighteen months of competition there were some issues with customer switching and new service hookups, but these problems were quickly resolved.

Cooperatives and municipal utilities may decide whether and when to "opt in" to retail competition. Outside of ERCOT, but within Texas, the statute gives the PUCT authority to determine when retail choice can be implemented. The customers of El Paso Electric Company, Entergy Texas (southeast Texas), AEP's Southwest Electric Power Company (northeast Texas) and Xcel's Southwest Public Service Company (Panhandle region) do not yet have retail choice. These decisions are dependent on wholesale market development, and retail choice in northeast Texas has been delayed until 2011 or later.

In Texas, ERCOT operates the high-voltage transmission wires, manages congestion, ensures that ancillary services are adequate, provides a market platform for wholesale competition, performs settlement, administers retail customer switching and administers the renewable energy certificate program. Despite recent deployment delays, ERCOT's zonal congestion management system is expected to be replaced with a nodal pricing and congestion management system over the next couple years. This development is being watched closely, as high zonal congestion management costs in the first half of 2008 contributed to wholesale market volatility and retail market disruptions. In June 2008, ERCOT revised its protocols for zonal congestion management to provide some short-term relief, however the nodal system is expected to be a more efficient long-term solution.

SB 7 required each investor-owned utility to separate business functions. Affiliated companies can provide retail electric service to customers, own and operate generating units, and provide transmission and distribution service. The law also required electric distribution utilities (which remain regulated) to refrain from retail marketing or the provision of competitive services. Texas has achieved a high degree of structural separation that has reduced the incentives for corporate integration, and reduced the concerns of competitors that the incumbent utility holds unfair competitive advantage.

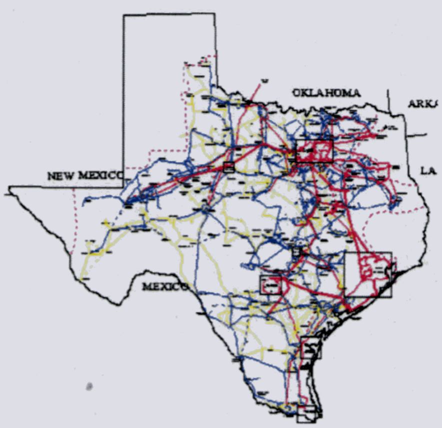
At the opening of the market, residential and small commercial customers could either remain a customer of the competitive retail electric provider (REP) affiliated with the incumbent utility, or switch to an alternative REP. Those who remained with the utility affiliate paid a regulated default service rate (this was called the "price-to-beat" or PTB) that could be adjusted up to twice a year. Default service was scheduled at the outset to last for only five years, and ended in December 2006. Provider of last resort (POLR) is a separate service for customers whose provider goes out of business. POLR service is the only remaining regulated electricity rate in the areas of Texas open for retail choice. POLR price is determined by a PUCT-approved formula based on short-term wholesale energy costs.

The success of Texas' renewable portfolio standard (RPS) and renewable energy certificate (REC) trading program has provided the impetus (along with a federal renewable energy tax credit) for rapid growth in wind turbine generation. Texas now leads the nation in wind turbine capacity (5,200 MW of new capacity as of May 2008) and wind energy production (2.9% of energy produced in ERCOT in 2007).

Another emerging issue related to wind power is transmission line capacity necessary to move wind energy from west Texas, where it is produced, toward the population centers in central and southeast Texas. Competitive Renewable Energy Zones (CREZ) with the greatest potential for wind energy development were identified in west Texas. The PUCT recently selected its preferred plan to designate and expedite the certification process to build over 18,000 MW of transmission capacity in these zones.

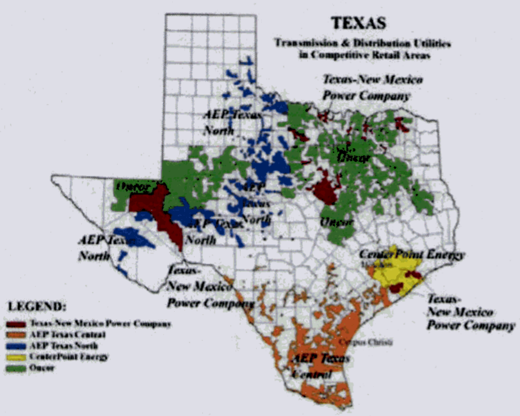
In 2005, six REPs defaulted, and in 2008, five more went out of business, forcing some customers to POLR service until they selected a new REP. Some of the failed REPs did not pay their energy bills to ERCOT, totaling more than $11 million in losses in the two years. The PUCT was concerned enough to open four new projects to consider market rule revisions. In Project No. 35767, Rulemaking Relating to Certification of Retail Electric Providers, a proposed rule was published in October to strengthen the certification requirements by raising the minimum financial requirements and by protecting customer deposits. In Project No. 35768, Rulemaking Relating to Retail Electric Providers Disclosures to Customers, the PUCT proposes to create four types of products (guaranteed fixed, limited fixed, variable and indexed), to require public disclose of contracts using these new terms, and to restrict certain changes in pricing based on the use of certain terms. The proposed rules are in the comment phase, to consider numerous issues, such as whether such rules should apply to larger customers or only to residential customers. In Project No. 35769, Rulemaking Relating to Electric Providers of Last Resort, the commission has published a proposed rule that will better protect customers and REPs that provide POLR service. Project No. 36131, Rulemaking Relating to Disconnection of Electric Service and Deferred Payment Plans, has no activity as of October 2008.

On issues relating to energy efficiency and advanced metering, the PUCT has several reports that will be considered by the Texas Legislature. Project No. 35770, PUC Report to the 81st Legislature on Advanced Metering will consider the deployment of advanced meter infrastructure (AMI). AMI deployment is going forward in the Oncor (Dallas-Fort Worth) and CenterPoint (Houston) transmission and distribution service provider areas. Other reports have been order by the Legislature on energy efficiency and combined heat and power.



ERCOT Major Transmission Lines

Source: ERCOT ISO Annual Report



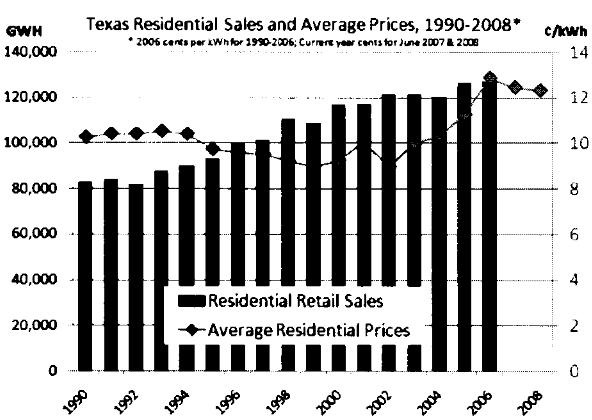
Texas T&D Utility Areas with Retail Choice

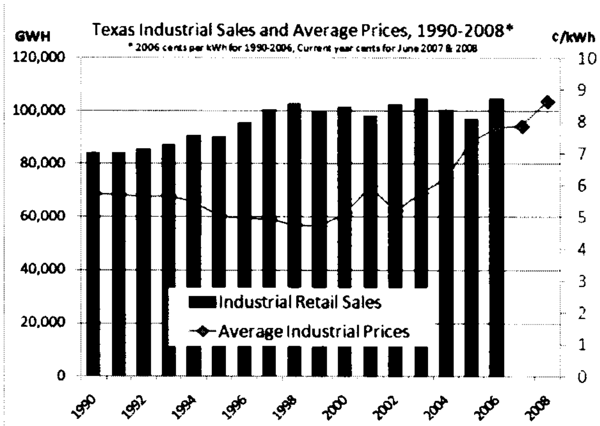
Source: Public Utility Commission of Texas

Texas Percent Switching* June 2008	Percent of Residential Customers	Percent of Small Commercial Load (MWH)	Percent of Large Industrial Load (MWH)	Percent of Total Load (MWH)
Oncor (Energy Future Holding Corp.)	39.8%	75.7%	**	59.8%
CenterPoint Energy	46.0%	61.1%	**	56.5%
AEP Texas Central	49.1%	90.1%	**	77.8%
AEP Texas North	57.5%	89.5%	**	81.6%
Texas-New Mexico Power Company	49.4%	78.0%	**	74.0%
State Total	43.9%	72.3%	68.3%	61.5%

* The regulated default service tariff (referred to as the "price to beat") is no longer offered. Therefore, essentially every retail customer receives service at a competitive price. These switching statistics show the percent of customers/loads no longer served by the affiliated (or incumbent) retail electricity provider.

** Large customer switching information is confidential because electric distribution utility service areas have a small number of very large customers.





Virginia

In July 1999, legislation (SB 1269) was enacted. Virginia's pilot program began in 2000 for the two largest investor-owned utilities (Dominion and American Electric Power) and one cooperative. Full retail access began a phased-in January 2002, with full choice to be implemented no later than January 2004.

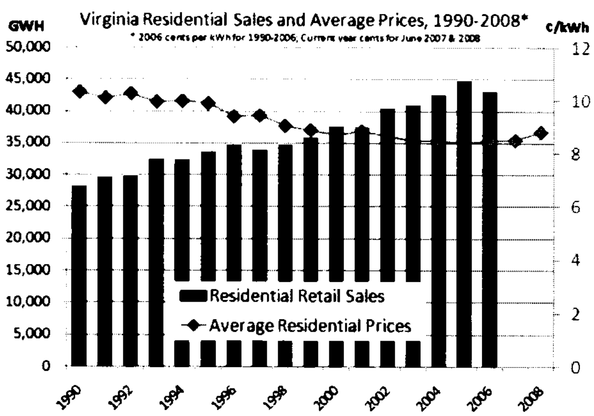
Utilities were required to functionally separate, and Allegheny Power and Connective voluntarily divested generation as part of the functional separation case.

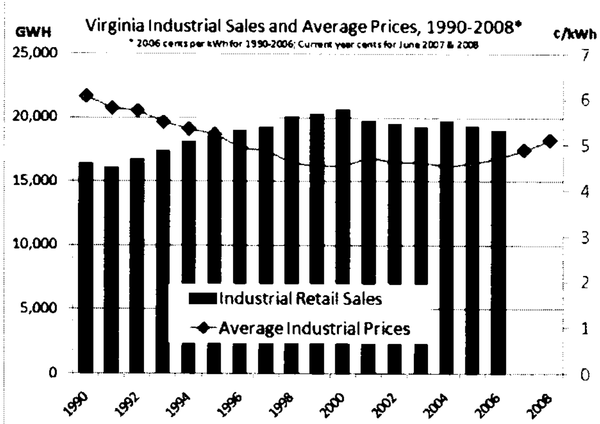
Competitive suppliers are licensed by the State Corporation Commission (SCC) and must register with each utility. In 2001, the Virginia General Assembly amended portions of restructuring legislation to cap default service rates only until January 2007. If there are capped rates, the utility is the default provider. After January 2007, the SCC would set rates based on competitive regional electricity markets. The Legislature created a Transition Task Force and Consumer Advisory Board, which worked collaboratively with SCC. The Legislation authorized alternative providers to direct bill customers beginning January 2003. Competitive metering began January 2002 for large commercial and industrial customers, and on January 2003 for residential and small commercial customers.

The practical result of low-capped rates has meant that there is no ability to choose a lower-cost alternative provider in Virginia. Only about 2500 residential and 24 small commercial customers were served by an alternative supplier (green power choice for residential customers). A contract was awarded for a statewide consumer education program. A survey indicated that awareness was raised, but given the slow development of actual competition, the budget for the second year was reduced. SCC has issued orders to address competitive metering, consolidated billing, minimum stay provisions, distributed generation, aggregation, and market price determination.

In early 2003, legislative activity included a bill to allow Kentucky Utilities to suspend retail choice in five counties in Virginia (HB 2637); a bill to allow the SCC to experiment with "opt in" options for municipalities (HB 2319); and a bill that defers a requirement to join an RTO to the utility with an adequate showing (HB 2453).

In 2007, HB 3068 and SB 1416 were enacted and signed by Governor Kaine, and Virginia suspended retail choice.



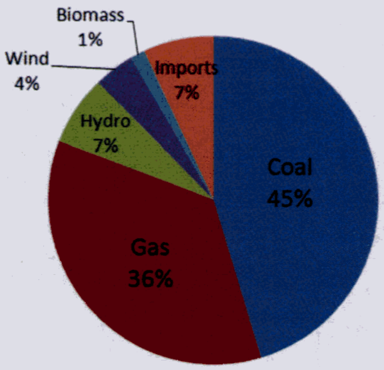


Alberta

In 1995, Alberta passed the Electric Utilities Act to initiate retail electric market restructuring in Canada. Wholesale competition began in 1996. Capacity reserves were very tight in 1998 as a result of rapid growth in electricity usage. Within the competitive market framework, over 2,000 MW of new capacity were added in 1998-2001, an additional 2,400 MW were constructed by the end of 2007. Presently there are over 12,000 MW of generating capacity in Alberta. Coal power plants generate more than one-half the electricity.

Energy-related industry is key to Alberta's economy, including oil, oil sands, natural gas, coal and minerals, and petrochemicals. Alberta serves electric demand with coal, natural gas (industrial cogeneration), hydropower, wind power and imports (transmission interconnections with British Columbia and Saskatchewan).

Alberta Generating Capacity (MW)



Customer Categories*	Number of Customers (2007)	2007 Customer Usage (GWH)
Residential	1,224,000	8,561
Farm	79,000	1,807
Commercial	145,000	13,132
Industrial	36,000	28,437
Total	1,485,000	51,927

* Note that the "commercial" and "industrial" categories reported here are not precisely the same as the "small commercial < 250 MWh/yr" and "large industrial > 250 MWh/yr" categories reported in the switching statistics below.

A 1999 pilot program gave large customers direct access to the power pool. Retail competition offered attractive options to large industrial and commercial customers enabling more than 80% of these customers to switch to competitive providers by 2008. Retail competition for customers of all sizes began on January 2001. Just prior to market opening, the wholesale market prices rose to very high levels, causing the regulators to institute a price cap – as a temporary shield against high prices – and a rate rider to collect any shortfall in revenue collection. By 2002, the wholesale prices had fallen to 1999 levels.

The Alberta Department of Energy embarked on a Retail Assessment Program to make mid-course corrections in the retail access program. The Electric Utilities Act was revised in 2003. A code of conduct addresses electric and natural gas service providers. Access to customer data is equal for competitive retailers and utility affiliates. A new independent system operator, the Alberta Electric System Operator (AESO), is responsible for market operations: power pool, system control, long-term transmission system planning and management and load settlement. In 2006, the Alberta Energy Utilities Board approved a standard tariff billing code for distribution utilities to ensure that retailers would receive information in a standard format. In 2007, the Legislature passed the Alberta Utilities Commission Act and divided the Energy Utilities Board into the two new regulatory bodies. The Alberta Utilities Commission continues to regulate utilities and a new conservation agency is focused on energy resource development.

The smaller customers, the energy portion of default service is calculated based on average monthly spot market prices plus short term hedging, encouraging risk-adverse customers to switch to competitive providers that guarantee a fixed price. Each year, 20% of customer needs are acquired and weighted with the four prior years' purchases. For users of greater than 250,000 kWh per year, default service is based on spot prices.

The AESO operates an energy only electricity market. In an energy only market design, the market determines the appropriate level of resource adequacy over the long term. The Electric Utilities Act mandates the collection and dissemination of information relating to the capacity of the interconnected electric system to meet future electricity needs. The AESO is conducting an investigation into long term resource adequacy to determine whether to create a bridging mechanism if adequacy becomes an issue. The AESO conducts two-year forecasts and has authority to take short term actions to maintain adequacy. As part of its review, the AESO is examining market conditions and incentives for investments in generation.

The province is very active with the development of advanced metering infrastructure (AMI). Electric distribution utilities are considering whether to install meters on their own without requesting reimbursement of the costs through rates.

In a March 27, 2008 letter, Alberta's Premier Stelmach outlined five priorities to the Cabinet Ministers, including "Ensure Alberta's energy resources are developed in an environmentally sustainable way." Development of the oil sands region should rely on "processes that use less energy, less water, reduce tailings ponds and improve land reclamation." Alberta is examining carbon capture and storage research and demonstration, and implementation of a climate change strategy, including "conservation, energy efficiency and adaptation initiatives."

Alberta Percent Switching March 2008	Percent of Customers	Percent of Sales
Residential	24%	NA
Farm	16%	NA
Small Commercial (< 250 MWh/yr)	45%	NA
Large Industrial (> 250 MWh/yr)	82%	NA
Province Total	NA	NA

Ontario

In 1998, legislation was enacted to provide authority for retail restructuring in Ontario. In April 1999, Ontario Hydro's assets were split into five successor entities. Ontario Power Generation, Inc. (OPG) assumed the generation business formerly operated by Ontario Hydro. Hydro One Inc. (formerly Ontario Hydro Services Company) assumed the network business and operated the transmission, distribution, and energy services businesses. The remaining three, operating on a not-for-profit basis, were the Electrical Safety Authority, the industry's safety inspection agency; the Independent Market Operator, responsible for operating and administering the new market and ensuring reliability and access to transmission and distribution systems; and the Ontario Electricity Financial Corporation, responsible for managing and retiring Ontario Hydro's outstanding debt and other obligations.

While future stranded costs were prohibited at that time, two types of payments on users were used to retire stranded costs incurred before restructuring: (1) a phased divestiture of the generation assets over a 10-year period to mitigate Ontario Power Generation's market power in Ontario, and (2) a per-kilowatt-hour charge (referred to as a Payment in Lieu of Taxes) on the monthly bills to all electricity users to retire the outstanding debt held by the Ontario Electricity Financial Corporation.

In May 2002, Ontario opening of its retail electricity market to all consumers. A high switching rate was attributed to the establishment of a formal Electronic Business Transactions (EBT) process, which included retail customer enrollment, testing, and scrubbing prior to market open. Ontario identified and corrected a large number of errors prior to full implementation. Ontario also initiated competitive billing and pass-through of default provider price risk, where majority of default providers sought exemption from a fixed reference price. In July 2002, the Energy Consumers' Bill of Rights came into effect creating new rules to protect low-volume consumers.

Record temperatures in summer of 2002 drove up the demand and market price. Concerns over these prices led to the passage in December 2002 of the Electricity Pricing Conservation and Supply Act 2002. This act mandated a fixed price of 4.3 cents per kWh for the electricity of low-volume consumers. Refunds were to be provided for amounts paid above 4.3 cents, retroactive to May 2002. Taxpayers were expected to make up the difference between market price and the capped rate.

In December 2004, the Government of Ontario passed the Electricity Restructuring Act of 2004, which reorganized the province's electricity sector, amended the Ontario Energy Board Act of 1998, and the Electricity Act of 1998. The act created a new Ontario Power Authority to ensure supply adequacy, created a new Conservation Bureau to set targets for conservation and renewable energy, redefined the role of the Independent Electricity Market Operator and renamed it the Independent Electricity System Operator (IESO), and regulated certain prices to ensure price stability.

The Regulated Price Plan (RPP) sets stable prices for small consumers with an inverted block schedule (use more, pay more) and a seasonal schedule that is undated every six months. In April 2008, the May 2008 – April 2009 prices were set. The prices are based on forecast hourly prices with an adjustment for the balancing account (unexpected variance) for past months. Customers with advanced meters are exposed to different prices than those with conventional meters.

Ontario has a Smart Metering Initiative to create a culture of conservation and a platform for demand management. Province-wide deployment of smart meters is underway through the Smart Metering System Implementation Program (SMSIP). A pilot time of use rate is available to residential customers. The local distribution utilities own the meters, and the IESO maintains the interfaces and the meter data management and data repository (MDM/R) functions.

Ontario Selected Electric Distribution Utilities*	Residential Customers December 2006	Residential Sales 2006 GWH
Enersource Hydro Mississauga Inc.	161,749	1,603
Horizon Utilities Corporation	209,370	1,655
Hydro One Brampton Networks Inc.	111,597	1,075
Hydro One Networks Inc.	1,055,204	12,229
Hydro Ottawa Limited	255,993	2,226
London Hydro Inc.	126,516	1,089
Toronto Hydro-Electric System Limited	599,080	5,352
Province Total	4,107,846	127,016 (all customer sales)

* Ontario has 86 Electric Distribution Utilities. Those shown have more than 100,000 Residential Customers.

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APPENDIX C

ANNUAL BASELINE ASSESSMENT OF CHOICE IN CANADA AND THE UNITED STATES (ABACCUS) – RESIDENTIAL REPORT

Annual **B**aseline **A**ssessment of **C**hoice in **C**anada and the **U**nited **S**tates

Residential ABACCUS:
An Assessment of Restructured Electricity Markets

Energy Retailer Research Consortium
December 2008

ERRC

Energy Retailer Research Consortium
A Project of DEFG

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Acknowledgments

The Energy Retailer Research Consortium is grateful to the ABACCUS Advisory Board for its leadership throughout the study period. ERRC would like to acknowledge the contributions of the numerous regulatory commission staff members who participated in telephone interviews. Any errors in this report are the responsibility of the ERRC Projects Manager.

Table of Contents

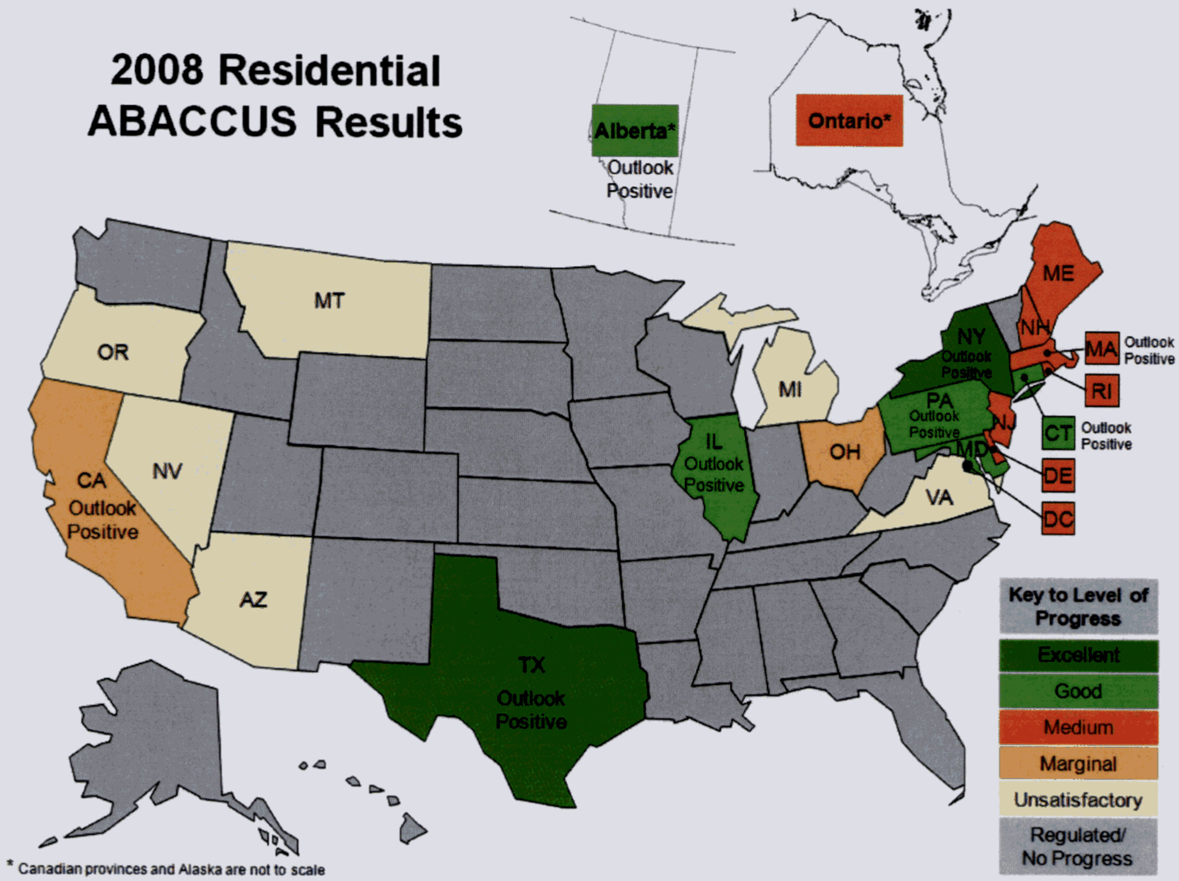
Executive Summary

Several states and Canadian provinces continue to make progress in restructuring the mass market portion of the retail electricity market, addressing issues that arise and moving forward. Residential electricity choice is thriving in Texas and New York because the markets are designed to encourage competitive activity. Adequate capacity has been constructed and numerous retailers are competing head-to-head for customers.

Residential consumers in Texas and New York can choose a contract period of one month to one, two, or three years, or even longer, to lock in today's prices; consumers can select green power that is backed by production from renewable resources such as wind energy; they can bundle heating/cooling equipment check up costs into their electric bills; they can enroll in rewards and cash-back programs; they can work with their retailer to enhance the energy efficiency of electricity use; and they can even take advantage of innovative demand response devices that let them take control of their energy usage and costs.

Consumer preferences differ and competitive markets are the best way to satisfy diverse needs and wants. The old "one-size-fits-all" regulatory model does not serve consumers as well. Competition is a mainstay of the US economy precisely because competitive service providers respond to consumers who shop. Choosing among products, services and suppliers is routine for consumers in North America and the introduction of choice to the electric industry is spurring innovation and efficiency.

Figure ES-1: 2008 Residential ABACCUS Results



"Annual Baseline Assessment of Choice in Canada and the US" (ABACCUS) considers the market structures, business practices and regulatory policies that support retail electricity choice. Two reports are prepared. The Residential ABACCUS is designed to assess each state on its progress in implementing retail competition in mass markets. A companion report, the Commercial and Industrial ABACCUS, assesses retail electricity choice for large commercial and industrial consumers.

The Residential ABACCUS methodology includes twenty-three important dimensions of service. The facts in each state were assessed, scored, weighted and summed, and states ranked accordingly. The level of progress is then assessed based on qualitative input from a team of advisors. The following five terms describe the state of each jurisdictional market: excellent, good, medium, marginal, and unsatisfactory.

- Texas made excellent progress by adopting rules that encouraged numerous power producers and retailers to compete and to offer a variety of services. Texas laws do not give incumbents undue advantage. Texas ended its "price-to-beat" (default service) after five years and residential consumers made a smooth transition to a competitive rate. Today, 99% of the Texans who are eligible to choose are served through non-regulated products and services. A high percent (83%) of eligible residential customers having made an observable choice and approximately 44% of all residential customers receive service from non-incumbent retailers.

- In New York, nearly 16% of residential consumers are purchasing power from competitive suppliers. Numerous electric rate offerings are available including guaranteed savings programs, fixed and variable prices, and green power. New York benefits from an intrastate independent system operator with advanced policies regarding demand response. Like Texas, New York is fine tuning its market rules. The PSC has recently required a number of additional consumer protection provisions.
- Illinois created an Office of Retail Market Development (ORMD) which prepared its first annual report in July 2008 to present the progress in addressing barriers to competition. New suppliers have been certified to offer service to small consumers. The ORMD is engaging all stakeholders to ensure that the barriers to residential choice are addressed, determine how to raise awareness among consumers about the right to choose an alternative electricity supplier and determine how to create an independent source of information for small consumers.
- Connecticut regulators limited utility requests to permit long-term power contracts as a hedge against future cost increases. They recognized the risks associated with hedging and the consequences for retail competition. Long-term contracts which become higher than future market prices will place a burden on consumers; on the other hand, long-term contracts which become lower than market prices will effectively freeze competitors out of the marketplace.

Table ES-1: Residential ABACCUS Scores and Rank

Jurisdiction	2008 Score†	2008 Rank	2008 Assessment	2007 Rank	2007 Assessment
Texas	83	1	Excellent	1	Excellent
New York	61	2	Excellent	3	Good
Alberta	61	3	Good	2	Good
Maryland	53	4	Good	4	Medium
Massachusetts*	51	5	Medium	6	Medium
Maine*	49	6	Medium	5	Medium
Connecticut	45	7	Good	10	Medium
New Jersey*	44	8	Medium	7	Medium
Pennsylvania	44	9	Good	9	Medium
Illinois	43	10	Good	8	Medium
District of Columbia	39	11	Medium	12	Medium
Delaware	37	12	Medium	13	Medium
Ontario	36	13	Medium	11	Medium
New Hampshire	33	14	Medium	18	Marginal
Rhode Island	33	15	Medium	14	Medium
Ohio	33	16	Marginal	17	Marginal
California*	24	17	Marginal	21	Unsatisfactory
Michigan*	NA	18	Unsatisfactory	15	Marginal
Montana*	NA	19	Unsatisfactory	19	Unsatisfactory
Virginia*	NA	20	Unsatisfactory	16	Unsatisfactory
Oregon*	NA	21	Unsatisfactory	22	Unsatisfactory
Nevada*	NA	22	Unsatisfactory	23	No Progress
Arizona*	NA	23	Unsatisfactory	20	Unsatisfactory

† Scoring is very tough and there is no "grading on a curve." No jurisdiction will ever score 100 because perfect scores for particular ABACCUS elements may not be ideal or even practical in a particular jurisdiction given its history of regulation and restructuring.

** Several states received a qualitative assessment inconsistent with the quantitative score. This is intentional. It is possible to score points with certain reasonable policies, yet limit the success of retail choice as a result of other policies.*

More than a decade has passed since the initial US state pilot programs to offer retail choice of power supplier to consumers. While the participation of large energy consumers has been good and widely lauded as a success, mass market participation has had mixed results. Some observers are very critical of the ability of residential consumers to benefit from retail choice in some areas citing increases in average prices and low retailer market entry. To some degree, these are self-fulfilling prophesies. States with higher and more volatile prices (often the result of a significant reliance on natural gas) were more likely to reject the regulatory scheme and attempt to use market forces to control costs. Over time, competitive states with great reliance on natural gas are expected to add generating units that have less fuel price volatility (e.g., wind turbines and nuclear power plants). Even more important than the long-term resource investment signals are the near-term policy choices that affect retailer market entry. A poorly designed market will not attract retail entrants – nor will a market where regulatory stability is suspect. A lack of interest in a market is a measure of a flawed market structure or flawed application of the structure.

Several of the states with moderate scores have made inappropriate choices and their success with residential consumers has been limited. These states offer retail choice, but they have had problems with implementation, including restrictions placed on retail electricity choice. In some instances the design of the default service has not supported the introduction of competition. Default service (standard or basic service), refers to a transitional regulated service. Stated plainly, in a few jurisdictions default service was designed to keep rate artificially low throughout the transition to competition, thereby discouraging market entry and competition. For example:

- In Ohio, the restructuring law was modified to further insulate retail electricity consumers from market forces. Ohio's SB 221 requires electric distribution utilities to provide consumers with standard offer service (SOS) that either relies on rate-based utility power plants, or market-rate offers determined through competitive bidding, or both. Distribution utilities must now have an electric security plan to provide rate stabilization through firm power commitments or file a market rate option.
- In Michigan, a bill introduced in December 2007 (HB 5524) became law to rescind restructuring. The law requires customers who have elected choice in the past to declare within 90 days whether they will continue to receive power from an alternative electric supplier. Customers would be required to give notice of a return to regulated service, and pay the higher (for one year) of average rates or market prices at the time of return.

The design of default service is the most significant factor that determines the success of retail choice among residential consumers. It is generally agreed that after a century of regulated tariffs, the typical residential consumer requires time and appropriate educational information to understand what new options are available, how to evaluate the alternatives and how best to align market choices with individual need. A poorly designed default service undermines retail competition. If default service attempts to address all residential consumers' needs, bundles and spreads risks among all consumers, or is priced below cost, then it is unlikely that retail electricity providers will enter the market. Experience has shown that to encourage the development of a competitive retail market, default service must be a more market reflective rate in the near term, and it must provide opportunities to competitive retailers. We recommend that each state or province adopt the following principles:

- Default service is a transitional service with a clear ending date for the majority of residential consumers.
- Default service is easy to understand and meets only a consumer's basic needs.
- Default service closely tracks the cost of power in the wholesale power market.

ABACCUS provides a baseline from which to build a properly functioning competitive energy market. It is anticipated that an ABACCUS assessment will occur each year. A hallmark of the ABACCUS analysis and report is the breadth of issues explored. The ABACCUS recommendations address design issues that are directly related to the ABACCUS methodology topics: 1) retail market status, 2) wholesale market competition, 3) default or standard service design, and 4) facilitation of the choice of retailer. This comprehensive assessment methodology was developed through a collaborative effort among retailers and representatives from eight state regulatory commissions. It is clear that electricity choice cannot be understood or judged in terms of only one issue, such as last month's switching rate or today's price. The provision of electric service is complex, and there are numerous important design issues that affect market performance over the long term.

Introduction

Purpose and Scope

"Annual Baseline Assessment of Choice in Canada and the US" (ABACCUS) gauges progress in the implementation of retail electricity choice. The Residential ABACCUS is a report card on the electric industry's achievements in mass market electricity choice. A companion report focuses on commercial and industrial customer electricity choice.

The ABACCUS report is intended to achieve the following:

- Identify the market structures, business practices and government policies that increase the likelihood of the success of retail electricity choice
- Identify best regulatory practices for the regulated network portions of the electricity market to support retail electricity choice
- Provide information useful to the US states and Canadian provinces that are implementing retail electricity choice
- Identify potential improvement areas and suggest solutions that US states and Canadian provinces may consider implementing
- Provide information that will enable other US states and Canadian provinces to better consider the market structures, business practices and government policies that provide a good foundation for the future successful implementation of retail electricity choice

Robust mass market (residential) competition is more difficult to achieve than competition in commercial and industrial markets. Residential customers can be relatively less well informed of their choices and the perceived transaction costs associated with change can be high relative to the potential savings. Progress in residential markets has been hampered by policy choices that make it difficult for companies to enter and sustain a presence in residential markets. Some jurisdictions that have achieved success with large customers may not score well in the Residential ABACCUS. Unless otherwise noted, all references to "electricity customer" or "consumer" means residential electricity consumer in the relevant jurisdiction.

ABACCUS Advisory Board

The ABACCUS process began in 2006 with the formation of an Advisory Board and, since that time, has added several new members. The Advisory Board desired a process that would balance the perspectives of retailers with other points of view. An *ad hoc* advisory group was formed to include representatives from some of the larger state regulatory commissions: California, Illinois, Maryland, Massachusetts, Michigan, New York, Pennsylvania and Texas. This advisory group met via conference call between October 2006 and May 2007 to consider which issues (or "elements") would be included in the ABACCUS methodology and to discuss the scoring and weighting of the elements.

The advisory group served an important function – to balance the interests of retailers with the interests of consumers, the general public, and regulatory commissioners. Although retail competition is focused on the successful operation of the restructured marketplace, the ABACCUS Advisory Board recognizes that regulatory commissions play a very important role in market monitoring, the regulation of the monopoly network functions, and in oversight of the transitional period that requires the establishment of new rules and business processes for the facilitation of a competitive retail market.

Outline of the Report

Methodology

The methodology section provides an overview of the Residential ABACCUS methodology. A detailed description appears in Appendix A.

Findings

The findings present a map and table of Residential ABACCUS results. We discuss the states and provinces that have made progress and the states and provinces that are falling behind as a result of their policies and actions relating to resource procurement and adequacy, and default service rate setting. Finally, we discuss the states that have recently closed or are considering closing retail choice, and a state that is considering reopening retail choice.

Recommendations

ABACCUS report recommendations are grouped into five categories: retail market status, wholesale market competition, default service design, facilitation of choice of retailer, and societal goals. The first four of these parallel the topics set forth in the methodology. The final recommendation relates to the increasing tendency of states and provinces to engage in activities relating to energy efficiency and renewable energy resources.

Appendices

Appendix A provides detailed information about the Residential ABACCUS methodology – the 23 elements, their options and scoring. Appendix B provides a write up about each state and province, including a high level summary of ten years of restructuring, switching statistics and data regarding residential sales and average prices.

Methodology

ABACCUS consistently applies an analytical tool to measure progress in implementing retail choice in North America. The Residential ABACCUS methodology poses about two dozen questions that are considered important to the measurement of progress. Data are collected from US states and Canadian provinces about each question, and points are assigned to various options. More points are assigned to options that would advance retail choice. Weights are assigned to each question to balance the numerous factors that affect the success of retail competition. The weighted average of the scores provides a total score for each jurisdiction. These scores are ranked to show which states have made the greatest progress toward successful implementation of retail electricity choice. ABACCUS is designed to highlight the best policies and the market platform that will provide sustained market performance and long-term consumer value. Qualitative information is then used to assess whether a jurisdiction is improving or falling behind in the implementation of retail choice. Appendix A provides a more detailed description of each element and the scoring methodology.

The Elements

A hallmark of the ABACCUS methodology is the breadth of issues explored. We do not believe that retail electricity choice can be understood in terms of one issue or dimension. The provision of electric service is fairly complex and there are numerous important design issues. In order to understand what is happening in these jurisdictions, we have adopted a methodology for Residential ABACCUS that gathers facts on 23 issues. The methodology is organized into four general topics: A. Status of Retail Choice, B. Wholesale Competition, C. Default Service, and D. Facilitation of Choice of Retailer.

We relied on a combination of fact checking and interviews in each jurisdiction. This involved a review of the source materials on state and utility Web sites and a telephone interview with staff members at the regulatory commission with responsibility for the implementation and tracking of retail competition.

Status of Retail Choice

ABACCUS first takes a snapshot of each state to determine the percentage of residential customers eligible to participate in retail electricity choice. Next, ABACCUS considers the number of active retailers making offers in the state and the percentage of eligible customers on a competitive price. These two measures are outcomes of a successful program and result from other appropriate actions by the state or province. ABACCUS also considers the percentage of eligible customers on a competitive price (not on an opt-out aggregated or regulated rate), and the extent to which the jurisdiction tracks and publishes statistics relating to switching. These are some of the most fundamental measures of progress in implementing a successful restructured retail market. These elements are labeled A.1 to A.4 in this report.

Table 1: Elements for Status of Retail Choice

No.	***Element***	***Key Question***
A.1	Eligibility of Residential Customers for Retail Electric Choice	What percentage of residential consumers in the jurisdiction was eligible for retail electricity choice on March 1, 2008?

No.	Element	Key Question
A.2	Number of Retailers Making Offers to Residential Customers	How many retailers are actively making offers to residential customers in the jurisdiction on March 1, 2008?
A.3	Residential Customers Receiving Competitive Rate	What percentage of eligible residential consumers receives service at a competitive retail rate as of March 1, 2008?
A.4	Market Switching Measure	Does the jurisdiction measure market switching in residential markets and regularly publish the result?

Wholesale Competition

Wholesale or bulk market competition can facilitate robust retail electricity choice. Policies to support fully integrated electricity markets include the adoption of advanced market policies and the integration of retail customers into demand response activities. Wholesale competition is important to retail electricity choice because retailers require access to competitive supplies of power. Retail customers who are allowed to participate in wholesale markets make choices that are good for their operations (lowering of costs) and good for the network (participation in markets for ancillary services such as responsive reserves, reduction in price spikes, and reduction in congestion). These elements are labeled B.1 to B.2 in this report.

Table 2: Elements for Wholesale Competition

No.	Element	Key Question
B.1	Wholesale Market Competition	Does the jurisdiction operate in a regional wholesale electric market that satisfies nationally established statutory criteria for open-market competition?
B.2	Responsive Demand	Are large and small retail electricity customers allowed to fully participate in wholesale reliability and capacity markets?

Default Service

Default service refers to the basic or standard rates that are established and periodically adjusted by regulators. Default service has been established as a mechanism to ease the transition from regulated tariffs to competitive electricity prices. The design and implementation of default service is the most significant issue affecting the success of retail choice. If regulators are determined to design default service so as to attempt to address all residential consumer needs, or price service below market cost, or bundle risks and spread the risk premium to all consumers, then it is unlikely that retail electricity providers will enter the market. That is, default service designed to undermine retail competition can undermine it!

Provider of last resort (POLR) service refers to "safety net" rates for consumers whose supplier goes out of business.

The elements in this topic include: which company provides default service, how default service is designed, how frequently default service is adjusted to wholesale market prices, what resources are used to supply default service (Does the supplier hedge resources?), whether restrictions are placed on customers who wish to leave default service, and whether the default service rate tracks the cost of service. Also addressed under this topic are stranded cost recovery and public purpose programs that may be required by the jurisdiction. These elements are labeled C.1 to C.8 in this report.

Table 3: Elements for Default Service

No.	*Element*	*Key Question*
C.1	Default Service Supplier	What type of company provides default service as of March 1, 2008?
C.2	Default Service Product Options	To what extent is default service designed to provide a substitute for the choices provided in a competitive retail market?
C.3	Default Service Rate Mechanism	How frequently is the default rate adjusted to reflect the cost of service in the wholesale market?
C.4	Default Service Resource Portfolio	Does the default service provider hedge resources or match the term of the resource contracts to the term of the default service?
C.5	Default Service Switching Options	Are consumers restricted in switching away from default service?
C.6	Default Service Cost Allocation	Does the default service rate reflect the cost of service?
C.7	Stranded Cost Recovery	How is stranded costs recovery treated?
C.8	Nondiscriminatory Public Purpose Programs	Are public purpose programs – such as resource portfolio standards and conservation program requirements – applied fairly to all retailers?

Facilitation of Choice of Retailer

Facilitation of choice of retailer refers to the market structures, infrastructure and programs that support retail electricity choice. First, the jurisdiction's policies with regard to electric distribution market structure and code of conduct are examined. Next we consider customer education, retailer access to customer information, and uniformity of transaction standards. Finally, this element includes billing protocols, access to meter information, and advanced metering infrastructure. These elements appear as D.1 to D.9 in this report.

Table 4: Elements for Facilitation of Choice of Retailer

No.	*Element*	*Key Question*
D.1	Distribution Utility Structure	Is the regulated distribution service function separate from competitive services?
D.2	Competitive Safeguards	Do distribution utilities operate under a code of conduct that governs relations with affiliates and is that code consistently enforced?
D.3	Consumer Education & Awareness	Is there a program to educate consumers about retail choice and to measure the results?
D.4	Access to Residential Customer Information	Do qualified retailers have easy access to basic customer information?
D.5	Uniformity of Standards	Does the jurisdiction apply uniform standards for the operation of competitive retail markets?
D.6	Transaction Standards	Does the jurisdiction require the use of a standard electronic data exchange for business transactions?
D.7	Billing Protocols	Does the jurisdiction treat billing in a manner that inhibits retail choice?
D.8	Access to Metering Information	Do retailers have on-demand access to real-time metered data regarding customer usage?
D.9	Advanced Metering Infrastructure	Has the jurisdiction invested in advanced metering and communications?

The Weighting of the Elements

Each element is assigned a weight that is used to calculate a weighted average score for each jurisdiction. All 23 weights total to 100 percent. There could be significant discussion regarding the most important element and the corresponding weight. We have determined that with a large number of elements, the specific weights are less important than if there were just a few data points. Nevertheless, a transparent methodology allows the reader to see what we felt was important.

The following table presents the weights used in the 2007 and 2008 residential ABACCUS reports.

The four general topics are weighted as follows:

A. Status of Retail Choice: 15%

B. Wholesale competition: 8%

C. Default Service: 52%

D. Facilitation of Choice of Retailer: 25%

No.	***Element***	***Weight***
A.1	Eligibility of Residential Customers for Retail Electric Choice	4%
A.2	Number of Retailers Making Offers to Residential Customers	4%
A.3	Residential Customers Receiving Competitive Rate	4%
A.4	Market Switching Measure	3%
B.1	Wholesale Market Competition	6%
B.2	Responsive Demand	2%
C.1	Default Service Supplier	8%
C.2	Default Service Product Options	6%
C.3	Default Service Rate Mechanism	12%
C.4	Default Service Resource Portfolio	10%
C.5	Default Service Switching Options	6%
C.6	Default Service Cost Allocation	6%
C.7	Stranded Cost Recovery	3%
C.8	Nondiscriminatory Public Purpose Programs	1%
D.1	Distribution Utility Structure	4%
D.2	Competitive Safeguards	3%
D.3	Consumer Education & Awareness	2%
D.4	Access to Residential Customer Information	3%
D.5	Uniformity of Standards	3%
D.6	Transaction Standards	2%
D.7	Billing Protocols	4%
D.8	Access to Metering Information	2%
D.9	Advanced Metering Infrastructure	2%
	Total	100%

Findings

More than a decade has passed since the initial US state pilot programs to offer retail choice of power supplier to consumers. While the participation of large energy consumers has been good since then, and has been widely lauded as a success, mass market participation in retail choice has had mixed results. Some observers are very critical of the ability of residential consumers to benefit from retail choice. The purpose of this report is to identify the successes and identify the policy choices that contribute to success in residential electricity choice programs.

Residential electricity choice began in the late 1990's with much positive anticipation and much initial success in several states. However, perceptions around the California market during 2000-02 brought uncertainty to retail markets, and more recent natural gas prices increases have resulted in higher market prices for electricity. These market prices have increased the cost of residential electricity default service. Further, states have adopted policies that limit or discourage the participation of retailers. As a result, the participation of residential customers in retail choice programs has declined in several states. Participation is growing in others states, raising questions about what is different among these states.

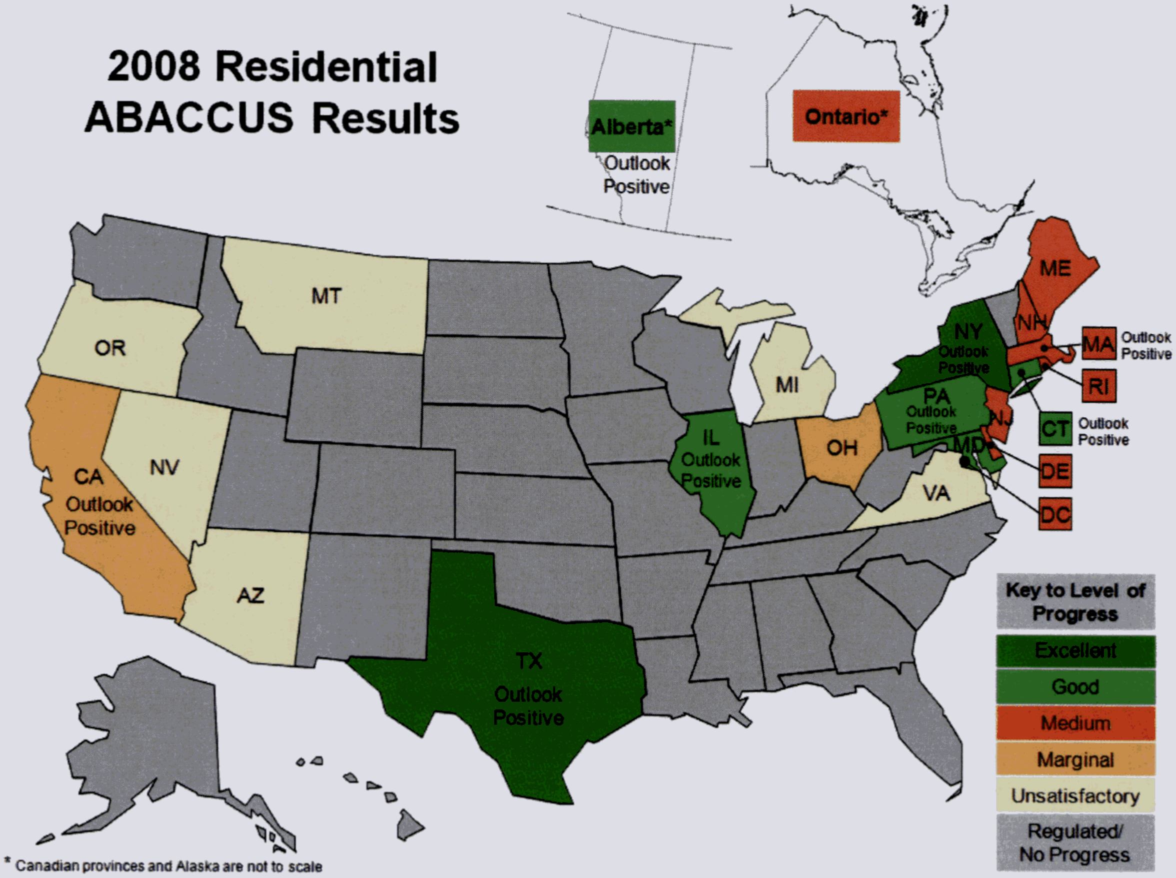
This report presents a summary of the current status of residential retail choice programs in North America, contrasts the different policy choices made in the individual states and Canadian provinces, and recommends improvements to market design elements like default service to improve participation in the future.

ABACCUS Scores

Several states and Canadian provinces continue to make progress in restructuring the mass market portion of the retail electricity market, addressing problems and moving forward. Residential electricity choice is thriving in Texas and New York because the markets are designed to allow competitive electricity markets to work effectively.

The ABACCUS map displays the results by converting the scores into five categories: places that have made excellent progress, good progress, medium progress, marginal progress, and states where the progress has been unsatisfactory.

Figure 1: 2008 Residential ABACCUS Results



The Residential ABACCUS considers twenty-three important dimensions of service. The facts in each state were assessed, scored, weighted and summed, and states were ranked accordingly.

Table 5: Residential ABACCUS Scores and Rank

Jurisdiction	2008 Score†	2008 Rank	2008 Assessment	2007 Rank	2007 Assessment
Texas	83	1	Excellent	1	Excellent
New York	61	2	Excellent	3	Good
Alberta	61	3	Good	2	Good
Maryland	53	4	Good	4	Medium
Massachusetts*	51	5	Medium	6	Medium
Maine*	49	6	Medium	5	Medium
Connecticut	45	7	Good	10	Medium
New Jersey*	44	8	Medium	7	Medium
Pennsylvania	44	9	Good	9	Medium
Illinois	43	10	Good	8	Medium

District of Columbia	**39**	**11**	**Medium**	12	Medium
Delaware	**37**	**12**	**Medium**	13	Medium
Ontario	**36**	**13**	**Medium**	11	Medium
New Hampshire	**33**	**14**	**Medium**	18	Marginal
Rhode Island	**33**	**15**	**Medium**	14	Medium
Ohio	**33**	**16**	**Marginal**	17	Marginal
California*	**24**	**17**	**Marginal**	21	Unsatisfactory
Michigan*	**NA**	**18**	**Unsatisfactory**	15	Marginal
Montana*	**NA**	**19**	**Unsatisfactory**	19	Unsatisfactory
Virginia*	**NA**	**20**	**Unsatisfactory**	16	Unsatisfactory
Oregon*	**NA**	**21**	**Unsatisfactory**	22	Unsatisfactory
Nevada*	**NA**	**22**	**Unsatisfactory**	23	No Progress
Arizona*	**NA**	**23**	**Unsatisfactory**	20	Unsatisfactory

† Scoring is very tough and there is no "grading on a curve." No jurisdiction will ever score 100 because perfect scores for particular ABACCUS elements may not be ideal or even practical in a particular jurisdiction given its history of regulation and restructuring.

** Several states received a qualitative assessment inconsistent with the quantitative score. This is intentional. It is possible to score points with certain reasonable policies, yet limit the success of retail choice as a result of other policies.*

Progress in Selected States

Several states and Canadian provinces continue to make progress in restructuring the mass market portion of the retail electricity market, addressing issues and moving forward. Residential electricity choice is thriving in Texas and New York because the markets are designed to allow competitive electricity markets to work effectively.

Residential consumers in Texas and New York have a choice of suppliers and a choice of products and services. Consumers can choose a contract period of one month to one, two or even three years or longer to lock in today's prices; they can select green power that is backed by production from renewable resources such as wind energy; they can bundle heating/cooling equipment check up costs into the electric bill; they can enroll in rewards and cash-back programs, and even take advantage of innovative energy efficiency and demand response devices that let them take control of their energy usage and costs.

Consumer preferences differ, and competitive markets can best satisfy these diverse needs and wants. Competitive markets are a mainstay of the US economy precisely because retail suppliers respond to consumers who shop – consumers who choose among products, services and suppliers. Advanced metering infrastructure (AMI; time-differentiated metering plus two-way communications and advanced data management) will soon be available for residential accounts in several states. It is expected that AMI technologies will increase the potential for new residential customer products and services moving forward.

Texas

Texas has made excellent progress toward the achievement of a competitive market for residential electricity consumers. Texas has several advantages over other states: a state-regulated (intrastate) independent system operator (ISO) with responsibility for reliability, open access transmission, settlement in the energy-only market, managing retail switches and managing renewable energy credit trading. Texas also has policies that promote investment in generation, a healthy economy, a favorable business climate, and a history of consistent regulation. However, it is not these features alone that have resulted in robust electricity choice. Rather, it has been the deliberate policy choices made by the Texas Legislature, the Public Utility Commission of Texas, and the ISO (ERCOT, the Electric Reliability Council of Texas) that have provided a new platform from which competitive services could be offered by electricity market participants.

Texas made excellent progress by adopting rules that encouraged numerous power producers and retailers to compete and to offer a variety of services. Texas laws did not give incumbents undue advantage in the provision of default service. Texas ended its "price-to-beat" (default service) after five years, and at the end of the transition, residential consumers on price-to-beat service remained with that retailer on what became a competitive rate. Today, more than 99% of the Texas consumers across all segments who are eligible to choose are served through non-regulated products and services. A high percent (83%) of eligible residential customers have made an observable choice and more than half of them (approximately 44% of eligible residential customers) receive service from non-incumbent retailers. The only regulated service is "provider of last resort" (POLR) which serves customers whose retailer has exited the market. Five small retailers exited the market in 2008 creating concern; however, POLR worked to provide continuity of electric service for impacted customers and this loss of retailers was part of the market maturation process.

New York

In New York, nearly 16% of residential consumers are purchasing power from competitive suppliers. Numerous electric rate offerings are available including guaranteed savings programs, fixed and variable prices, and green power. New York benefits from an intrastate independent system operator with advanced policies regarding demand response. Like Texas, New York is fine tuning its market rules. A pending issue involves sanctions for retailers who do not follow the rules – a compromise between taking back their license to operate in New York and doing nothing. The PSC has recently required a number of additional consumer protection provisions.

Alberta

Alberta has an active energy only power market that has increased capacity by about 50% over the past ten years. Nearly one-fourth of residential consumers are not on default service, and the Retail Markets Division of the Alberta Department of Energy is studying how to attract more retailers to the province.

Illinois

The Illinois Office of Retail Market Development (ORMD) prepared its first annual report in July 2008 pursuant to the requirements of Section 20-110 of the Illinois Public Utilities Act. Other changes in the law were designed to remove barriers to competition for residential and small commercial customers. There have been new suppliers certified to offer products and services to small consumers. The Illinois Commerce Commission has also been addressing the purchase of receivables (to encourage alternative electricity suppliers to serve all consumers), consolidated billing, and referral programs. The ORMD will continue to engage all stakeholders to ensure that the barriers to residential choice are addressed, determine how to raise awareness among consumers about the right to choose an alternative electricity supplier and determine how to create an independent source of information for small consumers.

Connecticut

Connecticut regulators considered utility requests to permit long-term power contracts as a hedge against future cost increases. The risks associated with hedging have significant consequences for retail market entry and the health of a competitive marketplace. Long-term contracts which become higher than future market prices will place a burden on consumers; on the other hand, long-term contracts which become lower than market prices will effectively freeze competitors out of the marketplace. Connecticut placed limits on utility contracting for default service. Connecticut also has incentives for on-site generation to reduce transmission constraints in the Southwest corner of the state, a portfolio standard for energy efficiency which has resulted in trading of energy efficiency certificates and a new greenhouse gas emission law.

Default Service

Several other states have made different choices and their success has been limited. These states offer retail choice to some or all retail consumers, but they have had problems with implementation, typically as a result of the restrictions placed on retail electricity choice. In some instances the design of the default service has not supported the introduction of competition. Default service, also called basic service or standard offer service or provider of last resort, refers to a transitional regulated service. Stated plainly, in some jurisdictions, default service has been designed to prevent consumers from engaging the competitive market, rather than encouraging consumer behaviors that are conducive to establishing a functional competitive framework.

The design of default service is the most significant factor that determines the success of retail choice among residential consumers. It is generally agreed that after a century of regulated tariffs, the typical residential consumer requires time to understand what new options are available, how to evaluate the alternatives and how best to align market choices with individual need. A poorly designed default service undermines retail competition. If default service is designed so as to attempt to address all residential consumers' needs, or if it bundles and spreads risks among all consumers, or if it is priced below cost, then it is unlikely that retail electricity providers will enter the market. Experience has shown that to encourage the development of a competitive retail market, default service must be a more market reflective rate in the near term, and it must provide opportunities to competitive retailers. We recommend that each state or province adopt the following principles:

- Default service is a transitional service with a clear ending date for the majority of residential consumers.
- Default service is easy to understand and meets only a consumer's basic needs.
- Default service closely tracks the cost of power in the wholesale power market.

The following states have taken actions inconsistent with these principles.

Ohio. In Ohio, the restructuring law was modified to disconnect retail electricity consumers from market forces. Ohio's SB 221 requires electric distribution utilities to provide consumers with standard offer service (SOS) that either relies on regulated rate-based utility power plants, or market-rate offers determined through competitive bidding, or both. In essence, distribution utilities must now have an electric security plan to provide rate stabilization through firm power commitments.

Maryland. In Maryland, rate caps were scheduled to expire, and the anticipated price increases led to consideration of numerous alternative rate mitigation proposals. The Maryland Public Service Commission has moved residential customers to a two-year bidding framework, with one-fourth of the load bid every six months. In the Baltimore Gas and Electric Company service territory, a rate stabilization charge spreads cost increases over the next 10 years.

New Jersey. The 2008 auction in New Jersey covers hourly-priced service for large customers for one year beginning June 1, 2008. The fixed price customer auction for is for a supply period of three years, with one-third of each utility's total load requirements acquired each year. The winning fixed price contracts averaged 11.15 to 12.05 cents per kWh. These supplies replace the 2005 contracts and will result in residential customer price increases of 11.5% to 17.3% in the various service areas.

It is easy to understand why it is politically expedient to take these actions. Residential customers are not used to price volatility, and it will take a while for new service providers to make the investments necessary to offer different services that will result in different outcomes. Wholesale markets are only now coming to grips with the need for demand response – a move that will lessen the need for peaking units, and decrease price volatility in wholesale markets. It will also take time in retail markets for consumers to get used to the new companies that assume price risk and offer guaranteed pricing plans. Whether it is price risk management services, green pricing alternatives, demand response services, etc., the competitive market is the best means of providing a flexible and cost-efficient response to market needs.

Closing or Reopening Markets

Virginia. In 2007, HB 3068 and SB 1416 were signed by Governor Kaine and Virginia suspended retail electricity choice.

Michigan. In Michigan, a bill introduced in December 2007 (HB 5524) has become law and more or less rescinds restructuring. It requires customers who have elected choice in the past to declare within 90 days whether they would continue to receive power from an alternative electric supplier. Customers are required to give notice of a return to regulated service, and pay the higher (for one year) of average rates or market prices at the time of return. New customer would not be eligible for choice and would receive standard tariff service.

California. In May 2007, the California Public Utilities Commission determined that it would investigate the potential to reopen the retail market for direct access. The CPUC has determined in Phase I of Rulemaking 07-05-025 that it does not currently have authority to reinstitute direct access. (Note: The California Department of Water Resources (DWR) still "sells electricity" under existing law and the CPUC must extricate DWR from that role prior to the reopening of the market.) Phase II of Rulemaking 07-05-025 will consider the public policy merits and prerequisites to reopening direct access.

Societal Goals

Competitive markets provide the best foundation for addressing social goals such as environmental protection, the promotion of technological advances, and the strengthening of the electric grid through dispersed generation. Many states are pursuing several of these goals simultaneously. A command and control approach is feasible, but less than ideal.

ABACCUS makes a distinction with respect to demand response because of its critical value to regional resource adequacy and customer choice. ABACCUS makes clear the preference for demand response programs to allow wholesale markets to function effectively and efficiently. Demand response programs improve the performance of bulk markets by better aligning demand and supply. Further, demand response activities provide customers with additional choices with respect to assignment of risk and the attribution of cost causation. That is, customers who are able to curtail their usage when congestion is high and/or supplies are tight can benefit from their ability to be flexible, and the total systems costs will be lower – a benefit to all consumers.

One well understood option for customers is renewable resource technologies and green pricing. Texas, New York and other places that have restructured have experienced rapid growth in renewable generation and this is not a coincidence. These states have numerous green pricing offerings available rather than one plain vanilla offering. By allowing consumers to "vote" directly with their dollars, these states are seeing a rapid flow of dollars into new technologies. Note that Texas has now passed California (long known as for its wind turbine installations) in wind turbine capacity and output.

Another trend has been increased interest of state and provincial governments to take actions relating to climate change and energy efficiency. The ABACCUS methodology is indifferent to policies relating to renewable resources and energy efficiency as long as the policies treat all the market participants fairly. As state and federal policies evolve, it may be appropriate in the future to measure and assess alternative approaches to provide incentives for energy efficiency and carbon mitigation. For example, white certificate trading may facilitate energy efficiency investments best and enhance the range of choice choices far more effectively than standards or centrally planned EE programs. This is an issue that will be revisited,

ABACCUS does not yet attempt to directly measure how renewable resource and energy efficiency activities might be implemented. Retailers may wish to bundle renewable resources and energy efficiency into the services they provide to consumers. For that reason alone, however, renewable resource and energy efficiency activities ought to be designed to maximize the use of markets, and minimize prescriptive or command and control activities. It is preferable to set goals for utilities or load serving entities, and then let them determine how best to achieve them. Programs that specify technologies that must be offered directly to residential customers may fail. Each jurisdiction ought to exhaust all the market based options for technology deployment before engaging directly in the activity, or requiring the electric distribution utility to engage in it. By establishing a platform for a market and marketers, energy efficiency and renewable energy deployment can support the establishment of competitive markets while achieving social goals.

Average Prices

Average electricity prices have been used to compare states and criticize electric restructuring and retail electricity choice. Recent increases in average price in regulated states reveals the folly of a snapshot comparison of prices. Further, this approach is fundamentally flawed in that it assumes that average electricity prices are the most important or only measure of success. Finally, emphasis on average price comparisons reveals a basic misunderstanding of economic value, consumer preferences, and technological advance.

Small consumers traditionally assess the market for electric service by looking at two measures: the price of electricity per kilowatt-hour and the value of the service they receive, including reliability. Simple comparisons of the price of electricity in traditional versus competitive markets are not particularly valuable. It is true that average price comparisons are simple to understand and price increases can garner headlines. Both regulated and restructured states have seen price increases. However, a regulatory mindset is focused on percent rate requests and cents per kilowatt-hour. Unfortunately, the cents-per-kilowatt-hour mindset is holding back progress. This mindset squashes reforms that could lower costs and increase the value of energy services to consumers, both today and over the long-term.

Decades of average price reductions occurred during periods of rapid electrification and supply-side technological change in the mid-twentieth century. This period was marked by power plant engineers who designed, and companies that constructed larger, lower cost-per-unit generating units. This period ended in the 1970s, but the supply-side mindset persists. Unfortunately, not enough utilities, regulators and consumers moved quickly enough to adopt a better cost reduction paradigm. As a result, average prices per unit have increased for several decades. Some federal and state policy makers in the 1970's recognized the power of energy efficiency and demand-side technological innovation, but new energy policies were not sustained or comprehensive. Energy efficiency and demand response have only recently become national policy and there is still much work to do. Now, all kinds of retailers and energy service providers are poised to deliver energy efficiency, demand response, renewable energy resources, financial and risk management products and smart grid choices that will transform the electric industry and move the policy debate away from cents per kilowatt-hour comparisons.

Let us examine the old debate. Where electricity costs were the highest, states considered restructuring to apply market forces where regulation had failed. For a variety of reasons, this did not lead to immediate average price reductions in some areas. In regulated states, it has been possible to shift costs from one time period to another, delaying the bad news. In many instances, this approach is catching up with those who advocate more regulation. Wholesale price increases have affected all market participants, not merely restructured states. But is it valid to compare one state's average electricity price with another's? Are average prices even a compelling measure of success?

It is generally agreed that large commercial and industrial consumers have benefited from the introduction of retail electricity competition. One way to measure robust C/I customer competition is in terms of the amount of load switching from the default service provider to a competitive retailer. C/I customers have signed favorable power contracts, benefited from price reductions, and benefited from new products and services that help them manage risk and energy costs. Large C/I customers are comfortable managing risks and input costs in this manner. The ability to procure energy to match a customer's fiscal budget cycle and to hedge that cost by fixing it, has been as important as absolute price. Control over price volatility is equal to the level of the price for risk adverse customers. Other C/I customers, whose energy budget is a smaller percentage of their cost of doing business, may choose a more volatile pricing product. Utilities and regulated default service providers that have routine fuel factor adjustments have the ability to shift the risk of price changes to customers who have little opportunity to hedge such price. A key advantage of retail choice is that customers can procure energy in a manner that best fits their risk profile.

Larger C/I customers are able to manage energy costs as a part of the overall business plan. Industrial operations with storage capability and production line flexibility may participate in demand response markets, for example. This may require the installation of new on-site equipment and may be part of a significant re-engineering of their industrial process. The absolute level of energy cost is merely one of many costs which are managed. The C/I customer loads can provide capacity and energy resources in organized wholesale markets and receive compensation for peak capacity, operating reserves and regulation service. Management of these cost and revenue streams is complex and assistance is provided by energy service specialists and retailers. Many C/I customers have also installed new equipment on-site to increase power quality and reliability. Overall, large electricity customers are comfortable with the ability to choose. The competitive market allows access to specialized products and services in a timely fashion. Market allocation of resources ensures efficiency and equity.

Smaller consumers have demonstrated a preference for green power. Customers have chosen to be EPA LEED certified and one way of doing so is to procure 20% of consumption as green or to acquire the equivalent in Renewable Energy Credits. Competitive packages can bundle such credits with other energy products to satisfy these customers' desires. Small consumers are also expressing a growing appreciation for energy-efficient appliances and devices, green building technologies, and actions to protect the environment. The beauty of the competitive market is the ability of retailers to respond rapidly to these stated or measured preferences. Retailers are able to bundle new energy services and products with non-energy offers and are willing to bear the full financial risk of their experiments. This entrepreneurialism is extremely valuable, and is a hallmark of competitive markets.

Technological change has been rapid and extremely valuable in industries that are exposed to market forces. The electric industry is poised to combine new infrastructure investments (such as advanced meters, communications and control) with the entrepreneurship of mass-market retailers. In the future, consumers may be able to lower their total energy costs, increase their reliability and control, reduce their impact on the environment, and increase the value of electric services in their lives. We have only just begun the changes that will transform the electric industry and the way consumers interact with their appliances and devices.

The search for the right combination of services and products is unlikely to come through regulation. Regulation is constrained by the outdated concept of focusing on the average cost of a unit of electricity. Anyone who has purchased a flashlight battery or recharged a cell phone may be aware of a value of electricity not based on minimizing cents per kilowatt-hour. (That is, whether they are aware of it or not, they value the convenience and mobility offered by these devices, and they pay extremely high costs per kilowatt-hour to obtain that value!) The need for change and reform is great and competitive markets can provide the best means of achieving enhanced value and reduced cost.

Recommendations

In preparing the Residential ABACCUS methodology presented in Appendix A, the advisory group attempted to define a framework and scoring system that reflected the direction in which each state or the US as a whole ought to go to improve the likelihood of success of retail competition. The recommendations are based on information collected from the jurisdictions. Throughout the interview process, it was apparent that certain states are on a course that is likely to enhance retail choice, while other states are continuing to regulate prices in a manner that drives retailers out of the market.

States that discounted prices and deferred costs into the future continue to deal with those costs a decade later. (Some of these costs were already decades old when retail choice was enacted!) While accepting the realities in each state, the ABACCUS Advisory Board believes it is important to point out the public policy choices that can allow a jurisdiction to rely on competitive forces to a greater degree. Some of the choices are difficult to make, but necessary if the states are interested in retail choice for residential consumers.

Retail Market Status

Customers must be eligible to participate. Several states have yet to open all areas to retail electric choice. Therefore, they limit the ability of commercial and industrial within those service territories to opt out of the local rates and regulatory decisions. This recommendation is not to be taken in isolation. It is understood that all the other public policy choices must be favorable before a state opens a new segment of the population to retail choice.

> *Recommendation #1: Allow all residential customers in the jurisdiction to participate in the competitive retail electricity market.*

Wholesale Market Competition

Effective wholesale markets are a key component of a working retail market because a retail power supplier can manage physical and financial risk in a way that is beyond the capabilities of a residential customer. Through scale economies and a deep understanding of both the wholesale markets and the customers' needs, a retailer can provide differentiated and customized risk management services that individual customers can choose which are generally not available through regulatory regimes. Policies to support fully integrated electricity markets include the adoption of advanced market policies and the integration of retail customers into demand response activities. Retail customer participation in wholesale markets is good for the customers who choose to participate in the market (lowering of costs) and it is good for the network (customer participation in wholesale markets can reduce price spikes and congestion).

> *Recommendation #2: Support the introduction of advanced wholesale market practices including market-based congestion management and markets for balancing energy, regulation and reserves.*

> *Recommendation #3: Support the establishment of a market platform that facilitates the participation of customer loads in demand response program, including aggregation of residential-scale loads.*

Default Service Design

Default service refers to basic retail pricing established to provide a transition from regulated rates to market-based prices and contracts. The design and implementation of default service is the most significant single issue affecting the success of retail choice. If regulators are determined to design default service so as to attempt to address all residential consumers' needs, set prices artificially below cost, or to bundle risks and spread the risk premium to all consumers, then it is unlikely that retail electricity providers will enter the market. A poorly designed default service program can undermine retail competition because it will attempt to provide the services that a robust market can provide and therefore creates greater barriers to entry for competitive entities that are better suited to meet unique customer needs.

There are a number of actions that a state can take to reduce the impediments of default service to competitive retail markets. Key among these is the movement of default service to a more market reflective rate in the near term. Short term prices are more efficient, and allow consumers to better respond to price changes. Short term prices exclude the premiums associated with long term fixed prices. For consumers who desire a longer-term fixed price product, retailers are likely to offer such products. The incorporation of a risk premium in default service, with forced repayment of that premium by all consumers, defeats a purpose of retail choice. Competitive markets can provide a range of products and services from which consumers may choose. Default service that operates in opposition to the following recommendations is likely one that mimics regulated ratemaking. However, it does not provide services that are consistent with a transition to retail competition.

> *Recommendation #4: Establish default service as a transition mechanism, with a clear ending date for the majority of residential consumers. Develop and implement a plan for a transition from the regulated default service to full competition for residential consumers.*

> *Recommendation #5: Design a default service product that is easy to understand and meets the basic needs of the consumer. Do not attempt to mimic the variety, scope or breadth of rates or services that are provided by competitive market participants.*

> *Recommendation #6: If supply procurement for default service is done through mandated auctions or competitive solicitations, the term lengths should be shortened to an appropriate level for each customer group. This will ensure that appropriate pricing signals are sent to customers to allow them to better select their electric service product and to efficiently manage their energy usage.*

Facilitation of the Choice of Retailer

Each state may adopt policies and programs to facilitate the choice of retailer. The options include laws regarding electric distribution utility structure, utility and utility affiliate code of conduct, rules governing billing and metering, and rules that require the standardization of business transactions among all utilities and market participants. A state may also promote retail choice through customer education.

> *Recommendation #7: Establish a plan for the separation of regulated services from competitive services, and for the application of a strict code of conduct to govern interactions between the regulated utility and its competitive affiliates.*

Recommendation #8: Establish standards for access to customer information, commercial practices and electronic data exchange to lower the transaction costs for market participants.

Recommendation #9: Establish a flexible approach to customer billing, provide reasonable access to customer billing data, and establish a program to improve metering infrastructure.

Societal Goals

With new interest in climate change, there is renewed interest in energy efficiency, renewable energy resources, demand response and small-scale power production/distributed generation. States and provinces employ a variety of mechanisms to achieve new goals for energy efficiency, renewable resources, demand response and the promotion of on-site power generation. Some states have taken a command and control approach through standards and codes. Others have used market-based incentives to encourage businesses to offer new technologies and services. It is worth noting at the outset that the delivery of goods and services to the customer premises – including these alternative energy options – is ideally suited for competitive markets. Most people are used to using competitive markets to secure and service their appliances, home repairs, and home improvements.

Collective government action in the pursuit of certain societal goals should keep in mind that the actions of individual consumers are necessary to the success of customer premises technologies. It behooves government to make sure that the implementation of the goals is done in a way that takes full advantage of the value of markets to achieve these goals; that is, the value of rational consumers and service providers determining how best to address consumer needs. The day-to-day interactions among consumers and retailers are important to successfully bring new technologies to a broad audience. Government has an important role to play in the creation of the market platform and rules.

Recommendation #10: Rely on market forces to the maximum extent possible to achieve goals relating to renewable resources, energy efficiency, demand response and distributed generation.

Conclusions

Residential customer electricity choice has been successful in delivering strong customer benefits in several jurisdictions that have adopted a model that encourages the participation of retailers. The other states and provinces of North America have an opportunity to take stock of the progress made with retail choice during the past decade, and to replicate the successes which have occurred in several states and provinces by adopting programs and policies that enhance competitive markets.

The ABACCUS report recommendations are consistent with the provision of lower cost, more reliable service through the creation and support of an appropriate market platform.

ABACCUS Sponsors

Energy Retailer Research Consortium

The Energy Retailer Research Consortium (ERRC) is an independent research consortium that supports retail energy choice. Membership is open to energy retailers and marketers, energy service companies, products vendors, and the manufacturers of retail energy devices and infrastructure technologies. ERRC studies retail energy market performance, business models and infrastructure investments that enhance the delivery of products and services. The ABACCUS report is sponsored by the members of ERRC.

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We are also indebted to the other companies on the ABACCUS Advisory Board for their contributions: ConEdison Solutions, Liberty Power, and Shell Energy.

Appendix A – Residential ABACCUS Methodology

Background

The ABACCUS report relies on the consistent application of a methodology to gauge progress in the implementation of retail electricity choice. The Residential ABACCUS provides a report card for each jurisdiction on the achievements in electricity choice for smaller customers. The important issues selected for analysis in the ABACCUS methodology are referred to as elements. Data are collected to assess each element in each jurisdiction. A ranking of jurisdictions by ABACCUS score provides an overall sense of which US states and Canadian provinces have done a good job at designing a platform for successful retail transactions.

The ABACCUS report is intended to achieve the following:

- Identify the market structures, business practices and government policies that increase the likelihood of the success of retail electricity choice
- Identify best regulatory practices for the regulated network portions of the electricity market to support retail electricity choice
- Provide information useful to the US states and Canadian provinces that are implementing retail electricity choice
- Identify potential improvement areas and suggest solutions that US states and Canadian provinces may consider implementing
- Provide information that will enable other US states and Canadian provinces to better consider the market structures, business practices and government policies that provide a good foundation for the future successful implementation of retail electricity choice

The Residential ABACCUS methodology considers the issues or elements of importance to mass market retail electricity choice, and sets forth reasonable options or paths that each jurisdiction might select. Data are collected from each affected state and province, and points are assigned to the different options, depending upon the degree to which an option helps or hinders retail choice. Weights are then assigned to each issue or element to balance the numerous factors that affect the success of retail competition. A weighted average of score is calculated for each jurisdiction. These values are ranked to show which states have made the greatest progress toward successful implementation of retail electricity choice.

Unless otherwise noted, all references to "electricity customer" or "consumer" or "customer" means residential or mass market electricity consumers in the relevant jurisdiction.

The 23 Residential ABACCUS elements are organized into four topics: (A) Status of Retail Choice, (B) Wholesale Competition, (C) Default Service, and (D) Facilitation of Choice of Retailer. A table is provided for each element. The tables list each discrete option (data entry) and the points assigned to each option. For convenience, options are assigned points on a zero- to ten-point scale.

Topic A: Status of Retail Choice

Status of Retail Choice takes a snapshot of each jurisdiction to consider the percentage of residential customers eligible to participate in the market, the number of active retailers making offers in the market, the percentage of eligible customers on a competitive price (not on an aggregated or regulated rate), and the extent to which the jurisdiction tracks and publishes statistics relating to switching. These elements are labeled A.1 – A.4 in this report.

A.1 Eligibility of Residential Customers for Retail Electricity Choice

Key Question: What percentage of residential consumers in the jurisdiction is eligible for retail electricity choice as of March 1, 2008?

Options and Points: Each jurisdiction receives a numeric data entry equal to the number of eligible residential electricity customers in the jurisdiction divided by the total number of residential electricity customers in the jurisdiction. This number is converted to percent, and rounded to the nearest 10%. Each 10% receives one point; the maximum is 10 points.

Note that in several states, a report of "100% eligibility" may overstate reality by a small percentage. Depending on the state, residential consumers served by municipal utilities or electric cooperatives may be exempt by operation of law. In other instances, a small percentage of the rural population may be located off the transmission grid, raising a distinction between percent on the grid and percent on or off the grid. While these issues are important to each jurisdiction, these differences are not substantial, and the effort to track these minor distinctions outweighs the value to ABACCUS.

Relationship between Points and Retail Market Success: Each jurisdiction with retail electricity choice ought to open its electricity markets to all residential customers. A greater percentage of eligible customers results in a greater the market size and greater market opportunities.

A.1 Eligibility of Residential Customers for Retail Electricity Choice (List of Options)	***Data (Abbreviation)***	***Points***
100% of the residential customers in the jurisdiction are eligible for retail choice	100%	10
Score is calculated as the percentage of residential customers eligible for retail choice, rounded to the nearest 10%, expressed in decimal form, times 10 points maximum	(percent)	formula
No retail residential customer choice	0%	0

A.2 Number of Retailers Making Offers to Residential Customers

Key Question: How many retailers are actively making offers to residential customers in the jurisdiction as of March 1, 2008?

Options and Points: Each jurisdiction receives a numeric data entry equal to the number of "active retailers"; that is, the number of retailers actively making offers to residential customers in the jurisdiction. The number of points assigned to each option is set forth in the table. "Eight or more" was selected as a proxy to indicate a fully competitive retail market. "Eight or more" received 10 points.

Relationship between Points and Retail Market Success: A significant number of retailers making offers to residential customers are an indication of healthy competition. A small number of retailers indicate a problem with the market; therefore, a small number of points are assigned to those jurisdictions that have failed to attract competitive retailers. It is acknowledged that this method is merely a proxy for what could be a thorough and detailed analysis of retail competition. A detailed analysis would require the definition of the appropriate market and a calculation of market concentration. These data are not available for each jurisdiction and the study is beyond the scope of this report.

A.2 Number of Retailers Making Offers to Residential Customers (List of Options)	***Data (Abbreviation)***	***Points***
Eight or more retailers offer a product to at least 50% of eligible residential customers in the jurisdiction	(number)	10
Seven retailers offer a product to at least 50% of eligible residential customers in the jurisdiction	7	9
Six retailers ...	6	7
Five retailers ...	5	5
Four retailers ...	4	3
Three retailers ...	3	2
Two retailers ...	2	1
One retailer ...	1	0
No retailers are making offers to residential customers	0	0
No retail residential customer choice	NA	0

A.3 Customers on Competitive Rates

Key Question: What percentage of eligible residential consumers receives service at a competitive retail rate as of March 1, 2008?

Options and Points: Each jurisdiction receives a numeric data entry calculated as the total number of residential customers who receive a competitive retail rate divided by the total number of <u>eligible</u> residential customers in the jurisdiction. This number is converted to percent, and rounded to the nearest 10%. Each 10% receives one point; the maximum is 10 points.

Relationship between Points and Retail Market Success: A greater percent of customers on a competitive rate, as compared to a regulated rate, is assumed to be highly correlated with robust and successful competition. Under retail electricity choice, a residential customer can switch to a competitive provider, can be assigned to a competitive provider, or can make a transition to a competition rate when rate regulation (of default or basic service) has ended, etc. This element is indifferent to how customers got on a competitive rate. The focus is on whether they are on a competitive rate, as compared to a rate that is set by a regulatory commission.

Different jurisdictions maintain different types of "switching statistics" that may consider, for example, the frequency of customer switching to and from default service. The measure of retail competition presented in this element takes a snapshot of the percent of eligible customers on a competitive rate without regard to how they got there or how long they have been there.

Note that "opt-out aggregation" does not count as a competitive rate under this element. That is, aggregated customers are assumed to be on a regulated rate. Several jurisdictions with active aggregation believe that this measure undercounts the percentage of customers on a competitive rate.

A.3 Customers On Competitive Rates (List of Options)	***Data (Abbreviation)***	***Points***
100% of the consumers in the jurisdiction who are eligible for retail choice are on a competitive product (off the regulated rate)	100%	10
Score is calculated as the percentage of consumers eligible for retail choice that are on a competitive product, rounded to the nearest 10%, expressed in decimal form, times 10 points maximum	(percent)	Formula
All residential customer eligible for retail choice are on a regulated rate	0%	0
No retail residential customer choice	0%	0

A.4 Market Switching Measure

Key Question: Does the jurisdiction measure market switching in residential markets and regularly published the result?

Options and Points: Each jurisdiction receives a data entry reflecting the degree to which a measure of switching is clearly defined, consistently calculated, and periodically published. The number of points assigned to each option is set forth in the table.

Relationship between Points and Retail Market Success: Measurement and publication of switching statistics is useful for nascent retail electricity markets. Information about switching is useful to market monitors, retail customers and retailers; therefore, this element rewards jurisdictions that consistently track and measure switching statistics and publish the results.

A.4 Market Switching Measure (List of Options)	***Data (Abbreviation)***	***Points***
There is a robust retail market; "switching" is clearly defined; switching is consistently and periodically measured across the jurisdiction; the measure of switching is widely published	Robust	10
Switching is clearly defined and switching is consistently and periodically measured across the jurisdiction	Measure	7
Switching is tracked but the measures are inconsistently applied across the jurisdiction	Track	3
Switching is not tracked	NoTrack	0
No retail choice	NA	0

Topic B: Wholesale Competition

"Wholesale Competition" refers to the degree to which the bulk power or wholesale electricity market is competitive. Wholesale competition is important to retail electricity choice because retailers must have access to competitive supplies of power, and retail customers must be allowed to participate in wholesale markets. Retail customer participation is wholesale markets for ancillary service (such as responsive reserves) is appropriate if demand and supply are to interact. These elements are labeled B.1 – B.2 in this report.

B.1 Wholesale Market Competition

Key Question: Does the jurisdiction operate in a regional wholesale electric market that satisfies nationally established statutory criteria for open-market competition?

Options and Points: Each jurisdiction receives a data entry consistent with the status of wholesale market competition in the dominant electric region in the jurisdiction. The number of points assigned to each option is set forth in the table.

Relationship between Points and Retail Market Success: Electric regions in North America have made progress during the past 15 years in adopting competitive practices through the adoption of open access transmission service and rules that facilitate wholesale market transactions and support the operation of a reliable grid. Access to competitive wholesale markets is important to the success of retail electricity choice. Advanced wholesale market features are valuable for successful retail electricity choice.

B.1 Wholesale Market Competition (List of Options)	***Data (Abbreviation)***	***Points***
Wholesale market operates with FERC-approved Regional Transmission Organization (RTO)/Independent System Operator (ISO) (or equivalent) including (a) market-based congestion management, (b) markets for balancing energy, regulation, and reserves, and (c) congestion management based on a nodal design, and (d) FERC exemption from PURPA purchase requirements (if relevant).	Advanced	10
Wholesale market operates with FERC-approved RTO/ISO and exemption from PURPA purchase requirements (or equivalent).	Open	5
Wholesale market operates in a manner consistent with or equivalent to FERC Order 888.	Restricted	0

B.2 Responsive Demand

Key Question: Are large and small retail electricity customers allowed to fully participate in wholesale reliability and capacity markets?

Options and Points: Each jurisdiction receives a data entry that indicates the degree to which demand response is integrated into ISO activities. The number of points assigned to each option is set forth in the table.

Relationship between Points and Retail Market Success: Greater direct participation of loads in wholesale markets helps to reduce price spikes, reduces the ability of generators to exercise market power, and provides a greater degree of service differentiation to retail customers. Full integration of demand and supply is essential for healthy and robust competition.

B.2 Responsive Demand (List of Options)	***Data (Abbreviation)***	***Points***
All customer loads are allowed to fully participate in the wholesale market	All	10
Large customer loads are allowed to fully participate in the wholesale market and small loads participate in a limited manner	Both	6
Large customer loads only are allowed to participate to a limited degree	Large	3
Customer loads are not allowed to participate in the wholesale market	None	0

Topic C: Default Service

"Default Service" and "Provider of Last Resort" include the "basic" or "standard" or "safety net" rates that are set by regulators. Default service has generally been established as a mechanism to ease the transition from regulated rates and tariffs to competitive electricity prices and bilateral contracts. Retailers have identified default service as the most significant issue affecting the success of retail electricity choice.

The elements in this topic include what company provides default service, how it is designed, how frequently it is adjusted to wholesale market prices, whether providers can hedge resources and contract term, whether restrictions are placed on customers who wish to leave default service, and whether the rates track the cost of service. Also addressed are stranded cost recovery and public purpose programs that may be required by the jurisdiction. These elements are labeled C.1 – C.8 in this report.

C.1 Default Service Provider

Key Question: What type of company provides default service as of March 1, 2008?

Options and Points: Each jurisdiction receives a data entry that indicates what type of company provides default (basic or standard) service or what type of company is the provider of last resort (POLR). (Default service and POLR service are considered the same service in many, but not all, jurisdictions.) The number of points assigned to each option is set forth in the table.

Relationship between Points and Retail Market Success: Fully competitive markets are characterized by numerous service providers and a variety of services. Generally speaking, fully competitive markets do not require government regulated services such as default service. In the electric industry, the mass market has been regulated for a century, and customers are accustomed to regulation. Change takes time, and it is understandable that government regulators will want to ensure that basic services are provided to everyone. The appropriate period of time for a market to make the transition from one approach to another is subject to debate.

A competitive market with default service or provider of last resort service could be deemed successful if the percentage of customers receiving regulated service grew smaller and smaller over time. That is, a large percent of customers who receive competitive services is one mark of a healthy market. (See also Element A.3, Customers on Competitive Rates.)

Due to the history and past market structure of the regulated electric utility industry, it is reasonable that the provision of default service by an entity other than the electric distribution utility will improve the ability of customers to understand that markets are in a transition period. Consequently, the options provide an indication of the preference associated with a non-utility or non-affiliated as default service provider.

C.1 Default Service Provider (List of Options)	***Data (Abbreviation)***	***Points***
Default service (basic or standard or provider-of-last-resort) is a backstop service provided by a non-utility retailer with less than 5% of residential customers on the service	Minor	10
The default provider is a non-utility retailer	Retailer	9
The default provider is an affiliate of the local distribution utility	Affiliate	5
The default provider is the local distribution company	LDC	2
No retail choice	NA	0

C.2 Default Service Product Options

Key Question: To what extent is default service designed to provide a substitute for the choices provided in a competitive retail market?

Options and Points: Each jurisdiction receives a data entry that indicates whether default service is designed as basic service, or whether the jurisdiction has determined that default service ought to mimic the differentiated services that the regulated market used to provide in the past, or that a fully competitive market may provide in the future. The number of points assigned to each option is set forth in the table.

Relationship between Points and Retail Market Success: Default service that is simple and basic is rewarded with more points. There is a preference for simple services that do not mimic or compete with the competitive market. The existence of default service is an impediment to competition because residential customers may stay with default service due to inertia or uncertainty. Greater differentiation and complexity in default service may infringe upon the pricing options and services that competitive retailers would provide in a competitive market.

C.2 Default Service Product Options (List of Options)	***Data (Abbreviation)***	***Points***
Default service (basic or standard or provider-of-last-resort) is a backstop service provided by a non-utility retailer with less than 5% of residential customers on the service	Minor	10
One product (a "plain vanilla" product offering)	One	7
Multiple default provider product options that closely track the historical tariff offerings to similar consumers	Multiple	3
New product offerings include a range of product options that retail markets can provide	Range	0
No retail choice	NA	0

C.3 Default Service Rate Mechanism

Key Question: How frequently is the default rate adjusted to reflect the cost of service in the wholesale market?

Options and Points: Each jurisdiction receives a data entry that reflects the manner in which default service prices are aligned to the cost of power in the wholesale market. Greater frequency of adjustment means that retail customers who take default service are exposed to wholesale market prices to a greater degree. The number of points assigned to each option is set forth in the table.

Relationship between Points and Retail Market Success: Default service that tracks the cost of power in wholesale markets is rewarded with more points. Default service already provides a substitute to the competitive market. Averaging of costs over time provides a price risk management service that competitive retailers may attempt to provide. Rates that are frozen or set below cost may prevent retail competition from taking hold by moving cost recovery to future time periods and using regulatory powers, not market mechanisms, to recover costs.

C.3 Default Service Rate Mechanism (List of Options)	***Data (Abbreviation)***	***Points***
Default service (basic or standard or provider-of-last-resort) is a backstop service provided by a non-utility retailer with less than 5% of residential customers on the service	Minor	10
Default service rate is realigned to market prices at least monthly	Monthly	9
Default service rate is realigned to market prices at least quarterly	Quarterly	6
Default service rate is realigned to market prices at least biannually (twice a year)	SixMonth	3
Default service rate is realigned to market prices at least annually	Annual	2
Default service rate is realigned to market prices only occur through a formal regulatory proceeding with no set minimum frequency of change	Regulated	1
Default service rate is realigned to market prices on a fixed schedule, but less than one rate change per year	Multiyear	0
Default service rates are frozen due to an administrative or legislative decision	Frozen	0
No retail choice	NA	0

C.4 Default Service Resource Portfolio

Key Question: Does the default service provider hedge resources or match the term of the resource contracts to the term of the default service?

Options and Points: Each jurisdiction receives a data entry that indicates the degree to which the default provider hedges a portfolio to serve default service customers. The number of points assigned to each option is set forth in the table.

Relationship between Points and Retail Market Success: Default service that tracks the term of the service contract (monthly or shorter) with the term of power contracts in wholesale markets is rewarded with more points. Hedging provides risk management services that competitive markets can provide efficiently. Consumers will find a variety of hedging services through the market that are not available in a regulated default rate.

C.4 Default Service Resource Portfolio (List of Options)	***Data (Abbreviation)***	***Points***
Default service (basic or standard or provider-of-last-resort) is a backstop service provided by a non-utility retailer with less than 5% of residential customers on the service	Minor	10
The term of resource purchases matches the term of the default provider product (hour to hour, month to month, etc.)	Match	7
The default provide is allowed to hedge the resource portfolio or to "ladder" the terms for periods longer than the term of the default provider product	Hedge	3
Default provider uses its own resource supply to serve default service customers	Own	1
No retail choice	NA	0

C.5 Default Service Switching

Key Question: Are consumers restricted in switching away from default service?

Options and Points: Each jurisdiction receives a data entry that reflects the degree to which switching away from the default provider is restricted. The number of points assigned to each option is set forth in the table.

Relationship between Points and Retail Market Success: Jurisdictions that allow customers to switch at any time without penalty or fee receive more points because this is consistent with the operation of a market. Each customer should be free to contract for whatever terms are preferred. Restrictions on switching from default service constitute government contracting on behalf of the retail customers and should be avoided.

C.5 Default Service Switching (List of Options)	***Data (Abbreviation)***	***Points***
Default service (basic or standard or provider-of-last-resort) is a backstop service provided by a non-utility retailer with less than 5% of residential customers on the service	Minor	10
Leave at any time; no exit or switching fees apply; the switch typically begins at the date of the next regular meter read	Open	8
Monthly opportunity to leave; no exit or switching fees apply	Monthly	7
Monthly opportunity to leave; exit and/or switching fees apply	MonthlyFee	5
Annual window of opportunity to leave; no exit or switching fees apply	Annual	2
Annual window of opportunity to leave; exit and/or switching fees apply	AnnualFee	1
Periodic window of opportunity to switch of greater than one year	Multiyear	0
No opportunity to leave default service	Restricted	0
No retail choice	NA	0

C.6 Default Service Cost Allocation

Key Question: Does the default service rate reflect the cost of service?

Options and Points: Each jurisdiction receives a data entry that indicates the degree to which default service is priced at full retail cost so that residential customers can compare services and prices in a fair environment. The number of points assigned to each option is set forth in the table.

Relationship between Points and Retail Market Success: Points are awarded for default service that is designed to fully reflect wholesale power costs, and include the full retail costs incurred in competitive markets (e.g., bad debt, marketing, administration, etc.). Rates that are capped below the cost of service are a detriment to retail competition and are not awarded points. Rates that are frozen or set below cost may prevent retail competition from taking hold by moving cost recovery to future time periods and using regulatory powers, not market mechanisms, to recover costs.

C.6 Default Service Cost Allocation (List of Options)	***Data (Abbreviation)***	***Points***
Default service (basic or standard or provider-of-last-resort) is a backstop service provided by a non-utility retailer with less than 5% of residential customers on the service	Minor	10
Default provider rates reflect wholesale power costs, and provide "gross margin" for default provider, and provide allocation of "competitive elements" of distribution rate (e.g., bad debt)	WhlslBoth	9
Default provider rates reflect wholesale power costs, and provide "gross margin" for default provider	WhlslGM	7
Default provider rates reflects wholesale power costs, and provide allocation of "competitive elements" of distribution rate (e.g., bad debt)	WhlslAlloc	5
Default provider rates reflects wholesale power costs, but do not provide a "gross margin" and do not allocate "competitive elements"	WhlslOnly	3
Default provider rates do not fully reflect wholesale power costs, and the residual is allocated to a wires charge	WhlslPart	0
Default provider rates are capped at a level below the cost of wholesale power	Capped	0
No retail choice	NA	0

C.7 Stranded Cost Recovery

Key Question: How is the recovery of stranded costs treated?

Options and Points: Each jurisdiction receives a data entry that indicates the degree to which stranded costs recovery affects the pricing of default service. The number of points assigned to each option is set forth in the table.

Relationship between Points and Retail Market Success: More points are awarded when stranded costs are calculated in a predictable manner and recovered in way that does not impact retail competition.

Stranded cost recovery that affects the ability of retails to offer alternatives will make it difficult for retailers to offer competitive products.

C.7 Stranded Cost Recovery (List of Options)	***Data (Abbreviation)***	***Points***
Stranded benefits exist or no stranded costs were created	None	10
Stranded costs have been fully recovered (regardless of amount, calculation methodology, or recovery mechanism)	Recovered	10
Stranded costs being recovered through non-bypassable distribution-based charge with an upfront determination of amount and mechanism and recovery does not impact the "shopping credit"	NoImpact	8
Stranded costs being recovered through non-bypassable distribution-based charge with an upfront determination of amount and mechanism; however, recovery does impact the "shopping credit"	ChangeCredit	3
Stranded costs being recovered through non-bypassable distribution-based charge with on-going adjustment of stranded cost and recovery impacts the "shopping credit"	Adjustment	0
No retail choice	NA	0

C.8 Nondiscriminatory Public Purpose Requirements

Key Question: Are public purpose programs – such as resource portfolio standards and energy efficiency program requirements – applied fairly to all retailers?

Options and Points: Each jurisdiction receives a data entry that indicates whether public purpose programs, if imposed, treat all market participants fairly. The number of points assigned to each option is set forth in the table.

Relationship between Points and Retail Market Success: In general, public purpose programs ought to be imposed on regulated entities such as local distribution companies. Competitive providers may be placed at a disadvantage if they are required to provide particular services that are desired by government. If required, public purpose program requirements and their costs should be imposed equally on all retail service providers.

C.8 Nondiscriminatory Public Purpose Requirements (List of Options)	***Data (Abbreviation)***	***Points***
No public purpose requirements	None	10
Public purpose requirements (resource portfolio standards, energy efficiency programs, environmental initiatives) are imposed consistently on all retailers	Fair	8
Some retailers must satisfy public purpose requirements, but other retailers are not required to do so	Unfair	0
No retail choice	NA	0

Topic D: Facilitation of Choice of Retailer

"Facilitation of Choice of Retailer" refers to the market structures, infrastructure and programs that support retail electricity choice. First, the jurisdiction's policies with regard to electric distribution market structure and the code of conduct are examined. Next, we consider customer education, retailer access to customer information, uniformity of transaction standards. Finally, this element includes billing protocols, access to meter information and advanced metering infrastructure. These elements appear as D.1 – D.9 in this report.

D.1 Distribution Utility Structure

Key Question: Is the regulated distribution service function separate from competitive services?

Options and Points: Each jurisdiction receives a data entry that indicates the degree to which electric distribution utilities and their affiliates are allowed to participate in the provision of competitive retail services. The number of points assigned to each option is set forth in the table.

Relationship between Points and Retail Market Success: A market structure that limits regulated electric utilities to the provision of transmission and distribution services (the network) presents a clean separation between regulated and unregulated functions. A wires only utility conducts transactions with all market participants, including its affiliates, on an arm's length basis.

Local electric distribution utilities that provide competitive services may use the network services to affect the behavior of consumers. In this context, competitive service may include the marketing of electricity, the sale of appliances or control devices, distributed generation services, bulk generation service, and other services that can be provided competitively. If affiliates of the local electric distribution utility offer competitive services, then, at a minimum, there is the perception of the potential for unfair practices. A formal separation of the regulated business units from competitive affiliates is appropriate. Oversight of these relationships through a code of conduct is likely to provide value to all competitive market participants. Elements D.1 and D.2 assess these issues.

D.1 Distribution Utility Structure (List of Options)	***Data (Abbreviation)***	***Points***
Distribution utilities are "wires only" (pure disco) and do not provide competitive retail service or competitive generation service	WiresOnly	10
About one-half of the residential retail choice customers receive distribution service from a wires-only distribution utility, while the other half receives distribution service from a utility with separate business units or affiliates that provide competitive retail service or competitive generation service	PartWires	8
Distribution utilities are separated from business units or affiliates that provide competitive retail service or competitive generation service	Separated	5
About one-half of the residential retail choice customers receive distribution service from a utility with separate business units or affiliates, while the other half receives distribution service from integrated utilities	PartInteg	3
Distribution utilities are part of integrated utilities that offer	Integrated	0

D.1 Distribution Utility Structure (List of Options)	*Data (Abbreviation)*	*Points*
competitive retail service or competitive generation service		

D.2 Competitive Safeguards

Key Question: Do distribution utilities operate under a code of conduct that governs relations with affiliates and is that code consistently enforced?

Options and Points: Each jurisdiction receives a data entry that indicates the degree to which electric distribution utilities interact with business units and affiliates on an arm's length basis under a strict code of conduct. The number of points assigned to each option is set forth in the table.

Relationship between Points and Retail Market Success: The greater the degree of separation – either physical or through a strict code of conduct – the greater the points awarded to the jurisdiction. A formal separation of regulated business units from competitive affiliates may be required. Regulation of these relationships through a code of conduct will help to address the concerns of competitive market participants. Elements D.1 and D.2 assess these issues.

D.2 Competitive Safeguards (List of Options)	*Data (Abbreviation)*	*Points*
Distribution utilities are "wires only" (pure disco) and do not provide retail services	WiresOnly	10
Distribution utilities interact with retail affiliates or retail business units under a strict code of conduct that is consistently enforced and that includes (a) prohibition on sharing employees and assets, (b) prohibition on affiliate using creditworthiness, (c) prohibition on joint marketing and advertising, (d) restriction on use of names and logos	Strict	7
Distribution utilities interact with retail affiliates or retail business units under a code of conduct that is consistently enforced and that includes many of the elements above	Weak	3
Distribution utilities are not restricted by a code of conduct or are part of integrated utilities	Integrated	0

D.3 Consumer Education and Awareness

Key Question: Is there a program to educate consumers about retail choice and to measure the results?

Options and Points: Each jurisdiction receives a data entry that reflects the seriousness of the consumer education effort relating to retail electric choice. The number of points assigned to each option is set forth in the table.

Relationship between Points and Retail Market Success: A comprehensive education program includes consumer education and an evaluation of the results. It is generally agreed that consumer education is an appropriate role for government to play in a nascent market.

D.3 Consumer Education and Awareness (List of Options)	*Data (Abbreviation)*	*Points*
Jurisdiction has a comprehensive education program including a periodic evaluation of customer awareness	Comprehensive	10
Jurisdiction has a government-directed consumer education program	Govt	5
Jurisdiction has a utility-directed consumer education program	Utility	2
No consumer education program	NoEducation	0
No retail choice	NA	0

D.4 Access to Residential Customer Information

Key Question: Do qualified retailers have easy access to basic customer information?

Options and Points: Each jurisdiction receives a data entry that reflects the ease with which basic customer information – address, monthly usage, etc. – is made available to qualified retailers. Each jurisdiction must balance access to sensitive data with a desire to make basic data available on a consistent basis to all retailers. The number of points assigned to each option is set forth in the table.

Relationship between Points and Retail Market Success: Greater access to information reduces the transaction costs and facilitates retail electricity choice. Policies that restrict access to customer data may impose costs on some market participants but not others.

D.4 Access to Residential Customer Information (List of Options)	*Data (Abbreviation)*	*Points*
Standardized, comprehensive information is provided to all qualified retailers	Comprehensive	10
Standardized information is provided to all qualified retailers and retail customers are allowed to opt out of any list	OptOut	8
Standardized, comprehensive information provided to qualified retailers for customers who "opt in" to a list that is distributed	OptIn	5
Standardized, comprehensive information provided to qualified retailers for customers who affirmatively permit dissemination of information (e.g., provide their account number at a trade show)	Permission	4
Customer information provided to qualified retailers, but it is not standardized or comprehensive	Limited	2
No customer information dissemination plan	Restricted	0
No retail choice	NA	0

D.5 Uniformity of Standards

Key Question: Does the jurisdiction apply uniform standards for the operation of competitive retail markets?

Options and Points: Each jurisdiction receives a data entry that corresponds to the degree to which it has adopted standard approaches for conducting the retail business in its jurisdiction. Jurisdictions that allow numerous electric distribution utilities to maintain separate, unique standards and approaches are imposing costs on retailers that operate across the jurisdiction, requiring that they adapt to different standards for each utility service area. The number of points assigned to each option is set forth in the table.

Relationship between Points and Retail Market Success: More points are assigned to jurisdictions that work toward uniform business standards. No jurisdiction has achieved the goal of supporting the creation and adoption of standards for North America, but that seems to be an appropriate goal.

D.5 Uniformity of Standards (List of Options)	***Data (Abbreviation)***	***Points***
Adoption of North American Energy Standards Board consensus standards for retail electricity	Continental	10
Adoption of comprehensive and uniform standards that are consistently applied with a jurisdiction	Jurisdictional	5
Standards vary by distribution utility	Utility	0
No retail choice	NA	0

D.6 Transaction Standards

Key Question: Does the jurisdiction require the use of a standard electronic data exchange for business transactions?

Options and Points: Each jurisdiction receives a data entry to indicate the degree of standardization for electronic data interchange in the jurisdiction. The number of points assigned to each option is set forth in the table.

Relationship between Points and Retail Market Success: A standard electronic data interchange (EDI) greatly reduces transactions costs. With large customers, the faxing or manual entry of data is a small cost relative to the size of the customer. However, in the mass market (residential customers) frequent, repetitive transactions can become very costly. A non-standard, utility-by-utility approach increases the cost of each transaction and reduces the viability of retail electricity choice.

D.6 Transaction Standards (List of Options)	***Data (Abbreviation)***	***Points***
Standard EDI set for retail transactions	StdEDI	10
Standard customer information set for retail transactions	StdInfo	5
Utility-by-utility transaction processing	Utility	1
No retail choice	NA	0

D.7 Billing Protocols

Key Question: Does the jurisdiction treat billing in a manner that inhibits retail choice?

Options and Points: Each jurisdiction receives a data entry that indicates whether billing is considered in a flexible manner that serves the operation of a retail market. There is no consensus on whether utility billing or retailer billing is essential to retail electricity choice. That is to say, retailers appear comfortable with either approach as long as it is conducted in a manner that treats retail customers fairly. The number of points assigned to each option is set forth in the table.

Relationship between Points and Retail Market Success: Two approaches are assigned maximum points because there is not yet a consensus on which is best. This element presents two approaches that are problematic, and assigns fewer points to signal the problems that may be created by adopting one approach or the other.

D.7 Billing Protocols (List of Options)	***Data (Abbreviation)***	***Points***
Retailer has the ability to bill directly, with the retailer bearing full credit risk	Single	10
Utility consolidated billing with purchase of receivables with 0% discount	UtilityPurch	10
Utility consolidated billing with credit exposure/bad debt expense on the retailer	UtilityExpos	3
Mandatory dual billing	Dual	0
No retail choice	NA	0

D.8 Access to Metering Information

Key Question: Do retailers have on-demand access to real-time metered data regarding customer usage?

Options and Points: Each jurisdiction receives a data entry that indicates whether retailers have access to metered information.

Relationship between Points and Retail Market Success: Enhanced ability to measure and manage customer data will improve the ability of retailers to provide services to customers and to manage their resource portfolio and cost structure. More points are associated with on-demand access to real time data about a retailer's customers.

D.8 Access to Metering Information (List of Options)	***Data (Abbreviation)***	***Points***
Retailers have on-demand, real-time access to customer meter and metered data	OnDemand	10
Retailers have access to real-time customer meter data, but not on demand	RealTime	5
No interval data available	NoData	0
No retail choice	NA	0

D.9 Advanced Metering Infrastructure

Key Question: Has the jurisdiction invested in advanced metering and communications?

Advanced metering infrastructure (AMI) is an important part of making the electricity network "more intelligent." AMI will enable time-of-use pricing, critical peak pricing, real-time pricing and demand response programs. "Advanced" meters refers to meters that are capable – at a minimum – of measuring and storing *hourly* consumption data and communicating these data at least once every *24 hours.*

Options and Points: Each jurisdiction receives a numeric data entry equal to the number of residential electricity customers in the jurisdiction with advanced meters divided by the total number of residential electricity customers in the jurisdiction. This number is converted to percent, and rounded to the nearest 10%. Each 10% receives one point; the maximum is 10 points.

Relationship between Points and Retail Market Success: Advanced metering infrastructure is considered an important part of improved pricing, and improved pricing will increase the ability of retailers to offer differentiated services to residential customers. A measure of the penetration of these investments is considered one element that must be considered in the eventual success of retail competition.

D.9 Advanced Metering Infrastructure (List of Options)	***Data (Abbreviation)***	***Points***
100% penetration of advanced meters	100%	10
Score is calculated as the percentage penetration of advanced meters, rounded to the nearest 10%, expressed in decimal form, times 10 points maximum	[percent]	formula
Less than 5% penetration of advanced meters	[percent]	0

Appendix B – Restructuring in States/Provinces

Appendix B provides a summary of the key events in restructuring during the past decade for each state and province, basic switching statistics, and a chart with sales and average prices. This appendix appears in both the residential ABACCUS report and commercial and industrial ABACCUS report.

A short description provides a high-level overview of the major restructuring legislation and decisions that have shaped retail choice in each jurisdiction during the past ten years. The information is based on regulatory commission and utility Web sites and press releases, interviews with individual staff members at regulatory commissions, and comments from the ABACCUS Advisory Board.

Switching (migration) statistics provide a snapshot of the status of retail choice. Switching refers to customers and loads that have moved from a regulated default service (standard offer service) to a competitive contract or price. The most recently available data are provided based on data available on regulatory commission Web sites. The tables present switching data in terms of percent of eligible residential customers, and percent of nonresidential load. Depending on the jurisdiction, "load" is either reported in terms of non-coincident customer class peak demand or megawatt-hours sales. Where available, such data are displayed at the electric distribution utility service area level as well as the aggregate state/province level.

Switching statistics are one way to assess the success of retail choice. However, switching statistics are just one of many inputs into the ABACCUS model (see Appendix A). It is also worth mentioning that the switching statistics may not indicate multiple customer switches ("churn"), or customers who may select a competitive contract or pricing plan from the default service provider (for example, were the default service provider is allowed to offer both regulated and competitive prices).

Two charts present residential and industrial electricity sales (bars) and average residential and industrial prices (dots) for the period 1990 to 2006 based on DOE Energy Information Administration statistics. In a few instances, sales data are presented for combined commercial and industrial customers because reclassification during the period from "industrial" to "commercial" made the industrial data alone misleading. Note that average price data are derived from revenues divided by sales. The 1990 to 2006 data are annual averages presented in real dollars (2006 dollars), while the last two data points are monthly data that represent June 2007 and June 2008 in current year dollars.

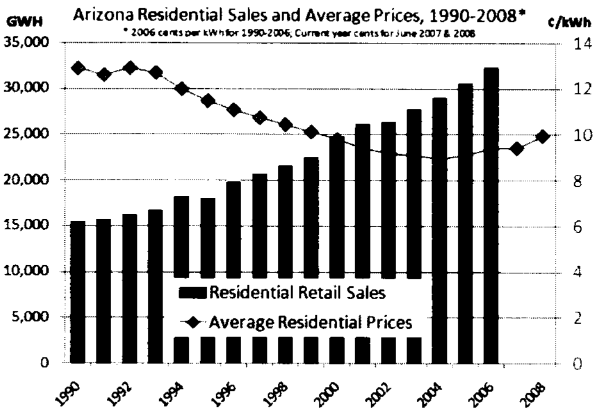
Arizona

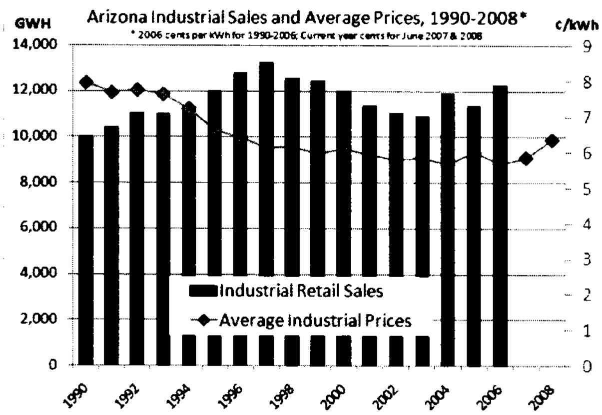
Legislation (HB 2663) was enacted in 1998. The Arizona Corporation Commission (ACC) rules required generation divestiture (transfer to a utility affiliate) and mandated a rate cut. Retail choice was phased-in, with about 90% of electric customers eligible for retail choice by January 2001. By June 2001, all competitors had pulled out of the market due to the way the shopping credit was established. Wholesale market prices rose, but the low credit subtracted from the retail rate for the energy service provider to compete was not increased. Switching halted and all customers were returned to the incumbents.

Citing market immaturity, Arizona Public Service Company (APS) asked the ACC to overturn the rules that compelled it to obtain power from the competitive market. APS proposed that the power needs be met through 2015 from the parent company, Pinnacle West Capital Corp., and the competitive generation affiliate. In making a determination, the ACC issued Decision No. 65154 (Track A) in September 2002, and ordering APS and Tucson Electric Power Company (TEPCO) to cancel any plans to divest interest in any generating assets. The ACC also stayed the requirement that 100% of power purchased for Standard Offer Service be acquired from the competitive market. Without an RTO in the western US, and with the problems in California markets, the ACC was not willing to wait for markets to function properly.

In March 2004, Arizona Court of Appeals ruled that the ACC's decision to require electric utilities to divest their generation assets was unconstitutional because the ACC was trying to control rates, not utilities, and had not proven the case for divestiture. By October 2004, restructuring was placed on hold.

Sempra has argued (Docket No. E-03964-06-0168) that it is fit to serve as a competitive energy service provider and it has requested reinstatement. In a recent order, the ACC has determined that certain other findings are still needed. It has ordered the ACC's Utilities Division to conduct public workshops to address the underlying policy issue of whether retail competition is in the public interest and to examine the potential risks and benefits of retail competition. By December 31, 2009, a report based on the workshops must include the staff recommendation as to whether or not retail competition should be implemented, and if so, how such implementation should proceed.





California

The California Public Utilities Commission (CPUC) issued reports in 1993 (Yellow Book) and 1994 (Blue Book) that addressed regulation and restructuring. In September 1996, Assembly Bill 1890 was enacted to start retail access January 1998 (delayed to April 1998). Approximately 14% of load was served by competitive energy service providers by 2000. California experienced setbacks with its wholesale markets that affected retail prices and resource availability. Because of supply shortages, wholesale market prices were very extremely volatile. San Diego Gas & Electric Company had completed its stranded cost recovery in 1999, and could therefore pass wholesale prices to retail customers. In contrast, Pacific Gas and Electric Company (PG&E) and Southern California Edison Company (SCE) paid high wholesale prices, but incurred significant debt because they were not allowed pass high wholesale prices to retail customers.

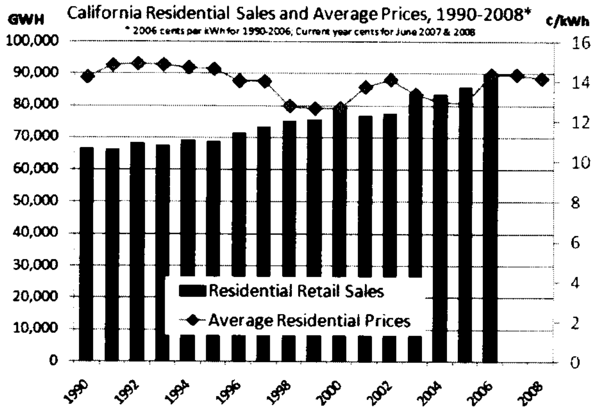
In January 2001, PG&E filed for bankruptcy protection. Subsequently, the State of California Department of Water Resources (DWR) purchased power on behalf of the utilities. (Authorized by emergency legislation AB 1X, February 1, 2001, this state procurement lasted until 2003.) In March 2001, the Federal Regulatory Energy Commission ordered suppliers to make refunds to utilities. On June 18, 2001, FERC voted to impose price controls on wholesale electricity prices for California and ten other Western states.

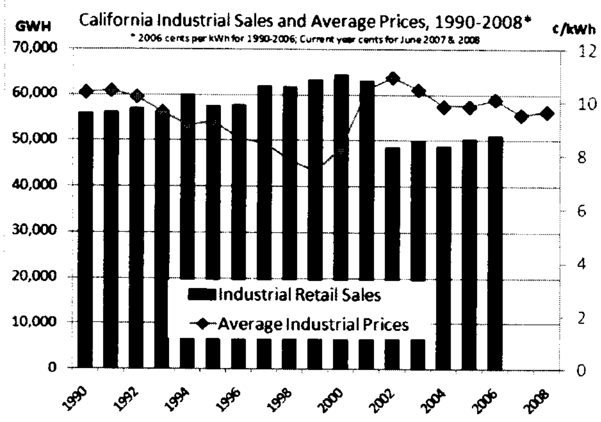
On September 20, 2001, in Decision 01-09-060, the retail access provisions of AB 1890 were suspended by the CPUC. Direct access contracts signed before September 20 were allowed to continue until their expiration. These direct access customers were charged Cost Responsibility Surcharges for costs incurred by the State and utilities during the energy crisis (Decision 02-11-022). As of February 2008, there were 18,700 residential direct access customers (0.2%) in California. In 2002, AB 117 passed to amend the Utilities Code to allow community choice aggregation with an "opt out" provision. In April 2007 the CPUC authorized the first community choice aggregation application.

In May 2007, CPUC determined that it would investigate the potential to reopen the retail market for direct access (Rulemaking 07-05-025). The CPUC has determined that it does not currently have authority to reinstitute direct access. (Phase I of the proceeding focused on legal issues. Since power is supplied when delivered to a retail customer, the DWR is still "supplying power" under the Water Code §80110. DWR still holds power contracts, has title, and receives payment. Although DWR no longer has contracting authority, it still administers contracts and "sells electricity" under existing contracts, therefore, the CPUC must extricate DWR from that role prior to the opening of the direct access market.) In a February 28, 2008 press release, CPUC President Peevey stated: "The suspension of choice cannot be lifted until DWR no longer supplies power through the contracts that were signed during the energy crisis. Accordingly, the CPUC can and should evaluate the merits of ways to extricate DWR from its current role as supplier of energy under those existing contracts. After that the CPUC can proceed to the question of whether and how to reinstate Direct Access." Phase II of R.07-05-025, scheduled for the fall of 2008, will consider the public policy merits and prerequisites to reopening direct access.

California has been very active during the past several years with resource adequacy, energy efficiency incentive programs, energy efficiency codes and standards, demand response programs and renewable resources. In 2006, California enacted comprehensive legislation to address climate change. AB32, the California Global Warming Solutions Act of 2006, requires the California Air Resources Board to adopt, monitor and enforce regulations. SB 1368, Emission Performance Standards, prohibits any load serving entity and any local publicly-owned electric utility from entering into a long-term financial commitment for base load generation that does not comply with an emission performance standard of 1,100 lbs CO2 per MWh.

California Percent of Customer Switching July 2008	Percent of Residential Customers	Percent of Small Commercial (<20 kW) Sales (MWH)	Percent of Medium Commercial (20 - 500 kW) Sales (MWH)	Percent of Industrial (> 500 kW) Sales (MWH)	Percent of Agricultural Sales (MWH)	Percent of State Sales (MWH)
State Total	0.2%	0.8%	11.7%	23.9%	1.2%	9.08%





Connecticut

The Act Concerning Electric Restructuring (HB 5005) was signed into law April 1998. The law required divestiture of nuclear assets, required participation in an ISO, functional unbundling, a renewable portfolio standard, a 10% rate deduction, and a rate cap until 2000. The utilities filed divestiture plans and there was some uncertainty with respect to the amount of stranded costs. Few competitive retailers entered the state. The Department of Public Utility Control (DPUC) set restrictions on switching back to standard offer service – a 12 month switching moratorium was instituted.

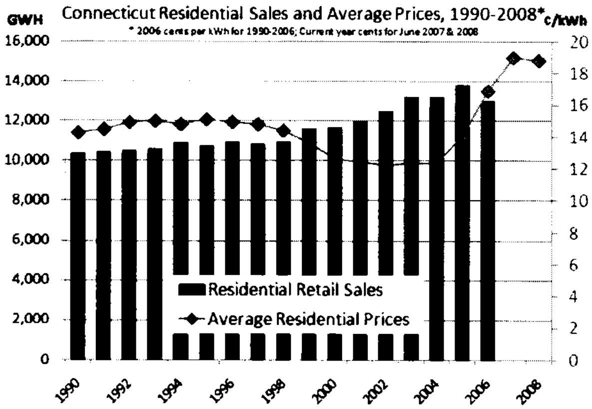
Rate caps ended and rates increased in 2004-05. In June 2006, DPUC passed regulations requiring Connecticut utilities to hold multiple auctions for standard offer power supply.

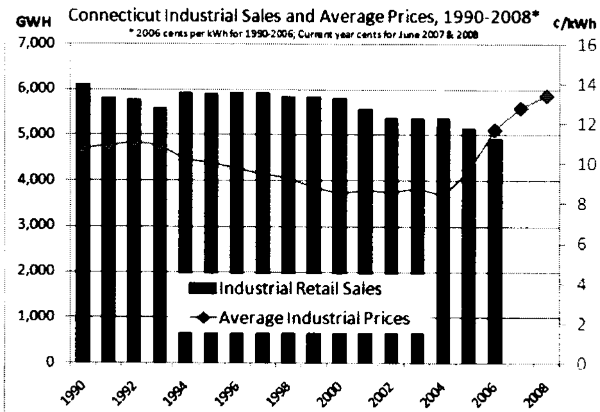
In June 2004 Connecticut passed a public act concerning climate change. In February 2007 the governor proposed a new state department of energy to work on energy policy and renewable resources. The state has a three-tier resource portfolio standard that includes renewable resources and energy efficiency. There is also an emphasis on distributed generation to address capacity needs in the southwestern corner of the state. April 18, 2008, Governor Rell signed the Governors' Declaration on Climate Change, joining 17 states to urge federal-state cooperation and federal support.

In 2007 the Connecticut General Assembly passed legislation allowing utilities (which had been divested of generation after the 1998 restructuring bill) to construct regulated peaking units. In March 2008, Connecticut Power and Light (CP&L) filed for permission to build four 50 MW units and two 32.5 MW units to come in service in 2010. In late January 2008, CL&P rates were approved by the DPUC in Docket Nos. 07-07-01 and 03-07-02RE10.

Connecticut Percent of Customer Switching September 2008	Percent of Residential Customers	Percent of Commercial/ Industrial Sales (MWh)
Connecticut Light & Power	5.9%	46.9%
United Illuminating	7.9%	55.3%

State Total	6.6%	48.6%





Delaware

In March 1999, Delaware enacted legislation (HB 10) mandating electric restructuring and a rate cut of 7.5% for most electric customers. Larger customers of Connectiv Power were eligible for choice October 1999, medium customers January 2000, and all residential and commercial customers became eligible October 2000.

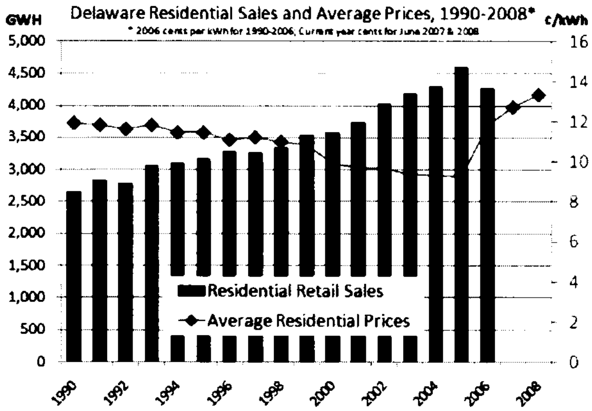
In April 2001, Delaware Electric Cooperative's customers became eligible for the choice plan. Rate caps were lifted for Delaware Electric Cooperative in March 2005 and rate increased 8%.

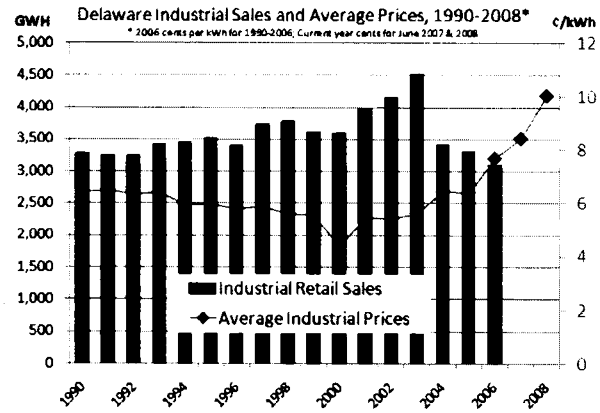
In 2003, the PEPCO/Connectiv (now Delmarva Power & Light Company) merger settlement increased rates about 1%, but extended the rate freeze for Delmarva Power customers until May 2006. In October 2004, the Commission opened PSC Docket No. 04-391 to determine which company would provide standard offer service (SOS) in Delmarva Power service territory after May 2006. Delmarva Power was selected. The Request for Proposal process is nearly complete and a technical consultant report was received in March 2008. It is expected that residential rate will increase about 2% as a result of increases in the blocks of power selected. (One third of the power need is acquired annually to reduce price volatility.)

The Electric Utility Retail Customer Supply Act of 2006 requires Delmarva Power to file a proposal for long-term supply contracts. On December 4, 2007, the Commission entered PSC Order No. 7318 to propose and take comments on Integrated Resource Planning regulations. Written comments were filed in February 2008.

Delaware Percent of Customer Switching July 2008	Percent of Residential Customers	Percent of Nonresidential Load (MW)

State Total	2.8%	59.8%





District of Columbia

The District of Columbia Public Service Commission (DCPSC) issued Order Nos. 11576 (December 1999) and 11796 (September 2000) to allow all residential and commercial customers to choose an alternative electric supplier effective January 2001. Potomac Electric Power Company (PEPCO) is the sole electric distribution company. At the end of 1999, PEPCO made a decision to divest itself of generating units. A Code of Conduct working group was created in 2000 to work on competitive safeguards, with an interim decision to adopt Maryland's Code of Conduct, and a longer-term effort to develop a DC-specific Code of Conduct. DCPSC orders issued in 2001 addressed customer education, new electric supplier tariffs, and interim customer aggregation standards.

In 2002, the DCPSC issued an order and report on a Municipal Aggregation Program. The DCPSC also approved the PEPCO/Connectiv merger subject to conditions. Divestiture resulted in a sharing of proceedings with customers. (The typical household received $80.42 of divestiture sharing credits in 2002.) PEPCO has moved toward a holding company structure.

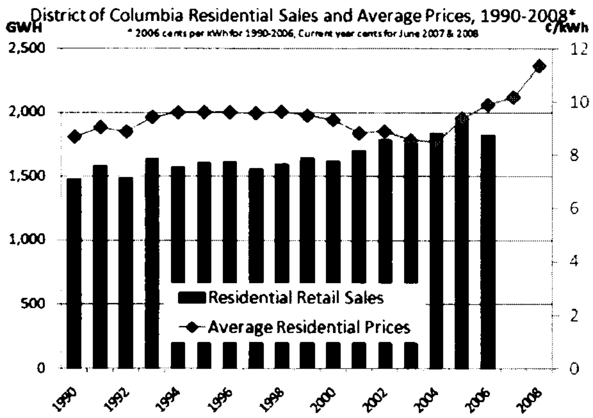
In 2003-04, the DCPSC examined the standard offer service (SOS) process (Order Nos. 12655 and 13118), including whether PEPCO should continue to provide SOS because its obligation to serve was set to expire at the end of 2004. A new process was adopted that relied on to a greater degree on wholesale market prices. In March 2006, PEPCO filed for rates increases for SOS of about 10% to 12%. In July 2006, the DCPSC issued Order No. 14006 to adopted improvements in the procurement process for SOS, and to consider the benefits of a portfolio approach.

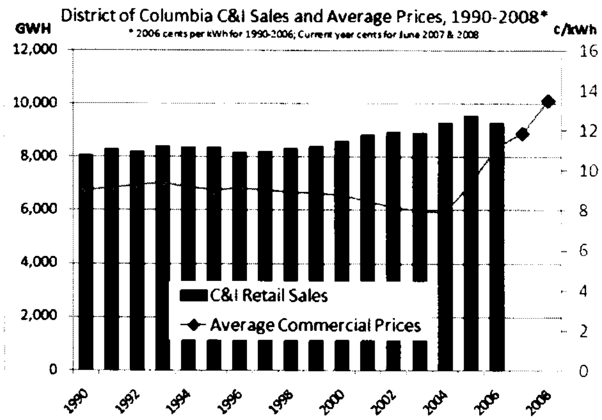
A Renewable Energy Portfolio Standard Act was enacted in 2005 which will require suppliers to acquire 11% of their energy from renewable resources by 2022. The DCPSC has increased the amount of information available to customers regarding energy efficiency.

During the peak period for switching (between September 2002 and December 2003), residential customer switching was between 10.2% and 11.9% in DC. As of March 2008, only 1.0% of residential customers in DC were served by competitive suppliers. All other residential customers were on PEPCO's SOS tariff.

District of Columbia Percent Switching August 2008	Percent of Residential Customers	Percent of Nonresidential Customers*
District Total	1.0%	19.8%

* Statistics are provided based on number of nonresidential customers, not the peak MW or MWH sales.





Illinois

In December 1997 and again in September 1999, the Illinois Public Utilities Act was amended (P.A. 90-0561, Electric Service Customer Choice and Rate Relief Law of 1997, HB 362). Large customers were allowed to choose their supplier in 1999, and other nonresidential customers were allowed to choose in 2000. The initial decision to give residential retail choice (in 2002) was moved up to a late-1999 to late-2000 phase in. The amendments also mandated rate cuts of 15% in 1998 and 5% in 2001. Other provisions promoted cogeneration and allocated $250 million to special environmental initiatives and to an energy efficiency fund. Rates were capped until 2005, providing relatively little incentive for mass market customers to switch. In 2002, the Illinois General Assembly extended the rate cap to January 1, 2007 (P.A. 92-357).

In late 2002, the Illinois Commerce Commission (ICC) eliminated the regulated rate for customers above three megawatts. As of the end of 2006, nearly 28,000 commercial and industrial customers have chosen to take delivery service from a retail electric service provider other than the utility, totaling approximately 28,500 GWH for that year. ("Summary of Annual Reports Filed by Electric Utilities Regarding the Transition to a Competitive Electric Industry: Required by Electric Service Customer Choice and Rate Relief Law of 1997", May 2007 (220 ILCS5/16-130)(1999)).

In 2007, Public Act 095-0481 (Illinois Power Agency Act) created the Illinois Power Agency (IPA) and amended the Illinois Public Utilities Act to return certain rates to 2006 levels. The IPA is responsible for overseeing the procurement of power and energy for retail customers who receive fixed-price bundled service from electric utilities with 100,000 or more customers (220 ILCS 5/16-111.5(a)(2007)). The IPA is to prepare a plan, by August 15 of each year, to procure the necessary energy and power in the following year (220 ILCS 5/16-111.5(b)(2007)).

The Illinois Power Agency Act also declared services in ComEd and Ameren whose peak demand is above 400 kW to be competitive as of August 2007 (220 ILCS 5/16-113(f)). ComEd customers who have peak demand above 400 kW are allowed to take bundled service until June 2008. ComEd customers who have peak demand between 100 kW and 400 kW are allowed to take bundled service until June 2010. Ameren customers with peak demand is above 1 MW are able to take bundled service until June 1, 2008, and customers with peak demand between 400 kW and 1 MW can take bundled service until June 1, 2010. Electric utilities are able to obtain determinations of competition for the customers who have peak demand between 100 kW and 400 kW if they can demonstrate that at least 33% of the customer's in the service area are eligible to take service from an alternative retail electric supplier and that at a least three alternative retail electric suppliers provide comparable service (220 ILCS 5/16-113(g)(2007)).

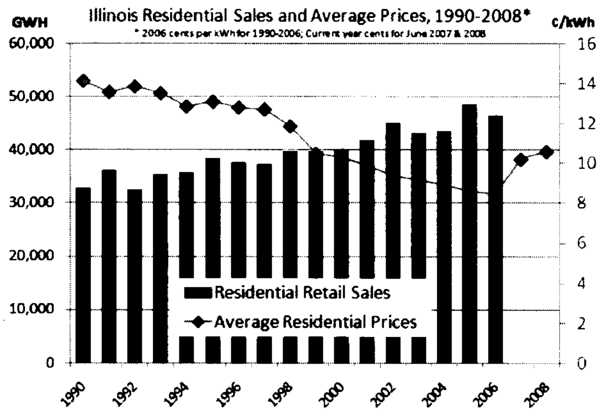
The ICC cannot make a determination of competition for residential customers, with peak demand less than 100 kW, until after July 1, 2012 (220 ILCS 5/16-113(h) (2007)). The Illinois Power Agency Act also set energy efficiency and demand response goals for Illinois utilities (220 ILCS 5/12-103)(2007).

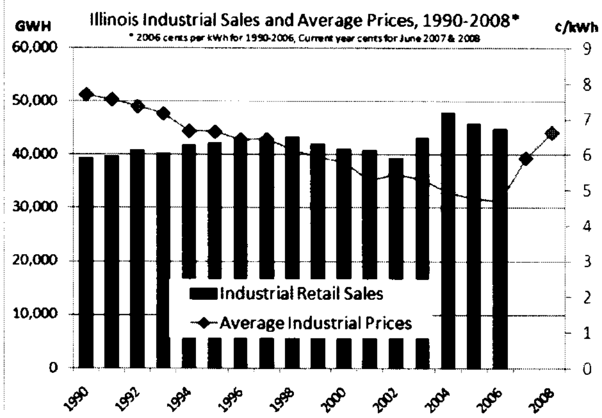
In April 2008, utilities in Illinois started offering net-metering (83 IL. Admin. Code Part 465) to eligible customers, that is, to retail customers who own or operate a solar, wind, or other eligible renewable electrical generating facility with a rated capacity of two MW or less. In addition, the ICC has initiated a rulemaking (Docket No. 06-0525) that will set standards for interconnection of direct generation to the distribution network (83 IL. Admin. Code Part 466).

The Illinois Office of Retail Market Development (ORMD) prepared its first annual report in July 2008 pursuant to the requirements of Section 20-110 of the Illinois Public Utilities Act.

Illinois Percent Switching August 2008	Percent of Residential Customers	Percent of Small C&I Load (< 1 MW)	Percent Large C&I Load (> 1 MW)	Percent Total Load (MW)
Central Illinois Light Company (AmerenCILCO)	0.0%	44.0%	69.4%	38.8%
Central Illinois Public Service (AmerenCIPS)	0.0%	30.8%	98.5%	43.7%
Illinois Power Company (AmerenIP)	0.0%	36.4%	97.5%	48.9%
Commonwealth Edison Company	0.0%	54.4%	92.4%	48.4%
MidAmerican Energy Company	0.0%	0.0%	0.0%	0.0%
Mt. Carmel	0.0%	0.0%	0.0%	0.0%

State Total	0.0%	50.2%	92.6%	47.9%





Maine

In May 1997, the Maine Legislature passed Directive 1804 to require divestiture of utility generation assets and initiate retail choice in March 2000. The Legislature imposed a 33% market share cap on investor-owned utilities in their old service areas, and instituted a renewable energy portfolio requirement of 30% (including hydroelectric power). Maine's law (Title 35-A, Chapter 32: Electric Industry Restructuring), allows retail consumers to purchase electricity supply from licensed competitive electricity providers, and requires customers not served competitively to accept standard offer electricity regulated by the Maine Public Utilities Commission (MPUC).

The MPUC has considered bids for resources to serve default customers. In 1999, the MPUC rejected bids and reissued a request in 2000 under amended rules in an attempt to attract more bidders. The MPUC set standard offer rates and ordered Central Maine Power to provide standard offer service from March 2000 to March 2002 for medium and large nonresidential customers. The MPUC also approved a transmission/distribution rate scheme for restructuring submitted by Maine Public Service Company (in far northern Maine, and isolated on the grid) that separated MPS's revenue requirements into a transmission component under FERC jurisdiction and a distribution component under MPUC jurisdiction.

The MPUC revisited standard offer service in 2002. To further connect the standard offer to market prices, the MPUC shortened the time period for its current medium and large standard offer categories to six months. That is, the winning bid sets the standard offer at start of the six-month period, with prices changing each month. In December 2002, the MPUC reported to the legislature that retail access had been a success for commercial and industrial customers in Maine, and that some residential customers had switched to renewable resource suppliers. At that time, 47% of the electricity in Maine was bought from competitive suppliers—the highest percentage in the nation. The MPUC stated that until retail markets mature, the legislature must keep standard offer service in place beyond the scheduled termination date of March 2005.

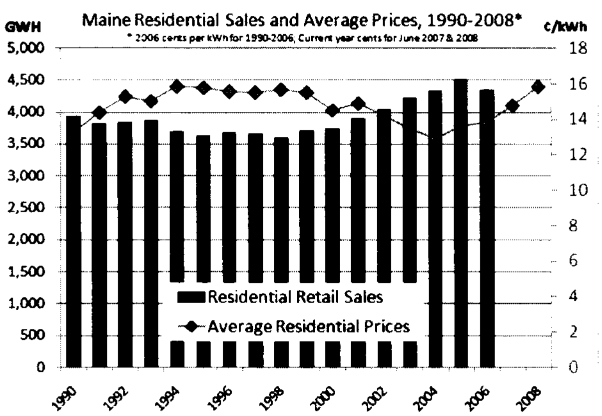
In late 2004, an auction produced standard offer rates with a nearly 30% increase in the generation price due to conditions in the wholesale market. In more recent auctions, the MPUC goes to the market each year for one-third of the load in a three-year contract. In January 2008, the MPUC accepted a one-year contract for one-third of the load at Central Maine Power and Bangor Hydro-Electric. As a result, in

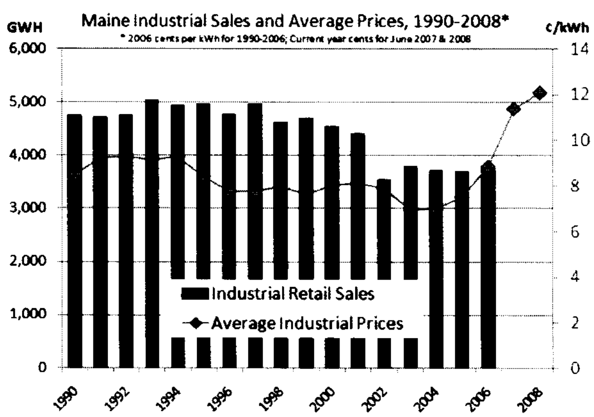
2009, there will be a need to replace two-thirds of the load (the 2006 and 2008 contracts). Standard offer rates have increased between 2% and 3% for each of the past two years for these two utilities, weighing together the net effect of power costs and decreases in stranded costs.

MPS with approximately 5% of the state's load is directly connected to the New Brunswick system, and is connected to the New England Power Pool through New Brunswick. There is only one competitive supplier serving the MPS service territory, and MPS is filing an application in 2008 for new transmission facilities to better connect with the rest of the state. Cost allocation for the investment will be an issue.

In addition to the 30% RPS requirement, Maine requires "new renewable resources" to be 1% of the portfolio in 2008 (and growing by 1% a year). In 2007, Maine created an Energy Conservation Board to assist the MPUC with energy conservation as it relates to carbon dioxide reductions.

Maine Percent Switching July 2008	Percent of Residential and Small Commercial Customers	Percent of Medium C&I Load	Percent Large C&I Load	Percent Total Load
Bangor-Hydro Electric	0.6%	39.6%	76.0%	31.1%
Central Maine Power	0.9%	36.5%	92.9%	38.2%
Maine Public Service	0.4%	24.1%	71.4%	26.4%
State Total	0.8%	36.0%	91.8%	36.6%





Maryland

In April 1999, Maryland adopted the Electric Customer Choice and Competition Act of 1999 (SB300 and HB703). The bill mandated retail access and a rate reduction. Customers of the investor-owned utilities became eligible for choice in July 2000, and customers of electric cooperatives became eligible at the end of 2001. Five municipal utilities remain locally controlled and are not required to offer retail choice.

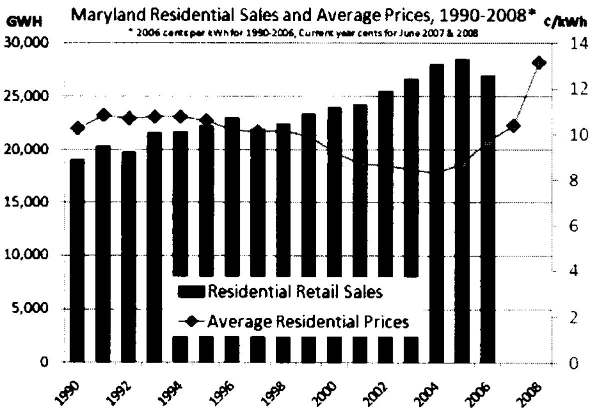
Standard offer service design and rate levels have been a point of contention. The initial standard offer service remained in effect until July 1, 2003. A subsequent case (Case No. 8908) determined that standard offer service would remain in effect to 2004 to 2008. During this period, utilities, as the default service providers, acquired 1, 2, and 3-year power contracts to meet the needs of residential customers. Commercial customers received a more variable price, and large customers received hourly pricing over a one-year period. If numerous customers remained with standard offer service, the utilities applied an alternative price of service – the PJM hourly price.

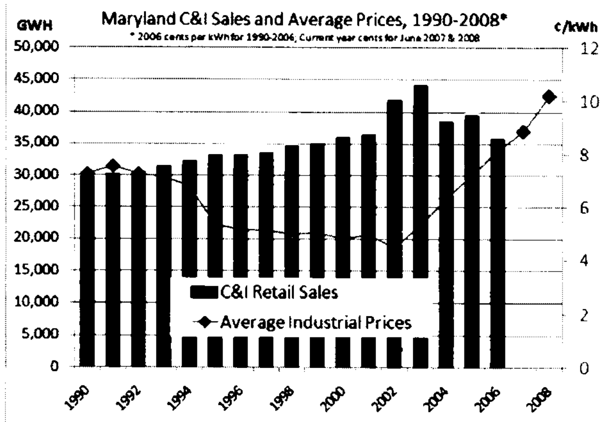
Rate caps were scheduled to expire, but the anticipated price increases resulted in numerous alternative rate mitigation proposals. For example, in anticipation of 72% rate increases in the Baltimore Gas and Electric (BGE) service territory, the legislature considered bills in 2005 and 2006 to limit the immediate increase to 5% to 25%, with future recovery of deferred costs through a new transition charge. In Case No. 9056, the Maryland Public Service Commission determined that everyone other than the smallest commercial customers would be moved to quarterly bidding and quarterly pricing. In Case No. 9064, residential customers were changed from to a two-year bidding framework, with one-fourth of the load bid every six months. In the BGE service territory, a Rate Stabilization Charge will collect a set amount over the next 10 years.

Maryland is pursuing climate change and energy efficiency issues. A significant portion of the revenues derived from a carbon auction in 2008 will be dedicated to energy efficiency activities and will be administered by the Maryland Energy Administration. Although advanced metering has not penetrated mass markets in Maryland, demand response remains important with approximately 1,000 MW of direct load control programs using smart switches, smart thermostats and radio frequency signals in PJM. State officials continue to work on reliability and resource adequacy issues, including the need for power plant construction in the state.

Residential customer switching in Maryland is 2.9 %, with a range from 0.0% to 5.8 % in the four distribution utility service areas.

Maryland Percent Switching September 2008	Percent of Residential Customers	Percent of Commercial and Industrial Load (MW)	Percent of Total Load (MW)
Allegheny Power	0.0%	63.1%	29.5%
Baltimore Gas and Electric	2.6%	72.1%	38.5%
Delmarva Power & Light	0.8%	63.5%	30.7%
Potomac Electric Power	5.9%	73.8%	42.6%
State Total	3.0%	71.1%	38.1%





Massachusetts

In November 1997, the state legislature enacted HB 5117 to restructure the electric power industry, granting rate cuts of 10% at first, and another 5% after 18 months, with full recovery of stranded costs over a 10-year transition period. In March 1998, the Massachusetts Department of Telecommunications & Energy (now known as the Department of Public Utilities) issued final decisions and regulations to open the electricity market to retail competition. The law included a provision for a systems benefits charge, and Massachusetts has adopted advanced plans for energy efficiency and renewable energy.

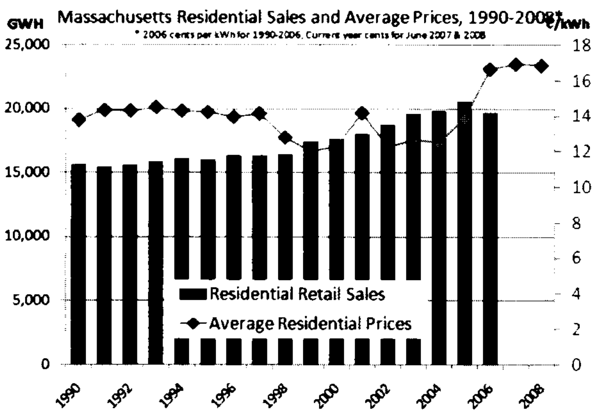
Generation service became competitive, but transmission, distribution and customer services remained regulated monopoly services. Standard offer service was created as a transitional service for existing electricity customers. The standard offer set at 2.8 cents with a trajectory to rise to 5.2 cents per kWh in 2005 (projected to be above market in 2005). These were administratively determined numbers (not market based) and included fuel triggers to increase if necessary.

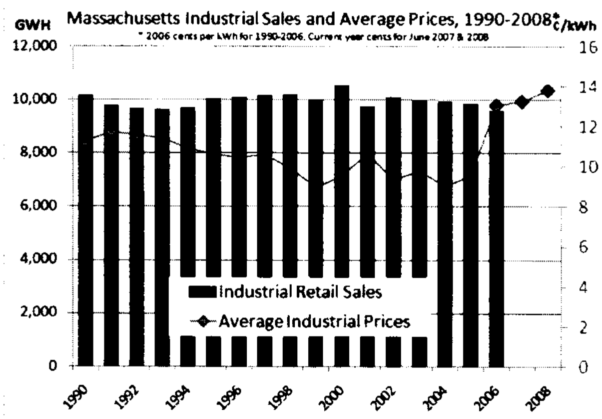
When markets opened, the 2.8 cents per kWh standard offer service rate was too low for competitors, stifling competition until the standard offer service rate was scheduled to rise in 1999. Utilities divested themselves of generation and natural gas plants were constructed. In 2000, standard offer rates were increased in response to market price increases.

In 2005, standard offer service expired. These customers were transferred to default service which had been designed for customers who were new to the system but not selected a competitive service provider. (In Massachusetts, "standard offer" and "default service" have distinct meanings.) Default service for smaller customers relies on twice a year procurement of 50% of the load for one-year terms. Default service for larger customers is procured four times a year, 100% of load at a time.

Aggregation is active on Cape Cod (eastern MA) with the Cape Light Compact serving a significant number of customers. Cape Light accounts for approximately one-half of the residential customer switching in Massachusetts. Customers who do not wish to participate can opt out of the aggregation program.

Massachusetts Percent Switching May 2008	Percent of Residential Customers	Percent of Small C&I Load (MW)	Percent of Medium C&I Load (MW)	Percent of Large C&I Load (MW)	Percent of Total Load (MW)
State Total	11.2%	33.9%	49.8%	87.3%	52.8%





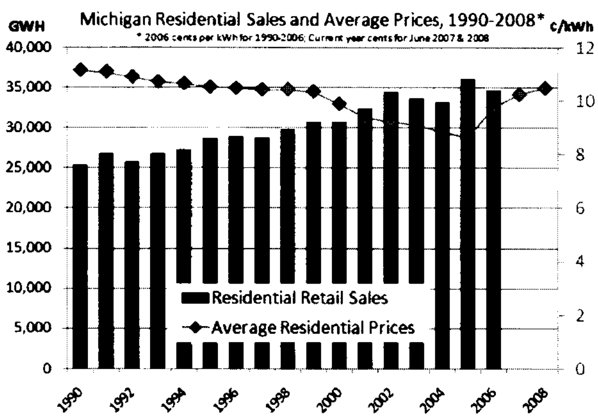
Michigan

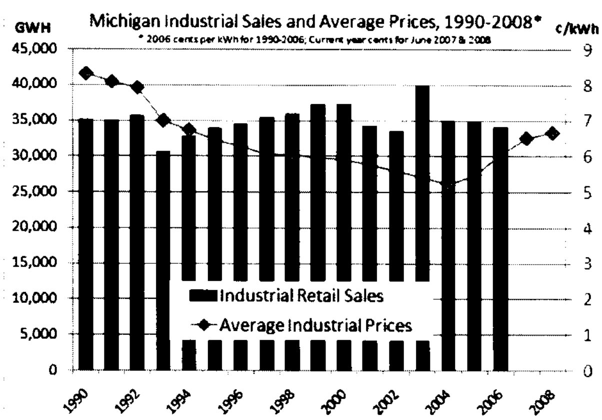
The Michigan Public Service Commission (MPSC) initially ordered retail choice pilot programs in 1998 and 1999. Michigan's Customer Choice and Electricity Reliability Act (2000 PA 141), enacted June 2000, introduced competition into the electric industry by offering Michigan customers the opportunity to choose to purchase their electric generation services from an alternative electric supplier (AES). While access for a few large customers began in 1999, all large customers (loads of greater than 1 MW) of Detroit Edison, Consumers Energy, and the electric cooperatives obtained retail access in January 2001. In December 2001, the MPSC issued nine orders to advance Michigan's competitive electric environment. Among the decisions: Detroit Edison and Consumers Energy could not change their depreciation accrual rates and practices until January 2006; rules would be drafted for service quality and reliability standards for electric distribution systems; standards were adopted for the disclosure of customer information, fuel mix and environmental characteristics; and net stranded costs for utilities were determined. Rate cuts were mandated for some default service tariffs.

Michigan is first state to have independent transmission company ownership of virtually all its high-voltage transmission facilities. Trans-Elect owns Consumers Energy's 5,400 miles of transmission, and Kohlberg Kravis Roberts and Trimaran Capital Partners own DTE Energy's (Detroit Edison) 3,000 miles of transmission.

On October 6, 2008, Governor Granholm signed a pair of bills. HB 5524 amends the Customer Choice and Electricity Reliability Act, and SB 231 addresses energy planning and renewable energy. HB 5524 was introduced in December 2007 and requires customers to declare within 90 days whether they would continue to receive power from an alternative electric supplier. Upon selection of this option, customers would be required to give notice to return to regulated service, and would pay the higher of average rates or market prices at the time of return for one year. Other customers would receive on standard tariff service. New customer would not be eligible for choice and would receive standard tariff service. The proposed legislation would also limit the market share of non-incumbent suppliers to 10% of sales.

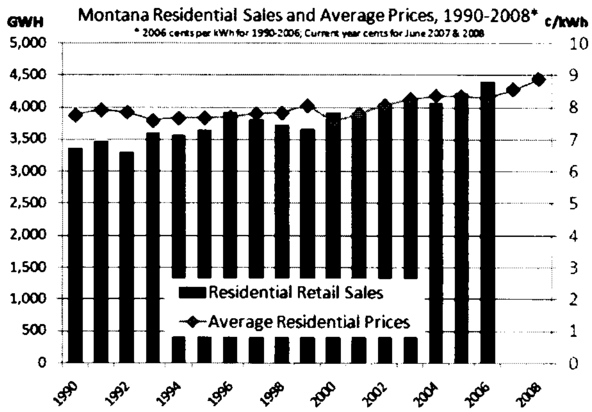
Michigan Percent Switching November 2007	Percent of Residential Customers	Percent of Commercial Load	Percent of Industrial Load
Consumers Energy	0%	3.9%	7.8%
Detroit Edison	0%	8.6%	5.1%
State Total	0%	6.8%	6.3%

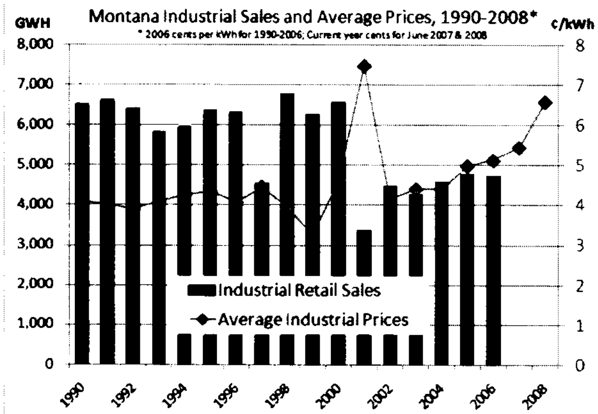




Montana

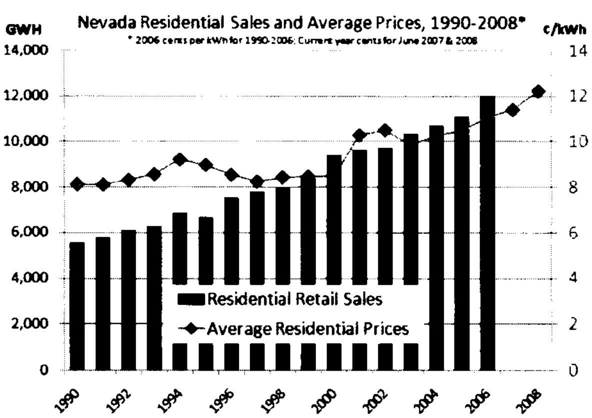
In May 1997, Montana enacted SB 390 that gave larger consumers the ability to choose their power supplier in 1998. Under the Act, electricity suppliers must file an application and obtain a license from the Montana Public Service Commission (MPSC) before offering electricity for sale to retail customers. The PSC decided in 2000 to delay full customer choice until 2004. Montana's investor-owned utility voluntarily divested its generation in December, 1999, and acquired default supply through competitive bidding. Legislation in 1999 (SB 406) allowed residential and small business customers to combine their buying power by forming a cooperative. The law exempts electricity suppliers from laws that prohibit cooperatives from expanding into cities of more than 3,500 persons. A standard information facts label is required for sales to residential and small commercial customers. The MPSC web site provides consumer protection information. Additional legislation in 2001 (HB 474) altered the existing legislation and extended the transition period to July 2007. Rates were increased and the PSC was criticized for not exerting enough control over the market participants. Every two years, Northwestern Energy must submit a plan detailing how it will secure electricity. The utility remains the default service provider and the MPSC conducts proceedings to consider the utility's Electricity Supply Procurement Plan.

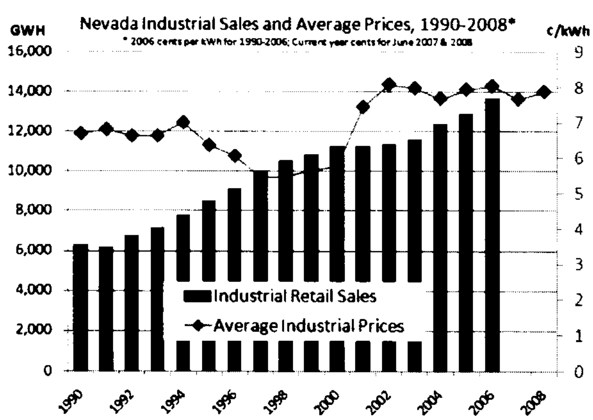




Nevada

In July 1997, Assembly Bill 366 was enacted adopting retail access. Larger customers became eligible in 2000. A settlement from a challenge by the Nevada utilities to the state's electric restructuring statue resulted in an agreement that the companies would not seek stranded cost recovery. In October 2000, the governor delayed implementation of the choice plan for residential customers until September 2001. In March 2001, the governor issued the Nevada Energy Protection Plan, a strategy to provide energy reliability, consumer protection, and long-term rate stability. In April 2001, AB 369 rejected retail access for small customers, returned utilities to regulation, and barred the sale of power plants before July 2003. Electric utility deregulation was halted because of high demand, low supply, and unstable prices.

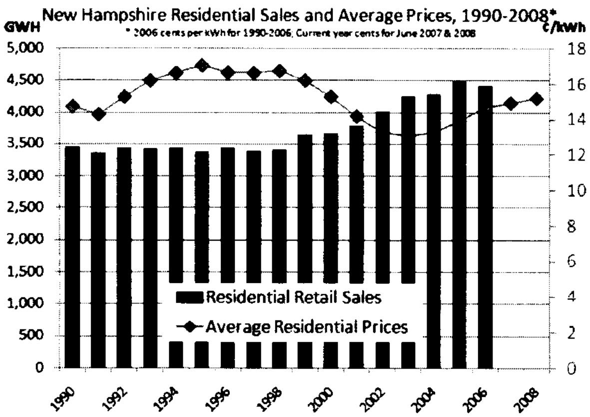


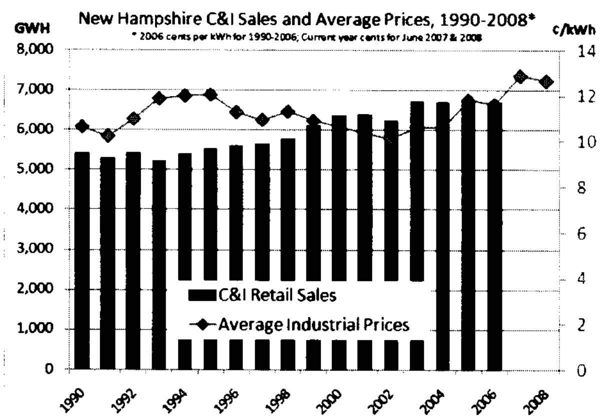


New Hampshire

In May 1996, legislation (HB 1392) was enacted for retail choice: statute RSA 374-F. In July 1998, Granite State Electric opened its retail load to competition. Litigation in state and federal courts tied up implementation for Public Service New Hampshire (PSNH). Additional legislation (SB 472) passed in May 2000 breaking the deadlock with PSNH. PSNH did not implement customer choice until May 2001.

Legislation mandated rate reductions and divestiture of generation. The other three electric distribution utilities restructured in between 1998 and 2002. Competitive suppliers are welcome to provide service in restructured areas, but most residential customers receive Transition (default) Service. The focus in recent years in New Hampshire has been on the development of comprehensive energy efficiency programs and the effective use of a system benefits charge of 3 mills per kilowatt-hour.





New Jersey

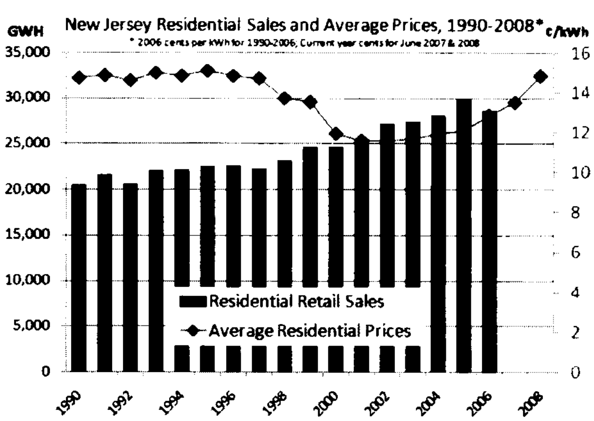
In February 1999, New Jersey adopted the Electric Discount and Energy Competition Act (EDECA) (AB 10/SB 5) which authorized the New Jersey Board of Public Utilities (NJBPU) to permit competition in the electric and gas marketplace, allowed electric utilities to divest themselves of electric generation assets, allowed securitization of stranded cost recovery that could be collected through a non-bypassable wires charge, provided an immediate rate reduction of 5% (10% by year four) and established a social benefits charge for the collection of monies for demand-side management programs. Utilities were allowed to use deferred accounting for expenses that were not collected under the rate cap. All customers in New Jersey can purchase their electricity from a third party supplier rather than the local utility company. Shopping credits, the rates against which outside suppliers must compete, were set at about 5 to 6 cents per kWh, depending on the rate class and utility.

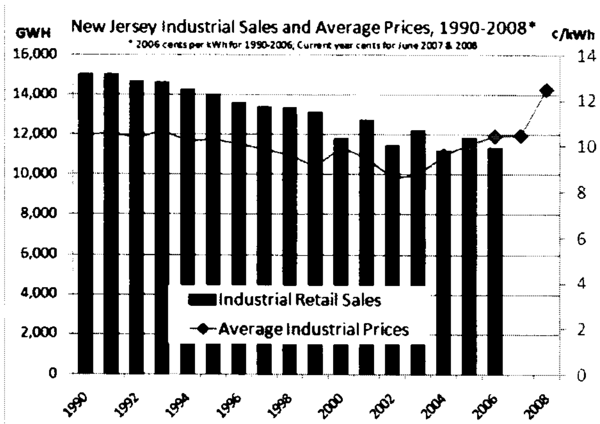
In December 2000, the NJ Supreme Court upheld a decision upholding the NJBPU restructuring and securitization orders for PSE&G. By 2002, the difference between the market cost of electricity and the mandated rates, known as "deferred balances," had grown to approximately $1 billion, largely because competition in New Jersey had not occurred as anticipated. A task force on deferred balances was convened by the governor.

Under EDECA, there was a requirement for a provider of last resource for basic generation service (BGS). BGS has been provided by the electric utilities since 2002-03. In February 2006, rate increases of 12% to 13.7% were announced as a result of the 2006 auction for BGS. The 2008 auction covers hourly-priced service for Commercial and Industrial Energy Pricing (CIEP) Customers for one year beginning June 1, 2008. The fixed price customer auction for is for a supply period of three years, with one-third of each utility's total load requirements acquired each year. The winning fixed price contracts averaged 11.15 to 12.05 cents per kWh. These supplies replace the 2005 contracts and will result in residential customer price increases of 11.5% to 17.3% in the various service areas.

The social benefits charge includes incentives for energy efficiency programs and renewable resource programs. The state adopted a renewable portfolio standard that includes a solar set aside (2.12% solar capacity by 2020). New Jersey has almost 55 MW of solar capacity and uses Solar Renewable Energy Certificate (SREC) trading to help finance solar projects. In 2007, New Jersey adopted the Global Warming Response Act (A3301) which set greenhouse gas emissions targets. The state has programs implemented by investor-owned utilities that are transitioning to third-party program management.

New Jersey Percent Switching March 2008*	Percent of Residential Customers	Percent of Nonresidential Load (MW)	Percent of Commercial and Industrial Energy Pricing (CIEP) Customer Load (MW)
Atlantic City Electric Company	0%	12.6%	99.8%
Jersey Central Power & Light (JCP&L)	0%	10.0%	83.6%
Public Service Electric and Gas Company (PSE&G)	0%	15.3%	80.4%
Rockland Electric Company	0%	6.6%	66.2%
State Total	0%	13.0%	82.8%
* Most recent nonresidential data reported is for June to September 2007.			





New York

The New York Public Service Commission (not the state legislature) ordered restructuring of the electric utilities in May 1996. The NYPSC implemented a plan for restructuring by approving utility plans in 1997 and 1998. The entire market is now open. Residential consumers can elect to receive service through the regulated tariff of the local electric distribution company, or through an aggregation program, or directly from a competitive retailer known in New York as energy service company (ESCO). Switching rates appear in the table below. Although New York does not use the term "default service," a majority of residential consumers receive electric service through the regulated tariff of the local electric distribution utility.

The NYPSC played a key role in the development of national uniform business practices. The NYPSC approved standards governing the electronic exchange of routine business information and data among electricity and natural gas service providers in New York in June 2001. The NYPSC also issued an order to establish uniform retail access billing and payment processing practices that facilitates a single bill option for customers.

In 2002, New York made important progress in enhancing retail competition in the areas of customer protection, information disclosure, and demand responsiveness. Under a 2002 law, the customers of ESCO receive the same protections as those of the utilities. The ESCOs lobbied for these provisions because they now have a greater chance of getting payment from customers, and customers have equal protection from all ESCOs and utilities. Electricity consumers now receive information in electric bills about the types of generating fuels and related air emissions. These steps encourage green power offerings in New York. ESCOs are participating in demand response programs. Electricity use curtailment competes directly with generation during periods of high electricity consumption.

Competitive electric metering and electric meter data services are permitted in New York for certain customers. New York is considering the deployment of an advanced metering infrastructure to realize the State's energy policy goals for time-differentiated pricing and energy efficiency.

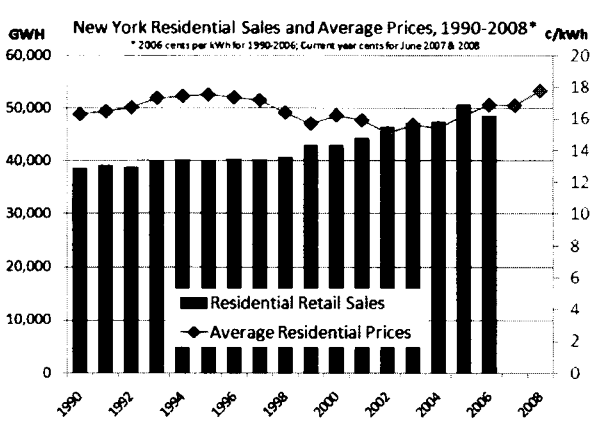
In May 2007, the NYPSC initiated a proceeding (Case 07-M-0548) to investigate an Energy Efficiency Portfolio Standard (similar to a renewable resources portfolio standard) to advance the Governor's goal of 15% reduction in electricity use by 2015. The existing systems benefit charge is used, in part, to fund energy efficiency incentive programs administered by the New York State Energy Research and Development Administration (NYSERDA). The NYPSC will determine how additional energy efficiency activities will be administered in the future.

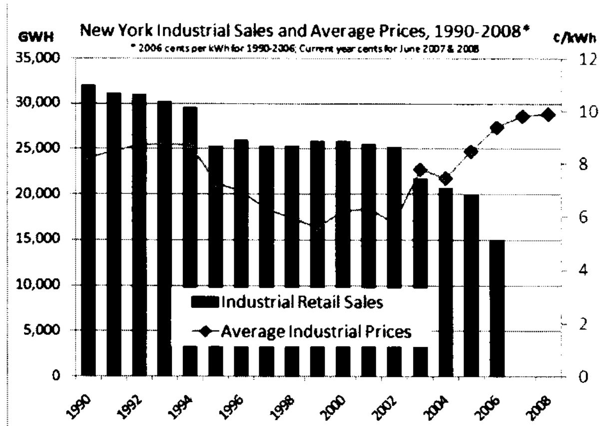
The New York PSC is fine tuning its market rules and is considering a requirement for a consumer disclosure statement, timelier dispute resolution and training of retailer representatives.

New York Percent Switching August 2008	Percent of Residential Customers	Percent of Small Nonresidential Load (MWH)	Percent of Large Nonresidential Load (MWH)	Percent of Total Load (MWH)
Central Hudson	3.9%	23.3%	85.5%	31.5%
Consolidated Edison	17.2%	46.9%	90.4%	44.8%
National Grid (Niagara Mohawk)	13.1%	61.7%	71.8%	46.3%

New York State Electric & Gas	14.4%	51.9%	59.9%	41.7%
Orange & Rockland Utilities	27.9%	49.8%	28.7%	36.5%
Rochester Gas & Electric	18.8%	62.7%	73.5%	53.0%
State Total	15.6%	51.0%	74.8%	44.3%

Does not include Long Island Power Authority and municipalities that purchase from the New York Power Authority.





Ohio

Legislation (SB 3) was enacted in July 1999 to allow retail customers to choose energy suppliers as of January 2001. The goal was to achieve retail competition with respect to the generation component of electric service. The law required a 5% residential rate reductions and a rate freeze for 5 years to allow a transition to competitive markets. The legislation contained consumer protections, environmental provisions, and labor protections; empowered the Ohio Public Utility Commission (PUCO) to determine the amount and recovery period for stranded costs; required that property taxes utilities paid would be replaced with an excise tax on consumer bills; and required that utilities to spend $30 million over six years on consumer education programs. Utility plans were approved in 2000 and choice began January 2001.

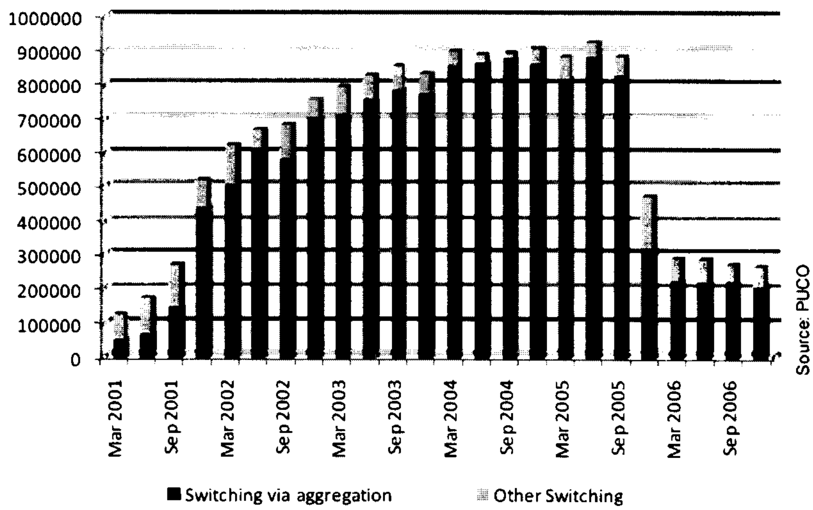
Ohio's law allowed communities to aggregate and strengthen their bargaining power in establishing electricity prices. Under aggregation, residents received a postcard in the mail notifying them of their new electricity choice, and those who choose to "opt out" and continue buying power from their current supplier had 21 days to act. Ohio was a model for aggregation with over 800,000 consumers receiving power in that manner in 2004-5.

During the five year "market development period," First Energy utilities offered relatively economical power (market support generation) that helped to encourage market entry by competitive suppliers. As the end of the five-year transition approached, the PUCO was concerned that the market had not developed sufficiently to quickly move to market based rates. PUCO adopted "rate stabilization plans" of three to five years duration for each utility, which went into effect in 2006. The "shopping credits" were inadequate to encourage sustained retail competition.

In April 2008, Ohio modified its restructuring law to address Governor Strickland's plan to protect retail electricity consumers from "rate shock" due to market forces. SB 221 requires electric distribution utilities to provide consumers with a standard service offer (SSO) that either relies on an "electric security plan" (ESP; a proposed standard service offer), or an SSO based on a "market rate offer" (MRO) that is determined through competitive bidding. Both approaches may be in effect during a transition period using a blended rate. If the utility elects the "electric security plan," then the utility may construct and place the investment costs of a power plant into rate base. Such generating units must forever remain under the "electric security plan" option; that is, in service to Ohioans under the SSO. If however the utility elects the "market rate offer" approach, then the market rate offer will be phased in over a period of years until it comprises 100% of the SSO. In the intervening years, "electric security plan" rates will make up a decreasing proportion of the blended SSO. The "market rate offer" approach is irrevocable – the utility cannot later elect to build power plants. Further, the competitive bidding process is subject to PUCO oversight and approval of the least cost bidder. The utility may recovery prudently incurred costs of fuel, purchased power, costs for energy and capacity, and purchases from affiliates.

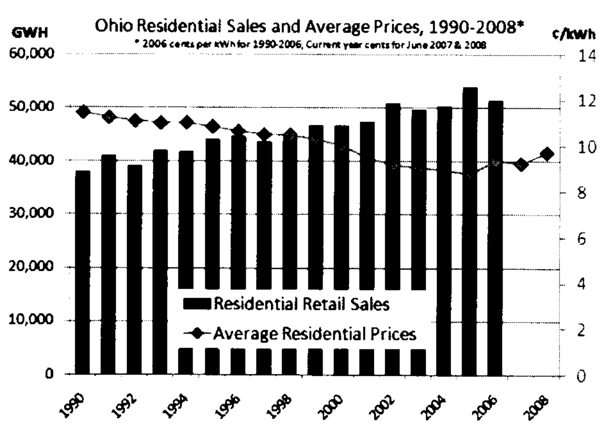
Retail choice is preserved under SB221 with specified safeguards, such as prohibiting the inclusion of generation costs in unbundled distribution rates. (Section 4928.02(H) of the law state, "[It is the policy of this state to] Ensure effective competition in the provision of retail electric service by avoiding anticompetitive subsidies flowing from a noncompetitive retail electric service to a competitive retail electric service or to a product or service other than retail electric service, and vice versa, including by prohibiting the recovery of any generation-related costs through distribution or transmission rates; ...") Section 4905.31 addresses "special arrangements" and allows large customers (over 700,000 kWh per year or part of a national chain) to file with the PUCO a request for a preferential deal outside any tariff. This provides large customers with leverage that they did not have before. Special arrangements can also be made between utilities, to allow a joint program or purchase, so long as the PUCO approves it.

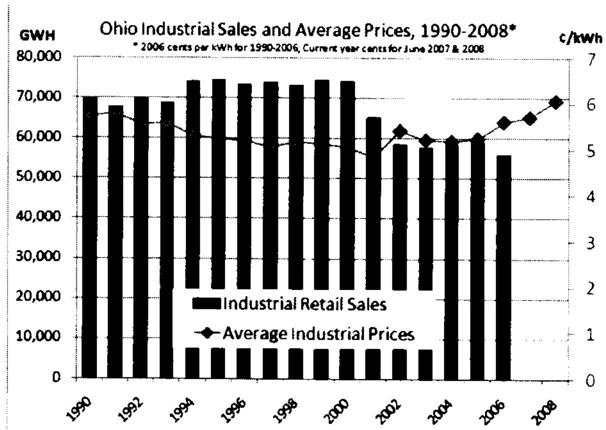
Figure 3: Number of Residential Customer Switches in Ohio 2001 - 2006



Source: Ohio PUC, "Ohio Retail Electric Choice Programs Report of Market Activity, July 2005 – December 2006," 2007.

Ohio Percent Switching June 2008	Percent of Residential Customers	Percent of Commercial Sales (MWH)	Percent of Industrial Sales (MWH)	Percent of Total Sales (MWH)
Cleveland Electric Illuminating Company	8.4%	16.9%	11.2%	12.1%
Duke Energy Ohio	1.7%	9.0%	0.3%	3.5%
Columbus Southern Power Company	0%	1.7%	0%	0.7%
Dayton Power and Light Company	0%	11.4%	58.6%	23.4%
Ohio Edison Company	17.1%	23.4%	15.7%	18.0%
Ohio Power Company	0%	0%	0%	0%
Toledo Edison Company	10.9%	33.8%	1.8%	12.7%
State Total	6.1%	13.0%	9.9%	9.8%





Oregon

In late 1997 Portland General Electric proposed a pilot project to allow customers to select a generation supplier. A few months later, PacifiCorp proposed a pilot that would allow customers to select from a portfolio of pricing and resource options. These pilots set the stage for SB 1149, the restructuring bill, enacted in July 1999. SB 1149 offered energy supplier choice to nonresidential customers by October 2001. Residential customers would be offered a portfolio of options including green power. In August 2001, two new bills amended the restructuring law (delaying the implementation date to March 2002 for nonresidential customers) and gave the Oregon PUC new powers to balance the interests of utility shareholder with electric customers. (NOTE ADD REF TO 3% systems benefit charge)

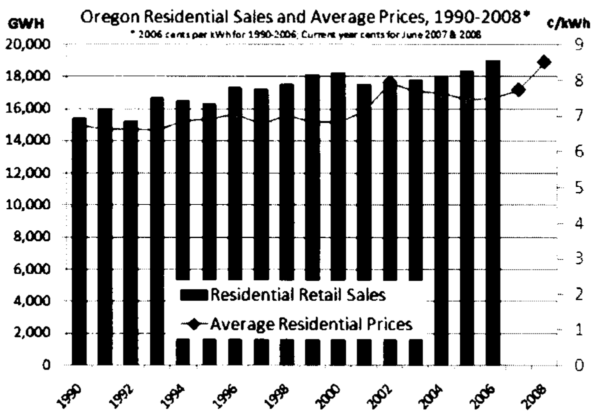
Under the portfolio approach, residential customers can choose among renewable energy pricing plans that rely on existing geothermal and wind sources, or contribute to salmon habitat restoration, or purchase new wind resources. As of April 2008, approximately 7.9% of residential customers in Oregon were served through one of these options (106,366 of these options have been selected, with some double counting as one customer selects more than one option).

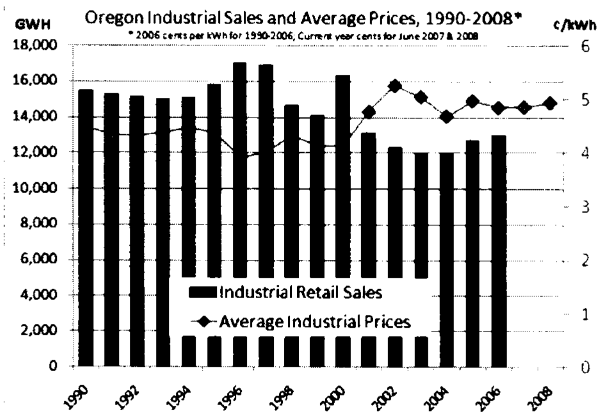
The Oregon PUC has conducted rate cases for both major utilities to resolve default service and stranded cost issues, and put in place programs for codes of conduct. At first, the transition charge was variable, and large customers were required to commit to not return to standard offer service for five years. There were also limitations with respect to when switching could occur. As a result, no switching occurred at first. By late 2002, the transition charge had been stabilized. As of April 2008, 12% of nonresidential load had switched to competitive suppliers. Direct access-eligible (nonresidential) customers may choose service from an alternative electric service supplier for 1, 3, 4, in some cases a 5 year period.

Oregon is engaged in a consideration of climate change issues. Under a proposed rule, utilities would be required to handle CO_2 risk by examining values that range from zero dollars to $40 per ton.

Oregon Percent Switching October 2008	Percent of Residential Customers	Percent of Nonresidential Load

Portland General Electric	0%	20.1%
PP&L (PacifiCorp)	0%	0.7%
State Total	0%	12.0%





Pennsylvania

The Electricity Generation Customer Choice and Competition Act (HB 1509) was enacted in December 1996. A pilot phase began in late 1997, and then a phase-in allowed one-third of consumers to join each year. Different utilities received different treatment with respect to initial rate decreases and the size of stranded cost recovery and competitive transition charge. A shopping credit was advertised to allow customers to compare competitive rates with the "price to compare" or "shopping credit."

After several years the Pennsylvania Public Utility Commission (PUC) approved a change in default service rates because some consumers were "gaming the system" by returning to the utility rate for the summer when competitive prices typically rose, making default service rates more attractive. Under the revised system utilities were able to impose switching restrictions and exit fees (a market based penalty called the "generation rate adjustment").

Competitive Default Service was authorized for 2001 for PECO Energy customers and allowed customers to be assigned to a new supplier, New Power Company. PECO retained the customers after this non-utility provider left the state. Several other utilities had similar experiences with price caps in place. In March 2002, Duquesne Light became the first Pennsylvania utility to send bills without a competitive transition charge. Duquesne was no longer subject to the rate cap. Shopping credits rise as the CTC decreases, and thus customers have a greater opportunity to find suppliers who can sell below the default service price.

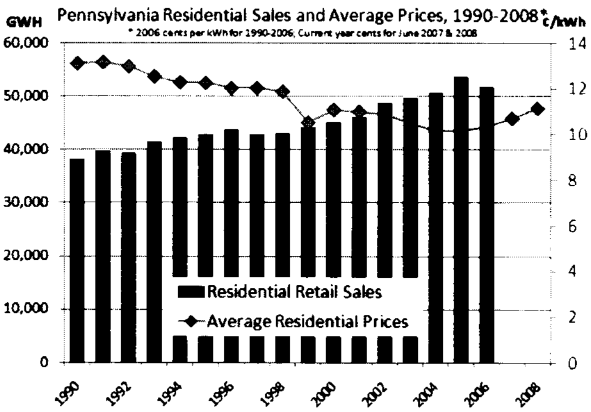
Most residential customers are protected by rate caps through 2010. Utilities and the PUC are getting ready for that day. The Pennsylvania Office of the Consumer Advocate stated in a February 1, 2007 press release that, "we not wait until 2010 and then roll the dice in a single wholesale market auction ... It is also essential that customers not have to rely solely on volatile short term and spot market prices ... we should be taking steps as soon as possible to secure stable, reliable, and least cost resources, including new renewable energy resources as well as conservation and energy efficiency, to meet consumers' future needs."

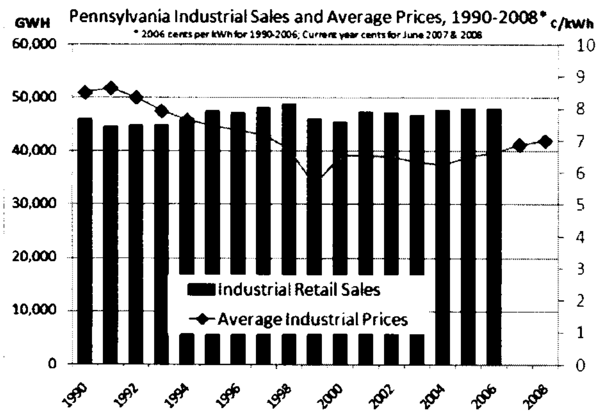
Under a new plan, Penn Power is purchasing one and two year power contracts for default service that will be effective through 2011. Penn Power's rate caps ended in 2006. The PUC is holding hearings on PPL Electric's Rate Stabilization Plan and the PPL Electric rate cap will come off in January 2010. Residential customer switching is very low in five of seven utility service areas. Switching in Duquesne Light exceeds 22% and nearly 10% of Penn Power residential customers have switched because prices are no longer capped. The average switching rate for residential customers is 2.8%.

Load serving entities are required to satisfy the state's Alternative Energy Portfolio Standard which will rise to 18% of load over time. While the state as a whole is not using advanced metering, the PPL Electric service area has 100% penetration of AMI which could support competitive offers in the future. Pennsylvania is not currently part of a climate change initiative, however, the governor is planning to address energy efficiency and the environment in the near future, and energy efficiency and demand response are addressed in pending legislation. Pennsylvania has recently committed $5 million dollars for consumer education, including education relating to retail choice and conservation of energy.

New legislative initiatives require utility service providers to buy power through a mix of short- and long-term contracts. The PUC will have oversight to ensure that there is no market manipulation. There is a new focus on renewable energy industries and programs to conserve and use power more efficiently.

Pennsylvania Percent Switching in Utility Distribution Regions July 2008	Percent of Residential Customers	Percent of Commercial Load (MW)	Percent of Industrial Load (MW)	Percent of Total Load (MW)
Allegheny Power (central & west)	0%	0%	0%	0%
Duquesne Light (Pittsburgh/west)	22.0%	50.3%	88.5%	48.8%
MetEd/Penelec (formerly GPU)	0%	0%	3.9%	1.0%
PECO Energy (Philadelphia/southeast)	0.2%	7.4%	0.1%	2.2%
Penn Power (west)	8.4%	44.9%	97.4%	53.6%
PPL Electric (central & east)	0%	0.1%	0.1%	0.1%
UGI (Scranton/Wilkes Barre)	0%	0%	0%	0%
State Total	2.8%	--	--	--

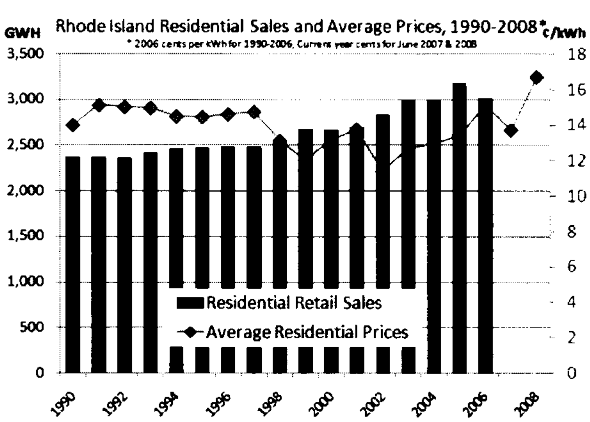


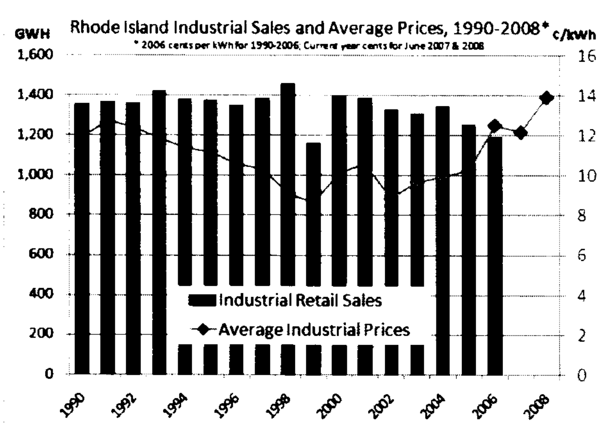


Rhode Island

In August 1996, legislation (HB 8124) passed, and Rhode Island became the first state to begin phase-in of statewide retail wheeling in July 1997 for industrial customers. Residential consumers were guaranteed retail access by July 1998. Very few customers switched because of the low standard offer service rate. SB 881, enacted May 2001, enabled non-residential customers enrolled in last resort service the option to return to standard offer service. These customers are required to sign a 2-year agreement prohibiting self-generation during non-emergency conditions and prohibiting remarketing of purchased electricity.

Rhode Island Percent Switching June 2008	Percent of All Customers	Percent of All Load
State Total	0.6%	15.3%





Texas

Texas developed a strong independent power industry in the 1980s. The implementation of PURPA under Texas law resulted in rapid cogeneration project development. The open-access transmission regime that began in 1996 is operated by the Electric Reliability Council of Texas (ERCOT), subject to the jurisdiction of the Public Utility Commission of Texas (PUCT). Legislation for retail choice was enacted in 1999 (SB 7), which set out to initiate competition with a pilot project in mid 2001, to be followed with a mandatory 6% rate cut and full customer choice implementation in January 2002. During 2001 pilot project enrollment, commercial and industrial classes exceeded the 5% participation limit, resulting in a lottery to determine which customers would be eligible. The pilot project started in the summer of 2001. Full retail choice began on January 1, 2002 for customers of investor-owned utilities within the ERCOT region of Texas. During the first eighteen months of competition there were some issues with customer switching and new service hookups, but these problems were quickly resolved.

Cooperatives and municipal utilities may decide whether and when to "opt in" to retail competition. Outside of ERCOT, but within Texas, the statute gives the PUCT authority to determine when retail choice can be implemented. The customers of El Paso Electric Company, Entergy Texas (southeast Texas), AEP's Southwest Electric Power Company (northeast Texas) and Xcel's Southwest Public Service Company (Panhandle region) do not yet have retail choice. These decisions are dependent on wholesale market development, and retail choice in northeast Texas has been delayed until 2011 or later.

In Texas, ERCOT operates the high-voltage transmission wires, manages congestion, ensures that ancillary services are adequate, provides a market platform for wholesale competition, performs settlement, administers retail customer switching and administers the renewable energy certificate program. Despite recent deployment delays, ERCOT's zonal congestion management system is expected to be replaced with a nodal pricing and congestion management system over the next couple years. This development is being watched closely, as high zonal congestion management costs in the first half of 2008 contributed to wholesale market volatility and retail market disruptions. In June 2008, ERCOT revised its protocols for zonal congestion management to provide some short-term relief, however the nodal system is expected to be a more efficient long-term solution.

SB 7 required each investor-owned utility to separate business functions. Affiliated companies can provide retail electric service to customers, own and operate generating units, and provide transmission and distribution service. The law also required electric distribution utilities (which remain regulated) to refrain from retail marketing or the provision of competitive services. Texas has achieved a high degree of structural separation that has reduced the incentives for corporate integration, and reduced the concerns of competitors that the incumbent utility holds unfair competitive advantage.

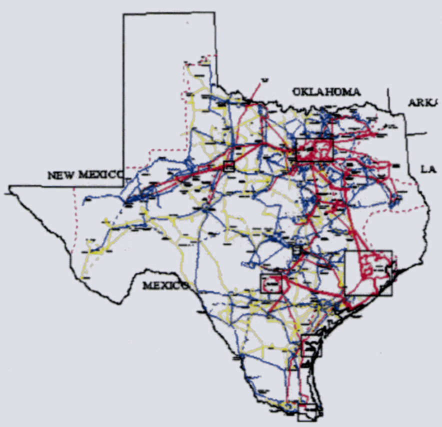
At the opening of the market, residential and small commercial customers could either remain a customer of the competitive retail electric provider (REP) affiliated with the incumbent utility, or switch to an alternative REP. Those who remained with the utility affiliate paid a regulated default service rate (this was called the "price-to-beat" or PTB) that could be adjusted up to twice a year. Default service was scheduled at the outset to last for only five years, and ended in December 2006. Provider of last resort (POLR) is a separate service for customers whose provider goes out of business. POLR service is the only remaining regulated electricity rate in the areas of Texas open for retail choice. POLR price is determined by a PUCT-approved formula based on short-term wholesale energy costs.

The success of Texas' renewable portfolio standard (RPS) and renewable energy certificate (REC) trading program has provided the impetus (along with a federal renewable energy tax credit) for rapid growth in wind turbine generation. Texas now leads the nation in wind turbine capacity (5,200 MW of new capacity as of May 2008) and wind energy production (2.9% of energy produced in ERCOT in 2007).

Another emerging issue related to wind power is transmission line capacity necessary to move wind energy from west Texas, where it is produced, toward the population centers in central and southeast Texas. Competitive Renewable Energy Zones (CREZ) with the greatest potential for wind energy development were identified in west Texas. The PUCT recently selected its preferred plan to designate and expedite the certification process to build over 18,000 MW of transmission capacity in these zones.

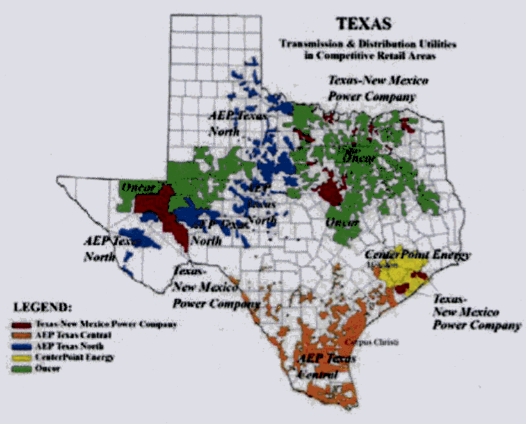
In 2005, six REPs defaulted, and in 2008, five more went out of business, forcing some customers to POLR service until they selected a new REP. Some of the failed REPs did not pay their energy bills to ERCOT, totaling more than $11 million in losses in the two years. The PUCT was concerned enough to open four new projects to consider market rule revisions. In Project No. 35767, Rulemaking Relating to Certification of Retail Electric Providers, a proposed rule was published in October to strengthen the certification requirements by raising the minimum financial requirements and by protecting customer deposits. In Project No. 35768, Rulemaking Relating to Retail Electric Providers Disclosures to Customers, the PUCT proposes to create four types of products (guaranteed fixed, limited fixed, variable and indexed), to require public disclose of contracts using these new terms, and to restrict certain changes in pricing based on the use of certain terms. The proposed rules are in the comment phase, to consider numerous issues, such as whether such rules should apply to larger customers or only to residential customers. In Project No. 35769, Rulemaking Relating to Electric Providers of Last Resort, the commission has published a proposed rule that will better protect customers and REPs that provide POLR service. Project No. 36131, Rulemaking Relating to Disconnection of Electric Service and Deferred Payment Plans, has no activity as of October 2008.

On issues relating to energy efficiency and advanced metering, the PUCT has several reports that will be considered by the Texas Legislature. Project No. 35770, PUC Report to the 81st Legislature on Advanced Metering will consider the deployment of advanced meter infrastructure (AMI). AMI deployment is going forward in the Oncor (Dallas-Fort Worth) and CenterPoint (Houston) transmission and distribution service provider areas. Other reports have been order by the Legislature on energy efficiency and combined heat and power.



ERCOT Major Transmission Lines

Source: ERCOT ISO Annual Report



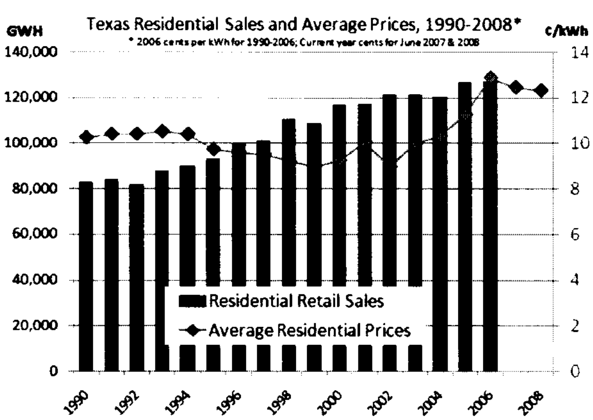
Texas T&D Utility Areas with Retail Choice

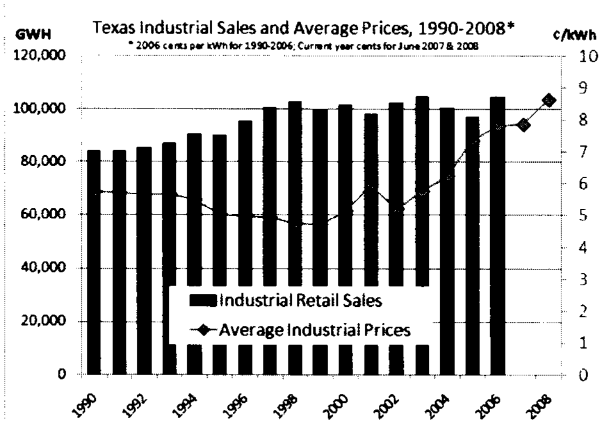
Source: Public Utility Commission of Texas

Texas Percent Switching* June 2008	Percent of Residential Customers	Percent of Small Commercial Load (MWH)	Percent of Large Industrial Load (MWH)	Percent of Total Load (MWH)
Oncor (Energy Future Holding Corp.)	39.8%	75.7%	**	59.8%
CenterPoint Energy	46.0%	61.1%	**	56.5%
AEP Texas Central	49.1%	90.1%	**	77.8%
AEP Texas North	57.5%	89.5%	**	81.6%
Texas-New Mexico Power Company	49.4%	78.0%	**	74.0%
State Total	43.9%	72.3%	68.3%	61.5%

* The regulated default service tariff (referred to as the "price to beat") is no longer offered. Therefore, essentially every retail customer receives service at a competitive price. These switching statistics show the percent of customers/loads no longer served by the affiliated (or incumbent) retail electricity provider.

** Large customer switching information is confidential because electric distribution utility service areas have a small number of very large customers.





Virginia

In July 1999, legislation (SB 1269) was enacted. Virginia's pilot program began in 2000 for the two largest investor-owned utilities (Dominion and American Electric Power) and one cooperative. Full retail access began a phased-in January 2002, with full choice to be implemented no later than January 2004.

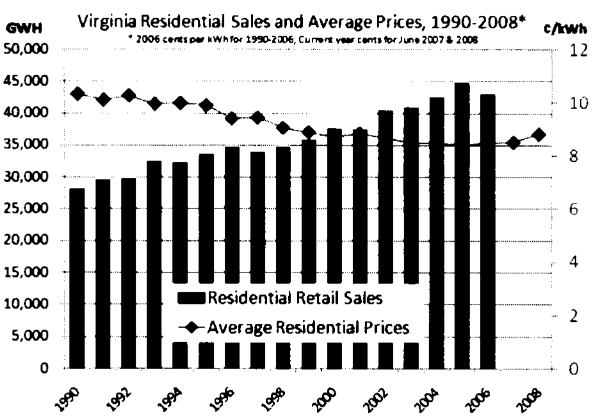
Utilities were required to functionally separate, and Allegheny Power and Connective voluntarily divested generation as part of the functional separation case.

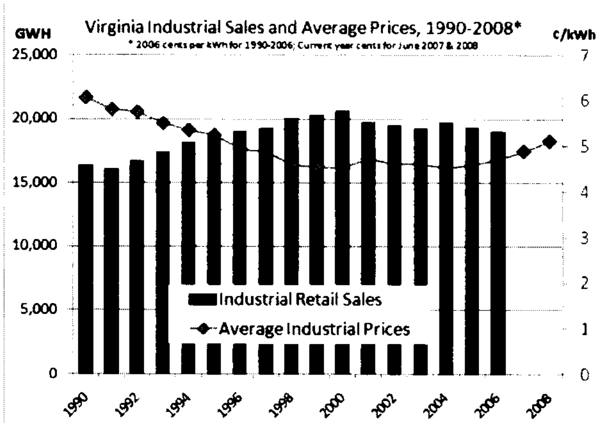
Competitive suppliers are licensed by the State Corporation Commission (SCC) and must register with each utility. In 2001, the Virginia General Assembly amended portions of restructuring legislation to cap default service rates only until January 2007. If there are capped rates, the utility is the default provider. After January 2007, the SCC would set rates based on competitive regional electricity markets. The Legislature created a Transition Task Force and Consumer Advisory Board, which worked collaboratively with SCC. The Legislation authorized alternative providers to direct bill customers beginning January 2003. Competitive metering began January 2002 for large commercial and industrial customers, and on January 2003 for residential and small commercial customers.

The practical result of low-capped rates has meant that there is no ability to choose a lower-cost alternative provider in Virginia. Only about 2500 residential and 24 small commercial customers were served by an alternative supplier (green power choice for residential customers). A contract was awarded for a statewide consumer education program. A survey indicated that awareness was raised, but given the slow development of actual competition, the budget for the second year was reduced. SCC has issued orders to address competitive metering, consolidated billing, minimum stay provisions, distributed generation, aggregation, and market price determination.

In early 2003, legislative activity included a bill to allow Kentucky Utilities to suspend retail choice in five counties in Virginia (HB 2637); a bill to allow the SCC to experiment with "opt in" options for municipalities (HB 2319); and a bill that defers a requirement to join an RTO to the utility with an adequate showing (HB 2453).

In 2007, HB 3068 and SB 1416 were enacted and signed by Governor Kaine, and Virginia suspended retail choice.

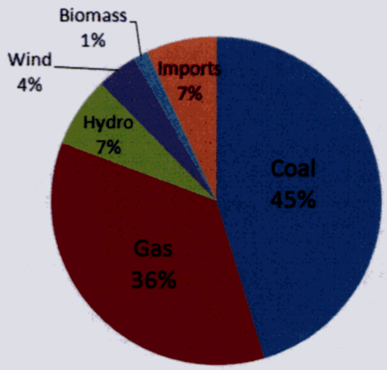




Alberta

In 1995, Alberta passed the Electric Utilities Act to initiate retail electric market restructuring in Canada. Wholesale competition began in 1996. Capacity reserves were very tight in 1998 as a result of rapid growth in electricity usage. Within the competitive market framework, over 2,000 MW of new capacity were added in 1998-2001, an additional 2,400 MW were constructed by the end of 2007. Presently there are over 12,000 MW of generating capacity in Alberta. Coal power plants generate more than one-half the electricity.

Energy-related industry is key to Alberta's economy, including oil, oil sands, natural gas, coal and minerals, and petrochemicals. Alberta serves electric demand with coal, natural gas (industrial cogeneration), hydropower, wind power and imports (transmission interconnections with British Columbia and Saskatchewan).



Customer Categories*	Number of Customers (2007)	2007 Customer Usage (GWH)
Residential	1,224,000	8,561
Farm	79,000	1,807
Commercial	145,000	13,132
Industrial	36,000	28,437
Total	1,485,000	51,927

* Note that the "commercial" and "industrial" categories reported here are not precisely the same as the "small commercial < 250 MWh/yr" and "large industrial > 250 MWh/yr" categories reported in the switching statistics below.

A 1999 pilot program gave large customers direct access to the power pool. Retail competition offered attractive options to large industrial and commercial customers enabling more than 80% of these customers to switch to competitive providers by 2008. Retail competition for customers of all sizes began on January 2001. Just prior to market opening, the wholesale market prices rose to very high levels, causing the regulators to institute a price cap – as a temporary shield against high prices – and a rate rider to collect any shortfall in revenue collection. By 2002, the wholesale prices had fallen to 1999 levels.

The Alberta Department of Energy embarked on a Retail Assessment Program to make mid-course corrections in the retail access program. The Electric Utilities Act was revised in 2003. A code of conduct addresses electric and natural gas service providers. Access to customer data is equal for competitive retailers and utility affiliates. A new independent system operator, the Alberta Electric System Operator (AESO), is responsible for market operations: power pool, system control, long-term transmission system planning and management and load settlement. In 2006, the Alberta Energy Utilities Board approved a standard tariff billing code for distribution utilities to ensure that retailers would receive information in a standard format. In 2007, the Legislature passed the Alberta Utilities Commission Act and divided the Energy Utilities Board into the two new regulatory bodies. The Alberta Utilities Commission continues to regulate utilities and a new conservation agency is focused on energy resource development.

The smaller customers, the energy portion of default service is calculated based on average monthly spot market prices plus short term hedging, encouraging risk-adverse customers to switch to competitive providers that guarantee a fixed price. Each year, 20% of customer needs are acquired and weighted with the four prior years' purchases. For users of greater than 250,000 kWh per year, default service is based on spot prices.

The AESO operates an energy only electricity market. In an energy only market design, the market determines the appropriate level of resource adequacy over the long term. The Electric Utilities Act mandates the collection and dissemination of information relating to the capacity of the interconnected electric system to meet future electricity needs. The AESO is conducting an investigation into long term resource adequacy to determine whether to create a bridging mechanism if adequacy becomes an issue. The AESO conducts two-year forecasts and has authority to take short term actions to maintain adequacy. As part of its review, the AESO is examining market conditions and incentives for investments in generation.

The province is very active with the development of advanced metering infrastructure (AMI). Electric distribution utilities are considering whether to install meters on their own without requesting reimbursement of the costs through rates.

In a March 27, 2008 letter, Alberta's Premier Stelmach outlined five priorities to the Cabinet Ministers, including "Ensure Alberta's energy resources are developed in an environmentally sustainable way." Development of the oil sands region should rely on "processes that use less energy, less water, reduce tailings ponds and improve land reclamation." Alberta is examining carbon capture and storage research and demonstration, and implementation of a climate change strategy, including "conservation, energy efficiency and adaptation initiatives."

Alberta Percent Switching March 2008	Percent of Customers	Percent of Sales
Residential	24%	NA
Farm	16%	NA
Small Commercial (< 250 MWh/yr)	45%	NA
Large Industrial (> 250 MWh/yr)	82%	NA
Province Total	NA	NA

Ontario

In 1998, legislation was enacted to provide authority for retail restructuring in Ontario. In April 1999, Ontario Hydro's assets were split into five successor entities. Ontario Power Generation, Inc. (OPG) assumed the generation business formerly operated by Ontario Hydro. Hydro One Inc. (formerly Ontario Hydro Services Company) assumed the network business and operated the transmission, distribution, and energy services businesses. The remaining three, operating on a not-for-profit basis, were the Electrical Safety Authority, the industry's safety inspection agency; the Independent Market Operator, responsible for operating and administering the new market and ensuring reliability and access to transmission and distribution systems; and the Ontario Electricity Financial Corporation, responsible for managing and retiring Ontario Hydro's outstanding debt and other obligations.

While future stranded costs were prohibited at that time, two types of payments on users were used to retire stranded costs incurred before restructuring: (1) a phased divestiture of the generation assets over a 10-year period to mitigate Ontario Power Generation's market power in Ontario, and (2) a per-kilowatt-hour charge (referred to as a Payment in Lieu of Taxes) on the monthly bills to all electricity users to retire the outstanding debt held by the Ontario Electricity Financial Corporation.

In May 2002, Ontario opening of its retail electricity market to all consumers. A high switching rate was attributed to the establishment of a formal Electronic Business Transactions (EBT) process, which included retail customer enrollment, testing, and scrubbing prior to market open. Ontario identified and corrected a large number of errors prior to full implementation. Ontario also initiated competitive billing and pass-through of default provider price risk, where majority of default providers sought exemption from a fixed reference price. In July 2002, the Energy Consumers' Bill of Rights came into effect creating new rules to protect low-volume consumers.

Record temperatures in summer of 2002 drove up the demand and market price. Concerns over these prices led to the passage in December 2002 of the Electricity Pricing Conservation and Supply Act 2002. This act mandated a fixed price of 4.3 cents per kWh for the electricity of low-volume consumers. Refunds were to be provided for amounts paid above 4.3 cents, retroactive to May 2002. Taxpayers were expected to make up the difference between market price and the capped rate.

In December 2004, the Government of Ontario passed the Electricity Restructuring Act of 2004, which reorganized the province's electricity sector, amended the Ontario Energy Board Act of 1998, and the Electricity Act of 1998. The act created a new Ontario Power Authority to ensure supply adequacy, created a new Conservation Bureau to set targets for conservation and renewable energy, redefined the role of the Independent Electricity Market Operator and renamed it the Independent Electricity System Operator (IESO), and regulated certain prices to ensure price stability.

The Regulated Price Plan (RPP) sets stable prices for small consumers with an inverted block schedule (use more, pay more) and a seasonal schedule that is undated every six months. In April 2008, the May 2008 – April 2009 prices were set. The prices are based on forecast hourly prices with an adjustment for the balancing account (unexpected variance) for past months. Customers with advanced meters are exposed to different prices than those with conventional meters.

Ontario has a Smart Metering Initiative to create a culture of conservation and a platform for demand management. Province-wide deployment of smart meters is underway through the Smart Metering System Implementation Program (SMSIP). A pilot time of use rate is available to residential customers. The local distribution utilities own the meters, and the IESO maintains the interfaces and the meter data management and data repository (MDM/R) functions.

Ontario Selected Electric Distribution Utilities*	Residential Customers December 2006	Residential Sales 2006 GWH
Enersource Hydro Mississauga Inc.	161,749	1,603
Horizon Utilities Corporation	209,370	1,655
Hydro One Brampton Networks Inc.	111,597	1,075
Hydro One Networks Inc.	1,055,204	12,229
Hydro Ottawa Limited	255,993	2,226
London Hydro Inc.	126,516	1,089
Toronto Hydro-Electric System Limited	599,080	5,352
Province Total	4,107,846	127,016 (all customer sales)
* Ontario has 86 Electric Distribution Utilities. Those shown have more than 100,000 Residential Customers.		

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APPENDIX D

EMBRACE ELECTRIC COMPETITION OR IT'S DÉJÀ VU ALL OVER AGAIN – THE NORTHBRIDGE STUDY

EMBRACE ELECTRIC COMPETITION
OR IT'S DÉJÀ VU ALL OVER AGAIN

By Frank Huntowski, Neil Fisher, and Aaron Patterson

The NorthBridge Group

October 2008

About The Authors

This study was prepared by members of The NorthBridge Group, Frank Huntowski (Director), Neil Fisher (Principal), and Aaron Patterson (Principal). The NorthBridge Group is an independent economic and strategic consulting firm serving the electric and natural gas industries, including regulated utilities and companies active in the competitive wholesale and retail markets. NorthBridge has a national practice and long-standing relationships with restructured utilities in Regional Transmission Organization ("RTO") markets, vertically-integrated utilities in non-RTO markets, and other market participants. Before and throughout the restructuring process of the U.S. electricity industry, the authors have assisted clients with wholesale market design, competitive market analysis and strategy, regulated power supply procurement, state regulatory initiatives and strategy, and mergers and acquisitions.

EMBRACE ELECTRIC COMPETITION
OR IT'S DÉJÀ VU ALL OVER AGAIN

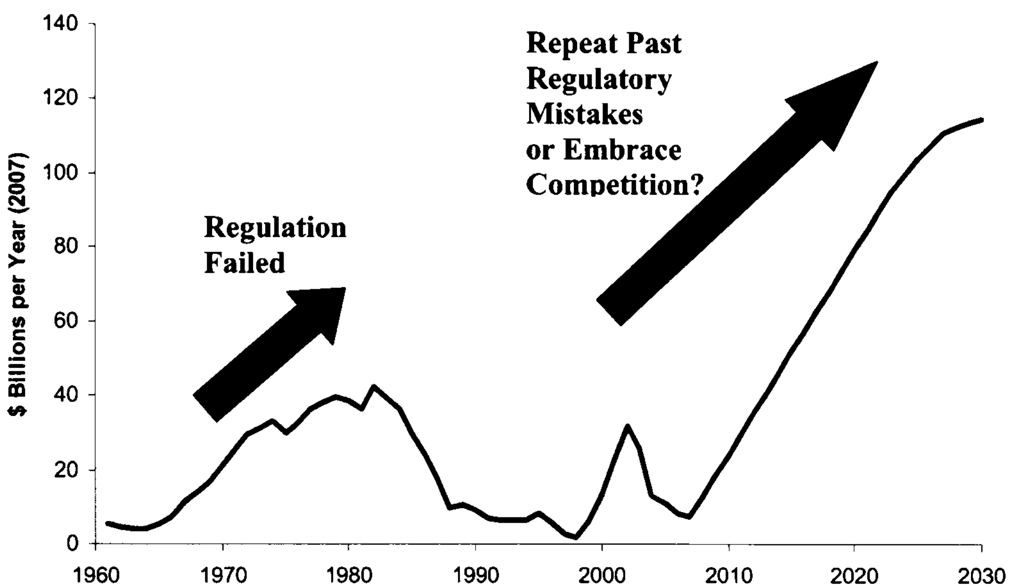
List of Figures

I. Executive Summary

Our nation strives for "reliable, affordable, and environmentally sound energy,"[1] but the electric industry must confront enormous challenges to meet this goal. Construction and fuel costs to generate electricity have increased dramatically, and proposed Greenhouse Gas ("GHG") legislation is expected to further boost costs. Over time, the combination of decreasing GHG emissions targets and the nation's current carbon-intensive generation fleet is likely to create the need for one of the most significant capital realignments in the industry's history (see Figure 1). At the same time, the electric industry is embroiled in a debate about the relative merits of competition, and many believe that we should return to the "good old days" of regulation.

But we should not forget that electric regulation has faced similar challenges in the more distant past...and it failed. The 1970s was a time of huge increases in fuel costs, substantial capital cost escalation, serious environmental concerns, and unanticipated changes in customer demand. Regulation tried to tackle these challenges with an administrative, command-and-control decision-making process, but the result was a massive overbuild of baseload capacity, skyrocketing rates, large shareholder disallowances, and huge cost overruns paid by customers. In the end, the regulated response to the events of the 1970s and 1980s likely amounted to a mistake on the order of $200 billion or more in today's dollars and resulted in excess supply and high rates that were felt for decades.[2]

Figure 1 Real Investment in Electric Generation, 1960-2030



Source: See Figure 8 and Figure 17.

[1] National Energy Policy Development Group, "Reliable, Affordable and Environmentally Sound Energy for America's Future," May 2001, viii.

[2] This value represents the aggregate costs borne by customers and other electric industry stakeholders due to the failure to abandon high-cost nuclear plants and above-market contracts entered into as a result of regulatory interventions. See footnote 15 for more discussions.

A careful examination of the U.S. electric industry's response to the external shocks and uncertainty during the 1970s reveals four inherent flaws of regulation:

- **Lack of clear price signals:** The "price signals" to both suppliers and consumers in a regulated framework were the result of internal forecasts of a regulated entity subject to political influence and negotiation with the regulator during the ratemaking process. Later, when market conditions turned out dramatically differently than forecast, the lack of clear price signals contributed to a slow regulatory response marked by a failure to curb the over-building of baseload nuclear and coal capacity as costs spiraled and the need for capacity evaporated. As a result, the total U.S. reserve margin peaked at 42 percent in 1982, more than twice the 15 to 20 percent level generally deemed necessary to maintain system reliability. In terms of capacity additions, from 1970 to 1988, utilities added an average of 15,000 MW of coal and nuclear capacity per year (plus 4,400 MW of other capacity), while peak load grew by an average of only 13,800 MW per year.

- **Perverse capital incentives:** Regulated utilities had a tendency to favor large capital investments and consider sunk costs when making investment and abandonment decisions. These tendencies were on full display during the 1970s and early 1980s as regulated utilities continued to develop coal and nuclear plants long after those plants were clearly uneconomic in forward-looking terms. By 1980, the construction costs of nuclear power plants were approximately two to six times greater than the value of their output. Therefore, nuclear plants in the early stages of construction should have been abandoned, but more than 40 of these plants were eventually completed, which unnecessarily cost consumers hundreds of billions of dollars.

- **Improper allocation of risks:** Regulation improperly allocated risk (including the risk associated with technological choices, excess supply problems, and cost overruns) to consumers rather than to investors. Not surprisingly, the regulatory process significantly underestimated these risks when making long-term resource commitments. There are many examples of customer-funded commitments that turned out to be uneconomic.

- **Tendency for regulatory "fixes" to overcompensate:** Political and regulatory reactions to fix perceived problems tended to overcompensate with unintended consequences which further increased costs and inefficiencies. The turmoil of the 1970s led to a dissatisfaction with the existing regulatory process, and a search began for new regulatory solutions and models to counter the rate shocks experienced by consumers. The resulting administratively mandated qualifying facilities program burdened electric utilities and their customers with a $50 billion overhang of mandatory long-term contracts established at prices well above their actual avoided cost or any reasonable proxy of market prices.

None of these flaws were responsible for the shocks that placed the initial stress on the industry: the oil price shocks, cost inflation, and falloff in demand growth. However, the industry's response to these external shocks was heavily influenced by the flaws inherent in a cost-of-service regulation regime, and ultimately led to higher costs for consumers and less efficient resource allocation than likely would have occurred in a competitive framework.

In part due to these problems, the industry turned toward competition in the late 1990s. However, nationally the industry restructuring process has been lengthier and more difficult than many anticipated. Numerous studies, articles, and reports that have criticized competition focus on the recent rate increases in competitive states. But, for a number of reasons, such historical rate comparisons have limited value, especially as we look toward the future. Rates in regulated states, as in restructured states, have increased significantly since the late 1990s, and most of the increase in rates in restructured states occurring in the past several years can be traced to the expiration of rate freezes and the rise in natural gas prices. Further, rate increases in gas-dependent restructured and regulated states track one another very closely, and the magnitude of rate increases in particular states is closely related to the state's fuel mix and the rise in price of particular fuels. For example, had natural gas prices remained at the $3/MMBTU level as in the late 1990s, the rates in restructured states would have risen since then by about four percentage points less than rates in regulated states.

In the next twenty years, the industry will have dramatically different investment needs than it has had in the last ten years, and the true test of competition is still yet to come. The decision to support regulation or competition should not depend on the effects of external shocks (such as the recent rise in natural gas prices)[3] or whether regulated average cost prices are below or above market-based marginal cost prices at any particular point in time, but instead on whether a competitive or regulated model will foster more efficient decisions and ultimately better price and reliability outcomes over a sustained period of time and varying market conditions.

In spite of the recent criticisms, the case for competition in the electric industry is still compelling, supported both by economic theory and examination of empirical evidence:

- **Market prices provide the right price signals:** In a competitive market, market prices are a function of marginal costs, whereas regulated rates have traditionally been determined using "average cost" pricing. Over long time cycles, marginal cost pricing produces a more efficient and ultimately lower-cost outcome relative to regulated average cost pricing because it provides the correct price signal for the efficient allocation of new and existing generation and demand response resources. The level of market prices seen today are appropriate in that they provide the correct price signal and incentive for investment in the different types of low carbon resources that will be needed in the future.

- **Competition promotes efficiency improvements in:**

    - **Existing plant operations:** Competitive markets provide strong incentives to improve plant performance and administration in the short-term. Empirical evidence suggests that restructuring has improved the efficiency of power plant dispatch, extended the benefits of pooling and coordination across broader markets, reduced plant operating costs, increased baseload capacity factors, and reduced plant heat rates. Since 1999, nuclear plants operated by competitive

[3] Historical rate comparisons between restructured and regulated states would appear much more favorable to competition if natural gas prices remained at their level in the late 1990s, instead of increasing dramatically in the 2000s. See Figure 21.

generators have had an average capacity factor that is about two percent higher than that of regulated plants, producing savings of about $350 million per year. Restructuring also contributed to the substantial reduction in the average refueling outage for nuclear plants from 104 days in 1990 to 40 days in 2007, and has increased the average capacity factor for coal plants transferred from regulated to competitive owners from 59 percent to 67 percent.

- **Plant investment and retirement:** One of the most significant areas of potential savings from restructuring is more efficient long-term investments. Thus far, the industry has experienced significant restructuring of generating plant ownership. The experience of the gas combined cycle build-out in the competitive market of the late 1990s and early 2000s was very different from that of the regulated nuclear and coal capacity additions of the 1970s and 1980s as private investors responded much more quickly to changing market conditions. In response to the changing economics of gas combined cycle turbine plants, competitive builders cancelled 78 percent of capacity planned or under construction with a planned in-service date of 2003 or later while regulated builders cancelled only 37 percent of capacity. Unlike in the 1970s and 1980s, these uneconomic investments did not adversely impact customers in non-regulated states since unregulated investors – not ratepayers – bore the risk of these investments.

- **Customer consumption:** The competitive market price of electricity also provides a valuable price signal to customers that may affect customers' time of electricity use, overall level of electricity use, fuel choice, and investment decisions. Actions have been taken in restructured markets to increase economic demand response and expand market pricing to retail customers. High market prices that reflect environmental costs or peak demand periods will encourage reductions in consumption that will both reduce costs and greenhouse gas emissions. Specifically, some conservative estimates suggest that a 10 percent increase in the average price of electricity will result in a one percent or more decrease in electricity demand, which could decrease CO_2 emissions by 30 million tons per year and eliminate the need for nearly 5 gigawatts of new generating capacity, saving at least $10 to $20 billion in capital investment.

- **Retail competition is still developing and provides additional benefits:** Retail competition has developed to the greatest extent in restructured states where the market design allows the default price to reflect market prices. In several states, the vast majority of large commercial and industrial customer load is served by competitive retail providers, and the overall amount of customer switched load in the United States has more than quadrupled since 2001. Retail competition for residential customers thus far has developed largely in two states where market rules fostered competitive market development: broadly, in the ERCOT area of Texas and, less broadly, in New York. In Texas, more than 26 retail suppliers provide over 90 different residential products in each service area. Retail suppliers also provide "green" products, manage price and other risks, and offer load management and energy efficiency services that reduce and shift consumption during peak periods. In contrast, while default service rates that reflect market price levels promote retail competition, jurisdictions that have established fixed default service rates at below-market levels have virtually eliminated retail competition.

- **Other industries illustrate the benefits of competition:** The experience of other industries (e.g., airline, telecommunications, trucking) demonstrates that competition results in better utilization of resources, increased customer choice and access to new products and services, technological innovation, elimination of cross-subsidies, and lower prices.

To successfully navigate the confluence of an increasing public desire for environmentally-friendly resources with the rising cost of energy globally, participants in the electric industry must confront tough decisions and make difficult technological choices. The potential magnitude of future capital investments is unprecedented and the decisions required must be made in a highly uncertain environment with constantly changing information and significant risk. Decades of experience in the electric industry suggest that regulation is not well-equipped to meet such challenges. But recent experience in restructured electricity markets and significant experience in other competitive industries suggests that competitive markets are. We should learn from this history rather than repeat the regulatory mistakes of the past. By embracing competition, we can avoid "déjà vu all over again."[4]

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[4] Yogi Berra, *The Yogi Book: I Really Didn't Say Everything I Said* (New York: Workman Publishing, 1998), 30.

II. The Electric Industry Faces Enormous Challenges

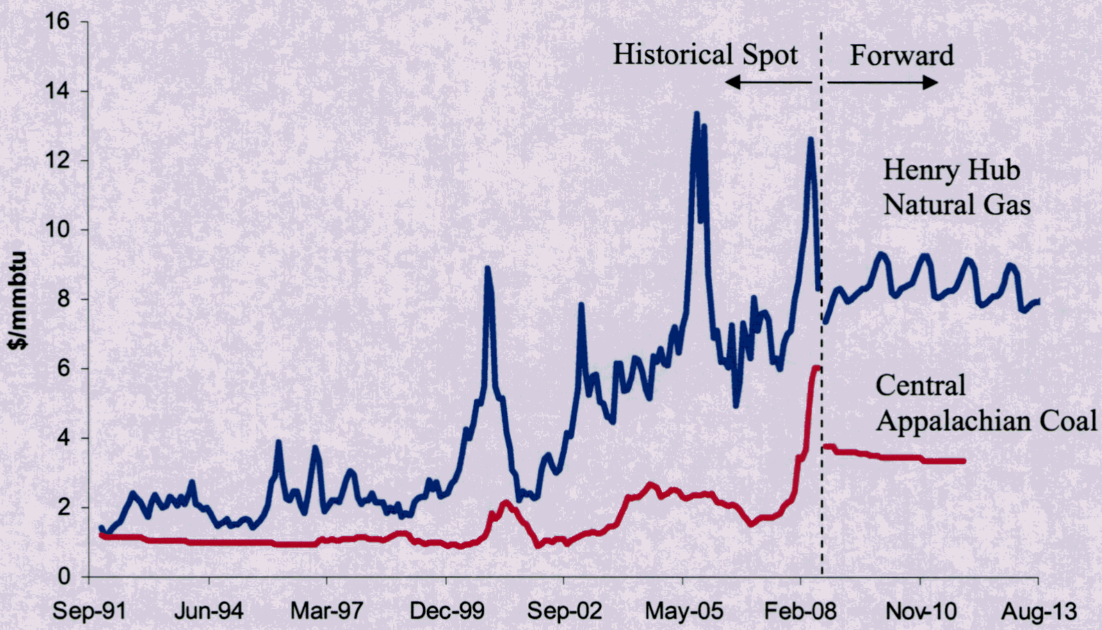
Looking forward, the electric industry faces a combination of significantly higher costs (both operating and capital) and massively increased need for capital investment, driven by ordinary load growth and, to an even greater extent, by the prospect of GHG regulation. Furthermore, a large degree of uncertainty and volatility will characterize the next twenty years: fuels markets and construction costs have become increasingly global and volatile, while the regulatory and technological uncertainties associated with carbon control are enormous. These conditions greatly increase the dollars at risk relative to recent history and will amplify any errors that are made in the coming years.

A. The Cost of Electricity is Rising and Increasingly Volatile

Electricity generation is primarily a fuel conversion process. Coal, gas, oil, and uranium (and, to a lesser extent, water, wind, and other renewable fuels) are converted into electricity by an electric generating plant. Both the cost of the input fuels and the cost of the plant used to convert these fuels have risen significantly in the last few years. As a result, electricity prices over both the short-term and the longer-term have increased.

Roughly 95 percent of the generating capacity built in the past ten years uses either coal or gas as an input fuel. These fuels currently generate roughly 70 percent of the country's electricity needs. As shown in Figure 2, after a period of relative tranquility in the 1990s, these input fuel costs to produce electricity have increased markedly and have reached unprecedented levels.

Figure 2 Increase in Natural Gas and Coal Market Prices, 1992-2013

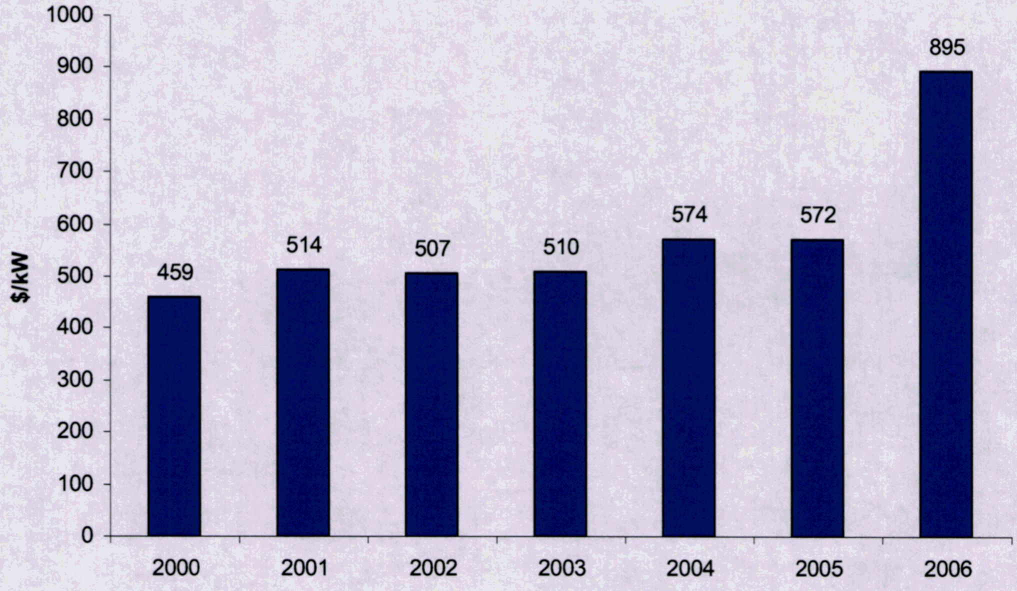


Source: Natural Gas: 1992-2004 – Bloomberg Daily Spot Price Assessment; 2005-2008 – ICE Day-Ahead Henry Hub Spot; 2008-13 – NYMEX Henry Hub Natural Gas Future (as of 9/15/08) Coal: 1992-2004 – Bloomberg Weekly Big Sandy Barge Spot Price Assessment; 2005-2008 – ICAP Prompt Month Big Sandy Forward; 2008-2011 NYMEX Central Appalachian Coal Forward.

Coal prices and natural gas prices have more than tripled since 1999. Current forward markets indicate that these relatively high fuel costs are expected to persist into the foreseeable future. Furthermore, fuel prices have also become more volatile: natural gas price spikes in the winter of 2000/01, in August/September 2005, and most recently in the first half of 2008 were at least twice as large as any price spikes seen previously.[5]

While fuel costs have increased, the cost to construct new power plants has also increased significantly in recent years, due to rising costs in materials and labor. The costs of steel and aluminum have grown by about 60 percent since 2003, and the costs of copper, nickel, and tungsten have tripled in the last few years. Primary drivers of these cost increases include increased global demand, increased production costs, and a weakening U.S. dollar. Labor costs, particularly costs for heavy construction and craft, have also increased at a rate much higher than inflation. As a result, the cost to build a new gas or coal plant has almost doubled over the 2000-2006 period. Figure 3 shows the increase in construction costs of a gas combined cycle turbine ("CCGT") plant since 2000.[6]

Figure 3 Increase in Gas Combined Cycle Installation Costs, 2000-2006



Source: The Brattle Group (Marc Chupka and Gregory Basheda), "Rising Utility Construction Costs: Sources and Impacts," prepared for the Edison Foundation, September 2007.

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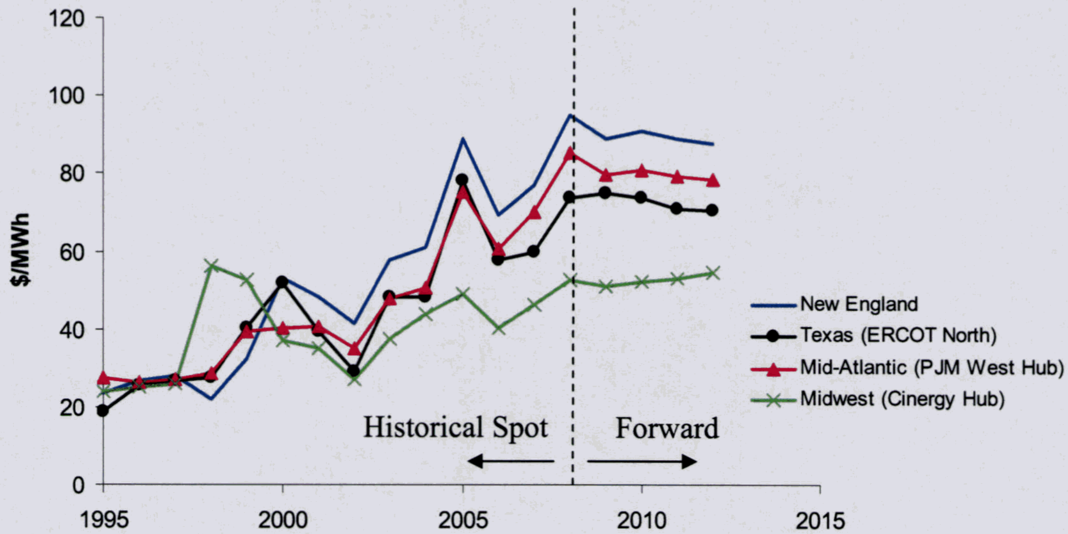
[5] While the reasons behind the increases in both natural gas price level and volatility are multiple and debated, there is consensus that the reserves of natural gas in North America have declined to the point where increasingly high-cost, marginal production sets the price for gas. In the long-term, the new-entry cost for liquefied natural gas ("LNG") will strongly influence the price for gas in North America, and this long-term price level is both relatively high and uncertain. Further, prices may exceed that level in the coming years, given the difficulty and time necessary to build new LNG import capacity.

[6] A more recent study from Cambridge Energy Research Associates suggests that these cost escalations have continued throughout 2007 and that the cost of all types of power plants as of early 2008 have increased by 130% relative to 2000, on average. ("U.S. Power Plant Costs Up 130 Pct Since 2000 – CERA," Reuters, 14 February 2008.)

These fuel and construction cost increases have caused wholesale electric prices to increase throughout the country, particularly in regions that rely heavily on gas-fired generation, such as in the Electric Reliability Council of Texas ("ERCOT") and New England, where wholesale electricity prices have increased by three to four times relative to the prices in the late 1990s. Other regions of the country have experienced significant price increases as well, as shown in Figure 4.

Figure 4 Increase in Wholesale On-Peak Electricity Prices, 1995-2012



Sources: Bloomberg Daily Spot Price Assessment for various regions; Megawatt Daily; ISO New England; Midwest ISO; PJM; Electric Reliability Council of Texas; New York Mercantile Exchange Forward Prices.

Wholesale electricity prices over the longer term will be a function of the total costs of new generation. Due to increased fuel and construction costs, the total costs of new gas and coal generation have nearly tripled and doubled, respectively, since 1999, as shown in Figure 5.

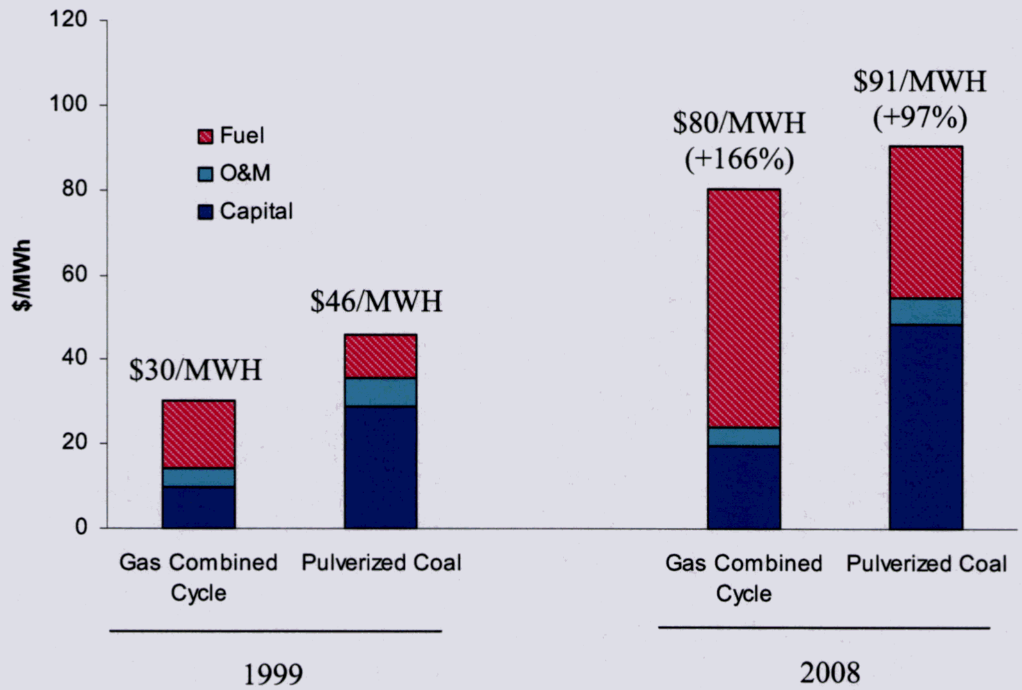
B. Climate Change Concerns Are Becoming More Critical and Are Expected to Further Increase Costs and Require Significant Capital Investments

The challenges posed by climate change and GHG emissions[7] add an unprecedented level of uncertainty and complexity to the challenges faced in the industry. Concerns regarding carbon dioxide (CO_2) and other pollutants affect the ability to site and build new power plants and also increase the cost of operating existing power plants. Both regulated utilities and unregulated developers have found it difficult to build new coal plants in several areas of the

[7] Gases that trap heat in the atmosphere are often called greenhouse gases. Some occur naturally, but the principal greenhouse gases that enter the atmosphere because of human activities include CO_2, methane, nitrous oxide, and fluorinated gases or ozone-depleting substances. CO_2 is the GHG most relevant to the electricity generation sector because it is emitted by power plants that burn fossil fuels such as coal, oil, and natural gas.

country,[8] and builders of new capacity face new regulatory and environmental hurdles in a carbon-constrained world, which will continue to put upward pressure on the cost of building new generation.

Figure 5 Increase in All-In Cost of New Build Generation, 1999 vs. 2008



Notes: Based on construction costs of $500/kW and $1,500/kW for CCGT and PC, respectively, in 1999 and $1,000/kW and $2,500/kW in 2008. Assumes baseload operation for both plant types (90 percent capacity factor), 10 percent after-tax weighted average cost of capital, and 40 percent tax rate. Does not include any provision for carbon-related costs.

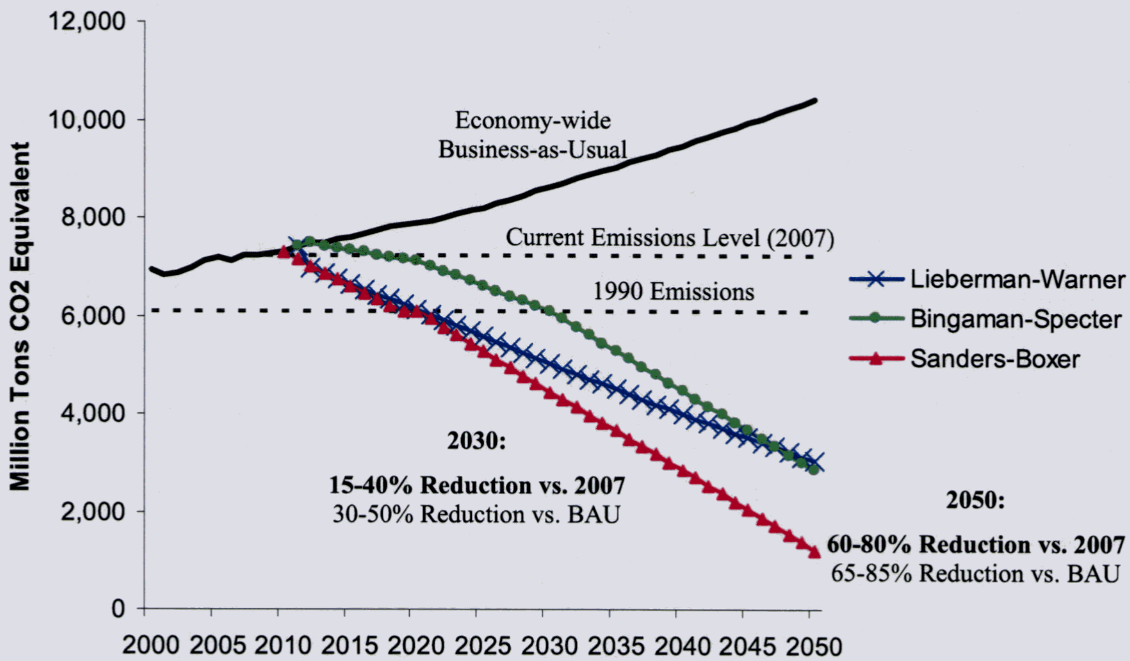
GHG regulation also will increase the cost of operating existing power plants. Most federal legislation being considered in Congress to control GHG emissions will place an explicit or implicit price on the right to emit CO_2 and other GHGs. This CO_2 price will be embedded in the marginal dispatch cost of CO_2-emitting generators, such as coal and natural gas fired generation plants, and will be reflected in wholesale electricity prices and generator costs. Thus, the economics of owning and operating existing capacity will change greatly under GHG regulation, along with capital investment incentives.

The recent concerns regarding new coal-fired plants are merely the opening act in what could potentially be the largest capital realignment in the history of the electricity industry, outdoing even the nuclear build-out of the 1970s. Most proposed GHG legislation in the United States contemplates extremely deep cuts in national GHG emissions by the 2030 to 2050 time frame. Figure 6 shows the mandated reduction path of the various proposals that have recently been advanced in the House and Senate. With few exceptions, all plans target a

[8] For example, Florida Power and Light shelved plans to build two gigawatts of regulated coal capacity due in part to environmental concerns. (Resource Media, "$45.3 billion in U.S. Coal-Fired Power Plants Cancelled in 2007: Rising Costs Force Energy Firms to Ditch Plans for 31 New Plants," Fact Sheet, 8 January 2008, 3.)

GHG atmospheric stabilization goal of 450 parts per million by 2050, implying reductions of 15 to 40 percent below the current U.S. CO_2 equivalent emission level by 2030, and 60 to 80 percent below the current level by 2050.

Figure 6 GHG Reduction Targets of Proposed U.S. Legislation



Source: Business-As-Usual Case: Energy Information Administration, Annual Energy Outlook 2008 with Projections to 2030, June 2008. Legislative cases based on NorthBridge analysis of relevant legislation.

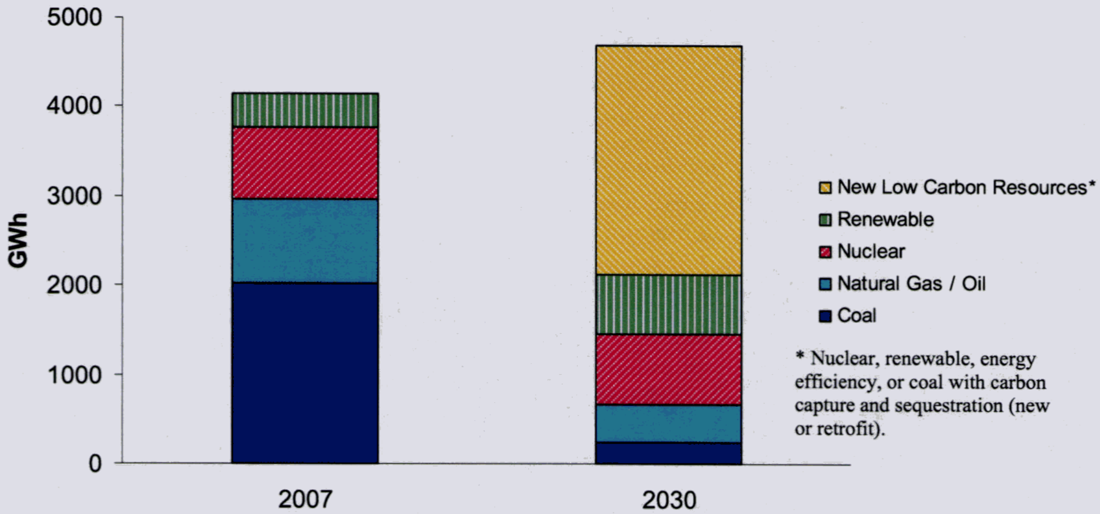
These emission reduction targets have enormous implications for the electric industry. The U.S. electric industry currently emits just under 2,500 million tons of CO_2 per year, or about one-third of total U.S. CO_2 emissions. Under the Energy Information Administration's "Business As Usual" projection, emissions are expected to rise to just under 3,000 million tons per year by 2030. If the electric industry bears a proportionate share of the emission reductions implied by the legislative proposals being considered (which is likely conservative since most models, such as the Energy Information Administration's National Energy Management System ("NEMS") model, suggest that the electric industry will bear a more than proportional share of emissions reductions), the industry must reduce emissions in 2030 by anywhere from 900 to 1,500 million tons relative to the "Business As Usual" amount. This reduction is equivalent to replacing between 250 and 400 average size coal units with zero-carbon capacity. The actual level of uncertainty is higher than that portrayed by this simple example: the relative costs of reducing emissions in other sectors of the economy and the degree to which the U.S. program is able to utilize international emissions reduction offsets add an additional layer of complexity. Achieving this emission reduction target will require that industry participants confront difficult resource decisions in the midst of tremendous uncertainty in future regulations, technology, and market conditions.

Unlike other types of pollutant regulation, there is currently no cost-effective, off-the-shelf means of reducing the CO_2 emissions of existing coal plants (such as Selective Catalytic

Reduction for NO_x or Flue Gas Desulfurization for SO_x). Consequently, to stabilize and reduce CO_2 emissions, the industry must make some difficult choices and respond to shifts in technology. Current supply choices – which include retrofitting existing coal plants[9] and increasing reliance on low carbon technology such as nuclear, coal with carbon sequestration, wind, solar, and, to some extent, natural gas – appear to have very high costs. Reductions in customer demand for electricity also will be necessary, but not sufficient, to reduce CO_2 emissions to target levels. The costs of these potential alternative low-carbon strategies are extremely uncertain and likely to be high.

The capital realignment necessary to ultimately achieve the proposed reduction targets is unprecedented. Figure 7 shows the generation capacity investment necessary to satisfy projected load growth and a CO_2 reduction target of 30 percent below current levels by 2030 (consistent with the Lieberman-Warner Bill) assuming no generation retirements. In order to meet this target, the industry will need to reduce its usage of existing coal generation by more than 80 percent and build enough low-carbon baseload capacity (nuclear, coal with carbon capture, renewables, and energy efficiency) to generate 80 percent of the output of the current baseload fleet. Overall, this implies increasing the industry's existing generation capital stock by a factor of 50 percent once retirements are considered.

Figure 7 Need for New Low Carbon Resources By 2030



Source: Energy Information Administration, Energy Market and Economic Impacts of S. 2191, The Lieberman-Warner Climate Security Act of 2007, April 2008.

Figure 8 illustrates the financial impact of this capital realignment by comparing the average annual real generation capital investment from 2007 to 2030 with earlier periods. The required investment over the next twenty to twenty-five years will likely be five to nine times the level seen in the previous twenty years, and two to three times the level invested during

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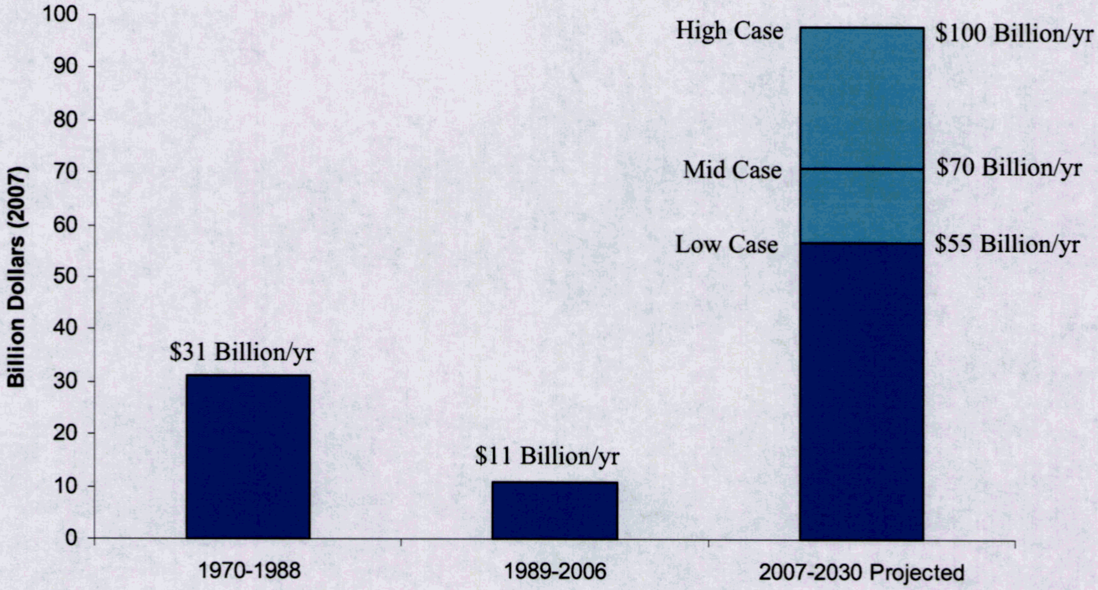
[9] In addition to any capital costs required to retrofit existing coal plants with carbon control technology, current estimates suggest that the output of these retrofitted coal plants would decline by 20 to 35 percent due to the carbon capture process.

the 1970s and early 1980s, when the industry built most of the nuclear and coal capacity in service today.

Figure 8 Expected Increase in Annual Real Investment in New Generation



Source: Edison Electric Institute, Historical Statistics of the Electric Utility Industry Through 1992; NorthBridge analysis based on Energy Information Administration, Energy Market and Economic Impacts of S. 2191, The Lieberman-Warner Climate Security Act of 2007, April 2008.

The political demand for non-polluting, low-carbon sources of energy is very high, as evidenced by the aggressive GHG legislation currently being considered. However, the available supply-side alternatives of meeting this demand are both costly and uncertain. The dollars at risk are as large as they have ever been in the electricity industry, and the decisions made over the next twenty years may very well have implications for electricity consumers reaching over the entire century.

III. Regulation Has Failed to Meet Similar Challenges in the Past

While these future challenges loom large, the industry is currently embroiled in a debate about the relative merits of regulation versus competition. Rate shocks in restructured states such as Illinois, Maryland, and Connecticut have led some to question whether those restructured markets are producing an outcome beneficial to consumers. Concerns about high profits, market power, and market manipulation on the part of deregulated electricity suppliers began with the California energy crisis[10] and the Enron scandal and have continued as electricity prices have increased. Tighter generation reserve margins in many restructured states have led to fears that new competitive generation investment may not be sufficient to ensure electric system reliability.

In light of these concerns, some politicians and regulators are calling for a return to the "good old days" of regulation. But memories may be failing, because the good old days of regulation were not always good, especially during the times when the industry faced challenges similar to those of today. We should recall the 1970s, a time of tumultuous change in the electricity industry, when the industry first had to contend with an environment of sharply rising costs.

A. The Challenges Faced in the 1970s Have Similarities to Those of Today

Many of the challenges particular to the 1970s eerily echo the challenges facing the industry today. In particular, both eras have in common three sources of shock and uncertainty: 1) rising fuel costs, 2) significant capital cost escalation and new environmental concerns, and 3) future electricity demand uncertainty. These external shocks were the primary forces behind the turmoil of the 1970s. Examining the response of the regulated industry structure to each of these shocks illuminates the shortcomings of regulation and the dangers of similar shocks in the electricity market today.

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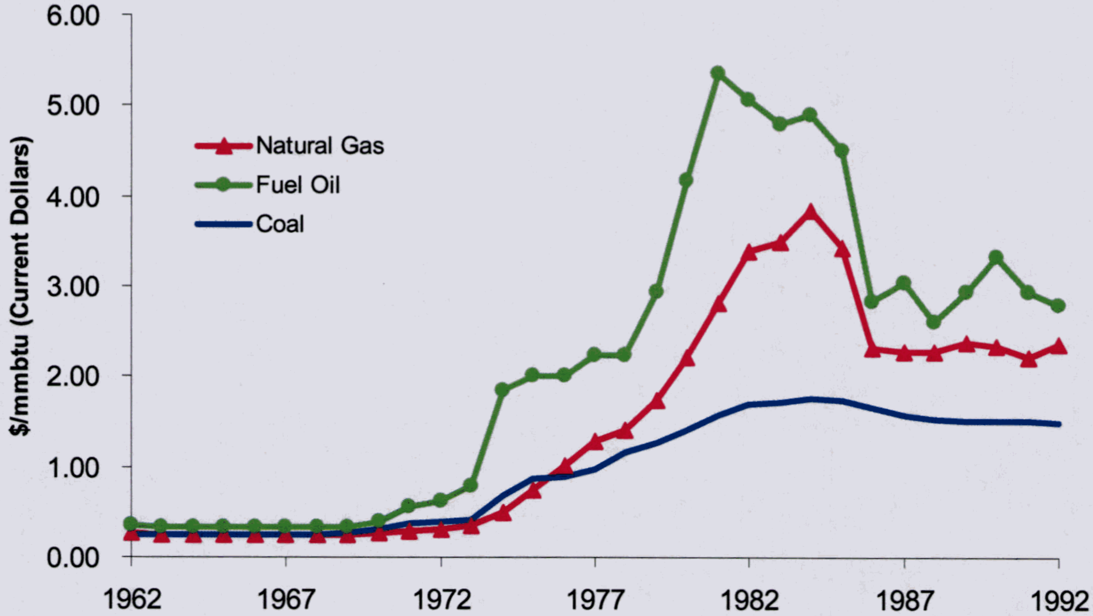
[10] In the summer of 2000, wholesale prices in California spiked above $1,000/MWH due to the convergence of several factors: hot weather with no demand response, limited supply from a capacity-constrained local market, a dry season limiting hydro-electric generation in the Pacific Northwest, high natural gas prices, and opportunistic behavior by wholesale suppliers. The high wholesale prices forced utilities to sell power to retail customers at prices far below their costs because there were no cost-recovery or rate adjustment mechanisms. The California market design left the utilities fully exposed to the spot market. Southern California Edison ("SCE") and Pacific Gas & Electric ("PG&E") had divested their fossil generating assets, and the utilities, as the provider of last resort, were to purchase electricity in high-priced spot markets and resell electricity to retail customers at lower, long-term fixed prices. This market design led to financial disaster for both companies, and ultimately large rate increases for retail customers. Dramatic price increases in late 2000 and early 2001 created a crisis that bankrupted PG&E and severely weakened SCE. PG&E and SCE suffered combined losses of billions of dollars in procuring power supplies to serve their load. As a result, retail access was halted, and the state government of California was forced to financially backstop procurement. Many economists and industry observers blame the California crisis on a flawed market design from a politically contentious regulatory and legislative process. (Frank Wolak, "Diagnosing the California Electricity Crisis," *The Electricity Journal*, Vol. 16, No. 7 (August/September 2003), 11-37; John Jurewitz, "California's Electricity Debacle: A Guided Tour," *The Electricity Journal*, Vol. 15, No. 3, (May 2002), 10-28; Paul Joskow, "California's Electricity Crisis," *Oxford Review of Economic Policy*, Vol. 17, No. 3 (2001) 6; Sally Hunt, *Making Competition Work in Electricity*, (Jon Wiley and Sons, New York: 2002), 378.)

1) Rising Fuel Costs

The dual shocks of the Arab oil embargo of 1973-4 and the Iranian revolution of 1979 caused world oil prices to rise to previously unprecedented levels in the 1970s. Natural gas prices and, to a lesser extent, coal prices followed suit. Figure 9 shows this rapid rise in the cost of input fuels for electric generators.

Figure 9 Rise in Nominal Input Fuel Costs for Electric Generators, 1962-1992



Source: Edison Electric Institute, Historical Statistics of the Electric Utility Industry Through 1992.

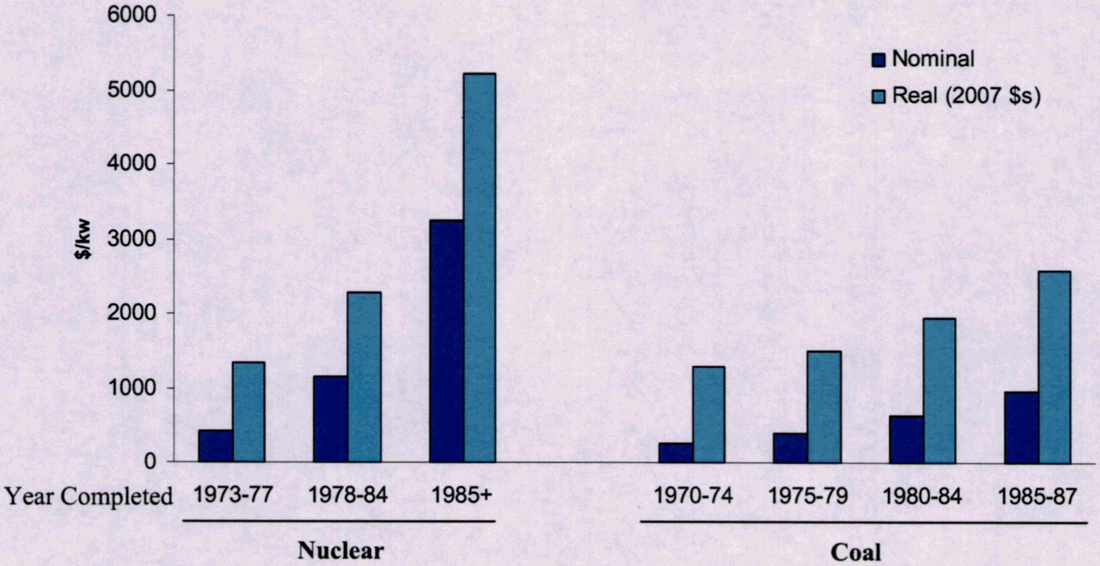
By 1982, coal, natural gas, and oil prices had risen to 6, 13, and 15 times their 1969 levels, respectively. As a consequence, variable generation costs for fossil fuel-fired power plants rose by a factor of 9 from 1969 to 1982. This increase led many utilities to develop fuel clauses that allowed the pass-through of higher fuel costs and/or contributed to numerous utility requests to increase rates.

2) Capital Cost Escalation and Environmental Concerns

Prior to the late 1960s, construction of new electric generating capacity had been characterized by increasing economies of scale. By increasing the size of power plants, utilities could achieve lower unit construction costs and greater thermal efficiency. This trend began to slow in the 1960s and essentially disappeared by the 1970s as reliability and economic dispatch problems associated with extremely large units began to appear. The average size of new coal units increased from 124 MW in the early 1950s to close to 600

MW in the early 1970s, but declined back towards 500 MW thereafter.[11] Around the same time, several legislative actions and market trends caused an increase in the cost of building and operating new power plants. In particular, the Clean Air Act of 1970 mandated that all new coal plants install equipment to reduce harmful air emissions, such as sulfur dioxide and nitrous oxide. Around 1973, the environmental movement also began to contest the construction and operation of nuclear plants, which led to construction delays, litigation, and increasing safety and environmental costs at nuclear units, a trend that intensified throughout the decade. The nuclear accidents at Brown's Ferry in 1975 and Three Mile Island in 1979 accelerated this trend, which ultimately led to long and expensive delays and re-designs for plants under construction throughout the late 1970s and 1980s. The costs of these delays in the construction and development cycle of coal and nuclear units were exacerbated by increasing input costs and inflation.[12]

Figure 10 Escalation of Generation Construction Costs in the 1970s and 1980s



Sources: Energy Information Administration, "An Analysis of Nuclear Power Plant Construction Costs," December 1986; Energy Information Administration, "Historical Plant Cost and Production Expenses For Selected Electric Plants, 1987."

All these factors put upward pressure on the cost of building and operating electric generation, with little or no offsetting gains in economies of scale and efficiency. Figure 10 shows the "overnight" construction cost per kilowatt of nuclear and coal-fired electric

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[11] Paul Joskow and Nancy Rose, "The Effects Of Technological Change, Experience, And Environmental Regulation On The Construction Cost Of Coal-Burning Generating Units," *Rand Journal of Economics*, Vol. 16, No. 1, (Spring 1985): 3, 4, and 24.

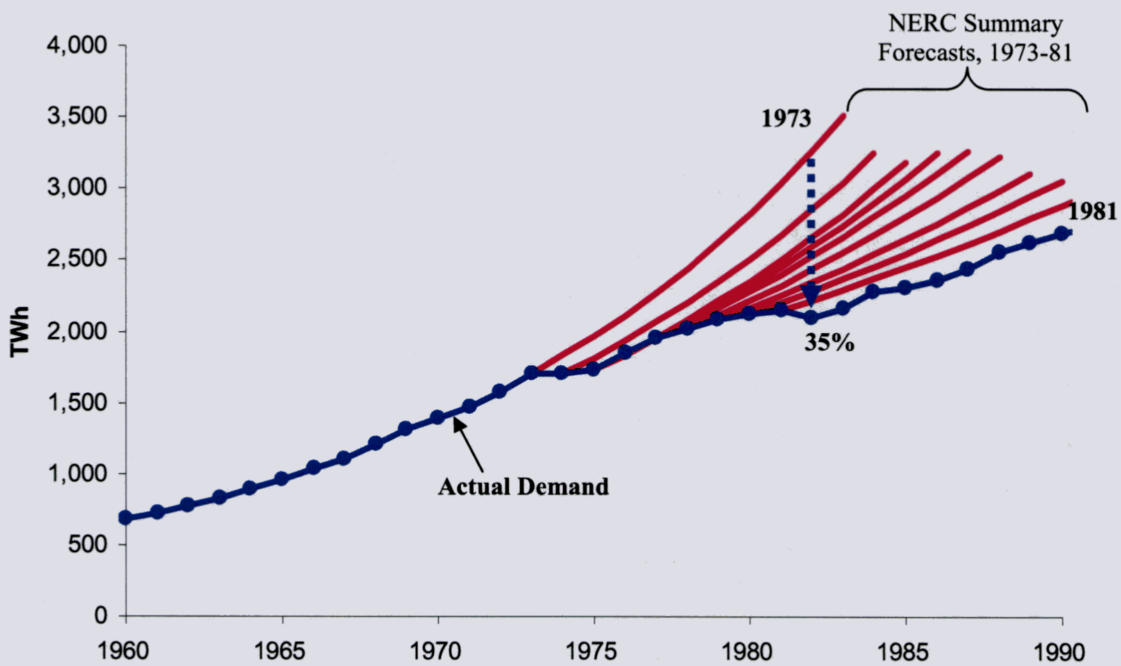
[12] Nominal construction costs for steam-electric power plants rose by 9 percent per year from 1973 to 1984, more than double the 4 percent per year increases from 1950 to 1973. (Based on data from the *Handy-Whitman Index of Public Utility Construction Costs*, Whitman, Requardt & Associates, various years.) Rising inflation, recession, and turmoil in financial markets also caused a dramatic increase in real and nominal financing costs. Nominal interest rates on utility bonds averaged over 11 percent from 1973 to 1984 compared to 6 percent from 1960 to 1972. (Edison Electric Institute, "Historical Statistics of the Electric Utility Industry through 1992," 1995.)

generation plants at different periods of time. Between 1970 and the late 1980s real and nominal nuclear construction costs increased by 113 percent and 679 percent, respectively, while real and nominal coal plant construction costs increased by 58 percent and 262 percent, respectively.

3) Demand Uncertainty

Prior to the early 1970s, demand for electricity grew at a rapid and fairly predictable clip. As Figure 11 shows, from 1960 to 1973 electricity consumption grew at an annual rate of 7.3 percent, with relatively little variance. Total electric generating capacity in this period grew by 7.7 percent per year, keeping approximate pace with demand growth. By the late 1960s, most utility demand forecasts reflected continued high load growth and a concomitant need for additional baseload coal and nuclear capacity. These demand forecasts buttressed a round of initial planning, completed between 1966 and 1973, for most units that were later built in the 1970s and 1980s. However, actual demand growth in the 1970s fell far below expectations. From 1973 to 1982 electricity consumption only grew by 2.4 percent annually, while generating capacity grew almost twice as fast at a rate of 4.5 percent per year. As Figure 11 shows, by 1982, actual demand was about 35 percent less than what it would have been had load continued to grow at its pre-1973 rate of growth.

Figure 11 Actual U.S. Electricity Demand Fell Below Projections in the 1970s



Source: Edison Electric Institute, Historical Statistics of the Electric Utility Industry Through 1992; Nelson, Charles, and Peek, Stephen, "The NERC Fan: A Retrospective Analysis of the NERC Summary Forecasts," *Journal of Business and Economic Statistics*, Vol. 3, No. 3, July 1985.

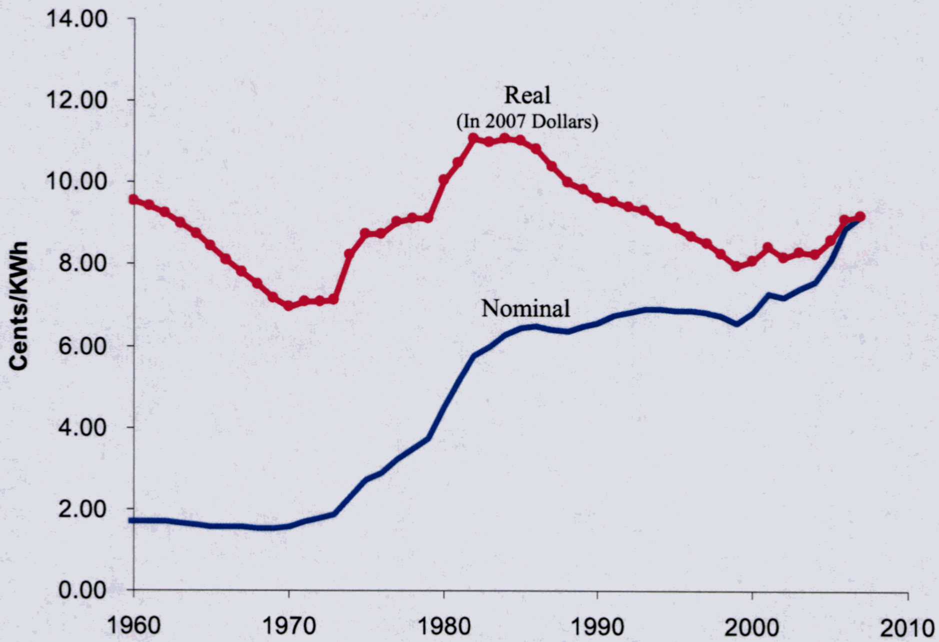
This falloff in demand growth was caused by a slowdown in the U.S. economy, a leveling-off of the nation's energy intensity,[13] and the inevitable demand response to higher electricity prices as rising fuel and capital costs eventually found their way into average-cost utility retail electric rates.

The overall effect of the lower-than-expected load growth was that the electric industry built up a huge oversupply of unneeded and expensive coal and nuclear capacity. The units built in the 1970s and 1980s were more expensive than originally estimated and the costs were spread over a smaller-than-expected customer base.

B. The Regulatory Response to the Challenges of the 1970s Was Poor

The ultimate effect of these three challenges – rising fuel costs, capital cost escalation and environmental concerns, and demand uncertainty – and policymaker's response to them was to create an unmitigated disaster for electricity consumers and utility shareholders. As Figure 12 shows, the increasing economies of scale in the electric industry that led to lower retail prices in the 1950s and 1960s virtually disappeared by the 1970s. Nominal electric rates rose by over 300 percent from 1970 to their peak in 1985, while real rates rose by 60 percent in the same time period.

Figure 12 U.S. Average Retail Electricity Prices Rose in the 1970s and 1980s



Source: Edison Electric Institute, Historical Statistics of the Electric Utility Industry Through 1992; Energy Information Administration State-Level Spreadsheets, 1990-2006. 2007 rates are from December 2007 Energy Information Administration Electric Power Monthly.

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[13] Energy intensity is a measure of the energy efficiency of a nation's economy that is generally measured in units of energy per unit of gross domestic product.

Electric utilities also endured approximately $60 billion in cost disallowances (in 2007 dollar terms) from the late 1970s to the early 1980s, costs which would have further raised rates had they not been borne by shareholders.[14] Overall, the regulatory response to the events of the 1970s and 1980s probably amounted to a mistake on the order of $200 billion or more in today's dollars.[15]

Figure 13 provides an indication of the misallocation of resources in the 1970s and 1980s. The figure shows capacity utilization for baseload coal plants from 1960 to the present. The economics of coal plants with high capital costs and low variable costs favor high capacity utilizations of 70 percent or more. In the 1960s and in recent years, coal plants have operated at this level of utilization. However, during the 1970s and 1980s, capacity utilization in the regulated electric utility industry remained low – at the 50 to 60 percent level.

When judged by the outcome of high electricity costs and low capacity utilizations, the regulatory response to the rising cost environment of the 1970s appears to have been a failure. But why was the response so poor? What portion of this poor outcome can be blamed on regulation, rather than exogenous shocks outside the control of industry decision-makers? And, would competition have produced a better result?

The external shocks that placed the initial stress on the electricity industry – the oil price shocks, cost inflation, and falloff in demand growth – were not caused by regulation of the industry. However, a careful examination reveals four inherent flaws of regulation behind much of the industry's response to the external shocks and uncertainty of the 1970s: 1) a lack of clear market price signals for both suppliers and consumers of electricity, 2) perverse capital incentives for regulated utilities to favor capital and consider sunk costs in investment and abandonment decisions, 3) improper allocation of risks that encourage regulated utilities to underestimate the risks of large capital-intensive investments that are borne by ratepayers, and 4) the tendency for political and regulatory "fixes" that overcompensate with unintended consequences. These flaws ultimately led to higher costs for consumers and a less efficient resource allocation than likely would have occurred in a competitive framework.

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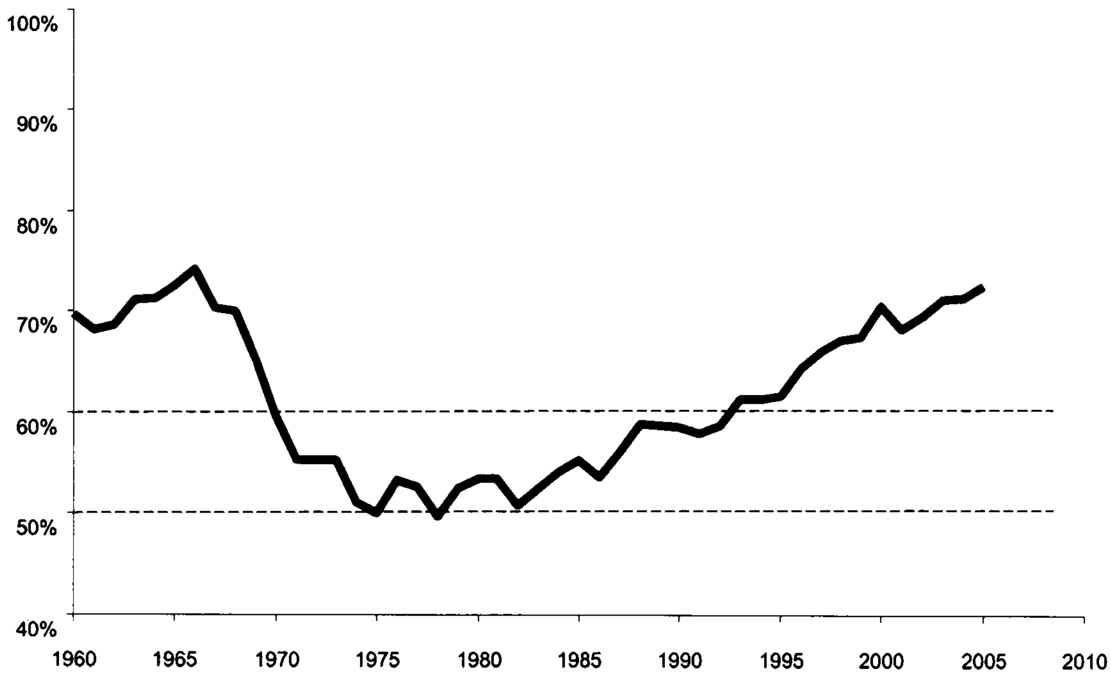
[14] Disallowances related to completed and in-service plants amounted to almost $31 billion in 2007$, or about $19 billion in mixed nominal dollars. (Thomas Lyon and John Mayo, "Regulatory Opportunism and Investment Behavior: Evidence from the Electric Utility Industry," *Rand Journal of Economics*, Vol. 36, No. 3, (2005): 628-644.) The other major source of disallowances was the sunk costs of abandoned nuclear units, which amounted to about $63 billion in 2007$, or about $36 billion in mixed nominal dollars. (Charles Komanoff, and Cora Roelofs, Komanoff Energy Associates, "Fiscal Fission, The Economic Failure of Nuclear Power," (December 1992), 15, Table 7.) These sunk costs were shared between ratepayers, utility investors, and taxpayers in a variety of ways depending on the jurisdiction. Assuming shareholders ultimately bore about half of these costs we arrive at a figure of about $60 billion in 2007$ for both sources of disallowances.

[15] This estimate is the summation of two sources of costs associated with the mistakes of regulation: the unsunk above-market cost of uneconomic nuclear units completed after the Three Mile Island incident, measured relative to avoided costs of fossil energy as of the early 1980s, and the above-market costs of uneconomic contracts entered into as a result of PURPA. We conservatively estimate the first source of costs at about $150 billion (in 2007$), while the second source has been estimated at close to $50 billion (also in 2007$) as of the mid 1990s (see Resource Data International, *Power Markets in the U.S.*, Boulder, CO, RDI, 1996). Note that these costs were shared among ratepayers, utility shareholders, and taxpayers.

Figure 13 Capacity Utilization of U.S. Coal-Fired Electric Generation Remained Low During the 1970s and 1980s



Sources: Energy Velocity; Edison Electric Institute, Historical Statistics of the Electric Utility Industry Through 1992; Energy Information Administration State-Level Spreadsheets, 1990-2006.

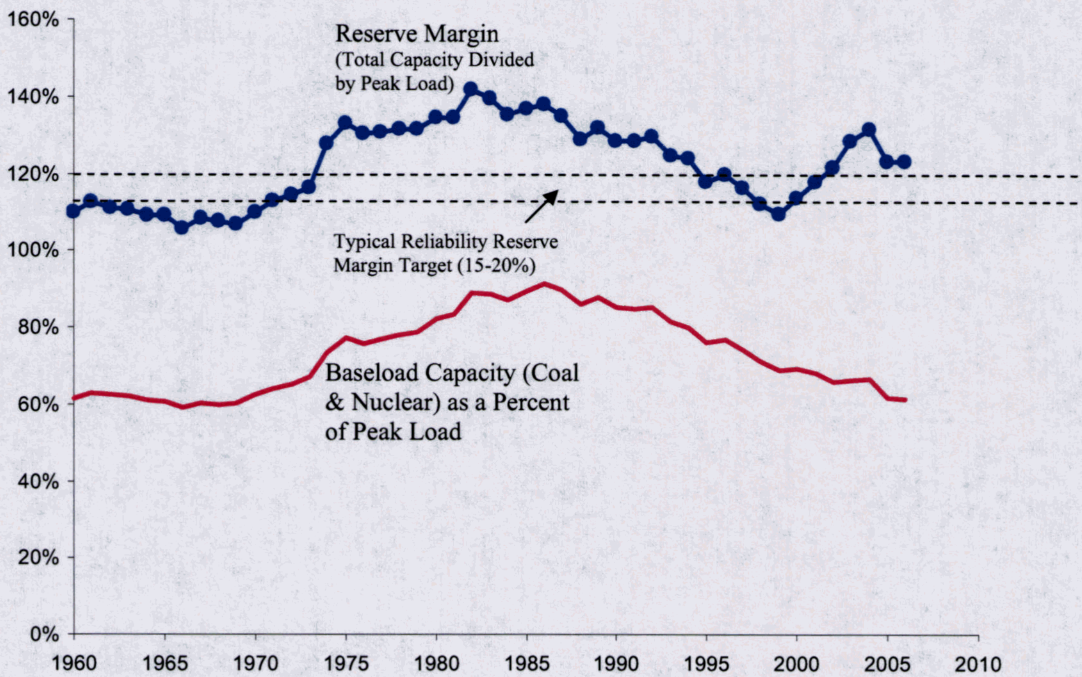
1) Lack of Market Price Signals

In the regulated-utility environment of the 1970s, utilities and regulators made generation resource decisions based on their long-term expectations about fuel prices, economic conditions, and supply/demand balances. These expectations were infrequently updated, and the "price signals" in this framework were the result of internal forecasts of a single regulated entity subject to political influence and negotiation with the regulator during the ratemaking process. Not surprisingly, such an approach can – and did – lead to poor resource allocation decisions, particularly during periods of market turbulence and uncertainty, where the relative economics of different resource types can change rapidly.[16]

[16] Today, the decision-making process regarding resource allocation is very different in a region with a competitive, visible wholesale electricity market. A competitive power plant developer considering the possibility of building a new plant is able to continuously evaluate the forward-looking economics of different types of generation using the various price signals generated by competitive markets. The price signal for revenues is the forward price of electricity that reflects a market consensus on future electricity supply and demand and the marginal costs of conversion of different fuels into electricity. The price signal for costs are the forward prices for different types of fuel (gas, coal, etc.) that reflect supply and demand conditions in those markets. The developer can meld these price signals into a continuously-updated picture of the relative economics of different types of generation and then act accordingly, along with other competing developers. Different developers may have different long-term expectations and different appetites for risk, but each

The generation resource allocation decisions of the 1970s clearly illustrate the shortcomings of decision-making without clear market price signals. During the 1950s and 1960s, capital and operating costs for nuclear and coal units were expected to be quite low (in fact, Lewis L. Strauss, chairman of the Atomic Energy Commission, famously proclaimed in 1954 that nuclear energy would be "too cheap to meter").[17] Not surprisingly, as reserve margins declined in the late 1960s, electric utilities initiated the development of a large number of nuclear and coal units. As the 1970s progressed, capital costs for these units began to rise, and demand growth failed to materialize, leading to a rapid deterioration of the economics of new generation in general, and baseload units (especially nuclear) in particular. Despite this change in economics, however, a large proportion of the excess baseload units planned in the late 1960s and early 1970s were ultimately built over the course of the 1970s and 1980s. In the period from 1970 to 1988, utilities added an average of 15,000 MW of coal and nuclear capacity per year, and 19,400 MW per year of capacity of all kinds, while peak load grew by an average of only 13,800 MW per year. Figure 14 shows the increase in U.S. reserve margin and the amount of baseload capacity as a percent of peak electric load during this period.

Figure 14 Excess U.S. Reserve Margins and Baseload Capacity in the Mid 1970s to Early 1990s



Source: Energy Velocity; Edison Electric Institute, Historical Statistics of the Electric Utility Industry Through 1992; Energy Information Administration State-Level Spreadsheets, 1990-2006.

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developer can monitor market prices and will need to bet its own money on decisions based on these differences in expectations and risks.

[17] Lewis Straus, Chairman of the Atomic Energy Commission, Speech to the National Association of Science Writers, New York City, 16 September 1954; "Abundant Power From Atom Seen; It Will Be Too Cheap For Our Children to Meter, Strauss Tells Science Writers," *New York Times*, 17 September 1954.

By 1986, coal and nuclear capacity reached 91 percent of national peak load, in comparison to approximately 60 percent today and in 1960. Similarly, total excess capacity as a proportion of peak load (i.e., the reserve margin) peaked at 42 percent in 1982, more than twice the 15 to 20 percent level generally deemed necessary at that time to maintain system reliability.[18] By the early 1980s, coal units, generally expected to have capacity factors greater than 70 percent, were operating at an average capacity factor of only 50 percent, indicating a large mismatch between the national generation supply portfolio and demand. As Figure 10 and Figure 11 show, both the falloff in demand and the escalation in generation capital costs were well underway by 1975 and were becoming readily apparent to utilities and regulators. However, utilities continued to overbuild baseload capacity well into the 1980s despite clear indications that such generation was no longer needed or economic.

Ultimately, over the course of the 1970s and early 1980s, electric utilities built a generation supply portfolio that was far too big in absolute terms, and too heavily-weighted towards capital-intensive coal and nuclear generation. The lack of clear market price signals was a significant culprit in this misallocation of resources. With no clear market pricing for electricity, utility builders and regulators lacked an unbiased indicator of future electricity supply and demand, and were thus slow to readjust their plans to build new generation as conditions changed. Furthermore, even when imperfect market price signals did exist, the command-and-control nature and perverse incentives of the regulatory process did not incorporate them well.

A more subtle problem was the lack of appropriate price signals for consumers of electricity. In the regulated utility framework, retail customers were charged a bundled rate that was based on the average historical cost of generating and delivering electricity to the customer. As such, the retail price incorporated the effects of numerous long-past decisions with respect to the historical costs and type of generation built by the utility. When the incremental cost of meeting load growth exceeded this historical embedded average cost (as it did in the rising cost environment of the 1970s and today) the retail price signal to customers was below the marginal cost of meeting the last increment of demand. Increases in retail rates lagged behind the increase in marginal cost. These artificially low price signals to customers encouraged over-consumption relative to the efficient level, which tended to exacerbate cost increases. While load growth did slow considerably in the 1970s and early 1980s relative to earlier periods (see Figure 11), it would have fallen faster and further had customers seen an appropriate marginal cost price signal.

Meanwhile, the lack of clear wholesale market price signals during this period led to poor resource decisions, in particular the over-build of regulated baseload capacity, which saddled the industry with the huge costs of oversupply.

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[18] Large-scale nuclear and coal units in the event of an outage tend to require a greater reserve margin than do a series of smaller-scale gas units and demand resources. As technology improvements enable smaller, more efficient plants to be built and there is increasing reliance on smaller customer demand resources in broader competitive markets, reserve margins should shrink while continuing to maintain or even enhance reliability. In recent years, many competitive markets (e.g., ERCOT and PJM) have been able to reduce their target reserve margins to the 12 to 18 percent range.

2) Perverse Capital Incentives

Several perverse incentives created by the regulated structure also contributed to the poor industry response to the challenges of the 1970s and early 1980s. In particular, regulated utilities in a cost-of-service structure have incentives to over-invest in capital,[19] overestimate consumer demand for electricity, or continue to build facilities even when costs have significantly increased or slow-downs in load growth no longer require the investment. Regulated utilities with regulatory prudence oversight have a tendency to consider sunk costs[20] when making investment/abandonment decisions.

In a competitive market, a power plant builder with a partially-constructed plant will compare "to-go" capital costs – without any sunk costs – to forward-looking profitability when evaluating whether to continue, delay, or abandon construction of the plant.[21] Removing sunk costs from the decision-making process helps participants avoid "throwing good money after bad" if the prospects for an investment sour after resources have been sunk into the investment. For a regulated electric utility operating under the traditional "prudent investment" and "used and useful" investment cost recovery standards, such decisions are very different. Canceling an under-construction power plant and never putting it into service makes it less likely that the utility will be able to recover the investment sunk into the plant prior to cancellation. Therefore, relative to a non-regulated developer, a regulated utility will tend to finish large capital investments and place them into service even if the investment becomes uneconomic on a forward-looking basis at some point along its development cycle. While the utility certainly risks disallowance on an uneconomic completed plant, this risk is lower than that of trying to recover the sunk costs of an abandoned plant. Utilities were forced to confront the unpalatable decision to either build unneeded facilities or cancel construction and face the daunting prospect of trying to recover from customers the already-sunk costs of facilities that would not be placed into service, thereby failing the "used and useful" regulatory principle of cost recovery. This tendency to "build no matter what" was on full display during the 1970s and early 1980s, as utilities continued to develop coal and nuclear plants long after those plants were clearly uneconomic in forward-looking terms.[22]

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[19] Economists Harvey Averch and Leland Johnson in 1962 demonstrated analytically that firms subject to rate-of-return regulation will have a tendency to overcapitalize and have a high capital to labor ratio. This phenomenon in the economics of utility regulation became known as the Averch-Johnson effect. (Harvey Averch and Leland Johnson, "Behavior of the Firm Under Regulatory Constraint," *The American Economic Review*, Vol. 52, No. 5 (December 1962): 1052-1069.)

[20] Sunk costs are unrecoverable past expenditures. These should not normally be taken into account when determining whether to continue a project or abandon it, because they cannot be recovered either way.

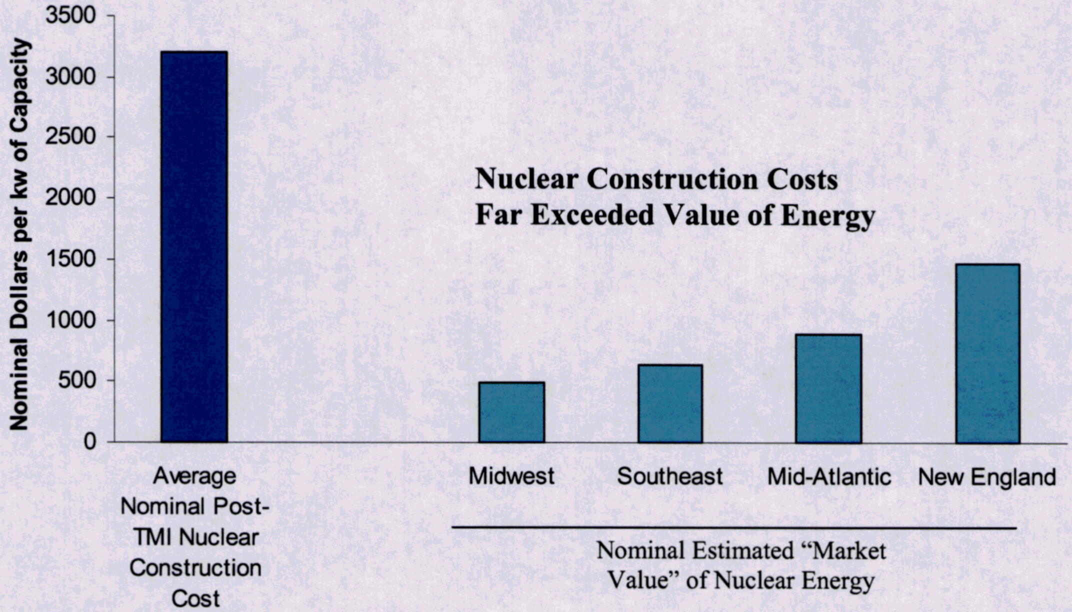
[21] Timothy Mount recognized this difference between regulated and merchant generators in a recent paper: "The important implication is that it is no longer realistic in a typical deregulated market to assume that a generating unit will be built after regulators have approved a license for construction. This was typically not the case under regulation. In a deregulated market, merchant generators have no obligation to complete projects if the prospects for recovering capital costs deteriorate during the construction process." (Timothy Mount, "Investment Performance in Deregulated Markets for Electricity: A Case Study of New York State," prepared for the American Public Power Association, September 2007, 28.)

[22] Further evidence of the tendency of regulated utilities to incorporate sunk costs into their decision-making has been found by examining the effect of nuclear plant cancellations on utility stock returns. For example, one analysis finds that utilities that cancelled nuclear plants under construction experienced significant negative excess stock returns. Furthermore, the larger the sunk costs relative to the size of the utility, the larger the stock price decline. This is consistent with the notion that cancelling a nuclear power plant under construction

For example, consider the situation in the nuclear industry in 1980. The Three Mile Island nuclear accident in March of 1979 led to a stoppage of new nuclear orders and a widespread questioning of the safety of plants in development.[23] The trend towards cost overruns and delays in the nuclear industry had been established for several years[24] and was likely to worsen in the current environment. Furthermore, it was apparent by that time that the country had reached a state of significant oversupply of generation, and that new nuclear plants were not needed – reserve margins had pushed above 30 percent by the mid-1970s and coal plant capacity factors averaged under 50 percent by 1975.

Figure 15 illustrates the forward-looking economics for nuclear power plants at the time by comparing nuclear plant construction cost to the approximate avoided cost of electric generation at the time in different regions of the country.

Figure 15 Nuclear Investment/Abandonment Decision, Circa 1980



Notes: Average nuclear construction cost based on data from Energy Information Administration, "An Analysis of Nuclear Power Plant Construction Costs," 1987. Market value of nuclear energy developed by estimating the nominal variable cost of energy produced from fossil fuel sources in each region, based on 1981 realized electric utility natural gas, coal, and oil costs.

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destroys value for the utility because it increases the likelihood that the utility will not be able to recover the sunk investment whereas taking the plant to completion provides at least some chance of recovering a portion of the investment. (Douglas Hearth, Darryl Gurley, and Ronald Melicher, "Nuclear Plant Cancellations: Sunk Costs and Utility Stock Returns," *Quarterly Journal of Business and Economics*, Vol. 29 (January 1990).)

[23] On March 28, 1979, a main feedwater pump malfunctioned at the Three Mile Island Generating Station near Middletown, Pennsylvania. A series of mechanical and human errors led to the most serious nuclear power plant accident in U.S. history.

[24] For instance, operations and maintenance costs for existing nuclear units, which is a barometer of the costs and difficulties of nuclear operations, rose in real terms by 73 percent from 1974 to 1979 and 137 percent from 1974 to 1980. (Energy Information Administration, "An Analysis of Nuclear Power Plant Operating Costs: A 1995 Update," April 1995, 7.)

By 1980, the construction costs of nuclear power plants were approximately two to six times greater than the value of the energy they provided. Put differently, only plants that had already sunk at least three-quarters of their likely final cost should have continued construction, and the rest should have been abandoned. Unfortunately, this did not happen. Ultimately, 53 nuclear units under construction at the end of 1979 were eventually completed, and of those, around 44 were less than 50 percent completed by 1980 (74 units on order were ultimately cancelled after 1979).[25] Six units were not completed until the 1990s. The costs associated with these decisions ran into the hundreds of billions of dollars and contributed greatly to the rise in rates in the 1970s and 1980s.[26]

3) Improper Allocation of Risks

Regulation improperly allocates risk between generation-building utilities and their customers. Prior to the 1970s, cost disallowances were virtually unknown in the electric utility industry. Should a generation facility prove uneconomic, the regulated model strongly suggested that the customers, rather than investors, would bear the risks of bad outcomes. Thus, there was little downside, and a great deal of upside, for utilities to bet large chunks of capital on big, capital-intensive baseload plants in the early 1970s. Customers still paid for the facility regardless of whether it was needed or not. The eventual disallowances of the 1970s and 1980s changed this calculus somewhat, but the risk distribution was still asymmetric, with customers paying for the majority of uneconomic capacity.

Not surprisingly, this inefficient allocation of risk creates an incentive problem for regulators and regulated utilities to underestimate risks, particularly risks associated with large baseload investments. The electricity supply business is inherently risky, because the future is uncertain with respect to those things that will determine the future market price of wholesale power: load growth, fuel prices, environmental costs, new technology, and so forth. For example, currently there is considerable uncertainty regarding the future cost and performance of new Integrated Gasification Combined Cycle (or "IGCC") plants, carbon capture sequestration technologies, and the costs and regulation associated with building new nuclear facilities. Therefore, large capital-intensive investments in new generation are unavoidably risky. Utility-built generation under a regulatory model or utility long-term contracts backed by ratepayer guarantees does not alter this fact – it merely shifts risks from the wholesale developer/supplier of generation to retail customers. In these risky electricity markets, unfavorable and unforeseen investment outcomes are common. Unfortunately, retail customers bear the responsibility of paying for those mistakes under regulation, while in competitive markets investors are responsible for the consequences of their decisions. Therefore, investors in competitive markets are more likely to respond quickly to changing market conditions than a regulated utility that can pass through its costs to retail customers. Indeed, under a regulated model of resource planning by utilities or regulators, with market risks assumed by customers, there have been many examples of long term generation commitments that turned out, after the fact, to be uneconomic. Whether the utility's commitments were in the form of utility-owned generation or long-term power purchase

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[25] Energy Information Administration, "An Analysis of Nuclear Power Plant Construction Costs," 1987.

[26] See footnote 15.

agreements, they were undertaken on behalf of ratepayers and were eventually paid for by ratepayers.

4) Political and Regulatory "Fixes" Overcompensate With Unintended Consequences

The turmoil of the 1970s led to a dissatisfaction with the existing regulatory process, and a search began for new regulatory solutions and models to counter the rate shocks experienced by consumers. Politicians and regulators then tried to "fix" some of the perceived imbalances in the energy industry. Related to the rise in fuel prices was an increase in concern that the nation's fuel supplies, oil and natural gas in particular, were insecure and limited in quantity. This concern led to a flurry of legislation and policy aimed at reducing the nation's dependence on oil and gas and promoting conservation, rationing, and end-use energy efficiency.

The most significant legislative response to the problems of the 1970s was the National Energy Plan, developed by the Carter administration and passed by Congress in 1978. The Plan actually consisted of several related pieces of legislation, the most important of which for the electric utility industry were the Power Plant and Industrial Fuel Use Act ("PIFUA") and the Public Utilities Regulatory Policy Act ("PURPA"). PIFUA and PURPA had unintended consequences that greatly influenced the course of the electricity industry through much of the 1980s and 1990s.

PIFUA was the culmination of a series of regulatory interventions in natural gas markets and federal restrictions on the development of gas-fired generation. PIFUA essentially prohibited development of new gas and oil power plants,[27] encouraged the conversion of gas/oil plants to coal, and limited the ability of utilities to run their gas/oil plants on a day-to-day basis. Starting in the 1950s, natural gas was subject to a complex regime of price controls that capped prices below their competitive market clearing levels and greatly limited the incentive to develop new gas supply. Exploration for new sources of gas production slowed, and the industry began to experience shortages by the mid-1970s. This regulatory interference with the gas market coupled with the federal restrictions placed on the use of gas as a power plant fuel (the Energy Supply and Environmental Coordination Act of 1974 and PIFUA in 1978) virtually eliminated natural gas as a viable fuel source for new generation, essentially forcing utilities to rely on coal or nuclear plants. While utilities were building up a huge surplus of coal and nuclear capacity, they also substantially reduced investment in less capital-intensive gas and oil capacity, building only about 2,400 MW, or about 2 to 4 plants, nationwide per year after 1975. Several studies of the natural gas industry have concluded that eliminating natural gas price controls and restrictions on gas-fired power plant investment would have provided a clear price signal and incentive to gas producers to increase production and develop new supply sources, ultimately lowering gas prices and potentially making natural gas a viable, cheaper alternative to much of the baseload generation developed in the 1970s and 1980s.[28] When gas prices were eventually decontrolled and PIFUA was scrapped, the

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[27] There were exceptions in specific cases to maintain system reliability, and, after 1978, to promote the development of non-utility cogeneration facilities.

[28] Paul MacAvoy, *The Natural Gas Market: Sixty Year of Regulation and Deregulation*, (New Haven: Yale University Press, 2000).

incentive to build gas-fired generation did indeed develop. Ultimately, over the course of the 1970s and early 1980s, regulated electric utilities built a generation supply portfolio that was far too big in absolute terms, and too heavily-weighted towards capital-intensive coal and nuclear generation.

PURPA's stated purpose was to encourage energy efficiency in an environmentally-friendly manner by increasing the usage of alternative, renewable electricity generation.[29] To achieve these goals, PURPA created a new class of power generators called Qualifying Facilities ("QFs") that were exempt from most of the cost-based regulation applied to utility generation. To be deemed a QF, a power generation facility had to demonstrate that it was either a cogeneration plant or a small renewable generator. Utilities were required to purchase all the electric energy that these QFs could generate at the utilities' "avoided cost," which PURPA ambiguously defined as the incremental cost to the utility of alternative electric energy. PURPA did contain some innovative elements that, in time, were to contribute to the transition of the industry towards a competitive model; most notably, it created a class of non-utility generators that built and operated power plants outside the cost-of-service regulated model. However, the command-and-control elements of PURPA, especially the mandatory nature of the utility obligation to purchase QF energy and the administratively-determined purchase price, would prove enormously costly to electricity consumers.

The first five years after the passage of PURPA were spent determining what the "avoided cost" principle established in the legislation meant in practical terms. Even after the Federal Energy Regulatory Commission ("FERC") defined avoided cost in 1980, state regulatory bodies were charged with developing long-term avoided cost forecasts to set the prices for the QF contracts. While the process of establishing prices and structuring contracts varied considerably from state to state, prices were administratively-determined, not market-based, and several key mistakes were made:

- In some states, contract rates were established above avoided costs in order to spur QF development. For example, the New York state legislature mandated that the states' utilities pay a minimum 6 cents/kWh long-term price to QFs,[30] even though utilities

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[29] "PURPA began the process of creating an independent generation sector and the supporting market and regulatory institutions to create a competitive market for new generating resources. The primary motivation for PURPA was to encourage improvements in energy efficiency through expanded use of cogeneration technology and to create a market for electricity produced from renewable fuels and fuel wastes. It was not motivated by a desire to restructure the electricity sector and to create an independent competitive generation sector. However, it turned out to have effects significantly different from what was intended when it was passed." (William Baumol, Paul Joskow, and Alfred Kahn, *The Challenge for Federal and State Regulators: An Efficient Transition from Regulation to Competition in the Electric Power Industry*, (Washington, DC: Edison Electric Institute, 1995) 8.)

[30] In New York, beginning in the 1980's in an effort to reduce reliance on utility-owned generation, the Public Service Commission ("PSC") required utilities to enter into contracts with non-utility generators at long-term fixed rates that were well above market prices. The New York Public Service Law was amended in 1981 to set the minimum sales price for the QFs' output at six cents/kWh. In practice, the PSC provided independent power producers the choice of six-cents or a fixed price stream equal to the PSC's estimate of long-run avoided costs ("LRACs"). The PSC's estimate of LRACs during the 1980s expected prices to rise well over six cents, and the PSC required that utilities provide the QFs with contracts of ten to fifteen years. Further, since the six-cent law provided no limit on the quantity of generation that could qualify for power contracts, QF developers planned projects with total capacity far in excess of what was reasonably required by load growth. Through this period,

estimated avoided cost at roughly half that amount.[31] In Maine, the rate was set at 9 to 10 cents/kWh based on the total all-in cost of the Seabrook nuclear generating station.[32]

- Many states did not readjust avoided cost rates as more QF capacity was added to the market. As QF capacity increased, the avoided cost (and the market price of electricity if it were known) should have gone down as the QFs displaced progressively cheaper capacity and energy. Many states failed to make this adjustment; however, with some establishing unvarying, above-market "standard offer" prices that QFs could receive without an avoided cost proceeding. This led to an oversupply of QF capacity in several states (California[33] and New York most notably), with long-term contract prices that were well above market.[34]

- Finally, many QF contracts were based on administratively-determined avoided costs using very high oil and natural gas price forecasts from the early to mid 1980s. Figure 16 shows the dangers of this approach. By the late 1980s and early 1990s, actual oil and gas prices had declined and were about 60 to 80 percent below the expected forecast levels from five to seven years earlier. Most long-term QF contracts, however, lacked any sort of adjustment clause to move the contract prices more in line with actual market conditions.

The overall effect of these mistakes was to burden electric utilities and their customers with a huge overhang of mandatory long-term contracts established at prices well above their actual avoided cost or any reasonable proxy of market prices. This burden was particularly concentrated in a number of states that set high, long-term, fixed PURPA prices without

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the PSC's forecast of LRACs failed to take into account the effect this excess supply would have on price until it was too late. When wholesale electricity prices fell dramatically in the 1990s, utilities and their customers were then saddled with onerous above-market long-term commodity contract costs. In addition, these contracts were structured as "must-take" agreements resulting in substantial uneconomic dispatch of New York generating plants, further exacerbating the collapse in wholesale electricity prices. The six-cent law was partially repealed in 1992, but many of the contracts already in place were grandfathered, preserving the six-cent minimum.

[31] Frank Graves, Philip Hanser, and Greg Basheda, The Brattle Group, "PURPA: Making the Sequel Better than the Original," prepared for the Edison Electric Institute, December 2006, 15-16.

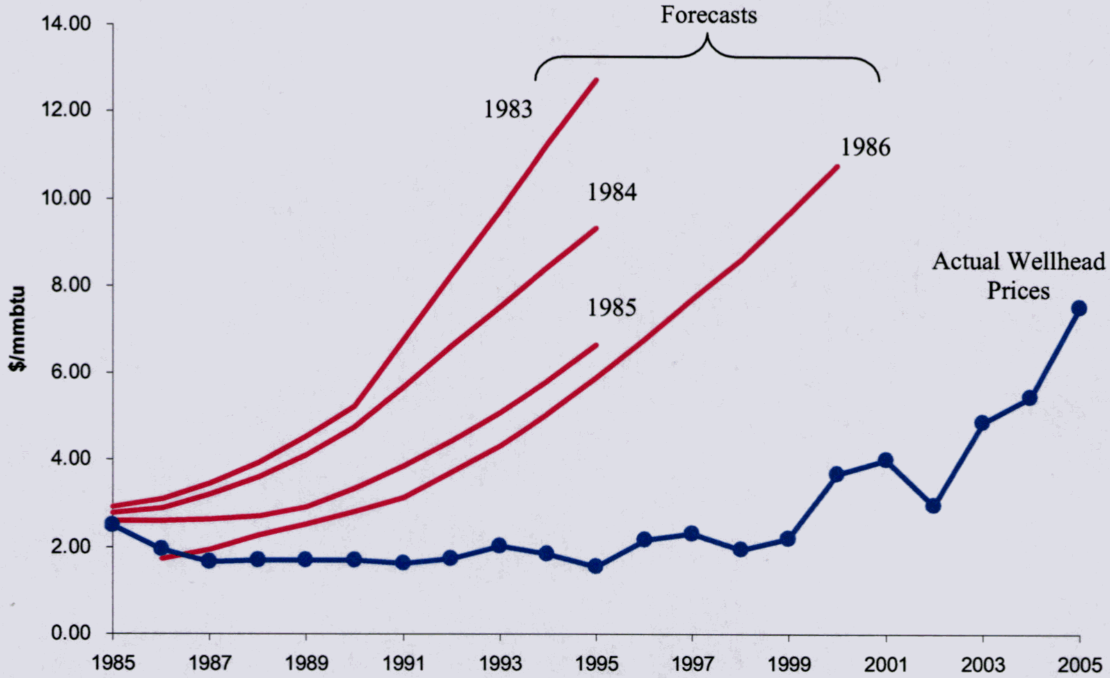
[32] Carroll Lee and Richard Hill, "Evolution of Maine's Electric Utility Industry, 1975-1995," *Maine Policy Review*, Vol. 4, No. 2 (1995): 22.

[33] Like New York, following the passage of PURPA, the California Public Utilities Commission interpreted the utility's obligation to purchase non-utility generation administratively. California utilities were required to purchase power at the utilities' long run marginal costs based on the expected cost of oil. At the time, oil was very expensive and expected to increase further in the future so the purchase price from QFs was set very high. California utilities were required to contract for all of the power offered at the state-determined price during an extended period. Unexpectedly, QF cogenerators were able to rely on low natural gas prices that were well below the oil price used to set the QF contract price. As a result, California utilities committed to contract for several thousand MW of QF electricity at high prices before the offer was terminated.

[34] Graves, Hanser, and Basheda, 16-17.

regard to the impacts of this QF supply on the price.[35] Overall, the cost to consumers from the mid-1990s onward was estimated at almost $50 billion in 2007 dollars.[36]

Figure 16 Actual Natural Gas Prices Fell Below Forecasts of the Mid-1980s



Source: Forecasts – Energy Information Administration, *Annual Energy Outlook*, Various Editions; Actual wellhead prices from Energy Information Administration, *Annual Energy Review*, 2005.

Problems similar to those experienced with the PURPA contracts have recurred in other later situations where regulators mandated long-term contracts. Most recently this happened in 2001 when the California Department of Water Resources stepped in to buy power under long-term contracts in the midst of the California energy crisis. Just a year later, the California Public Utilities Commission estimated that these contracts had burdened customers with approximately $21 billion in above-market costs and filed a (largely unsuccessful) complaint with FERC to allow the state to abrogate the contracts and to replace the contracts with lower-priced power at prevailing market prices.[37]

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[35] By the time restructuring was being contemplated in the second half of the 1990s, the difference between PURPA contract prices and competitive market prices was estimated to be a major contributor to regulated utilities' stranded costs - roughly 30 percent nationwide and as much as 70 percent in certain regions such as New York and California.

[36] Resource Data International, *Power Markets in the U.S.,* Boulder, CO, 1996.

[37] California Public Utilities Commission (CPUC), "PUC to Make Complaint to FERC Against Sellers of Long-Term Contracts," CPUC Press Release, 24 February 2002.

C. Key Lessons of the Past Should Not Be Forgotten

Reviewing this past experience in the electric utility industry reveals several lessons on the shortcomings of regulation:

1. First and foremost, future electricity costs and prices are inherently uncertain. Because future load levels and fuel prices are unknown – as are changes in technology and environmental requirements – investments in long-lived generation assets are inherently risky. We can centrally plan these decisions, and impose the risks on retail customers, but we should not be surprised when things turn out badly for customers, particularly when we evaluate projects over 30 year time horizons and the risks are not borne by investors.

2. Decision-making under regulation performs particularly poorly in times of uncertainty. As the prior discussion makes clear, many of the difficulties in the electric industry arose from the fact that the administrative, command-and-control approach to resource allocation under regulation was too inflexible and too slow to respond to external stresses and changing market conditions.

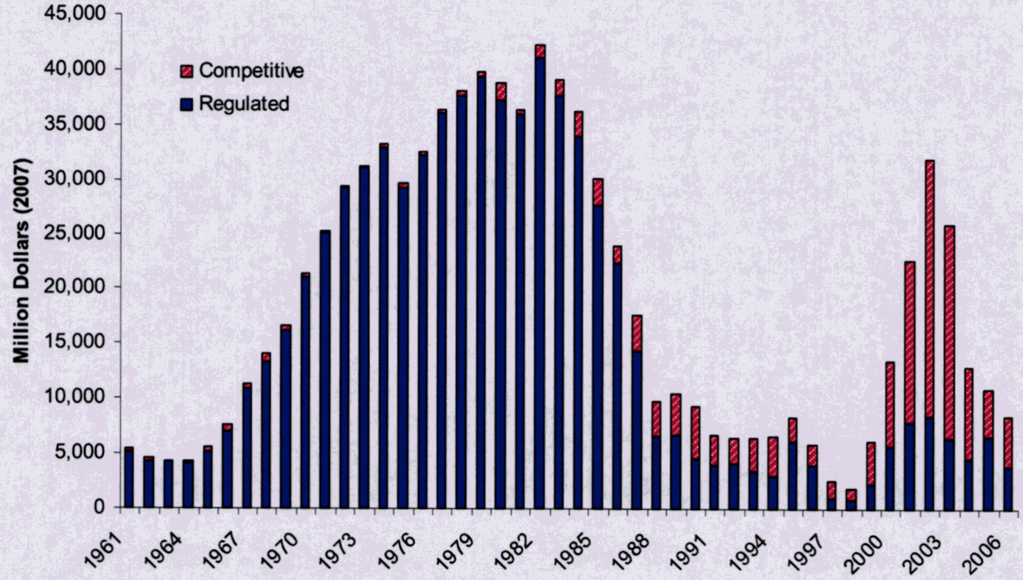
3. Inherent incentive problems with regulation create a tendency to take into account sunk costs when making decisions and to significantly underestimate the risks associated with high-capital cost investments. Much of the excess of planned baseload capacity at the start of the 1970s energy crises and the failure to trim that excess sufficiently in response to changing conditions can be attributed to improper incentives for regulated utilities.

4. Political and regulatory "solutions" to perceived problems can produce costly and unintended consequences. While PIFUA and PURPA may have seemed like reasonable responses to the headline problems of the time, their failure to incorporate market elements led to costly, inefficient responses that took years to correct.

Some might suggest that we can create a new, better form of regulation that would not repeat such mistakes. But the problems with regulation are inherent: decisions are administratively-determined versus market-driven, and the dollars at risk are highest and the potential for damage greatest during times of high capital investment. The mistakes of the 1970s were amplified by the sheer scale of the investment that utilities put at risk through baseload investments.

Figure 17 shows real investment in electric generation capacity in dollar terms since 1961. From 1970 to 1988 regulated utilities invested an average of $30 billion dollars per year in generation, compared to an average of $5 billion per year from 1989 to 2006. Over the past twenty years, because of the capacity overhang from the 1970s, there has been relatively little generation investment activity in the electric industry, particularly by regulated utilities. Thus, the opportunity for regulatory mistakes has been much lower. But, as discussed earlier, a new wave of investment is coming.

Figure 17 Real Investment in Electric Generation Capacity, 1961-2006



Source: Edison Electric Institute, Historical Statistics of the Electric Utility Industry Through 1992; NorthBridge analysis.

Some industry observers have advanced the notion that the coal and nuclear plants of today, with capital costs largely paid off and collected from customers, represent beneficial low-cost generation that is badly needed in today's rising-cost environment and that policy-makers should be glad that these plants were built. While it is true that coal and especially nuclear plants that were built in the 1970s and 1980s represent low-cost generation today, this is only because the high capital cost of those plants was borne by customers over the thirty-odd years since they were put into service. Measured over their entire life-cycle, many of these plants represented a bad investment for ratepayers and resulted in substantial excess capacity in the 1970s and 1980s and billions of dollars in higher costs relative to alternative supply strategies.

IV. The Case for Competition is Still Compelling

The case for competition is still compelling, supported by both economic theory and a careful examination of empirical evidence. While the restructuring of the electric industry has proven to be a lengthier and more difficult process than anticipated, many of the recent arguments criticizing competition do not warrant returning back to regulation. Competition and market pricing encourages: (1) greater improvements in existing plant operations and administration, (2) greater efficiencies in plant investment and retirement decisions, (3) better customer consumption decisions, and (4) a wider selection of retail products and services. This innovation throughout the electric industry value chain, spurred by competitive forces, is greater than that experienced under regulation. Many of these benefits have already been evidenced in the brief history of electric competition, and the additional benefits that will materialize over time are illustrated by the experience of other competitive industries.

A. Many Criticisms of Competition Have Emerged Recently

Today, electricity competition is under attack in the press and in many state legislatures and regulatory commissions. Since the beginning of the restructuring process, the public has read newspaper headlines about the California energy crisis, the Enron scandal, skyrocketing fuel prices, competitive generating company bankruptcies, and competitive generating company excess profits. Numerous studies, articles and reports have criticized competition or various aspects of restructuring. These complaints can be categorized into four broad concerns – high prices, high profits, poor resource planning, and limited customer switching to competitive suppliers.

First, opponents claim that competition has led to high prices – either high rate levels and/or high percentage rate increases – in restructured states relative to those experienced in regulated states.[38] Large rate shocks recently experienced in many states (e.g., Maryland, Delaware, Connecticut, and Illinois) are used as evidence to question the merits of competition.[39] While opponents acknowledge the recent increases in fuel costs, they argue that markets are not workably competitive[40] and competition has imposed new administrative

[38] Based on a comparison of percentage rate changes in industrial prices in restructured and regulated states, Jay Apt finds no improvement in prices in restructured states. (Jay Apt, "Competition Has Not Lowered U.S. Industrial Electricity Prices," Electricity Journal, Vol. 18, No. 2, (2005), 52). On the other hand, Mark Fagan developed an econometric model of industrial prices in 1970-1997 by state that he used to predict prices in 2001-2003. From his analysis, he concludes that predicted prices were higher than actual in restructuring states relative to states without restructuring, suggesting that restructuring has lowered prices. (Mark Fagan, "Measuring and Explaining Electricity Price Changes in Restructured States," Kennedy School Working Paper, No. RPP-2006-02, June 2006.)

[39] Paul Davidson, "Shocking Electricity Prices Follow Deregulation," *USA Today*, 10 August 2007.

[40] Synapse Energy Economics in a study prepared for the American Public Power Association ("APPA") states that the LMP approach to electricity pricing generally supports the efficient operation of existing resources, if the LMP pricing reflects short run marginal costs, but because electricity markets are bid-based, not cost-based and markets are not perfectly competitive, implementation of LMP is compromised and opens the door for the exercise of market power under certain conditions. (Ezra Hausman, et. al, Synapse Energy Economics, Inc., "LMP Electricity Markets: Market Operations, Market Power, and Value for Consumers," 5 February 2006, ix.) London Economics prepared a study that compared simulation-based estimates of prices that would result if all generators in PJM Classic were bidding their short-run marginal cost of producing electricity with actual market

and regulatory costs on customers, including high RTO costs,[41] capacity prices, congestion costs, and reliability payments.

Second, several studies claim that competition has led to high profits and profiteering, particularly for unregulated owners of baseload nuclear and coal generation that was built under prior regulation.[42] Opponents of restructuring argue that it has led to an enormous wealth transfer from retail customers, who paid for these assets, to unregulated utility affiliates, who now own this generation. The high profits of restructured utilities as compared to those that remain regulated are cited as evidence of market failure. Part of the concern stems from marginal cost pricing, which reflects the variable generating cost of the most expensive unit needed to meet load. Opponents argue that generator payments to baseload and mid-merit plants based on the higher marginal costs of peaking plants unjustly pays the operators of baseload and mid-merit plants more than their costs, allowing them to earn more than they would under cost-of-service regulation.[43] Some blame large capacity payments to owners of existing generation, while others raise issues of market price

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clearing prices for a 43-month period, January 2003 through July 2006. The study reported that for most months studied the price-cost markup indices, especially for peak periods, are significantly higher than zero and that further study and analysis is necessary before conclusions can be drawn about the efficacy of the market system in PJM. (Julia Frayer, Amr Ibrahim, Serkan Bahceci, and Sanela Pecenkovi, London Economics International LLC, "A Comparative Analysis of Actual Locational Marginal Prices in the PJM Market and Estimated Short-Run Marginal Costs: 2003-2006," 31 January 2007.) In a paper prepared by John Taber, Duane Chapman, and Timothy Mount, the authors developed an econometric model of total average rates as well as residential, commercial, and industrial rates, by utility, for the period 1990-2003, controlling for differences in climate, fuel costs, and electricity generation by energy source. Their analysis does not support a conclusion that deregulation has led to lower electricity rates. They find that even though most customers in deregulated states saw declines in the real price of electricity, they faced higher prices relative to customers in still-regulated states. (John Taber, Duane Chapman, and Timothy Mount, "Examining the Effects of Deregulation on Retail Electricity Prices," Cornell University Working Paper, February 2006, 45.)

[41] A GDS Associates report examines the operational and administrative costs incurred by the nation's RTOs for 2001 through 2005. It finds that in 2005, RTO participants paid over $1 billion in total costs, most of which (75 percent) consists of administrative costs with the remainder (25 percent) operational. As RTOs mature, these costs on a per MWH basis tend to decrease, but as RTOs expand their services, costs tend to increase. (GDS Associates Inc., "Analysis of Operational and Administrative Cost of RTOs," prepared for the American Public Power Association, 5 February 2007, 28.) John Kwoka reports that many of the studies he reviewed fail to address the rising costs of RTOs, inadequate RTO governance processes, and the failure of RTOs to deal with transmission congestion or encourage new investment in transmission. (John Kwoka, "Restructuring the U.S. Electric Power Sector: A Review of Recent Studies," prepared for the American Public Power Association, November 2006, vii.)

[42] Edward Bodmer performed a study in February 2007 for the APPA, "The Electric HoneyPot: The Profitability of Deregulated Electric Generation Companies," that concludes that profits for deregulated generation are far higher than they would be if the plants were still under cost-based regulation. His analysis reviews the profitability of the largest sellers of unregulated generation in the PJM market and compares their financial performance with that of regulated, vertically owned utility companies. He observes that companies that fared the best tend to be owners of baseload generating assets that were formerly regulated. The APPA claims that certain sellers into RTO-run centralized markets are leveraging baseload generation built under prior regulation and are making very substantial profits and that incumbent sellers in PJM are making profits well-above what they would make under cost-of-service pricing. (Comments of the APPA, FERC docket RM07-19-000 and AD07-7-000, September 2007, 27)

[43] Baseload plants tend to be cheaper to operate but more expensive to build, while peaking plants tend to be more expensive to operate and less-expensive to build. Mid-merit or intermediate plants are in between.

manipulation and the potential exercise of market power, concluding that RTO prices appear "unjust and unreasonable."[44]

Third, there is considerable concern within the industry that competitive wholesale markets are not encouraging enough new investment in generation.[45] Parties cite projected declines in reserve margins in restructured regions of the country as compared to reserve margins in regions that remain regulated. Some opponents believe that only regulation and cost-of-service rate-making will ensure reliability, and others suggest that utilities be allowed or required to enter into long-term contracts, backed by regulatory guarantees, to promote the development of new generation. Other opponents lament the separation of generation and transmission functions and the loss of benefits associated with vertical integration.[46]

Finally, in most states (with the exception of Texas), there is the complaint that competition has resulted in little customer switching, especially among residential and small commercial customers. This lack of retail shopping is used as evidence for the failure of restructuring.[47]

In evaluating these arguments, it is important to recognize that many recent studies focus on the past ten or so years of restructuring experience, several of which are cited throughout this paper. But as described earlier, many of the challenges experienced in the industry today are more similar to those of the 1970s than those of the past ten years.

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[44] See Comments of the APPA, FERC docket RM07-19-000 and AD07-7-000, September 2007, 18. Kenneth Rose also prepared a study for the APPA, "The Impact of Fuel Costs on Electric Power Prices," (June 2007) that concludes while fuel price increases have played a role in higher electricity prices, they do not explain everything. He points out that while electricity price and natural gas costs often moved together, other factors are also important (e.g., customer load and its seasonal variation, and supplier costs and risks embedded in full requirements service retail rates). Mr. Rose raises the possibility that "strategic actions by suppliers" or "market design and structure" may also explain price changes in wholesale markets. In another study for the APPA, John Kwoka reports that studies generally do not consider that restructuring has been accompanied by market power, market manipulation, and numerous mergers among utilities. They also ignore costs of the loss of vertical integration and risk of market power abuses. (Kwoka, 73-75.)

[45] Timothy Mount prepared a study for the APPA that reviews NERC capacity margin forecasts 2003-2006 by region. He concludes all deregulated regions are having trouble getting investors to commit to building new generating capacity when it is needed. He notes that resources in deregulated regions are not being committed as far in advance as they used to be under traditional regulation, and the current performance of deregulated markets is poor in terms of ensuring that there is enough installed capacity to meet projected loads reliably. Meanwhile, substantial payments have been made to existing generators that supplement their earnings in the wholesale market. (Timothy Mount, "Investment Performance in Deregulated Markets for Electricity: A Case Study of New York State," September 2007, 1-10.)

[46] Jerry Taylor and Peter Van Doren of the Cato Institute argue that unfortunately, price deregulation has been accompanied by rules encouraging the legal separation of generation from transmission and the purchase of wholesale power through organized spot markets. Vertical integration of generation and transmission is efficient – since an integrated owner would not "hold-up" new investments, would consider substitution effects, and provide for more coordinated real-time operation. (Jerry Taylor and Peter Van Doren, "Short-Circuited," *Wall Street Journal*, 30 August 2007.)

[47] Davidson, "Shocking Electricity Prices Follow Deregulation."

B. Historical Rate Comparisons to Date Are of Little Value

Authors of the competition versus regulation studies, as well as critics, acknowledge a variety of difficulties with attempting to compare regulated and competitive markets.[48] Many of the recent studies focus on historical rate comparisons – both before and after restructuring in the same state, and across regulated and restructured states. Presumably, the purpose of such rate comparisons is to determine whether competition has produced higher or lower rates than would have existed under regulation. However, it is difficult, if not impossible, to know what rates would have been in the absence of competition, making a fair rate comparison problematic.[49]

To further complicate state comparisons of restructuring and regulation, restructuring is not well-defined. In fact, many studies often do not agree on whether a particular state should be included in the "restructured" or "regulated" category. Unlike restructuring in other industries, which often occurred as a result of changes in federal legislation, restructuring in the electric industry occurred in a more decentralized manner. Key elements of the restructuring process include: a) providing utilities and non-utilities open-access transmission service, b) splitting up vertically integrated utilities by separating control of transmission and generation assets, c) the formation of ISOs and RTOs and centralized wholesale electricity markets, d) developing stranded cost recovery mechanisms for past utility investments and past contracts that regulators approved/required during regulation, e) establishing transition periods and default service pricing to move from a regulated to a competitive market structure, and f) allowing retail access programs (including customer switching, customer protection, deposit and disconnect rules, and systems for processing retail market transactions). These changes both in wholesale and retail electricity markets have occurred in stages that vary in form over time and often by U.S. region, state, service area, and even customer type. And in several instances, there has been considerable conflict between federal and state authorities over legal jurisdiction over market structure design. The lack of consistent policies, along with fundamental changes in economic conditions since the advent of restructuring, has made it difficult to compare regulated and competitive market structures.

In addition, certain market initiatives integral to industry restructuring, such as open-access transmission and the expansion of competitive generation have also benefited regulated states, even though those states do not have retail choice. For example, almost 72 GW of unregulated generation were constructed in regulated states between 1997 and 2007. This construction reduced both prices in these states and the need for regulated utilities to build rate-based plants, further complicating comparisons between regulated and restructured states.

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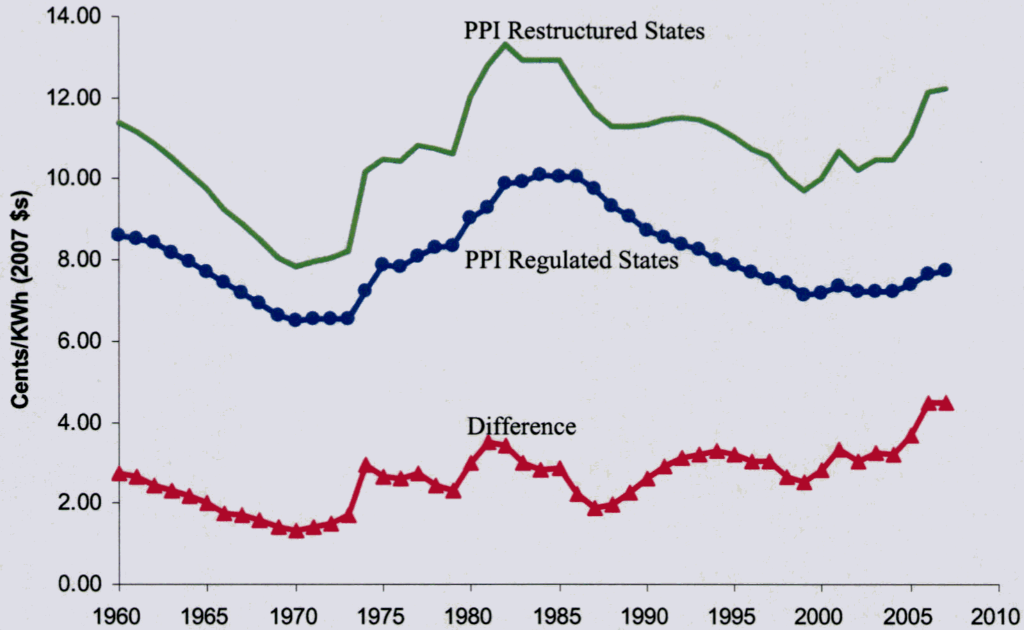
[48] Efforts to date attempting to compare regulated and competitive markets have proven difficult due to the lack of sufficient data and other fundamental complications with such an analysis. John Kwoka, in his review of restructuring studies, found three common problems with most studies: 1) lack of precision about what is meant by restructuring, 2) failure to recognize that post-reform prices were set administratively and do not reflect market levels, and 3) failure to control for other factors that affect prices unrelated to restructuring. (Kwoka, 7-24.)

[49] Several econometric studies have attempted to control for some of the variables and changes that have occurred since restructuring. However, the results of these studies are mixed. See citations within these footnotes.

Most studies, however, attempt to compare regulated and restructured states, and acknowledge that rates in states that have restructured have been higher than rates in regulated states for a long time, and that this price gap predates restructuring and the introduction of competition. Figure 18 compares historical average real rates for states that have restructured with states that have remained regulated based upon the state characterization utilized in a recent analysis by Power in the Public Interest (hereafter referred to as "PPI Restructured States" and "PPI Regulated States").[50]

Figure 18 Real Retail Electric Rates in PPI Restructured and PPI Regulated States, 1960-2007



Source: Edison Electric Institute, Historical Statistics of the Electric Utility Industry Through 1992; Energy Information Administration State-Level Spreadsheets, 1990-2006; 2007 rates are from December 2007 Energy Information Administration Electric Power Monthly; Average rates are weighted by consumption in each state.

The significant rate gap between states that restructured and those that remain regulated is due to regional differences in a wide variety of factors: fuel and construction costs, state regulatory policies, generation mix, customer types, consumption patterns, population density, and supply and demand balances.[51] The gap between the two groups actually closed as competition was introduced in the late 1990s – primarily due to rate cuts embedded in the

[50] For purposes of this comparison only, we utilize the same definition of restructured states as a recent analysis by Marilyn Showalter of Power in the Public Interest, "Trends in State Electricity Prices and Policies" (*Presentation to MEAG*, 17 July, 2007.) This analysis defines CA, CT, DC, DE, MA, MD, ME, MI, NH, NJ, NY, RI, and TX as restructured/deregulated. While we disagree with certain elements of this categorization (particularly the inclusion of California and the exclusion of Illinois and Pennsylvania), we adopt this definition to allow for comparison of our results with other studies that take a critical view of competition.

[51] Local transmission monopolies facilitated the disparity in retail rates by restricting the ability to move electricity economically across service territory boundaries. When purchasing electricity, a buyer often had to pay the transmission rate to each utility that it moved through, commonly referred to as rate "pancaking." This limited the ability to move power from low-cost areas to more expensive areas.

restructuring deals and transition periods[52] – but has expanded since 2005. Once transition periods and rate controls began to expire in restructured states, market conditions were dramatically different than at the start of restructuring. Significant increases in fuel costs, unrelated to the restructuring of the electric industry, have caused wholesale market prices to increase significantly throughout the United States (see Figure 2 and Figure 4).[53] As a result, when rate caps expired at the end of restructuring transition periods, many consumers of electricity were exposed to sudden price increases. In several instances, these rate shocks resulted in legislative and/or regulatory intervention, which ultimately led to phase-ins of market rate increases and deferred cost recovery.

While acknowledging this long-running rate gap between regulated and restructured states, many opponents of competition focus on a snapshot comparison of rates as they are today in restructured states to the rates in effect in those same states in the late 1990s, prior to restructuring. This comparison misses several key points. First, rates in regulated states have also experienced significant rate increases over the same period.[54] Figure 19 shows the annual change in nominal rates for both PPI Regulated and PPI Restructured States indexed to 1997, just prior to restructuring in most states. By 2007, nominal rates in PPI Restructured States had increased by 44 percent relative to 1997, but had also increased by 28 percent in PPI Regulated States.

Second, most of the increase in rates in PPI Restructured States has occurred in the past three years. This lag in the rate of increase in restructured states was primarily due to rate freezes that were part-and-parcel of the restructuring process. These negotiated rate structures, which did not reflect market prices, prevented more gradual increases in rates like those experienced in regulated states or restructured states with market adjustable rates. The price increases in restructured states from 2005 onward can be primarily traced to the expiration of rate freezes[55] coinciding with an increase in marginal generation costs, largely due to the rise in natural gas prices. Had natural gas prices not increased dramatically, the rate comparisons between restructured and regulated states may have appeared substantially different. Figure 20 shows a similar comparison between PPI Restructured States and PPI Regulated States, but compares only states where natural gas either strongly influences the competitive market price in restructured states or forms a large portion of fuel costs in regulated states.

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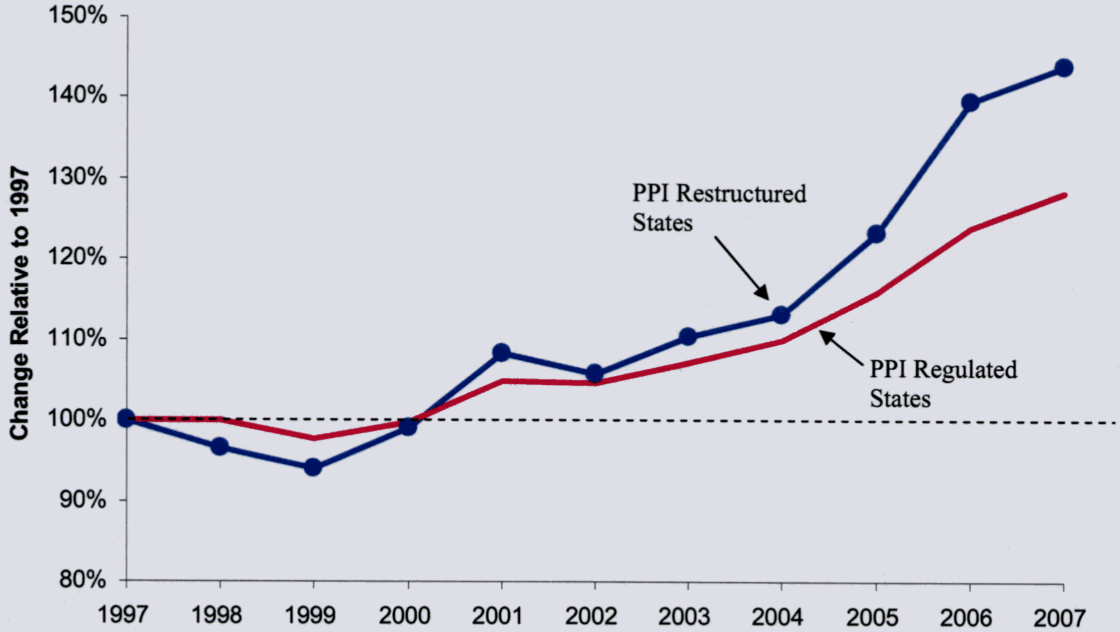
[52] Past restructuring deals included stranded cost determinations along with negotiated rate decreases and/or mandated rate freezes during prescribed transition periods.

[53] A Brattle Group report finds that, "On an industry-wide basis…fuel and purchased power costs account for roughly 95 percent of the cost increases experienced by utilities in the last five years. The increases in the costs of these fuels have been unprecedented by historical standards, affecting every major electric industry fuel source." (Greg Basheda et. al., The Brattle Group, "Why are Electricity Prices Increasing? An Industry-Wide Perspective," prepared for The Edison Foundation, June 2006, 2.)

[54] Studies performed both by The Brattle Group and the Analysis Group also find that regulated states have seen substantial increases in average annual retail prices similar to that observed in the restructured states. (Analysis Group, "Electricity and Underlying Fuel Prices - A Survey of Non-Restructured States," April 2006; Greg Basheda, Johannes Pfeifenberger, and Adam Schumacher, The Brattle Group, "Restructuring Revisited: What We Can Learn From Retail-Rate Increases In Restructured And Non-Restructured States," *Public Utilities Fortnightly*, June 2007, 64-69.)

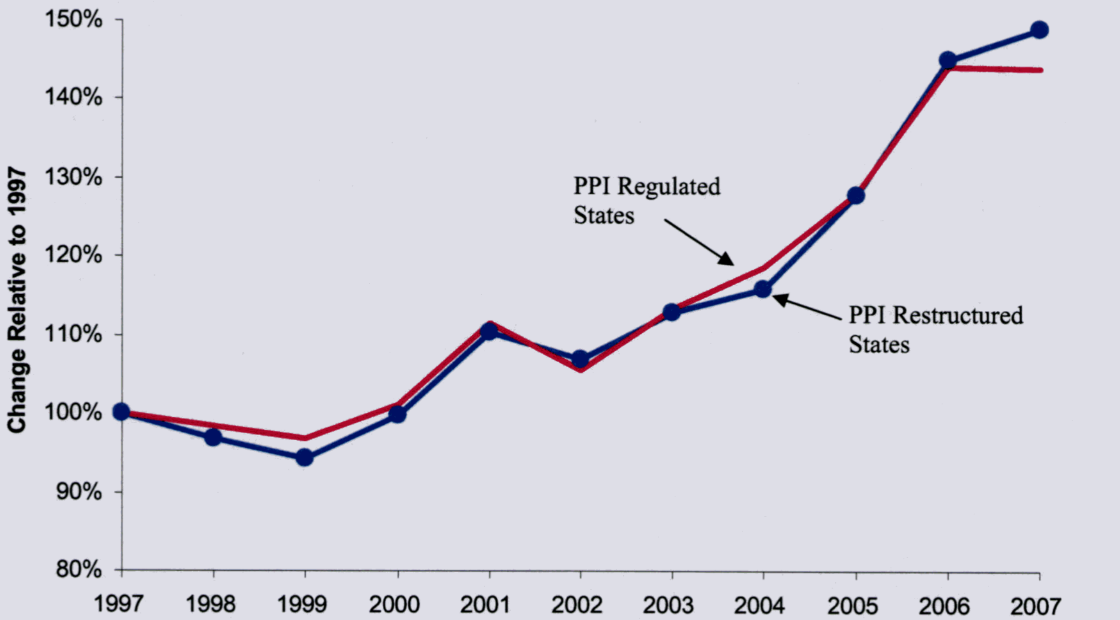
[55] Since 2005, several major restructured states such as Illinois, Massachusetts, Connecticut, and Maryland have transitioned from rate freezes to auction-based frameworks in which customers receive competitive wholesale market prices. Other states such as Texas and New Jersey had transitioned to a market price framework earlier.

Figure 19 Rate of Change in Nominal Electric Rates in PPI Restructured and PPI Regulated States, 1997-2007



Source: Edison Electric Institute, Historical Statistics of the Electric Utility Industry Through 1992; Energy Information Administration State-Level Spreadsheets, 1990-2006; 2007 rates are from December 2007 Energy Information Administration Electric Power Monthly; Average rates are weighted by consumption in each state.

Figure 20 Rate of Change in Nominal Electric Rates in Gas-Dependent PPI Restructured and PPI Regulated States, 1997-2007

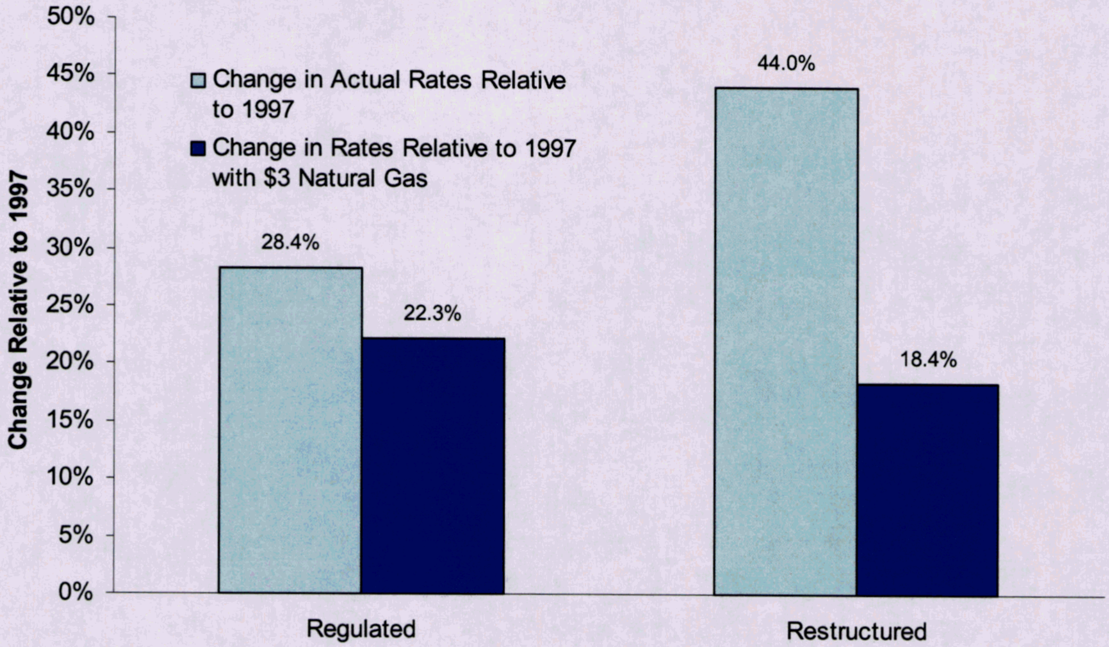


Source: Edison Electric Institute, Historical Statistics of the Electric Utility Industry Through 1992; Energy Information Administration State-Level Spreadsheets, 1990-2006; 2007 rates are from December 2007 Energy Information Administration Electric Power Monthly; Average rates are weighted by consumption in each state; Gas-dependent restructured states are from the ISO-New England, NY ISO, ERCOT, PJM East, and CA ISO market regions and include all PPI Restructured States except Michigan; Gas-dependent regulated states are defined as any regulated state where gas/oil generation comprises 30% or more of total generation output (FL, LA, NV, MS, and OK).

When compared in this manner, rate increases in both PPI Restructured and PPI Regulated States track one another very closely.

Figure 21 compares actual price changes over the 1997 to 2007 period to an estimate of what rates would have been had natural gas prices remained at $3/MMBTU, approximately their level in the late 1990s.

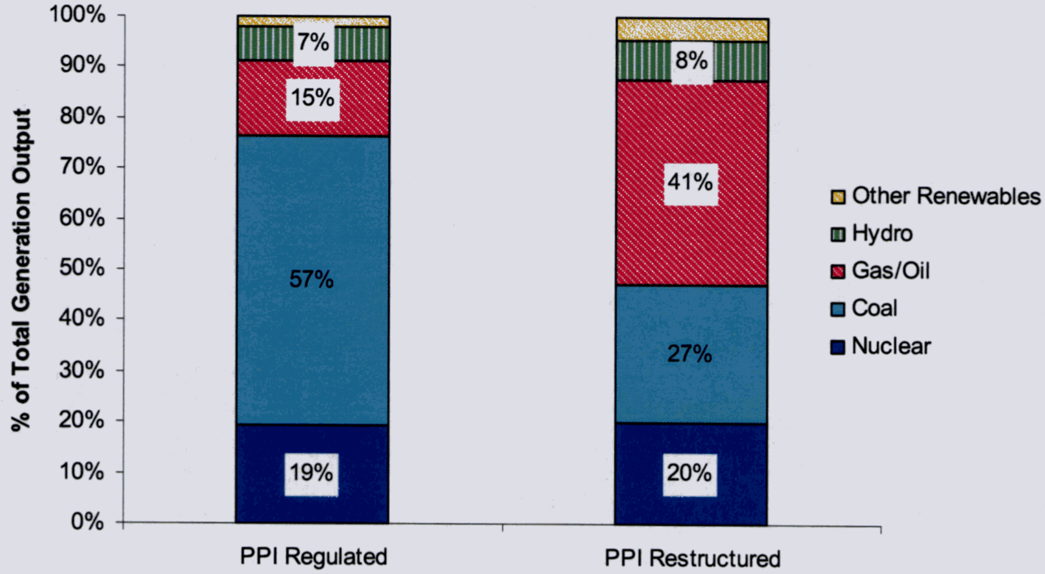
Figure 21 Change in Nominal 2007 Rates Relative to 1997, Actual vs. If Natural Gas Remained at $3 Per MMBTU



Source: Edison Electric Institute, Historical Statistics of the Electric Utility Industry Through 1992; Energy Information Administration State-Level Spreadsheets, 1990-2006; 2007 rates are from December 2007 Energy Information Administration Electric Power Monthly; Average rates are weighted by consumption in each state; NorthBridge Analysis.

Under this comparison, rates in PPI Restructured States would have only risen by 18 percent by 2007, relative to 1997, while rates in PPI Regulated States would have risen by 22 percent. These differences are primarily caused by the variation in fuel inputs used to produce electricity combined with differences in how electricity is priced to end-use customers in regulated and restructured states (as discussed later). Figure 22 compares the electric generation by fuel type in both PPI Regulated and PPI Restructured States.

Figure 22 Electric Generation By Fuel Type: PPI Regulated vs. PPI Restructured States



Source: Energy Information Administration, State-Level Spreadsheets, 1990-2006. Data shown is for 2006.

PPI Restructured States generate 41 percent of their electricity from natural gas, compared to 15 percent in PPI Regulated States.[56] This difference dates back at least to the 1980s and is not a product of restructuring or competition. Instead, it reflects decisions made by utilities and regulators in favor of cleaner gas generation relative to cheaper, but dirtier, coal.[57] As a result, PPI Regulated States, as a group, emit about 30 percent more CO_2 per MWH than do PPI Restructured States. The reliance on natural gas in restructured states has the effect, however, of amplifying the effect of changes in natural gas prices on rates in restructured states. Florida, a similarly gas-dependent regulated state, has experienced much larger rate increases – 26 percent – from 2004 to 2007. This is much larger than the average rate increase of 17 percent in other regulated states, but similar to the average rate increase of 27 percent in restructured states over the same period.

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[56] "…some regions (like New England, California, and Texas) that rely significantly on natural gas to produce power have relatively high electricity prices…States in parts of the country (such as the South, the Mountain states, and the Midwest) that produce more than 50 percent of their power from coal have among the lowest electricity rates in the country. Of the 30 states with rates below the average state electricity rate in 2006…, 26 of them were from these regions with a high percentage of power produced by coal." (Susan Tierney, Analysis Group, "Decoding Developments in Today's Electric Industry – Ten Points in the Prism," commissioned by the Electric Power Supply Association, October 2007, 4.)

[57] While both natural gas and coal are fossil fuels, natural gas burns more cleanly than coal. Per megawatt-hour of power produced, relative to a typical coal plant, a natural gas combined cycle plant will emit about 40% of the CO_2, 5-50% of the acid-rain causing nitrogen oxides (depending on the level of control at the comparison coal plant), and essentially zero sulfur, mercury, and particulate matter.

C. Market Prices Provide the Right Price Signals

Retail rates in most restructured states are now based on competitive wholesale prices. In a competitive wholesale market, the variable generating cost of the most expensive generating unit needed to meet load sets the wholesale price for all generation in the market.[58] The price is determined by the market: all transactions between sellers and buyers tend toward one price for the same product (electricity at a given time and location), taking into account available supply and demand. The price obeys what is referred to in economics as the "law of one price."[59] This is commonly referred to as "marginal cost" pricing. The price-setting marginal unit will be a higher-cost unit, such as a gas/oil unit or older coal plant. Therefore, the price for the entire market will be based on the higher variable costs of these types of units, regardless of whether coal or nuclear units with lower variable costs are also online and generating electricity.

Regulated retail rates, however, have traditionally been determined using "average cost" pricing. Under this approach, the total cost of the portfolio of resources needed to serve load, from baseload plants to peaking units, is averaged across total load, and this average price is charged to each increment of load. This total cost includes both variable operating costs as well as the historical embedded capital costs of building and financing generation. These two types of pricing differ most significantly in how generators recover their capital and fixed operating costs: in market-based marginal cost pricing all fixed cost recovery flows through the market price (although recovery is not guaranteed), while in average cost pricing generators are allowed to pass through their variable costs and recover their capital and fixed operating costs through regulated base rates. All else equal (ignoring any demand-side effects), we would expect both marginal cost pricing and average cost pricing to yield a similar average price over long time periods. However, there are two important differences. First, in the presence of uncertainty and rising/falling costs, the two types of pricing will usually differ at any particular "snapshot" in time. Second, because market-based marginal cost pricing reflects the variable generating cost of the most expensive unit needed to meet

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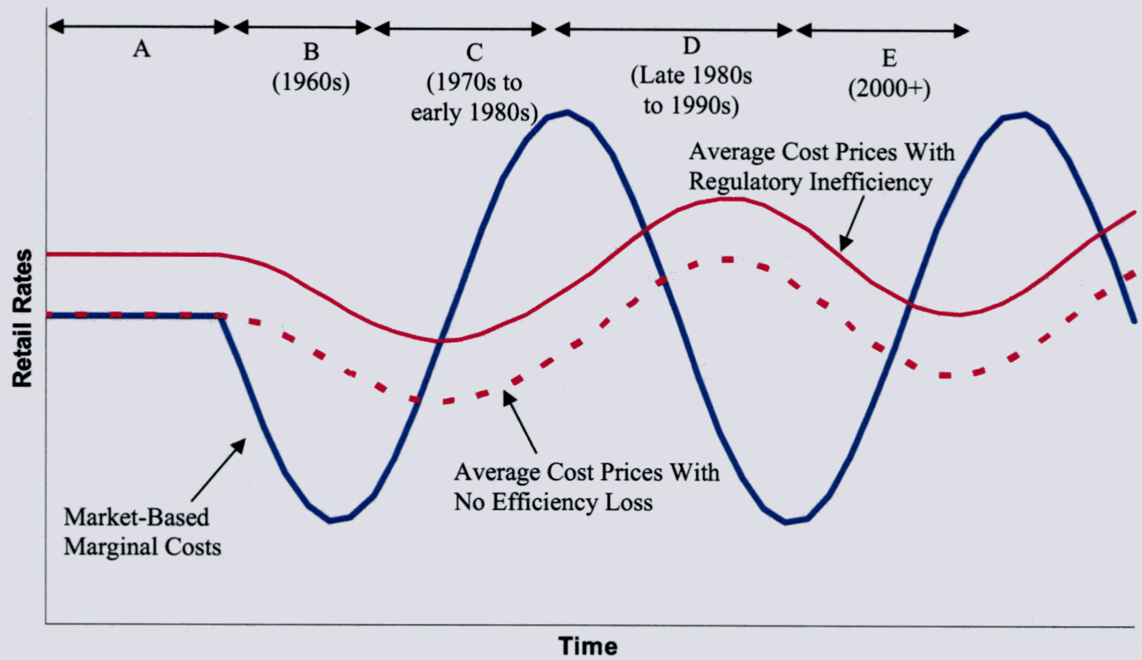
[58] In a pool trading system, an auctioneer can see all the bids and can choose between two broad payment schemes. The auctioneer can pay dispatched generators what they bid – this is similar to the bilateral trading model described in the footnote below. Alternatively, the auctioneer can pay dispatched generators a uniform market price based on the marginal cost of the highest cost generator operating. In theory, neither the market structure nor the payment scheme should make any difference for the level of wholesale prices. In a bidding system where generators are all paid the same market clearing price – like in the United Kingdom and most U.S. energy markets – the generator bidding strategy changes but the resulting market price does not. As before, no generator would rationally bid a price below its marginal cost. However, rather than bid the estimated market clearing price, each generator will have an incentive to bid its actual marginal costs. Economist William Vickrey (1961) noted that by making the price received by a player independent of its own bid, marginal cost pricing can be induced as a dominant bidding strategy for all participants. This system is perhaps more efficient since it encourages generators to reveal their true marginal costs rather than attempt to estimate the market price – although the price outcome is essentially the same in markets with good information flows.

[59] Bilateral transactions allow buyers and sellers to propose prices and indicate desired quantities with different payments. However, with good information available and many buyers and sellers, i.e. a liquid market, traders are aware of each other's price quotations, and they come to have nearly identical opinions of the prevailing market price at any moment. For a buyer to quote too far below "the price", or for a seller to quote too far above it, is essentially to withdraw from the market, and there is no reason to expect such extreme quotations to be accepted. Commodity exchanges organize this type of trading at a single point in time on a trading floor. The outcome of this competitive trading process is that all buyers and sellers are price takers, not price makers.

load, it provides a superior price signal (as described further below) for dispatch of existing resources, new entry of generation, innovation, and customer demand response than does average cost pricing. Market-based marginal cost pricing will ultimately lead to a more efficient allocation of resources than would average cost pricing, and will result in lower average prices over the long-term.

These two differences are best illustrated through an example. Figure 23 shows an illustrative example of the behavior of market-based marginal cost and average cost rates through a progression of changing cost environments over time, with a relative abundance or shortage of generation resources.

Figure 23 Comparison of Marginal Cost vs. Average Cost Rates



Because marginal costs represent the incremental cost of serving the final unit of demand while average cost rates represent the historical embedded cost of serving every unit of demand, market-based marginal costs rates are much more sensitive to changes in input costs (such as fuel and capital costs) and the marginal supply/demand balance of generation and load. For average cost rates, however, historical embedded costs tend to dominate and changes in marginal unit economics represent only a small portion of the average. This difference causes average cost rates to lag behind market-based rates as electric input costs change and the supply/demand balance fluctuates. Segment A shows an initial period of unchanging costs: all else equal, market-based marginal cost rates and average cost rates will be the same. As marginal costs fall (over segment B), market-based rates will fall faster than average cost rates because average cost rates contain the higher embedded costs from segment A. When marginal costs start rising (segment C) average cost rates will lag behind market-based rates in reflecting these rising costs in prices. Eventually, however, this will lead to average cost rates overshooting market-based rates when costs start falling again (segment D). This pattern is what occurred as we moved from the 1960s (falling costs) to the 1970s and early 1980s (rising costs), to the late 1980s and 1990s (falling costs again). Indeed, much of the impetus for restructuring in the late 1990s centered on the observation that average generation costs (reflected in retail rates) substantially exceeded marginal generation costs (as observed in wholesale market prices), just as the illustration predicts. Since 2000, however, costs have begun to rise again and we are now on segment E of the curve. Recent changes in retail electricity rates confirm this, as rates based on wholesale electricity prices (such as those produced by wholesale auctions or competitive retail offers) have risen quickly over the past three years, while rates in regulated states have lagged behind.[60]

As the illustration makes clear, a "snapshot" comparison of current rates does not imply that market-based, marginal cost rates are inherently higher than regulated average cost rates. The appropriate comparison is over the longer-term, which allows a more complete evaluation of a full cycle of changing cost environments. In the end, the historical rate evidence to date is of little value to the ongoing debate on competition; it does not definitely prove that competition has reduced rates over the last ten years, nor does it conclusively show that competition has increased rates. Furthermore, a definitive answer to this question may not help us solve the challenges ahead. If we accept that rates in competitive states were lower than they would have been if those states had remained regulated through 2005, but, because of high natural gas prices, are now higher than they would be if those states had remained regulated, would this mean that the industry should return to regulation? We believe the answer to this question is "no." The decision to support competition or regulation should not depend on external shocks (such as the recent increase in natural gas prices) or whether regulated average cost prices are below or above market-based marginal cost prices at any particular point in time, but whether a competitive or regulated model will foster more efficient decisions and ultimately better price and reliability outcomes over a sustained period of time and varying market conditions.[61]

Thus far, given the large oversupply of capacity built during the regulated period of the 1970s and 1980s and the recent unregulated generation development of the early 2000s, there has been relatively little need for significant regulated generation investment since the start of restructuring. As we have already discussed, the electricity market in the next twenty years will look very different than it has in the past ten years. Therefore, the recent historical "test period" of the past ten years examined in most studies does not provide a complete picture – especially of what is to come as we confront the significant challenges ahead.

Over longer time cycles, marginal cost pricing will produce a more efficient and ultimately lower-cost outcome relative to regulated average cost prices because it provides the correct

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[60] Jerry Taylor and Peter Van Doren of the Cato Institute acknowledge that regulation delivers lower prices than the market during shortages, but regulation delivers higher prices during times of relative abundance. (Taylor and Van Doren, "Short-Circuited.")

[61] At the time of restructuring, utility retail rates based on regulated average costs were much higher than competitive marginal cost prices in the wholesale market. Buyers, especially large customers, wanted direct access to these lower wholesale prices. This large gap between high utility retail rates and low wholesale market prices provided much of the impetus for restructuring. Today, the situation has reversed. Marginal prices have risen above average cost rates in many places. Hence, there is increasing pressure to look back more fondly upon regulation.

price signal for the efficient allocation of new and existing generation and demand response resources. Market-based, marginal cost prices provide the correct entry signal for new resources, whether in real time (such as committing a peaking unit) or over a longer time horizon (such as building new capacity or developing demand response resources).[62] As noted earlier, the rising costs observed over the past few years are unlikely to disappear soon, and will become even more pronounced in a carbon-constrained world. High market prices in the context of today and the near future are appropriate in that they provide the correct price signal and incentive for investment in the different types of low-carbon resources that will be needed in the future.

In an effort to limit "high" profits, some critics of competition argue that today's low cost generators (e.g., nuclear and coal plant owners) should not be paid the price associated with the higher marginal cost unit (e.g., a gas plant), but rather should be paid according to their individual (and much lower) variable costs of production. This logic represents a key misunderstanding about how competitive markets function. As Figure 23 suggests, in the presence of market volatility, prices and ultimately profits for all types of units will fluctuate, often significantly, in a competitive electricity market with marginal cost pricing. "High" profits in one period provide the necessary incentive for market entry and an eventual reduction of those profits through increased supply and competition. High market prices do not necessarily imply market manipulation or the exercise of market power.

Allowing the market to determine the price, of course, should rest upon the existence of a "workably" competitive market. Clearly, developing competitive markets are not perfect, and legitimate concerns exist that require safeguards and regulatory oversight (see discussion in Section V.B.). Examples of inappropriate generator bidding behavior, price manipulation, and poor market design have been uncovered during the transition period. Just as the industry experienced unanticipated consequences from past legislation and regulatory policies, it should not be surprising that new restructuring initiatives and market designs do not always work as anticipated. However, these are reasons to improve markets, not abandon them. There are several key reasons why policymakers should support the continued development of competitive markets, as discussed in the remainder of this section.

D. Competition Promotes Efficiency Improvements in Existing Plant Operations and Administration, in Plant Investment and Retirement, and Customer Consumption

Market-based marginal cost price signals, while not always lower than regulated average cost rates, provide a superior price signal to power plant operators, investors in new generation and new supply and demand side technologies, and consumers of electricity. In the short term,[63] competitive markets provide strong incentives to improve plant performance and

[62] The incremental cost of serving the final increment of load represents the true opportunity cost that new resources appropriately measure themselves against: if market prices rise to a level where they allow new capacity to cover its operating and capital costs, then that capacity will have an incentive to enter, if market prices remain below this level the market will utilize cheaper existing resources.

[63] In economics, "short-term" generally refers to the period of time over which the quantity of some inputs (e.g., such as existing plant capacity) cannot, as a practical matter, be varied, while the "long-term" refers to the period of time long enough for all inputs to be varied.

administration. Restructuring also has increased the geographic size of regional markets, extending the benefits of pooling and coordination across a broader market area. In the long term, competition provides efficiency gains in resource planning and investments, making investors, not ratepayers, responsible for a host of decisions (e.g., choice of technology, fuel, timing, pollution control, etc.) in an electricity market that is inherently risky. This shift in responsibility will allow customers to avoid having to pay for the stranded costs associated with investments or long-term contracts that later turn out to be uneconomic. Market price signals, when visible to customers, ultimately will lead to more efficient customer consumption and investment decisions both in the short and long term – impacting a customer's time of electricity use, overall level of electricity use, fuel choice, and investments in equipment and energy efficiency.

1) Competition Promotes Efficiency in Existing Plant Operations and Administration

a) The Theory

Competitive markets provide strong incentives to improve plant performance and administration in the short term. This improvement is often called "static" efficiency, which refers to the benefits that can be realized within the existing fleet of generators. In a competitive wholesale market, generators sell their output by either bidding directly into the spot market or through bilateral contracts based on expected spot prices. As discussed earlier, in most competitive wholesale markets, the market-clearing bid of the marginal plant is paid to all plants that are dispatched. High-cost bidders will be less likely to be dispatched and less likely to earn revenue, while plant operators that reduce costs and are able to submit lower bids are more likely to get dispatched and increase their profit margin between their own costs and the market price. This competitive structure, as opposed to a regulated model that allows plant operators to pass through their operating costs to customers, provides a strong financial incentive to lower both variable and fixed operating costs, since each incremental dollar of cost reduction benefits the plant owner. Competition impacts decisions related to operating and maintenance budgeting, capital improvements, fuel procurement, environmental compliance, and so forth. When evaluating specific operational changes, a number of incremental performance measures (e.g., increased availability, heat rate reduction, increased maximum output, increased ramp rates, start-up cost reduction, reduced minimum generation levels, etc.) provide the critical link between market prices and decentralized decision-making. By weighing the relative costs and benefits of any decision, managers can implement actions that are economic based on market price signals.

b) Early Results – Improvements in Dispatch Efficiency, Plant Performance, and Fuel Efficiency

First, restructuring has improved the efficiency of power plant dispatch (i.e., how generators are turned on or off to meet customer demand). Efficient dispatch is a function of marginal operating costs subject to transmission and unit commitment constraints.[64] Restructuring has increased the geographic size of regional markets, extending the benefits of pooling and

[64] Neither sunk capital nor fixed operating costs, nor who paid for them, is relevant to dispatching existing generators efficiently.

coordination across a broader market area.[65] Non-discriminatory open transmission access combined with broad geographic energy markets improves economic dispatch and coordination within the industry, ultimately lowering overall system supply costs. Restructuring reduces the level of rate "pancaking" through each utility service area that allows parties to trade more easily within a broad geographic area. Numerous studies have quantified these benefits, and the magnitude of estimated savings far exceeds the incremental RTO administrative and operating costs.[66] A particularly striking example of increased dispatch efficiency in a competitive market is provided by the large shifts in plant dispatch and physical power flows that occurred when the PJM market expanded to incorporate the service areas of American Electric Power, Commonwealth Edison, and Dominion. In each case, capacity utilization of relatively cheap baseload capacity in the newly incorporated area rose, and power flows into the high-cost, congested area of Eastern PJM increased. This

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[65] The benefits of coordination have been recognized within the industry for many years. The reliance on relatively short-term coordination services among nearby integrated utilities developed in order to reduce system operating costs and the costs of maintaining reliability through reserve sharing and emergency support. This coordination expanded dramatically after 1973 due to the increase in oil prices as the gap between oil, gas and coal prices widened. Utilities began to rely on medium and longer term wholesale contracts to allow them to defer construction of new facilities when other utilities had excess capacity or to reduce operating and maintenance costs of higher cost generating facilities. This "sharing" of resources in the wholesale market provided benefits to both buyers with capacity shortfalls and/or high-cost generation and sellers with excess capacity and/or low-cost generation.

[66] Scott Harvey, Bruce McConehi, and Susan Pope of LECG prepared an econometric study of customer savings in PJM and the NY ISO as a result of implementing coordinated markets, comparing 1990-2004 average residential rates in PJM classic and NY ISO with those in traditional markets, namely SERC and Florida. They used data for munis and co-ops in order to isolate the effects of retail access. Regressions were used to isolate the effects of RTO participation, regional fuel mixes, utility size, sales per customer, and the portion of industrial load, and to derive the "would have been rates" in order to calculate savings in PJM and the NY ISO regions. Based on this analysis, they concluded that the implementation of coordinated markets has led to residential customer savings of $0.50 to $1.80 per megawatt-hour (or $430 million to $1.3 billion per year) in PJM and NY ISO. These savings are net of RTO costs. (LECG, "Analysis of the Impact of Coordinated Electricity Markets on Consumer Electricity Charges," November 2006, 1.) Polestar Communications and Strategic Alliance performed a calculation of customer savings in New England due to restructuring based on historical trends in prices. They examined average retail rate growth from 1990 to the year of restructuring to construct "would have been" rates and compared those to actual rates. They concluded that customers have saved $6.5-$7.6 billion in New England between 1998 and 2005, including the savings associated with rate cuts and freezes. (Polestar Communications and Strategic Analysis, "A Review of Electricity Industry Restructuring in New England," prepared for members of the New England Energy Alliance, September 2006, 4.) Cambridge Energy Research Associates developed econometric models of total average electric prices in 1981-1997 for four regions and predicted 1998-2004 prices. They found that predicted prices were above actual prices in 3 out of 4 regions, and concluded that U.S. residential electric customers paid about $34 billion less over a 7 year period than they would have under regulation. ("Beyond the Crossroads: The Future Direction of Power Industry Restructuring," 2005). Global Energy Decisions performed a simulation of expected market prices had deregulation not occurred in the Eastern Interconnect, 1999-2003. They concluded that wholesale customers in the region saved $15.1 billion as a result of deregulation, attributed to increased operating efficiencies at power plants (e.g., shorter refueling outages, better capacity factors and improved reliability). (Global Energy Decisions, "Putting Competitive Power Markets to the Test – The Benefits of Competition in America's Electric Grid: Cost Savings and Operating Efficiencies," July 2005, ES-1.) Charles River Associates performed an analysis of customer benefits in SPP from having coordinated dispatch and an energy imbalance service market, concluding that transmission owners would save $373 million between 2006 and 2015 as a result of the energy imbalance market, net of implementation costs, and transmission owners would save $71 million between 2006 and 2015 as a result of coordinated dispatch. (Ellen Wolf et al., "Southwest Power Pool: Cost-Benefit Analysis," performed for the SPP Regional State Committee, July 2005, Tables 1 and 4.)

indicates that previously unrealized opportunities for economic dispatch and wholesale power trade were unlocked by pooling resources within an expanded competitive market.[67]

Second, U.S. generating plants are now more efficient than in the past. Some of this improvement in performance is attributable to improvements in technology over time, but some of it also is due to powerful profit incentives to adopt best practices and invest in productivity gains in an economic manner. A recent study of all large steam and combined cycle gas turbine plants in the United States suggests that municipally-owned plants, whose owners were largely insulated from market reforms, experienced the smallest efficiency gains, while investor-owned plants in states that restructured their wholesale electricity markets have improved efficiency the most. Investor-owned plants in states that did not restructure were in between these extremes. Industry restructuring reduced labor costs by 6 percent and non-fuel costs by 12 percent, holding output constant, relative to government and municipal-owned plants.[68] In general, studies suggest that restructuring has led to substantive operating efficiency gains in a relatively short period of time.

Competitive power plant operators have a strong incentive to maximize the output and capacity factor of baseload units such as nuclear and coal units. As shown in Figure 24, capacity factors of nuclear plants, while generally improving over time, improved dramatically since the time of restructuring from around 70 percent to the 90 percent level. Furthermore, since 1999, nuclear plants operated by competitive generators have realized an average capacity factor that is close to 2 percent higher than that of regulated plants, producing savings of about $350 million per year at current market prices.[69]

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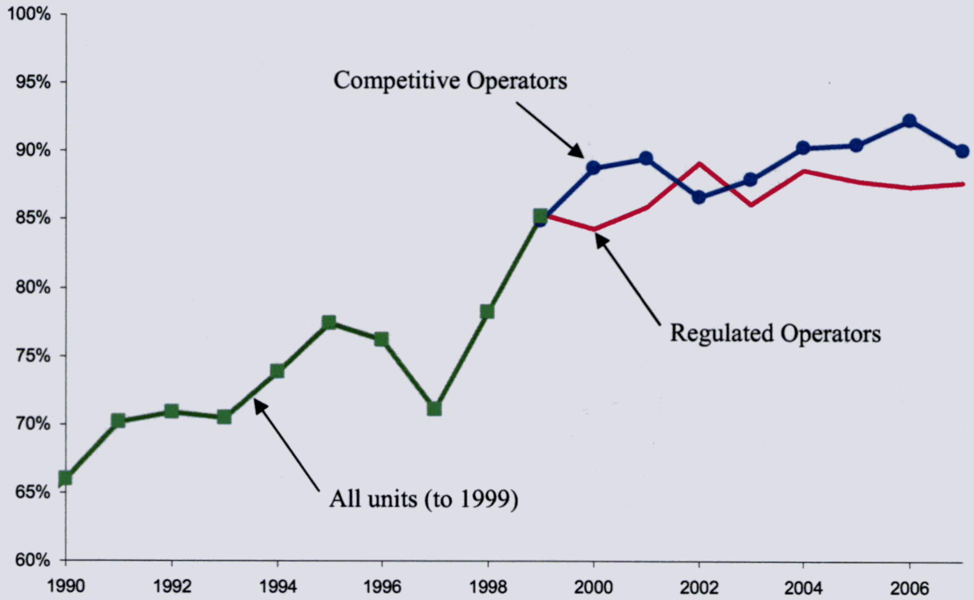
[67] Energy Security Analysis calculated prices across the expanded PJM pre- and post- its expansion from PJM Classic, and also examined market heat rates, price convergence across different zones, and price flows over interfaces. They concluded that the PJM region-wide price would have been $0.78/MWH higher in 2005 without expansion, resulting in 2005 savings of over $500 million. (Edward Krapels and Paul Fleming, "Impacts of the PJM RTO Market Expansion," prepared for PJM, November 2005, 58.)

[68] Kira Fabrizio, Nancy Rose, and Catherine Wolfram, "Do Markets Reduce Costs? Assessing the Impact of Regulatory Restructuring on US Electric Generation Efficiency," *American Economic Review*, Vol. 97, No. 4, September 2007, 29. See also James Bushnell and Catherine Wolfram, "The Guy at the Controls: Labor Quality and Power Plant Efficiency," *National Bureau of Economic Research Working Paper No. 13215,* June 2007, 5-6. An earlier analysis of the 1981 through 1999 period found that plant operators most affected by restructuring reduced labor and non-fuel operating expenses by 5 percent or more relative to other regulated IOU plants, and by 15-20 percent relative to government and cooperatively-owned plants.

[69] Capacity factor improvements at divested nuclear plants add about 5 million MWH per year from these plants. We estimate that running these nuclear plants versus running the marginal unit in their particular market produces savings of about $70/MWH (at current forward market prices), leading to annual savings of just under $350 million per year.

Figure 24 Improvement in Nuclear Capacity Factors, 1990-2007



Source: Based on plant-level output data from the Nuclear Regulatory Commission. Several units passed to competitive ownership prior to 1999, but reliable separation of competitive and regulated data is not possible prior to this year.

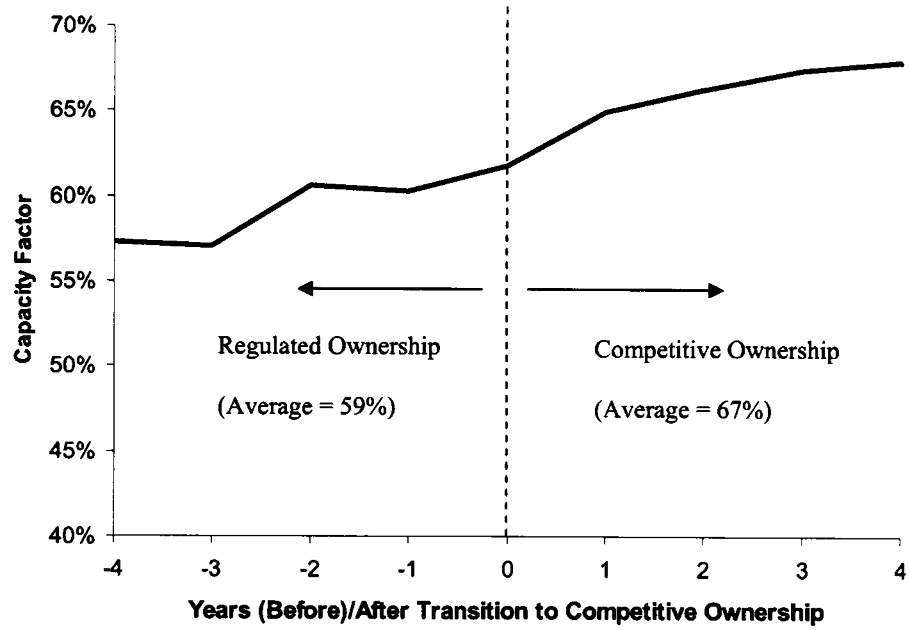
Restructuring also has led to a consolidation of nuclear plant operators. These firms tend to specialize in the operation of nuclear plants and implement best practices. The improvement in capacity factors occurred mostly through reducing the period of time needed to refuel the plant as well as better management and preventive maintenance. In 1990, the average refueling outage was 104 days, and by 2007, it had been reduced substantially to 40 days, as shown in Figure 25.

Figure 25 Reduction in Nuclear Refueling Outage Days

Source: Nuclear Energy Institute.

The evolution of coal plant operations is also significant. As Figure 26 shows, previously-regulated coal plants that have been acquired by a competitive operator have experienced significant gains in capacity factor and availability after transitioning to competitive ownership and operation, producing savings on the order of $300 million per year at current market prices.[70]

Figure 26 Improvement in Capacity Factor for Coal Plants Transferred to Competitive Ownership



Source: Based on data from FERC Form 1 (Annual Report of Electric Utilities) for various years as well as data from the EPA Continuous Emission Monitoring Systems (CEMS) database. Values shown are an average for 55 coal-fired power plants that were either purchased by a competitive operator or transferred to an unregulated generation affiliate.

Finally, restructuring also appears to have led to better fuel efficiencies (i.e., better heat rates) of fossil-fueled plants. Divested generating plants improved their fuel efficiencies compared to other comparable plants. Controlling for output level, deregulated plants used 2 percent less fuel per MWH of electricity produced, averaged across different fuel types than regulated plants, producing savings of about $550 million per year.[71]

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[70] Improved capacity utilization at divested coal plants adds about 34 million MWH per year from these plants. We estimate that running these coal plants versus running the marginal unit in their particular market produces savings of about $30/MWH (at current forward market prices and inclusive of environmental costs), leading to annual savings of just over $1 billion per year. Roughly 70% of this value can be attributed to changes in market conditions (such as rising gas prices) and improvements in technology that affected both regulated and competitive plants. The remaining 30% is attributable to gains made by competitive plants in excess of improvements observed at always-regulated plants. Multiplying $1 billion by 30% we arrive at an annual savings estimate of $300 million for the gains attributable to competitive ownership.

[71] James Bushnell and Catherine Wolfram, "Ownership Change, Incentives and Plant Efficiency: The Divestiture of U.S. Electric Generation Plants," Center for the Study of Energy Markets (CSEM) Working Paper Series, March 2005, 21-22.

2) Competition Promotes Efficient Plant Investment and Retirement Decisions

a) The Theory

One of the most significant savings from restructuring is believed to be efficiency gains in long-term investments (sometimes referred to as "dynamic efficiency"). Dynamic benefits are those that can be achieved over a longer term, including changes in the capital stock such as investment in new generation, demand response, and energy efficiency. Economic theory suggests that a properly functioning competitive wholesale market (including customer demand response) will induce the right amount of generating capacity with the appropriate levels of reliability, as well as the right mix of generating technologies in the right locations.

Competitive markets can provide significant improvements in resource planning and capital additions. Price signals, rather than administrative determinations, guide economic retirements and capacity improvements, economic new entry, and environmental compliance strategies. In a competitive market in long run supply/demand equilibrium, prices will approximate long run marginal costs, a figure which includes the cost of capacity and therefore provides for capital recovery. As supply and demand become more balanced over time and the market for bulk power reaches long run equilibrium, prices will increase to the point where capital is recovered. The dynamics of a competitive market continually pushing toward equilibrium are responsible for these forces. If returns exceed full cost recovery, new generation will be built that will tend to drive profits and prices down. On the other hand, if profits are suffering and capital is not recovered, generators will not add capacity. If profits on existing plants do not cover their fixed costs, operators will shut down units, and may make plans for early exit – activities that allow prices to rise.

Markets also provide the necessary incentives for investments in different fuel sources. Competitive generators have the appropriate price signals (including environmental costs) to evaluate the relative economic value and risks of alternative generation fuel sources in order to develop the most economically efficient combination of generation fuel sources over time. New solid fuel (nuclear or integrated gasification combined cycle) or renewable generation will be built when it is economic, that is, when expectations of gas prices and/or CO_2 allowance prices are sufficient to make such investments economic on an expected basis. If such plants are not economic for investors, then they will not be built in the absence of regulatory mandates. If a new plant with a particular fuel type can be constructed at a profit based on expected market prices, it will be. This investment decision is similar to that of other capital-intensive industries, as Paul Joskow explains, "investors finance oil refineries, oil and gas drilling platforms, cruise ships, and many other costly capital projects where there is considerable price uncertainty without the security of long term contracts."[72]

Competition makes investors, rather than consumers, responsible for investment decisions with no assured recovery of the investment. In the 1970s and 1980s, a competitive market would have allocated risks appropriately: it would have transferred the risks of technology choice, excess supply problems, and cost overruns from the consumers to the investors. Instead, under regulation, electricity consumers bore these risks. In a competitive market,

[72] Paul Joskow, "Competitive Electricity Markets and Investment in New Generating Capacity," AEI-Brookings Joint Center for Regulatory Studies Working Paper 06-14, May 2006, 39-40.

where a new plant is not guaranteed a return, there is no incentive for investors to over-invest in capital or "gold-plate" investments, overestimate consumer demand for electricity, or build facilities even when costs have significantly increased or slow-downs in load growth no longer require the investment. A competitive market model will allow regulators and customers to avoid future situations in which a utility makes a long-term commitment that later becomes uneconomic and costly for customers. Rather, investors in the competitive market will bear these risks.

b) Early Results – Significant Improvements in Open Access and Price Signals That Support Development of Competitive Generation

To date, significant progress has been made in the development of wholesale markets and non-utility generation. A series of FERC policies and orders has improved investors' access to information that they can rely on to plan and invest in new generation. The Energy Policy Act of 1992 expanded FERC's authority to order utilities to provide transmission service to facilitate wholesale power transactions. In 1996, FERC Order 888 required transmission-owning utilities to offer open access transmission service. FERC Order 889 required utilities to provide information about the availability and the price of transmission service on their system. In late 1999, FERC Order 2000 encouraged the formation of RTOs to further promote competition. These actions have led to considerable improvements in non-discriminatory, open transmission access that facilitate coordination and promote competitive entry into the market.[73]

Most regions that have created ISOs have implemented bid-based security constrained dispatch[74] with locational or nodal pricing. Differences in locational prices highlight transmission congestion within regions to allow an efficient allocation of scarce transmission capacity and to provide market signals that indicate the need to make new investments in either generation, transmission or load response resources. These price signals adjust to changes in supply and demand conditions and allow both investors and regulators to more accurately identify resource needs. As of 2007, about two-thirds of customers in the United

[73] Utilities that own transmission either directly or through an ISO/RTO have developed standardized, cost-based transmission service tariffs to third-parties. Third parties also have real-time information on transmission availability and prices. Utilities are required to interconnect independent power producers to their networks and must provide certain network support services, including balancing services to third parties. Utilities are also required to follow functional separation rules between the operators of their transmission networks and affiliated generators to mitigate self-dealing. Utilities are required to use best efforts to expand their transmission system in order to meet service availability requests when there is not sufficient capacity available. These changes are discussed in more detail in Paul Joskow's paper, "Markets for Power In the United States: An Interim Assessment," *The Energy Journal*, Vol. 27, No. 1 (2006), 5-7.

[74] Bid-based security constrained dispatch refers to a regime under which each generation unit is bid by its operator into a centralized market at a price that the owner sets at its discretion subject to market rules. The centralized market first considers dispatching all available on-line generating resources and power purchases to achieve the lowest possible cost to satisfy load. Once this "pure" economic dispatch is developed, reliability and other constraints (such as transmission congestion) are considered in order to modify the economic dispatch with the minimum increase in cost. Many markets have developed integrated day-ahead, hour-ahead and real-time energy prices based on these bids.

States are served by an ISO or RTO.[75] Many of these changes have led to increased competition from non-utility generation both in restructured and regulated states.

Thus far, the industry also has experienced a significant restructuring of the ownership of generating plants. In 1996, investor-owned utilities ("IOUs") owned 580 gigawatts of capacity. Since 1996, about 100 gigawatts were divested by IOUs and another 100 gigawatts were transferred to unregulated utility affiliates. Between 1999 and 2004 about 200 gigawatts of new generating capacity was completed, about 80 percent of which was owned by unregulated generating companies. By 2004, over 40 percent of the power produced in the United States (excluding federal, state, municipal and cooperative generation) came from unregulated power plants.[76]

More new generating capacity entered the market between 2001 and 2003 than in any other three-year period in U.S. history.[77] Most of this capacity relied on natural gas and was built by unregulated developers using project finance without long-term contracts. When wholesale market prices fell after 2001, many of these projects could not meet their debt obligations and went bankrupt or faced severe financial difficulties.

The experience of the competitive market gas combined cycle build-out of the late 1990s and early 2000s was very different from that of the regulated nuclear capacity additions of the 1970s and 1980s. Figure 27 shows the forward price signals applicable to new build gas combined cycle generation (in the form of the on-peak spark spread, which is the difference between electricity prices and the variable cost of a gas combined cycle).[78]

From late 1998 through early 2001, combined-cycle new entry economics were highly favorable and triggered a huge wave of new CCGT plants. In early 2001, however, the forward price signal dropped well below the threshold needed for new units to make money. This crash in the price signal triggered a quick response from competitive builders, and a much slower response from regulated builders. For competitive builders, 78 percent of capacity with a planned in-service date of 2003 or later (relatively little of which would have been sunk by late 2001) was ultimately cancelled, while for regulated builders only 37 percent of capacity was cancelled. Comparing this to the nuclear industry experience we can see that: 1) a price signal improves the responsiveness of generation builders to changes in market conditions, and 2) regulated builders still respond much less efficiently to price signals than do non-regulated builders. This experience also demonstrates that, regardless of the market structure, investors in capital-intensive generation plants face enormous risks and make mistakes; but, in a competitive market, the recognition of and response to these mistakes is much more rapid than in a regulated environment. Private investors responded much more quickly to the crisis of the early 2000s than regulated builders did in the 1970s and 1980s. Further, the crisis of the early 2000s had little impact on customers in non-

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[75] ISO/RTO Council, *About the ISO/RTO Council (IRC),* 2007, Accessed 24 March 2008, http://www.isorto.org/site/c.jhKQIZPBImE/b.2603917/k.7A3F/About_the_IRC.htm.

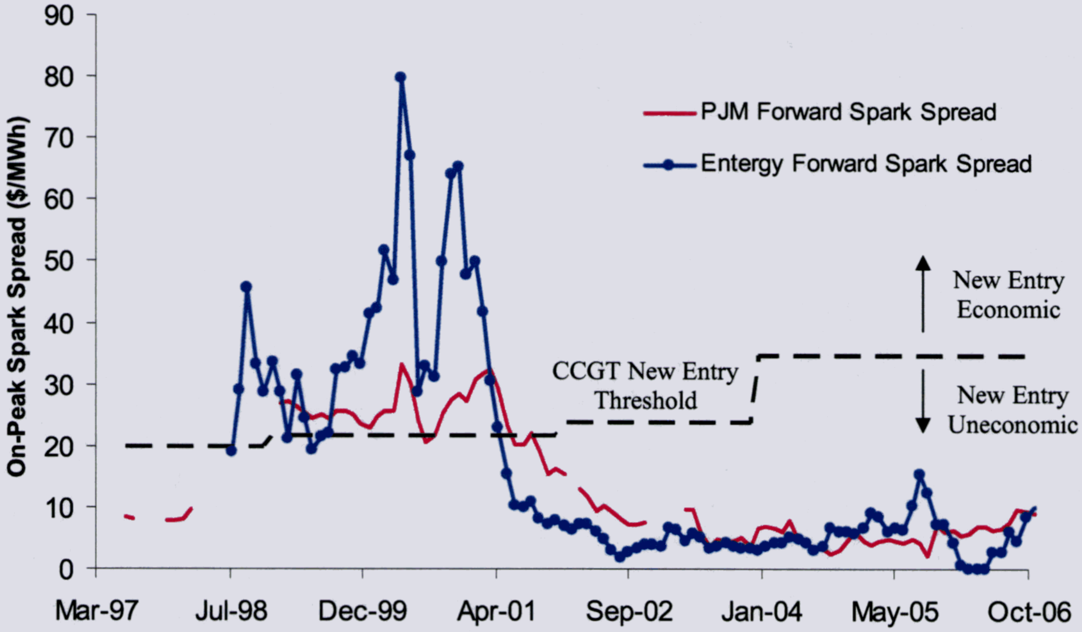
[76] Joskow, "Markets for Power in the United States," 7.

[77] Joskow, "Markets for Power in the United States," 7.

[78] While competitive power plants were built throughout the country, reliable forward market price information going back to the 1990s is limited to only a few locations. Entergy and PJM provide the longest-running forward market datasets available.

regulated states, since unlike prior investments in new capacity; unregulated investors – not ratepayers – bore the risk of these uneconomic investments. We estimate that private generation developers lost about $30 billion (in 2007 dollars) in economic profits over the period 1996 to 2005 – losses that likely would have been paid for by ratepayers had they been incurred by regulated builders.

Figure 27 Decline of Gas Combined-Cycle New Entry Economics in 2001



Source: Based on year-ahead forward market data from Bloomberg, Inc., Intercontinental Exchange, and the New York Mercantile Exchange.

Currently, locational market energy and capacity prices in constrained regions, such as Eastern PJM, are providing price signals for new entry by both generation and demand response resources – and these signals have generated a response from investors. PJM has experienced 10,000 MW of net new resources since the Reliability Pricing Model ("RPM") auctions were implemented.[79] Further, several generators in PJM plan to build additional new capacity in response to RPM. For example, PSEG Power recently announced plans to build up to 1,000 MW of peaking capacity in response to recently-observed forward energy and capacity prices.[80] Exelon is actively pursuing development of a 600 MW combined cycle plant and Reliant reversed plans to mothball a 315 MW gas/oil plant in Pennsylvania.[81] Constellation and PP&L also announced plans to expand capacity and return mothballed capacity in PJM.[82] Similarly, over 1,300 MW of new demand response resources have been

[79] "PJM Reliability Pricing Model Draws Largest Amount of New Capacity So Far," PJM Press Release, 1 February 2008.

[80] "PSEG Plans Up to 1,000 MW of Peakers," *Megawatt Daily*, 15 October 2007.

[81] "Capacity Prices Support PJM Additions: Reliant," *Megawatt Daily*, 2 May 2008.

[82] "Constellation, PPL See Gold In Tight Markets," *Megawatt Daily*, 6 September 2007.

added in PJM over the first four RPM auctions.[83] The ISO-New England also completed its first forward capacity auction in February 2008 and received an excess of bids to meet its targeted reliability margin at the auction's floor price.[84] The auction resulted in 626 MW of new generating capacity and 1,188 MW of new demand resources from energy efficiency, demand response and distributed generation.[85] Many of the new resources are concentrated in areas of high demand, including Connecticut and Massachusetts.

Lastly, the restructuring process in many regions has been accompanied by more efficient environmental compliance. One study concludes that utilities in restructured states have been able to meet environmental requirements with less expensive pollution abatement techniques than regulated utilities, since regulated utilities tend to favor more capital-intensive approaches that can be included in rate base:

> Although state regulators have allowed electricity generators to earn a positive rate of return on capital investments in pollution control equipment and recover the average costs of operating pollution controls and purchasing permits (profits from the sale of permits are also passed through to rate payers), the opportunity costs of using or holding allocated allowances are not reflected in regulated rates. Regulated firms have an incentive to choose compliance options that require more capital investment relative to pollution permit "inputs" than is consistent with cost minimization.[86]

These capital-intensive solutions tend to be more costly for customers.

3) Competition Promotes Efficient Customer Consumption Decisions

a) The Theory

The retail price of electricity also provides a valuable price signal to customers that may impact customers' time of electricity use, overall level of electricity use, fuel choice, and investment decisions. Unfortunately, most markets for electricity suffer from the lack of customer demand response. This lack of customer response is reinforced by retail rate design in both regulated and many restructured states. As shown earlier in Figure 23, conventional utility tariff rates based on average costs often diverge substantially from marginal cost market prices. Tariff rates, when exceeding market prices, limit the economic use of electricity, prevent economic development, and encourage customers to bypass the system even when it is uneconomic to do so. Tariff rates, when below market prices, encourage

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[83] PJM Interconnection, "2010/2011 RPM Base Residual Auction Results," 1 February 2008.

[84] "ISO New England's First Forward Capacity Market Auction Completed Successfully," ISO New England Press Release, 6 February 2008.

[85] "Demand-Side Trumps Plants in ISO-NE Auction," *Megawatt Daily*, 14 February 2008.

[86] Meredith Fowlie, "Emissions Trading, Energy Restructuring, and Investment in Pollution Abatement," University of California Energy Institute Center for the Study of Energy Markets, Paper CSEM WP-149, November 2005, 8-9.

customers to over-consume electricity especially during high-priced hours when capacity is in short supply and energy is expensive to produce.

This mismatch between conventional retail rates and market prices creates several problems. First, it results in inefficient use of electricity. The failure to induce customers to shift consumption from higher-price on-peak periods to lower-price off-peak periods creates poor capacity utilization of both baseload and intermediate power plant resources, and requires a greater level of installed capacity in order to accommodate higher peak loads. Second, because customers do not see a time-varying market price, they are generally unable to curtail their usage in times of high demand and/or supply scarcity. As a consequence, demand for electricity is almost completely inelastic in the short-run; during periods of scarcity, market prices can increase by orders of magnitude without inducing any reduction in load. Third, to the extent that regulated or default service price cap rates do not reflect overall market price levels, even over longer time periods, retail customers are forced to make investment decisions based on distorted price signals, which leads to over- or under-investment in energy efficiency and inappropriate fuel choices.

In contrast, when customers see competitive, market-based marginal prices, there are several types of efficiency benefits. Customers can respond to changing power market prices and reduce their electric bill by shifting or curtailing their consumption. An extensive body of research has been conducted to estimate customer response to changing electricity price signals. This research suggests that electricity is similar to most other commodities, whereby decreasing prices leads to greater consumption and increasing prices leads to less consumption, all other things being equal. While customer response is hard to measure precisely, the research in the industry and growing empirical results convincingly demonstrate that customers do respond to changes in electricity prices, and relatively low customer response can still result in significant benefits to society. Some conservative estimates suggest that a 10 percent increase in the average price of electricity will result in a one percent or more decrease in electricity demand,[87] and with each one percent reduction in demand nationwide, the industry could avoid CO_2 emissions of 30 million tons per year and the need for nearly 5 gigawatts of new baseload/intermediate generating capacity, saving $10 to $20 billion or more in capital investment.[88]

Market price signals also guide customer investment decisions in energy efficiency equipment and business expansion and productivity enhancements. Customers also can benefit by investing in new technologies that automatically regulate the power consumption of certain appliances or machines (commonly referred to as "direct load control"). For example, automated price signal thermostats that control air conditioning and hot water heaters have been used in residential markets and heat and energy storage systems have been installed on a commercial scale. There also is renewed interest in hybrid electric cars. These cars with advanced battery technology use a small amount of liquid fuel but can "plug-in" to the electric grid. These cars could serve as distributed off-peak storage of electrical energy,

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[87] Christian Crowley and Frederick Lutz, "Weather Effects on Electricity Loads: Modeling and Forecasting," Study Prepared for EPA, 12 December 2005; Steven Wade, "Price Responsiveness in the AEO2003 NEMS Residential and Commercial Buildings Sector Models," Study Prepared by the Energy Information Administration, 2003.

[88] Assuming a capital cost for low-carbon baseload/intermediate generation of $2,000/kW to $4,000/kW.

using off-peak energy to displace oil consumption as well as potentially provide power for individual homes.[89] Market pricing makes the value of such products and equipment more visible to customers, and competitive providers of these products and services have strong incentives to help customers capitalize on their value.

Demand response also can provide customers with reliability benefits by reducing the likelihood of involuntary curtailments. While the relationship between market prices and regulated average embedded costs will vary depending on the weather, time of day, time of year, supply and demand balance, and other factors, providing customers with these market price signals will ultimately lead to more efficient customer consumption and investment decisions both in the short and long term. Here again, competitive providers have strong incentives to develop innovative ways to assist customers in taking advantage of these opportunities.

More efficient price signals and demand response also complement and improve the performance of the competitive wholesale market, resulting in better resource and generation investment decisions and enhanced system reliability. The integration of supply and demand resources will improve system load factors and defer capital investments in generation, and may result in a shift in the mix of peak versus baseload capacity needed. Market pricing can enhance system reliability by enabling price to balance supply and demand. When demand tightens, prices will increase; customers will see and respond to the price increases by reducing consumption; demand will fall, prices will fall, and the system will balance. The ability of customers to lower consumption during high marginal cost periods also provides the added benefit of mitigating market power concerns when capacity is scarce.

Competition improves retail pricing efficiency by reducing subsidies inherent in "one size fits all" rates. Traditional utility rates typically include cross-subsidies within and among rate classes. For purposes of ratemaking, customers within a rate schedule are generally assumed to be homogenous in terms of consumption patterns. In reality, however, customers within the same rate schedule may have very different consumption patterns. Competition allows retailers to develop tailored pricing by customer, which will more appropriately reflect individual consumption patterns of a customer and will drive costs out of the system as customers modify their behavior in response to the true costs of supply.

Finally, customer demand response and customer-owned resources provide other benefits, including enhanced reliability to protect customers from outages, reduced air emissions, and utility deferral of transmission and distribution upgrades.

b) Early Results – Increase in Retail Market-Based Pricing and Customer Demand Response

Several states and utilities within restructured markets have taken actions to increase economic demand response and have expanded market pricing initiatives. While demand response programs, time-of-use pricing, and interruptible programs have also been

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[89] Peter Huber and Mark Mills, *The Bottomless Well: The Twilight of Fuel, the Virtue of Waste, and Why We Will Never Run Out of Energy* (New York: Basic Books, 2005) 75-90. See also "Can better batteries pummel US oil addiction in a few years?" *Restructuring Today*, 29 January 2008.

implemented at a number of regulated utilities over the years, such programs ultimately must be tied to market-based, marginal cost rates in order to be efficient.[90] As transition periods are completed, customer rates increasingly reflect market prices and more customers are experiencing more frequent price adjustments that vary by year, by season, by time-of-use period, or by hour. More customers, especially large C&I customers, are beginning to see the proper price signals associated with their consumption at a specific place and time. There are at least sixteen utilities in five states that now offer hourly price default service to large C&I customers.[91] Competitive retailers in Texas, where there is no longer utility-provided default service, also offer Market Clearing Price for Energy ("MCPE") products based on spot market electricity prices. Customers on hourly price default service or MCPE receive a clear price signal and have the ability to act immediately to reduce demand during times of high prices or increase their consumption during times of low prices. These benefits are clearly transparent in a competitive market that allows retail pricing to match real-time market conditions.

Currently, there is about 21,000 MW of demand response in the United States, consisting of capacity (73 percent), energy (15 percent), and ancillary services (12 percent).[92] The level of interest in demand response has increased as generation costs have increased and as market prices have become more visible. RTOs and utility companies have established economic curtailment programs and demand reduction programs that are tied to these visible energy and capacity markets. As shown in Figure 28, RTO and ISO regions with organized wholesale markets lowered system peaks by over 8,300 MW on peak days during the summer of 2006.[93]

These customer demand resources can avoid substantial capital costs in peaking capacity. As an example, 8,300 MW of customer demand response could avoid roughly $3.7 to $5.8 billion of capacity costs.[94] In addition, by reducing demand at critical times, system operators can enhance system reliability on short notice in the event of unexpected generation or transmission failures and/or extreme weather conditions. Demand response plays an even more valuable role in load pockets, such as in southwest Connecticut and New York City-Long Island,[95] since demand response typically requires shorter lead times and can be less costly than building new generation, transmission, or distribution facilities. Several RTOs

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[90] For example, many interruptible customer load programs provided by regulated utilities traditionally were used only in cases of "system emergencies" or as a means to offer fixed discounts to large users, but in developing competitive markets, the economic use of customer resources is increasing.

[91] These include utilities in Maryland (APS, BGE, DPL, Pepco), New Jersey (AECO, JCPL, PSEG, RECO), Illinois (ComEd), New York (NIMO, CH, NYSEG, O&R, RGE, ConEd), and Pennsylvania (DLC).

[92] ISO/RTO Council (IRC), Markets Committee, "Harnessing the Power of Demand: How ISOs and RTOs Are Integrating Demand Response Into Wholesale Electricity Markets," 16 October 2007, 8.

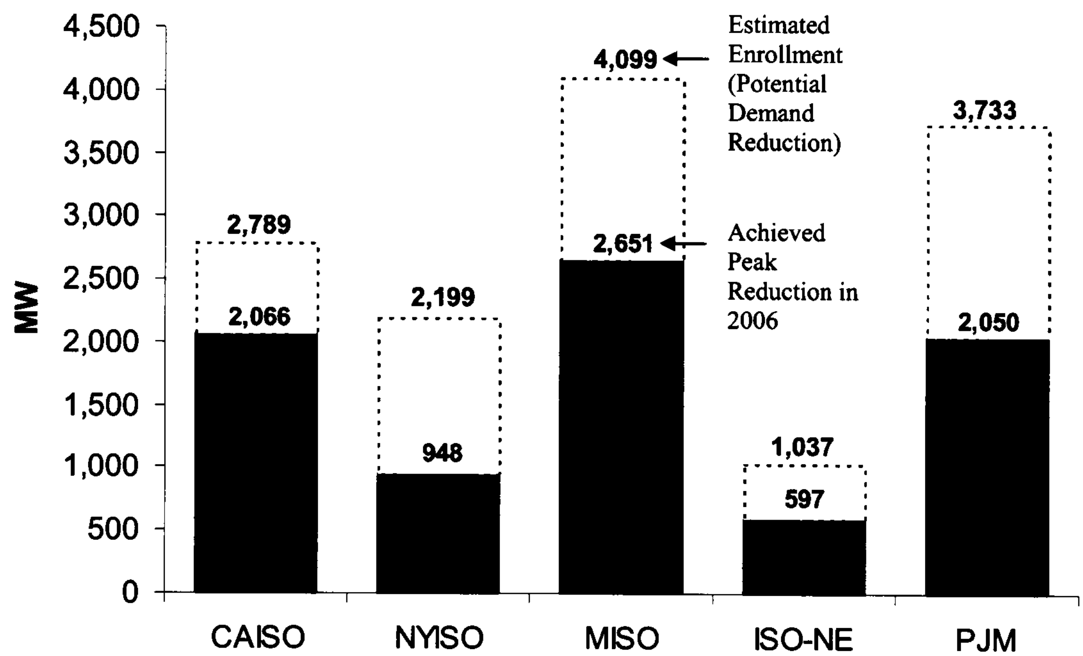
[93] "2007 Assessment of Demand Response and Advanced Metering," FERC Staff Report, September 2007, i.

[94] This assumes that the cost of a peaking combustion turbine ranges from $450 per kW, as it did around 2006, to $700 per kW, which is a more current estimate. (PJM, "PJM RPM Proposed CT Cost of New Entry (CONE) Update, corrected 12-04-07, http://www.pjm.com/markets/rpm/downloads/20071204-rpm-ct-cost-new-entry-update.xls.)

[95] FERC, "2007 Assessment of Demand Response and Advanced Metering," 6.

also report that demand response reductions during peak hours have reduced wholesale prices, particularly during periods of price spikes.[96]

Figure 28 Customer Demand Response In RTO/ISO Programs, Summer 2006



Source: "2007 Assessment of Demand Response and Advanced Metering," FERC Staff Report, Table B-1, September 2007. Enrollment figures from FERC Staff analysis. Achieved peak reductions based on called demand response in summer of 2006. CAISO: Emergency Stages 1&2, FERC estimate based on difference between forecast and actual peak load; NYISO: Emergency DR activated, "Responses to FERC," FERC Wholesale Demand Response Technical Conference; MISO: Max Gen Warning NERC EEA2, actual reductions based on MISO survey to Balancing Authorities; ISO-NE: OP-4 Action 12, ISO-NE 2006 Annual Markets Report, June 11, 2007, 116; PJM: Full Emergency Load Response Mid-Atlantic only, "PJM 2006 State of Market Report," Vol. 1, 12-13.

More recently, demand resources have been included in forward capacity markets and certain ancillary services markets, so that they can be assessed along with competing generation resources.[97] Third party firms, who aggregate demand reductions across customer groups,

[96] In competitive spot markets, demand response on the margin can lower the overall price for all energy traded in the market. PJM reported estimated energy payment reductions of more than $650 million in one week during 2006. (PJM, "Early Aug. Demand Response Produces $650 Million Savings in PJM," PJM press release, 17 August 2006.) ISO-New England attributed average savings of $1.74/MWH during hours with interruptions over the period April to September 2006. (ISO New England, "2006 Annual Markets Report," 11 June 2007, 11.) The Midwest ISO found a reduction of $100 to 200/MWH in market clearing prices during a peak day in August 2006. (FERC, "2007 Assessment of Demand Response and Advanced Metering," 6-7.)

[97] In the first 2007 capacity auction in PJM, demand response offers that cleared were about 41 percent of the new capacity that cleared (127 MW versus 311 MW). In the second auction in 2007, the demand response offers that cleared increased to 536 MW. (PJM, "PJM Completes First Reliability Pricing Model Auction," PJM News Release, 16 April 2007 and PJM, "PJM Reliability Pricing Model Producing Results," PJM News Release, 13 July 2007.) The ISO-NE forward capacity market allows different types of demand resources to participate, including energy efficiency, load management, distributed generation, and real-time demand response.

are increasingly able to bid customer demand resources into markets in an integrated manner side-by-side with supply resources.[98] Customer enrollment in RTO/ISO demand reduction reliability and economic programs also has increased, with the total number of MW enrolled growing by more than 50 percent since 2003 in the Eastern markets of PJM, ISO-NE, and the NYISO.

The level of interest in advanced metering infrastructure ("AMI") has also increased and utilities recently have announced plans to install more than 40 million advanced meters during the period 2007-2010. The increase in AMI market activity, as measured by the number of meters planned or installed, has nearly tripled from 2005 to 2006, and is projected to double again in 2008.[99] While advanced meters are being installed in both regulated and restructured states and not all of these plans will be implemented, the installation of more sophisticated metering and control technology will allow retail customers in competitive markets to respond efficiently to market energy prices and to provide capacity as demand-side bidders in competitive wholesale markets. Expansion of these customer resources, especially among smaller customers, will become more feasible with smart metering, faster internet connections and improvements in direct load control technology. Finally, as more retail customers begin to see accurate market price signals, customer demand response will increase and competitive suppliers will have the incentive to offer expanded choices of products that will manage customer load and hedge market price risks. For example, some competitive suppliers offer large C&I customers "swing" products that fix a portion of the customer bill based on some defined consumption pattern, but allow prices to adjust with market when consumption deviates from certain levels. Competitive suppliers have strong incentives to provide these types of new products and services when considered valuable to customers.

E. Retail Competition is Still Developing and Provides Additional Benefits

1) The Theory

In a well-designed market, retail competition will produce the most efficient outcomes, provide customers with more choices and improve customer value and customer satisfaction. First, retail competition increases customer choice in suppliers and in products. Traditional utilities typically offered "one size fits all" service with limited service options and no choice of supplier. Retail choice allows customers to choose their supplier, manage their demand, and determine the level of risk they want to assume. Second, competition leads to service improvements and innovation. Competition provides new incentives to develop value-added services and product offerings as competitive retailers gain access to customers and become more familiar with their needs and desires. Competitive retailers have strong incentives to attract and retain existing customers to maximize the lifetime value of the consumer in order

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[98] For instance, EnerNOC reports that it currently manages over 1,100 MW of customer demand response (EnerNoc, "EnerNOC Reports Fourth Quarter and Year-End 2007 Financial Results," EnerNoc News Release, 27 February 2008) and Comverge reports that it has over 600 MW of customer capacity under contract (Comverge, "Comverge Announces 2007 Third Quarter Financial and Operating Results," Comverge News Release, 6 November 2007).

[99] FERC, "2007 Assessment of Demand Response and Advanced Metering," 31.

to capture market share and enhance profitability.[100] This can be accomplished through better understanding of customer desires (e.g., recognizing that customers are different and developing products that address customers preferences: length of fixed price term, renewable energy, demand response, smart energy, quicker response times, eliminating busy signals, and so forth). Finally, retail competition aligns the industry value chain with the customer. Competitive suppliers have strong incentives to satisfy customer demand for supply and services, while avoiding the generation overbuild problems and the one-size-fits-all service of the 1970s and 1980s.

2) Early Results – Retail Competition is Still Developing and Provides Additional Benefits

The first retail competition and restructuring programs began in Massachusetts, Rhode Island, and California in early 1998. By the end of 2000, more than a dozen states had initiated their own restructuring programs. While the slow pace of the development of retail competition has disappointed many observers both within and outside the electric industry, very few states have enacted the rules and infrastructure necessary to allow retail competition to develop. Nonetheless, overall customer switching to competitive suppliers has more than quadrupled from 22 GW in 2001 to 91 GW in 2007 of customer peak load as shown in Figure 29.

Across the United States, approximately 480 terawatt-hours from 8.3 million customers are currently served by competitive suppliers.[101] This competitive load represents about 30 percent of the eligible load in retail access states, and most of the shopping load (over 80 percent) is non-residential.[102] Competitive markets have expanded as transition periods have ended and retail rates have become more aligned with market price levels. In particular, large C&I customer switching rates have grown significantly in certain parts of the country. In fact, the majority of large C&I load is shopping in service areas within Texas, New York, New Jersey, Maryland, and Massachusetts, with switching levels that range from 60 percent to 98 percent.[103]

Retail competition for residential customers thus far has developed largely in two states where market rules fostered competitive market development – broadly in the ERCOT area of Texas and less broadly in New York. Although residential customer shopping has been limited in other parts of the country, small C&I customers in restructured states have had a larger number of competitive service options and somewhat higher switching levels than residential customers. This difference is due in part to state regulators allowing competition at the large C&I level to gradually work its way down to smaller customers.

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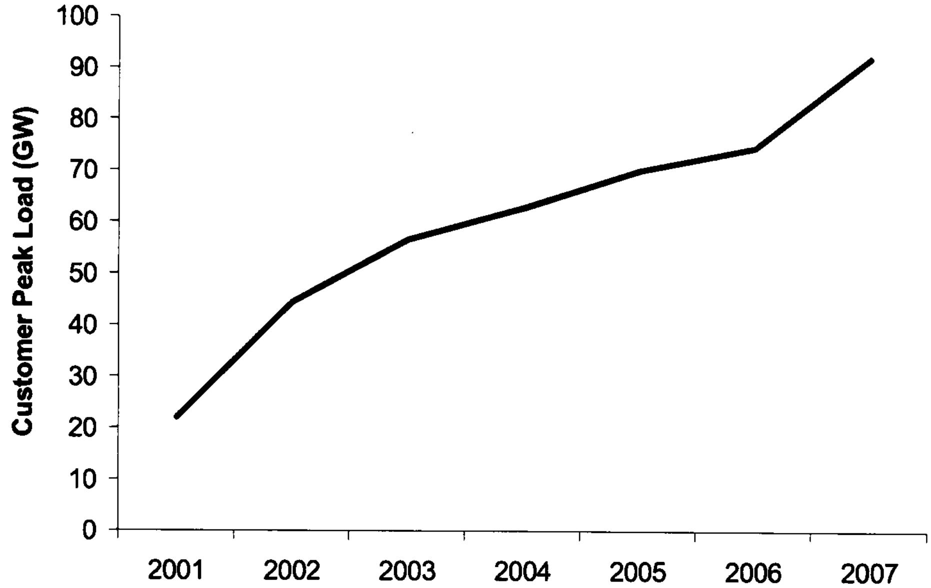
[100] Customer acquisition costs can be high, particularly for smaller customers. Retail suppliers, therefore, have strong incentives to retain customers.

[101] KEMA, "Sharp Increase US Competitive Power Market," KEMA News Release, 6 August 2007.

[102] KEMA, "Sharp Increase US Competitive Power Market."

[103] While jurisdictions have different definitions of what constitutes a "large" customer, more and more customers are facing hourly or short-term market prices over time as regulators expand the definition of a "large" customer and become more comfortable with market pricing to smaller size customers.

Figure 29 Increase in U.S. Retail Shopping Levels, 2001-2007



Source: KEMA

Retail competition among residential and smaller customers in many jurisdictions has been hampered by below-market default service rates, lack of standard market rules, policies that favor utility default service, and a variety of other factors. While default service rates that reflect market price levels promote retail competition, jurisdictions that have established fixed default service rates at below-market levels have virtually eliminated retail competition.[104] In many ways, retail competition – and the lack thereof – is a function of policy decisions made by regulators and politicians.[105] In service areas where substantial customer switching has occurred, it has been accompanied by a regulatory commission, legislature, and/or utility that has allowed market-based default pricing.

In markets with significant retail competition, customers can choose new suppliers and products. In Texas, the most active retail market in the United States, more than 26 retail suppliers provide over 90 different residential products in each service area.[106] Customers

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[104] In some instances, "blended" default service rates, which are based on the average prices from a mix of wholesale supply contracts, also have not been conducive to retail competition. Blended average market-based rates resulting from competitive solicitations at different points of time provide customers rate stability, but they can differ from prevailing market prices at a particular point in time. During prolonged periods of rising market prices, this makes it difficult for retail suppliers to attract new customers, since utility default service rates are likely to be lower than current market price offers. This has contributed to the lack of retail shopping among residential and small C&I customers in some jurisdictions that rely on a portfolio of laddered supply contracts.

[105] A key question for policymakers is how often utility default service rates should adjust to changes in market prices. In general, a reasonable transition to market prices that adjust more often will improve economic efficiency and customer demand response; but as a practical policy matter, the optimal frequency often depends upon a number of factors, including customer sophistication, market price volatility, the number of competitive service alternatives, what customers are accustomed to, and the costs and benefits associated with exposing customers to greater price volatility.

[106] *Texas Electric Choice, 2008*, Public Utility Commission of Texas, accessed 1 April 2008, www.powertochoose.org.

have a wide range of choices in contract length, pricing options, and exposure to risk. Contract lengths offered by retail suppliers range from one month to many years. Pricing may vary by hour, may be indexed to wholesale prices, may be completely fixed, or may have some combination of fixed and variable prices. Customers can choose among varying levels of green power. But in all cases, prices reflect the current market price for the product selected. Customers choose the product they wish, including their desired level of market price stability. Depending on the individual needs and desires of market participants, short-term commodity fluctuations can be borne by speculators, generators, retail suppliers or customers.

Competition also has led to service improvement and innovation. Retail suppliers provide "green" products, manage price and other risks, and offer load management and energy efficiency services that reduce and shift consumption during peak periods. Retail suppliers can aggregate multiple customer locations and provide bundled services, such as total energy management for other fuels (gas, oil, etc.). As retail suppliers have grown in size, they have been able to lower their administrative overhead costs on a per unit basis. The top competitive suppliers in terms of size currently supply between 10,000 and 20,000 MW of customer peak demand, which is equivalent to that of a large-sized regulated utility.

Nationally, it is clear that retail markets are still evolving and we are still in the early stages of retail market development. Unfortunately, price increases driven by commodity costs have caused regulators in many states to react negatively to a perceived lack of control over price. The reluctance of regulators to allow utility default service to reflect market prices in the face of escalating prices only exacerbates the problem. Given the lack of market-based pricing for utility default service in many parts of the country, it is not surprising that many customers still remain on utility default service. Thus, customer switching statistics should not be relied upon to justify the failure of retail markets. Rather, the success of retail competition should be judged by the new value-added services,[107] market-based pricing, and efficient customer consumption decisions that competition encourages. It also is worth noting that in areas where retail rates more closely reflect market prices, electric retail shopping development compares favorably to the telecom industry. Six years after AT&T's divestiture, AT&T still had more than a 60 percent share of the long distance market.[108] In 1990, six years into a competitive retail electric market in Texas, the incumbents' share of their traditional markets is less than 60 percent.[109]

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[107] Paul Joskow originally suggested this notion in his article, "Why Do We Need Electricity Retailers? or Can You Get It Cheaper Wholesale?," 13 February 2000, 4-5. He concluded that the success of retail competition should be judged by the new value-added services it brings, not by the number of customer who switch from default service. He further adds that regulators who focus on retail switching statistics and who are subsidizing customer switching are likely to be making customers worse off than if the default supplier simply provided them basic electricity service at the spot market price.

[108] Federal Communications Commission, Industry Analysis and Technology Division "Statistics of the Long-Distance Telecommunications Industry," May 2003, pg. 17, Table 7.

[109] ERCOT, *Retail*, 2008, Electric Reliability Council of Texas, accessed 25 March 2008, http://www.ercot.com/mktinfo/retail/index.html. See Historical Number of Premises Switched January 14, 2008.

F. Other Industries Illustrate the Benefits of Competition

The benefits of competition are evidenced by the experience of other industries that have deregulated (e.g., airlines, telecommunications, and trucking), other competitive industries in the U.S., and electricity deregulation in the United Kingdom.

Figure 30 Overview of Deregulation in Other Industries

	Pre-Deregulation	Deregulation	Post-Deregulation
Airlines	• Civil Aeronautics Board determined routes, set fares, regulated entrance into markets, and approved mergers and acquisitions.	• Airline Deregulation Act of 1978 mandated that domestic route and rate restrictions be phased out over four years.	• Decline in fares, an increase in passenger miles, new ways to improve asset utilization, and new services.
Telecom	• Federal Communications Commission imposed service requirements at regulated rates. Any deviation required government approval.	• The Justice Department's antitrust suit forced AT&T to divest its regional local exchange companies in 1984. • The Telecommunications Act of 1996 opened up competition between local telephone companies, long distance providers, and cable companies.	• Significant improvement in technology, lower long-distance rates, and numerous new products and services.
Trucking	• The Interstate Commerce Commission regulated operating permits, approved trucking routes, set tariff rates and required market entrants to apply for certificates of public convenience and necessity.	• Motor Carrier Act of 1980 eased regulation of entry and pricing and eliminated most restrictions on commodities and routes.	• Significant decline in rates, improved service quality, reduced empty return hauls, reduced complaints, simplified rate structures, and an increase in new entry.
U.K. Electricity	• Central Electricity Generating Board was responsible for central planning of all aspects of electricity generation, transmission and investment in England and Wales.	• The Electricity Act of 1989 established a wholesale pool, broke down existing vertical monopoly structures, and eventually led to the privatization of regional electricity companies and retail access.	• Lower electric rates and a greater variety of retail products.

As suggested by Figure 30, the benefits of competition in these cases are clear and definitive. Compared to other industries that have deregulated, electric restructuring in the U.S. has proceeded in a patchwork, state-by-state fashion, often with prolonged transition periods and rate stabilization plans. Furthermore, most U.S. electricity markets that are today considered "restructured" lack most of the retail customer market-based pricing flexibility that was one of the critical elements of deregulation in industries such as airlines and trucking. Ultimately, however, the underlying economic forces that govern these other industries are also present in the electricity industry, and we would expect restructured electricity markets to provide similar results over time, provided regulators remain supportive of competition and efforts to improve market price signals to retail customers. In particular, competitive markets will encourage 1) a more efficient utilization of resources, 2) increased customer choice and access to products and services, 3) technological innovation, 4) elimination of cross-subsidies, and 5) lower prices.

1) More Efficient Utilization of Resources

Competition promotes more efficient utilization of resources on both the supply and demand side. On the supply side, firms that receive a competitive rather than an average cost-based price for their output have a strong incentive to efficiently utilize their productive resources and reduce operating costs. On the demand side, firms in a competitive, deregulated market will have flexibility to tailor their prices based on their products' differing value to different consumers at different points in time. This pricing flexibility aligns the marginal cost of production with the value customers' place on the product, resulting in a more efficient utilization of productive resources over time.

The deregulation of the airline industry provides an example of both these supply and demand effects at work. Prior to deregulation, airlines received a regulated cost-based price and were restricted by regulation to an inefficient point-to-point route structure. This command-and-control approach resulted in considerable excess capacity – load factors (the fraction of seats filled on an average flight) averaged about 50 percent in the decades prior to deregulation. On the supply side, deregulation provided airlines with strong incentives to reduce costs and the ability to improve utilization of their aircrafts. Deregulation exposed airlines to a competitive price signal and allowed them flexibility in developing their route structure to best fit their operations. The result was a move to a more efficient hub-and-spoke routing system as well as stronger emphasis on minimizing turnaround times, maintenance downtime, and matching capacity to demand. Furthermore, on the demand side, removal of price regulation allowed airlines to tailor their pricing to different groups of customers to better match supply and demand over time. For example, airlines were able to time-differentiate their fares such that late-booking, time-sensitive customers on heavily booked flights were charged a higher price while customers with more time flexibility could shift their travel to another flight and receive a lower price. Many customers currently can buy discounted tickets with advance purchases, weekend stays, and non-refundable tickets. By using price as a tool to allocate a limited number of airline seats to the appropriate passengers, airlines could offer discounted prices for seats that would otherwise not be filled and improve capacity utilization. This price and route flexibility, along with intense competitive cost pressures, led to significant improvements in the utilization of airline resources. The overall effect of these changes on resource utilization was dramatic: carriers added more seats on their planes – the average went up from 136.9 in 1977 to 153.1 in 1988 – and succeeded in filling a greater percentage of those seats.[110] Load factors remained between 50 and 55 percent in the years immediately preceding deregulation, but increased after deregulation, reaching 77 percent by 2005.[111]

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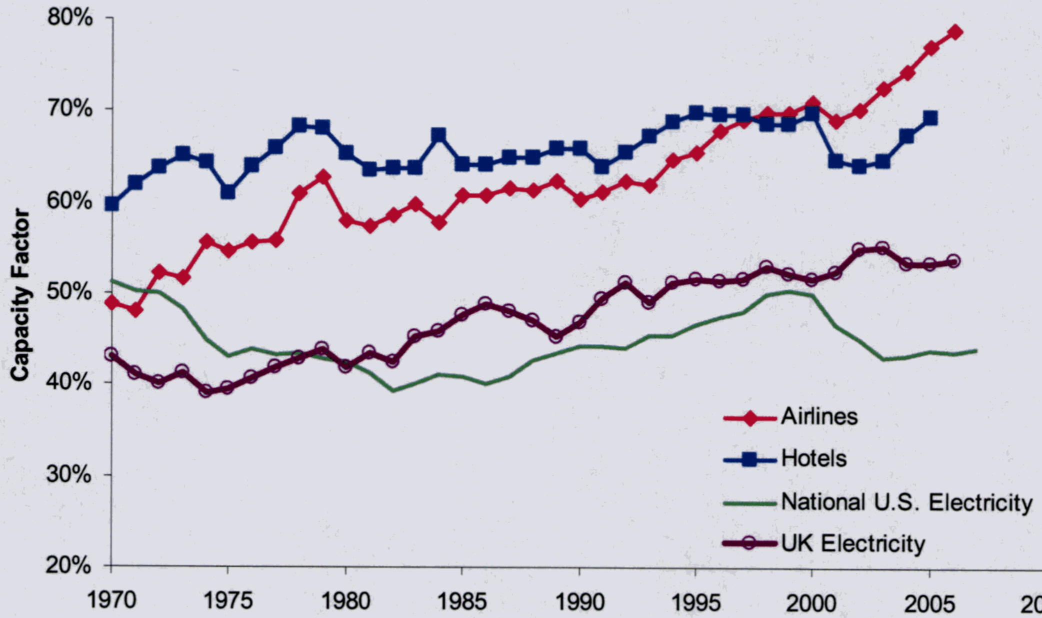
[110] Alfred Kahn, *Airline Deregulation*, 2002, The Concise Encyclopedia of Economics, Accessed 26 March 2008.

[111] Severin Borenstein and Nancy Rose, "How Airline Markets Work, or Do They? Regulatory Reform in the Airline Industry," 30 October 2006, 22.

In general, we expect the electricity industry to also show improvements in resource utilization when and if it transitions from today's patchwork and incomplete implementation of restructuring to a broader and deeper form of competition. Figure 31 compares capacity utilization in the U.S. electricity industry with several other capital-intensive industries that feature a relatively non-storable or perishable product.[112] These other industries include: a) airlines (which deregulated in 1978), b) hotels (which have always been a competitive industry), c) and U.K. electricity (which began introducing elements of competition in the early 1990s).

Figure 31 Capacity Utilization in Selected Capital-Intensive Industries

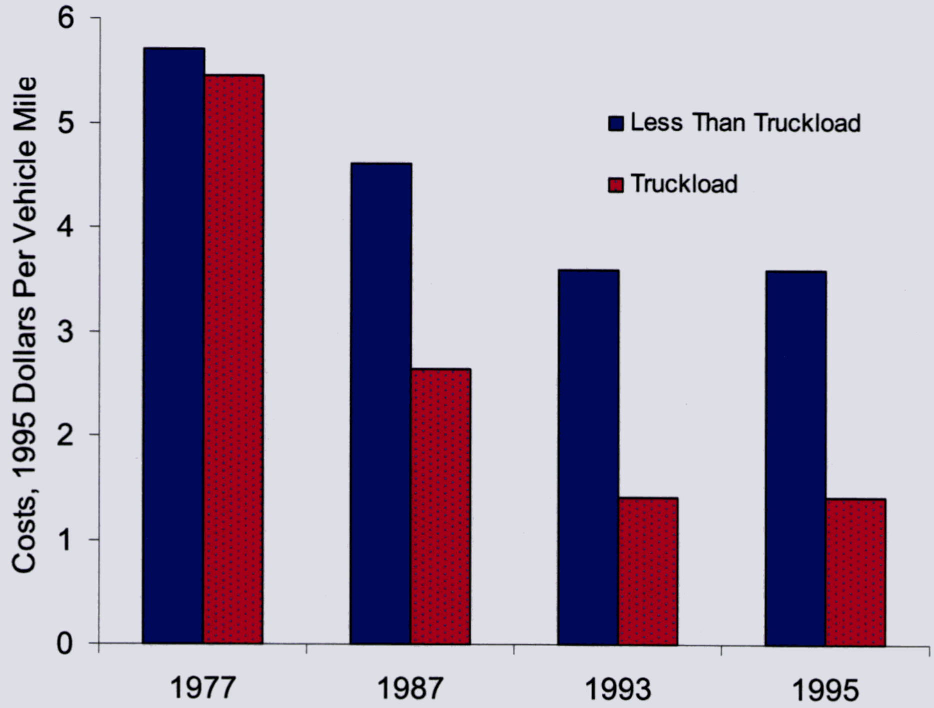


Sources: Airlines Pre-1990: Air Transport Association (http://www.airlines.org/economics/traffic/Annual+US+Traffic.html); Post-1990: U.S. Bureau of Transportation, *National Transportation Statistics*, Table 4-21. Hotels: PKF Hospitality Research, *Trends in the Hotel Industry, 2005*. U.S.: Edison Electric Institute, Historical Statistics of the Electric Industry to 1992, and Energy Information Administration, State-Level Electricity Spreadsheets, 1990-2006. U.K. Electricity: U.K. Department for Business, Enterprise, and Regulatory Reform, *Digest of United Kingdom Energy Statistics*, various years.

The trucking industry also experienced significant declines in operating costs (which include both improved utilization of capital stock as well as reductions in variable operating costs) following deregulation in 1980. As Figure 32 shows, real operating costs per vehicle mile dropped by 35 percent in the less-than-truckload sector ("LTL") for shipments less than 10,000 pounds and by 75 percent in the truckload sector ("TL") for shipments over 10,000 pounds between 1977 and 1995.

[112] Capital-intensive industries with storable products (such as iron and steel, refining, and pulp and paper) tend to have higher capacity utilization than the electric industry with limited storability. The reason for this is that there is little need for a "cushion" of rarely-utilized peaking capacity to meet peak period demand because that need can be met with inventory.

Figure 32 Cost Reductions in the Trucking Industry, 1977-1995



Source: T. Lakshmanan and W. Anderson, "Transportation Infrastructure, Freight Services Sector and Economic Growth," February 2002, 3.

A review of the airline and trucking industries in the U.S. and the electric industry in the U.K. suggests that competition in electricity will lead to higher long-run capacity utilization and ultimately lower prices for customers. Deregulation in both airlines and trucking led to a dramatic improvement in capacity utilization for both industries. In fact, President Carter stated at the time of trucking deregulation that "regulation needlessly wastes our Nation's precious fuel by preventing carriers from making the most productive use of their equipment, and by requiring empty backhauls and circuitous routings."[113] More specific to electricity, the gradual deregulation of U.K. electricity over the course of the 1990s coincided with an improvement in capacity factor of about 10 percent, from an average of about 45 percent in the 1980s to between 50 and 55 percent since 2000.

2) Increased Customer Choice and Access

Competition in many industries has also led to increased customer choice and access to products and service. Regulation in telecoms, airlines, and trucking greatly restricted the degree to which firms could tailor their product, service, and price packages to different customers, and limited the ability of firms to reach customers for whom the regulated "one-size-fits-all" product was of limited value. In all three industries, deregulation led to an

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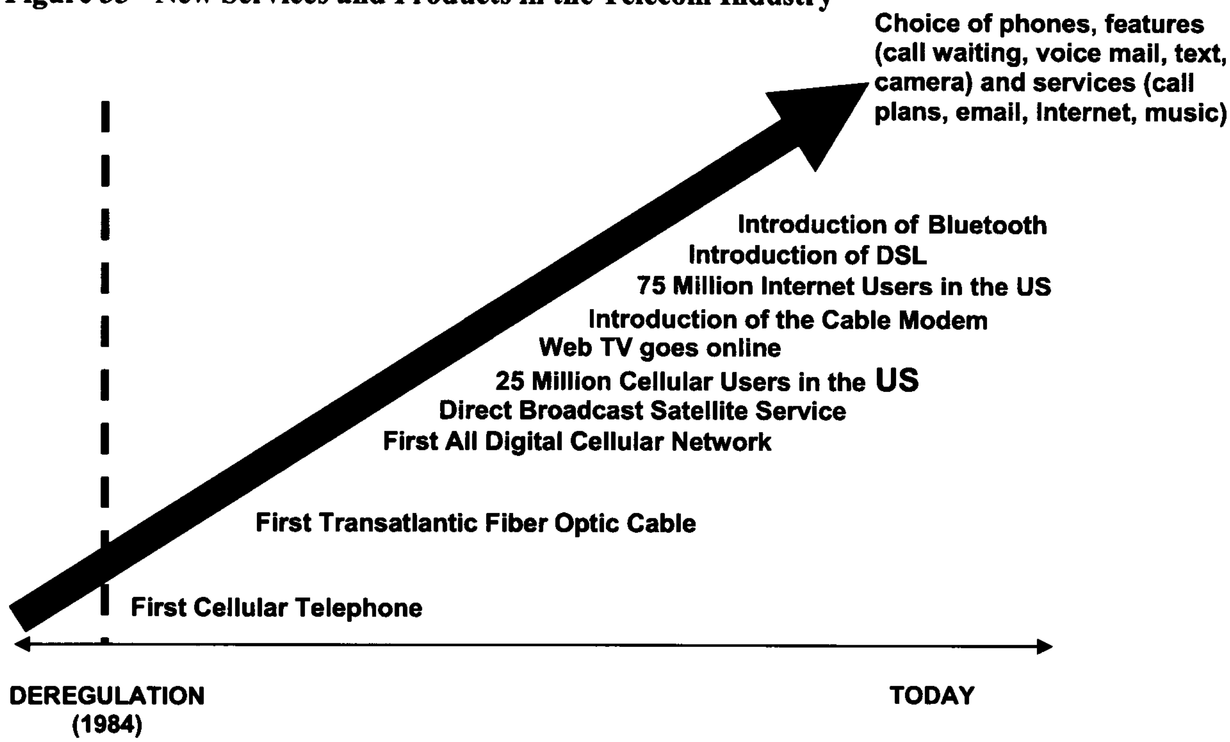
[113] President Jimmy Carter, "Trucking Industry Deregulation Message to the Congress Transmitting Proposed Legislation," 21 June 1979.

explosion in the number and variety of product/price offerings as well as attempts to reach new customers not well served under the regulated model.

AT&T's breakup in 1984 and ensuing deregulation of the telecommunications industry has led to a broad range of new products and services as shown in Figure 33. Customers initially were presented with greatly increased variety in pricing and service packages from both local and long-distance carriers. Over time, competition led to the introduction of a wide selection of additional features and choices such as voice mail, call waiting, and mobile phones, all the way to today's integrated services and devices allowing voice, data, e-mail, and Internet, all through one device and service package.

Figure 33 New Services and Products in the Telecom Industry



In the airline industry, competition led to more frequent service, increased routes, fewer connections, and an estimated 25 percent increase in the average number of airlines per route. For example, between 1979 and 1988 American Airlines and United Airlines increased the number of domestic airports it served from 50 to 173 and from 80 to 169, respectively.[114] Overall, the number of airlines certified for scheduled service with large aircraft has increased from 43 in 1978 to 139 by 2005.[115] Airlines developed marketing innovations to segment their customers with differentiated pricing and services. Virtually all airlines created customer loyalty programs, through which customers could accumulate "miles" to apply to

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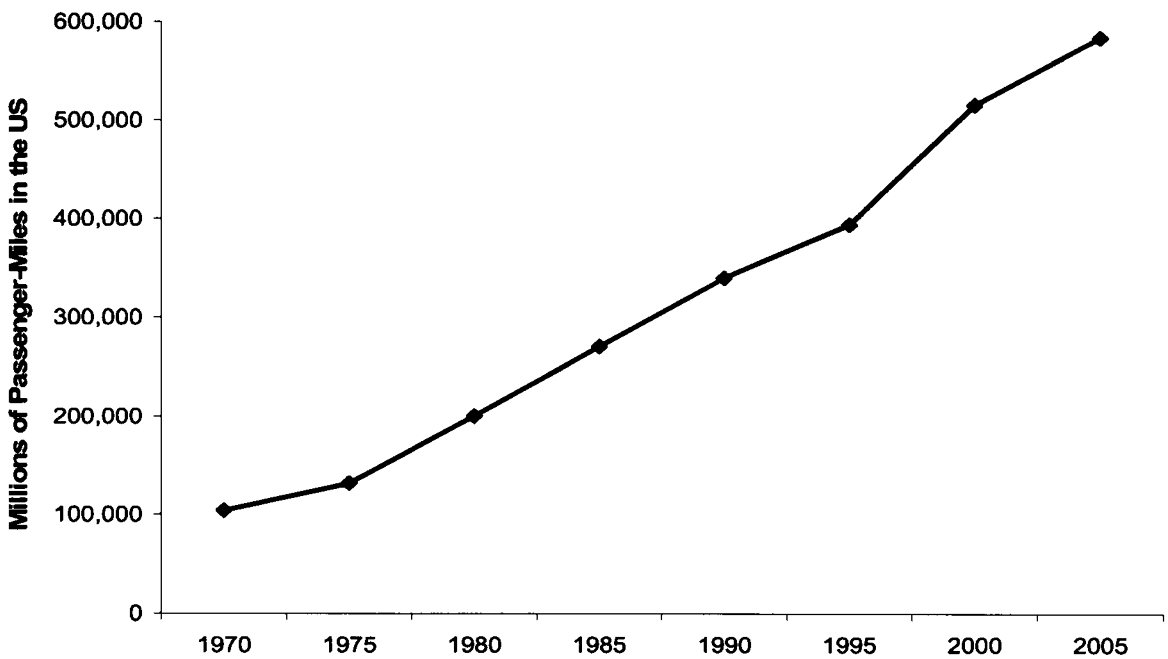
[114] Kahn, _Airline Deregulation_.

[115] "Airline Handbook Chapter 2: Economic Deregulation," 20 November 2007, Air Transport Association of America, Accessed 26 March 2008, http://www.airlines.org/products/AirlineHandbookCh2.htm.

future ticket purchases or other goods and services. Loyal frequent flyers also are rewarded with cabin upgrades, priority check-in, priority boarding, lounge access and other benefits. More recently, the industry has developed marketing partnerships tied to these programs to help promote other services such as credit cards, and in some cases, even electricity. Meanwhile, newly developed reservation and Internet services over the years have provided customers with greater access to flight and fare options. This increased access and product/service tailoring, accompanied by competition reductions in prices, greatly expanded the number of consumers utilizing air travel. Airline capacity grew significantly from 306 billion available seat miles in 1978 to 758 billion in 2005,[116] and as Figure 34 below shows, the number of total domestic revenue passenger-miles flown has more than tripled since deregulation in 1978 – from 188 to 584 billion revenue passenger miles.

Figure 34 Increase in Air Travel, 1970-2005



Source: US Government Accountability Office, "Airline Deregulation: Re-Regulating the Airline Industry Would Likely Reverse Consumer Benefits and Not Save Airline Pensions", June 2006, 10.

In the trucking industry, competition led to the simplification of highly complex regulated tariffs and increased competition on service quality. In 1975 (pre-deregulation), the Interstate Commerce Commission handled 340 complaints against truckers; in 1976, it handled 390 complaints. By 1980, after deregulation, this number had decreased to 23 cases.[117] The number and variety of companies exploded as regulatory barriers to entry were removed. In

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[116] Government Accountability Office (GAO), "Airline Deregulation: Regulating the Airline Industry Would Likely Reverse Consumer Benefits and Not Save Airline Pensions," Report to Congressional Committees, GAO-06-630, June 2006, 10.

[117] Thomas Gale Moore, *Trucking Deregulation,* 2002, The Concise Encyclopedia of Economics, 26 March 2008.

1975 only 18,000 trucking firms nationwide were authorized to provide service, compared with nearly 500,000 by 2000, with most firms specializing in a particular segment or product type.[118] With deregulation and improvements in technology, trucking and warehousing firms developed logistical services throughout the entire transportation process that enabled firms to manage all aspects of the movement of goods between producers and consumers. These changes led to value-added services to track packages, to maintain and retrieve computerized inventory information on the location, age, and quantity of goods available in order to better manage inventory, and to provide other customer services.

Meanwhile, retail electricity competition in the U.K. provides a glimpse of the potential for customer product/service tailoring in electricity. Small customers in the U.K. have seen greater choice in the number and variety of different supplier offers. As a result, the level of customer switching has grown steadily over the last eight years. According to a recent government report on residential retail markets, the incumbent Retail Energy Companies have lost nearly half of their customers to new suppliers.[119] In order to attract customers, suppliers are offering new products, such as fixed and capped price offers, online discounts, and supply from "green" resources. Such products now account for 20 percent of all electricity and gas accounts.[120] In addition, some suppliers are beginning to offer new services, such as free energy surveys and discounted energy efficient appliances along with their regular products. A 2005 survey of customer experiences in the U.K. retail market indicated that 97 percent of customers were aware that they could switch suppliers, 47 percent had switched suppliers at some point, and 85 percent were satisfied or very satisfied with their current supplier.[121] A review of currently available offers for residential customers in urban areas suggests that customers typically can choose from between 40 to over 50 distinct offers from 8 to 12 suppliers.[122]

3) Technological Innovation

Competition provides incentives for firms to innovate and improve technology. Most regulated companies are unable to retain much, if any, of the economic value of the innovations or technological developments they may introduce. While this may seem like a good deal for consumers, it tends to slow technological progress by dampening the incentive of regulated companies to innovate. Therefore, in the long-run, customers lose.

Deregulation in most industries has been accompanied by significant improvements in technology. In the airline industry, new technology was developed to attract and retain customers and improve financial performance. For example, two airline companies,

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[118] U.S. Department of Transportation, Bureau of Transportation Statistics, *The Changing Face of Transportation – Chapter 2: Growth, Deregulation, and Intermodalism*, (Washington DC: 2000), 2-40.

[119] Office of Gas and Electricity Markets (OFGEM), *Domestic Retail Market Report – June 2007*, Ref. No. 169/07, 4 July 2007, 23.

[120] OFGEM, *Domestic Retail Market Report – June 2007*.

[121] U.K. Office of Gas and Electric Markets, *Domestic Retail Market Report - June 2005*, Ref. No. 24b/06, 7 February 2006, Detailed Appendix Tables 1 and 3 and Figure 3.

[122] TheEnergyShop.com, 2006, Energy Services Online Limited, Accessed 27 March, 2008, www.theEnergyShop.com.

American and United, developed sophisticated computerized reservation services to better offer services and segment customers. These reservation systems allowed airlines and travel agents to track fare and service changes more efficiently for hundreds of millions of passengers. Over time, these reservation systems increased in functionality and were divested from airlines as separate independent businesses. Today, this technology has evolved, making it possible for individual travelers to book reservations, purchase hotel rooms, rent cars, and arrange other travel services online.

Furthermore, the incentive to reduce costs brought on by competition led airlines to demand a greater focus on fuel economy and operating economics in aircraft design from the airline manufacturers. The most recent Airbus and Boeing aircraft are around 35 percent more fuel efficient than late 1970s vintage designs.[123] The improved sensitivity to customer demands brought on by competition led to the development of regional jets, a technology that was not used in the United States until 1993, but proved highly successful in bringing jet travel to previously underserved routes and timeslots. To further reduce costs and expand services, airlines developed code-sharing agreements that allowed two or more airlines to offer a broader array of services to their customers than they could individually. These marketing arrangements enabled airlines to expand service at a reduced cost by allowing them to issue tickets on a flight operated by another airline as if it were its own. These programs typically link marketing and frequent flyer programs and facilitate convenient connections between the code-sharing partners. In addition to code sharing, several groups of airlines have formed global alliances that compete against each other for international passengers, whereby participating airlines benefit from expanded networks and reduced costs through the sharing of staff, facilities, and sales offices.[124]

The telecommunications industry offers a similar example of significant innovation unlocked by technology. Similar to electricity, most of the early groundbreaking innovation that established the industry took place in the late 19th and early 20th century, prior to any form of deregulation. From the point when the Federal Communications Commission was created in 1934 to oversee interstate telephone service through to deregulation in the early 1980s, innovation in the industry slowed. While direct-dialing, touch-tone phones and pagers were all developed and adopted during this period, other innovations from the time, such as communications satellites and mobile-phone technology were not significantly adopted until after deregulation. In the twenty-odd years since deregulation, however, the industry has experienced an explosion of groundbreaking innovations, including, among others, fiber optic cables, computer switching equipment, and wireless data/internet services.

Competition has also driven innovation in the trucking industry. Examples of new technologies that have been introduced since the advent of deregulation in 1980 include electronic data interchange, new vehicle location detection systems, voice and data communication services, and just-in-time delivery services.[125] In addition, because trucking companies are no longer bound to deliver goods along pre-specified routes, as was the case

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[123] P.M. Peeters, J. Middel, and A. Hoolhorst, National Aerospace Laboratory NLR, "Fuel Efficiency of Commercial Aircraft: An Overview of Historical and Future Trends," Report No. NLR-CR-2005-669, 12.

[124] Air Transport Association, http://www.airlines.org/products/AirlineHandbookCh2.htm.

[125] Cynthia Engel, "Competition Drives the Trucking Industry," Monthly Labor Review, April 1998, 39.

under regulation, they continually seek to optimize routes. Consequently, there has been a surge of services over the last 20 years that provide sophisticated dispatch management. These optimization and dispatch services provide fuel savings by reducing empty miles and increase truck utilization.[126]

4) Elimination of Cross-Subsidies

In many industries, the transition to competition eliminated cross-subsidies that distorted consumption and customer decision-making. Regulatory restrictions on pricing and product structure led to some groups of customers receiving higher or lower prices than they would under competition, encouraging inefficient over- or under-consumption. For example, in the telecommunications industry, regulated rates did not reflect the cost for each service offered. Rates were broad averages designed to recover total revenue requirements across all services. Embedded in this structure were numerous cross-subsidies among different customer groups: long-distance customers subsidized local service while large customers subsidized small and individual customers. Deregulation of the telecommunications industry resulted in elimination of these cross-subsidies as competing suppliers unbundled these two services and priced each individually based on their separate cost structures and value to consumers.

Similar subsidies existed in the regulated airline industry due to regulatory restrictions on pricing and routing. Routes with high density (many travelers), and thus more favorable cost structures, generally subsidized higher-cost routes with low density in more rural areas. These subsidies eroded as markets became competitive and suppliers were able to price different routes individually based on their unique economics.

Competition can be expected to reduce similar subsidies in the electric industry as competitive suppliers develop tailored pricing for a variety of customer services and consumption patterns.

5) Lower Prices

Ultimately, industry deregulation and the introduction of competition have resulted in lower prices for consumers. Figure 35 shows real prices as they have evolved in the airline, trucking, and telecommunications industries indexed to the years immediately around deregulation. All three industries saw sustained price reductions beginning with deregulation and continuing to the present in most cases, with airline[127] and telecoms customers realizing real price reductions of close to 40 percent since deregulation. These price reductions are the consequence of increased competition from a larger group of competitors, improved incentives to drive down costs, and better utilization of resources.

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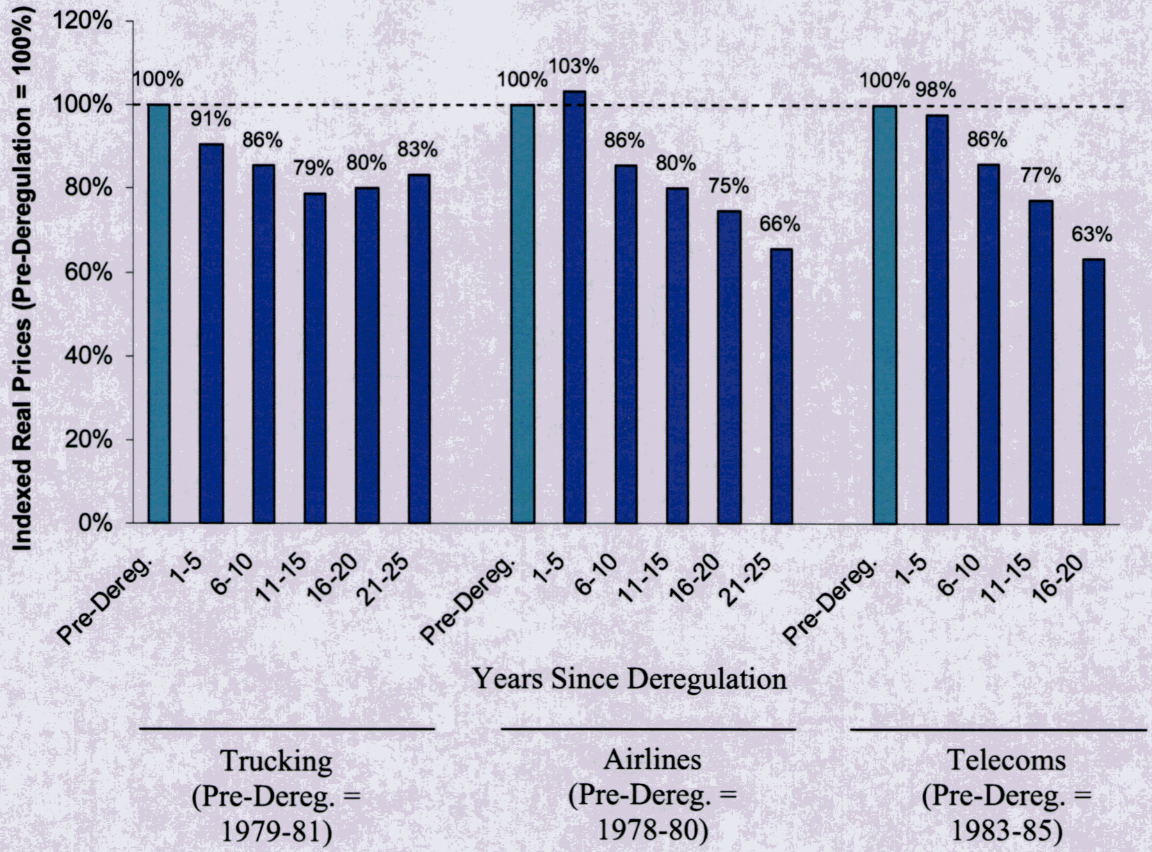
[126] Steven Strong, "Optimization Leads Quiet Revolution in Trucking," SupplyChainBrain.com, Global Logistics and Supply Chain Strategies, June 2001.

[127] A June 2006 report by the GAO concluded that "reregulation of airline entry and rates would not benefit consumers and the airline industry. Although some aspects of customer service might improve, reregulation would likely reverse many of the gains made by consumers, especially lower fares." (GAO, Airline Deregulation, 36.)

Figure 35 Post-deregulation Prices for the Trucking, Airline, and Telecommunications Industry



Source: Based on the U.S. Bureau of Economic Analysis Gross Domestic Product and Chained Price Indices by Industry, 1977-2006. See http://www.bea.gov/industry/gdpbyind_data.htm. Nominal prices are deflated using the GDP deflator.

As Figure 35 shows, the initial years after deregulation were not always marked by significant price declines, and certainly other external factors such as changes in input costs (e.g., fuel costs) or non-related changes in technology may affect overall price levels from one period to the next. However, as competition drove costs out of the system and the industry adjusted, sustained deep price declines were the norm in trucking, airlines, and telecoms. Given that competition in electricity has been a far less complete transition than these other industries and that electric generation construction and fuel costs have increased significantly in recent years, it is not surprising that the price benefits for electric consumers in the United States are harder to discern. Nonetheless, our expectation is that a competitive electricity market will show similar benefits over the long-term, provided competition is allowed to continue to develop.

V. Competition Will Provide a Better Path to Confront the Enormous Challenges Ahead

The experience of the 1970s and 1980s in the electric industry suggest that regulation is not well-equipped to navigate the industry's future challenges of the rising global cost of energy and environmental requirements. The more recent experience of the electric industry and those of other industries suggest, however, that competitive markets will provide a better path to confront the enormous challenges ahead.

A. Re-Regulation Will Not Fix the Perceived Problems

In response to the perceived problems associated with competition, some states are moving back toward regulation.[128] Some of this backpedaling, like re-regulation bills, is very direct. Other actions are more subtle: there are new efforts to pick the "right" generation technologies, to mix cost-of-service and market-based new construction, to establish "vintage pricing" with special higher pricing for new builds, and to rely on rate-funded, customer-guaranteed long-term contracts using an integrated resource planning process in an effort to stimulate new capital investment. All of these actions are forms of re-regulation that are not only intended to "fix" competitive pricing issues but also ensure that "enough" investment in new generation is made on a timely basis. Proponents of these initiatives argue that they are necessary to ensure adequate reliability, environmental compliance, fuel diversity, and even national security.

Some policymakers likely will try to characterize these efforts as a new, better form of regulation or a mix between regulation and competition. But these actions are nothing more than a return to the central planning of the past – the same central planning that tried to select the right amount and the right mix of technologies in the 1970s and failed. There is no reason to believe that this "new" least-cost planning approach will be more successful today. The inherent flaws, especially the underestimation and misallocation of risks, are still present. And, as before, customers will become responsible for inefficient choices and significant risks inherent in future electricity markets. Re-entry of regulated utilities into the generation business, whether through direct utility ownership or allowing utilities to enter into long-term contracts with new generators, is risky for customers. Either action is a centrally planned, ratepayer-funded approach to new generation that transfers risk from the developer and utility to the retail customer. Long-term contracts and/or investments increase the risk that costs will be above market, potentially for significant periods of time.

Further, re-entry of utilities into the generation business is incompatible with wholesale competition and will deter – and perhaps even eliminate – market-based entry of new generation. It is not likely that rate based investments could co-exist with competitive generation. The different risk profiles of rate-funded investments, compared to competitive investments, lead to more and earlier building under the regulated model. This occurs because investment decision rules for rate-funded new generation are less stringent than those for competitive generation – there is a lower investment "hurdle" for rate-funded

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[128] These efforts are particularly being made in states which made little effort to have retail competition at the residential level.

commitments than for competitive investment because the risks are shifted from the investor in generation to retail customers.[129] As a result, under most circumstances, a project will appear economic on a rate-funded basis before it would appear economic on a market-funded basis. So, under the utility procurement model, new rate-funded commitments will be made before new market commitments. Once these rate funded commitments are made, they serve to depress the visible forward price signals, and resulting market price expectations will be inadequate to bring forth investment on a competitive basis. Hence, the continuation of cost-of-service rate-making for generation – either with utility-owned generation or long-term contracts guaranteed by ratepayers – is a barrier to the emergence of a competitive market model. Therefore, both immediate re-regulation and gradual re-entry of regulated utilities into the generation business are likely to end up in the same place – that is, a *de facto* return to the regulatory decision-making of the 1970s that relied on a sluggish, administrative, command-and-control process to solve inherently risky resource allocation problems.

B. A Competitive Market Should Remain the Desired End State

Relying on markets to make investment decisions, rather than on central planning backed by ratepayer guarantees, is sound public policy. The industry must tackle an ongoing need for new generation investment to serve growing load, to replace its aging power plant fleet, and to achieve ambitious environmental objectives. Reliance on a well-structured competitive market model, in which end-use customers receive efficient price signals and do not assume long-term investment risks, and investors and market intermediaries actively manage such risks, will serve customers better in the long run.

Although relying on competitive markets is preferable to the traditional regulatory model, there is still a need for safeguards and regulatory oversight. In order for market-based pricing to result in an efficient and effective outcome, generation markets must be "workably" competitive. A well-structured competitive market model should include wholesale and retail competition, central energy markets using locational prices, non-discriminatory open-access transmission, and new generation built without utility long-term contracts or regulatory guarantees funded by ratepayers. In order to ensure non-discriminatory open access of the transmission system and to ensure that companies cannot exercise market power, regulators and/or system operators must monitor market activities to ensure a fair and level playing field. As competitive generation markets develop, federal and state actions have already been taken and continue to be improved upon to monitor electricity markets. These safeguards include: federal oversight of non-profit RTOs to ensure non-discriminatory open-access of the transmission system, state and federal oversight of market power and concentration (mergers, market price manipulation, etc.), state

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[129] Rate-funded projects typically evaluate, on a present value basis, the projected production cost savings from the project over its assumed operating life to the incremental capital or demand charge payment required. The discount rate used in this evaluation usually reflects the utility's cost of capital, which is typically lower than that used by a competitive developer. Competitive project evaluation incorporates a higher discount rate, or hurdle rate, and often a shorter payback period requirement, in recognition of the uncertainty of future market prices. While it may appear that the lower utility hurdle rate results in lower cost to consumers, this is not the case when the continued risks that consumers bear under that model are taken into consideration. A regulatory guarantee does not eliminate any of the risks associated with the generation asset; it merely shifts the risks from the investor to ratepayers.

certification/licensing of retail suppliers (e.g., rules governing communication and marketing practices, supplier credit requirements, state oversight of consumer protections and services including education, disconnection, low-income assistance, etc.), federal oversight of wholesale trade accounting, federal and state safety standards, federal and state environmental emission requirements, and so forth. These oversight and monitoring functions will likely be necessary for the foreseeable future and should not be ignored. Meanwhile, incidents of market abuses in relatively young markets should not be used as an excuse to return to the mistakes of the past. Nor should the unfavorable and unforeseen outcomes of certain negotiated transition plans or settlements that were used to "unwind" the regulatory past be relied upon to demonstrate the failure of competitive markets. Unfavorable and unforeseen outcomes are likely to occur in electricity markets that are inherently risky and mistakes will be made whether there is competition or regulation. Key questions for policymakers are who should pay for those mistakes – investors who make the decisions or ratepayers who have to live with the consequences of central planning – and which model is likely to respond more quickly to ever-changing market conditions. The authors of this paper believe that competitive markets allocate these risks more efficiently, and that the benefits of competition can be achieved while continuing to maintain or even enhance funding for public policy programs, such as low-income assistance, energy efficiency, and customer education.

We also believe that retail competition, if given a chance to develop, is likely to play a bigger role in the future and can reinforce competitive wholesale markets with market pricing and customer response. Many larger customers face market prices and have already switched to competitive suppliers. Utilities also need to establish retail prices at market levels for smaller customers still on default service, so that these customers can see the "true costs" (including environmental costs) of their consumption decisions. This transparency will become increasingly necessary as we strive to meet the challenges of climate change. Over time, competitive suppliers will be able to extend the benefits of value-added services to smaller customers, especially if improvements are made in market design, metering, communications, computer, and energy control technologies.

C. Embrace Electric Competition or It's Déjà Vu All Over Again

It has been said that those who cannot learn from history are doomed to repeat it.[130] Many states that have embarked on electric industry restructuring are at a turning point – trying to decide whether to go back to a regulatory model or move forward with restructuring. As Paul Joskow concluded:

> ...the jury is still out on whether policymakers have the will to implement the necessary reforms effectively...Creating competitive wholesale markets that function well is a significant technical challenge and requires significant changes in industry structure and supporting institutional and regulatory governance arrangements. It requires a commitment by policymakers to do what is necessary to make it work...the revisionist history about the 'good

[130] Based on quote by George Santayana, a Spanish-born American author and philosopher. (*The Life of Reason, Vol. 1, Reason in Common Sense*, New York: Charles Scribner & Sons, 1905, 284.)

> old days of regulation' has conveniently ignored the $5,000/MW nuclear power plants, the 12 cents/kWh PURPA contracts, the wide variations across utilities in the construction costs and performance of their fossil plants, and the cross-subsidies buried in regulated tariffs that characterized the regulatory regimes in many states. As we look at the costs and benefits of competition we should not forget the many costly problems that arose under regulation.[131]

Either policymakers will take steps to facilitate competitive markets or they may find themselves – consciously or not – back in the 1970s. Under the latter scenario, we will be entrenched in a regulated model that requires utilities and regulators to make billions of dollars of resource choices in a centrally-planned manner supported by ratepayer money, while confronted with tremendous uncertainty about technology, carbon control, fuel prices and demand levels. Poised now at a point where generation supply must accommodate higher natural gas prices on the one hand and the need for carbon control on the other, it is critical to rely on the market to make choices about fuel type and technology for new investments and actively manage the associated risks. We do not need another round of regulated investments that later prove to be uneconomic and cost consumers billions of dollars.

The goal of policy changes should not be to attempt to reverse the impacts of the increased costs of producing electricity, but rather to focus on ways to improve future investment, operating and consumption decisions – that is, to increase efficiency and provide customers with a greater choice of products and services. This ultimately will produce lower costs for consumers. In order to achieve these efficiency benefits, the electricity industry should not repeat the mistakes of the past, but should instead embrace competition.

[131] Joskow, "Markets for Power in the United States: An Interim Assessment," 32-33.

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APPENDIX E

TEXAS RETAIL COMPETITION – IMPACT ON RESIDENTIAL PRICES 1995-2008

INTELOMETRY STUDY

Texas
Retail Competition

Impact on Residential Prices
1995 - 2008

December 1, 2008

Prepared by
intelometry

Table of Contents

Executive Summary

The electric industry in Texas experienced a fundamental change at the outset of 2002. Previously, residential consumers in the State had no choice in their electric service; they were limited to one provider, one product and one price. Beginning in 2002, however, retail electric competition replaced traditional monopoly utility service in a significant portion of Texas. In those areas of the State opened to retail competition,[1] residential consumers could choose the company providing electricity to their homes for the first time. Today, these companies—called retail electric providers (REPs)—vigorously compete against each other for customers on the basis of price, product design, customer service and other factors.

This study concludes that the price of residential electric service in Texas--when adjusted for factors unrelated to retail electric competition—decreased after customer choice began in 2002. Although residential customers in Texas have paid more for electricity in recent years, this study demonstrates that retail competition is not a contributing factor. Other factors, such as the significant increase in natural gas prices since 2002, are responsible.

The price of generation supply is the most significant component of the total price of retail electric service. This study finds that the price of generation supply for residential customers decreased by as much as 13 percent following the introduction of retail competition in the State, when compared to the price of generation supply prior to customer choice.

Retail electric prices paid by residential customers before and after the introduction of retail competition in Texas were reviewed as part of this study. Specifically, the study reviewed prices during a 13-year period (1995 to 2008)[2] in three Texas utility service areas: CenterPoint Energy Houston Electric, LLC (CenterPoint); Oncor Electric Delivery Company (Oncor); and AEP Texas Central Company (AEP TCC). The percentage by which the price of generation supply for residential customers in each area has decreased since the onset of retail competition is shown in Table 1.

Table 1 - Residential Generation Supply Prices

Adjusted for 1995 Fuel Costs, Inflation and Regulated Rate Changes

	CenterPoint	Oncor	AEP TCC
Post Retail Competition Price Decrease	13.87%	13.07%	2.67%

[1] The areas open to retail competition in Texas include the service areas of investor-owned utilities located in the Electric Reliability Council of Texas (ERCOT) region.

[2] The period of time encompassed by the study concludes in August 2008.

Study Overview

Retail electric competition offers Texas consumers an array of service and pricing options for meeting their electricity needs. For example, as of October 2008, there were at least 25 REPs offering more than 82 different retail products to residential customers in the CenterPoint service area.[3] The success of the State's retail competitive market, however, should not be measured only in these terms. Customer choice also has brought a level of innovation to the Texas market that would not exist absent competition. For example, consumers now have the option to select from one of many 100-percent renewable energy products available in the market.

Many of the benefits that have accrued from retail competition, however, are often overshadowed by the increase in residential retail electric prices that began shortly after the introduction of customer choice in 2002. During the five-year period beginning in 2002, in which affiliated REPs were statutorily required to offer residential customers the transitional Price to Beat (PTB), the price charged for the PTB increased in each utility service area.[4] For example, the total PTB price in the CenterPoint service area was 25 percent higher in 2005 than the bundled price of electricity in 2001 prior to the advent of retail competition.

Simply looking in isolation at the level of PTB prices during this five-year period, however, is not the appropriate way to identify why retail electric prices for residential customers have increased since retail electric competition began in the State. Rather, a rigorous investigation of factors and events relevant to the price of electricity paid by residential customers during the time frame examined is necessary before a credible assessment can be made.

This study analyzed residential electricity prices from 1995 to 2008 in an examination of the possible factors contributing to the increase in residential electric prices after retail competition began. Specifically, it examined prices for residential customers in the CenterPoint utility service area, which encompasses Houston and the surrounding area; the Oncor utility service

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[3] This information was obtained for the CenterPoint service area on the PUCT's Power to Choose website, http://www.powertochoose.com/_content/_compare/showoffers.aspx.

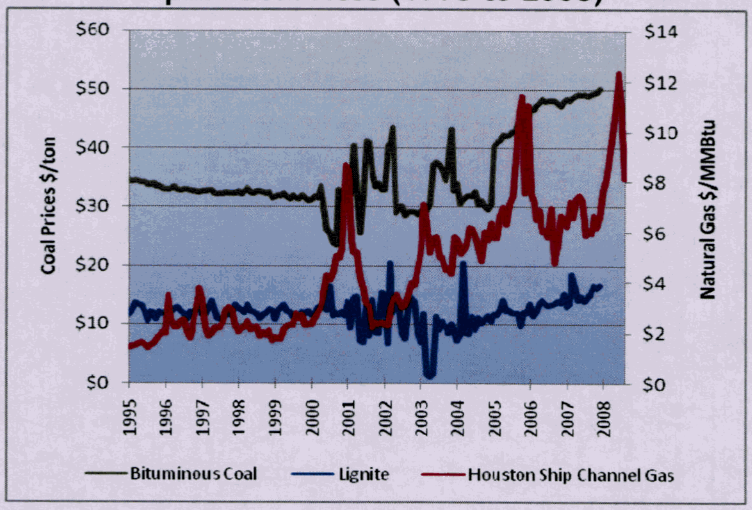
[4] Beginning in January 2002, the affiliated REP in each utility service area was required to provide retail electric service to residential and small commercial customers pursuant to a Price to Beat (PTB) tariff for a five-year period. These affiliated REPs were either actually affiliated with the utility serving the area or were a successor in interest to such an affiliated company. The PTB charged by an affiliated REP was based on the legacy rate charged residential customers by the formerly bundled investor-owned utility. Unlike the prices charged by competitive retail electric providers in the market, the PTB was statutorily set and regulated on a limited basis by the Public Utility Commission of Texas (PUCT). By law, the PUCT could adjust the PTB no more than two times per year based on significant changes in the market price of natural gas. The PTB tariff ended at the end of 2006, upon which time the retail market in Texas subject to customer choice became fully competitive.

territory, which serves Dallas and other regions in North Texas; and the AEP TCC utility service area, which serves Corpus Christi and other areas in South Texas. The price of generation supply is the most significant component of the total price of retail electric service in the regulated and competitive electric markets.[5]

In addition to analyzing retail electric prices for residential service, the study examined critical factors that impact electricity prices independent of customer choice. Factors such as inflation, fluctuations in fuel prices and changes in state-regulated utility "wires charges"[6] all impact the retail electric price that a residential customer pays, regardless of whether the area in which the customer resides is open to competition.

Of the critical factors examined in the study, the price of natural gas has played a significant role in the price of retail electric service in ERCOT, given that approximately 70 percent of the generating capacity in the region currently utilizes natural gas as a fuel source.[7] Soon after customer choice began in January 2002, natural gas prices rose dramatically. By August 2008, natural gas prices were more than three-and-a-half times what they were in January 2002. At its peak, the price of natural gas increased more than five-fold in comparison to its level in January 2002. The increase in natural gas prices since 2002 has increased the price of wholesale power used to provide retail electric service in the ERCOT region. As a result, upward pressure has been exerted on the price of retail electric service in this area.

Figure 1
Spot Fuel Prices (1995 to 2008)



5 Other components include the state-regulated wires charges paid to a transmission and distribution utility for the delivery of power, as well as costs incurred by the REP in marketing, customer service, and other administrative activities.

6 The PUCT regulates the wires charges (i.e., transmission and distribution rates) for all utilities in the ERCOT region.

7 NERC 2007 Long Term Reliability Assessment.

To adjust for these critical factors affecting electricity prices independent of retail competition, Intelometry analyzed their impact on the generation supply portion of retail electric prices for residential customers in Texas.[8] Only the generation supply portion of prices was examined because utility rates and services in ERCOT are still regulated today, due to those entities' continued status as providers of monopoly transmission and distribution services. In other words, any changes in a utility's distribution and transmission wires charges occur as the result of the regulatory process and not as a result of market forces or competition. Furthermore, consumers do not have the option to acquire transmission and distribution service from a provider other than the utility certificated to serve the area in which they reside.

Table 2

Residential Generation Supply Prices

Adjusted for 1995 Fuel Costs, Inflation and Regulated Rate Changes

(1995 cents/kWh)

	CenterPoint	Oncor	AEP TCC
1995-2001	6.67	6.55	5.75
2002-2006 Price to Beat	6.78	6.46	6.78
2002-2008 CREP/REP Offers	5.75	5.69	5.59
Post Retail Competition Price Decrease	13.87%	13.07%	2.67%

After making adjustments to account for the critical variables that exist independent of retail competition, a price for generation supply was calculated for each of the three periods studied, assuming fuel costs and inflation remained at 1995 levels for the entire period analyzed (1995-2008). The calculations of residential generation supply prices in Table 2 demonstrate that a residential customer who chose to take service from a competitive REP rather than remain on the affiliated REP's PTB experienced a decrease in the price paid for retail electric service, in terms of the price paid for generation supply.[9]

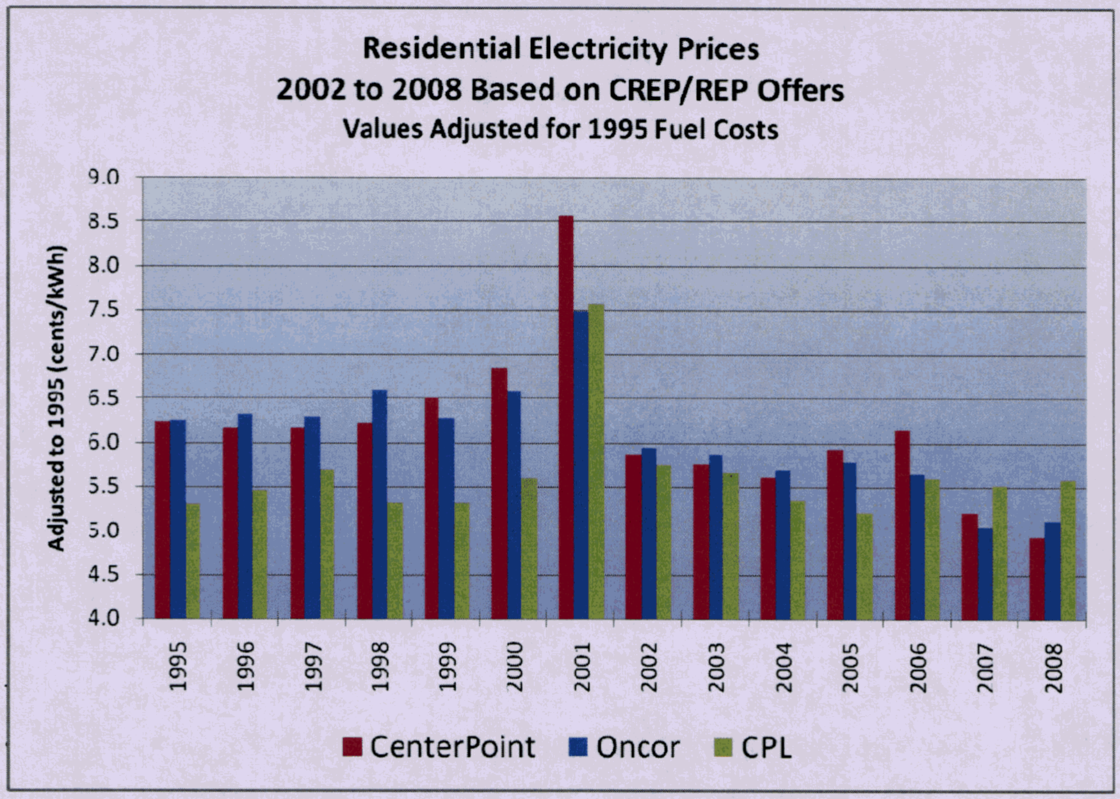
[8] Throughout this report, the portion of the retail electric price attributable to the cost of generation and associated services procured in the provision of retail service is referred to as "generation supply." However, it is important to note that a REP in the competitive retail market also incurs administrative costs and risks in addition to this cost of generation.

[9] A company that entered the competitive retail market upon the introduction of customer choice was referred to as a competitive REP or CREP. A competitive REP was unaffiliated with the utility and had no obligation to offer retail customers a specific rate such as the PTB. The distinction between a competitive REP and an affiliated REP disappeared at the end of 2006, when the PTB expired and the retail market became fully competitive.

While Table 2 shows that residential customers remaining on the PTB rates in the CenterPoint and AEP TCC service areas experienced increases in the price of generation supply, the disparate price impact between customers taking PTB service from an affiliated REP and customers taking service from a competitive REP can be explained.[10] The PTB was designed to provide a price floor to avoid predatory pricing by affiliated REPs and to induce competitive REPs to enter the market. It was also designed to encourage residential customers to shop for a better price. Broadly speaking, the PTB was a transition mechanism intended to further the ultimate goal of full competition in the market. Consequently, the price increases experienced by some residential PTB customers is not an appropriate benchmark by which to measure the success or failure of retail competition in the State.

This study's conclusion that generation supply prices for residential customers decreased after the introduction of retail competition in 2002 is further supported by Figure 2, which depicts adjusted residential prices for the three utility service areas analyzed year over year. Price levels dropped significantly immediately after the introduction of customer choice in 2002. In addition, price levels dropped even further once the statutorily set PTB rate expired at the end of 2006 and the market became fully competitive.

Figure 2



Analysis Details

Utility Name History

This study analyzed electricity price changes from 1995 to 2008 in the service areas of the transmission and distribution utilities that are currently known as CenterPoint, Oncor and AEP TCC. Prior to the restructuring of the electric industry in Texas, the company responsible for providing distribution and transmission service, the company responsible for providing generation supply service and the company selling retail service to customers were one and the same—the vertically integrated utility. After the unbundling of ERCOT's investor-owned utilities, separate companies performing transmission/distribution, generation and retail functions were formed. In addition to new names for these new companies, corporate name changes occurred during this time period. This report generally refers to the three analyzed service areas by the current names of the transmission and distribution utilities that serve those areas: CenterPoint, Oncor and AEP TCC. However, in describing the details of the analysis and the various models, the report also references previous names or affiliates that were responsible for offering PTB service. Table 3 through Table 5 summarizes these names across the relevant analysis periods.

Table 3 - CenterPoint History

Analysis Period	Years	Transmission and Distribution Provider	Retail Provider
Pre-Retail Competition	1995-1997	Houston Lighting and Power	Houston Lighting and Power
Pre-Retail Competition	1998-2001	Reliant Energy HL&P	Reliant Energy HL&P
Retail Competition Transition	2002-2006	CenterPoint	Reliant Energy (AREP) and CREPs
Full Retail Competition	2007-2008	CenterPoint	REPs

Table 4 - Oncor History

Analysis Period	Years	Transmission and Distribution Provider	Retail Provider
Pre-Retail Competition	1995-2001	TXU Electric Company	TXU Electric Company
Retail Competition Transition	2002-2006	Oncor Electric Delivery	TXU Energy Services (AREP) and CREPs
Full Retail Competition	2007-2008	Oncor Electric Delivery	REPs

Table 5 - AEP Texas Central Company History

Analysis Period	Years	Transmission and Distribution Provider	Retail Provider
Pre-Retail Competition	1995-2001	Central Power and Lighting Company	Central Power and Lighting Company
Retail Competition Transition	2002	AEP Texas Central Company	Mutual Energy CPL (AREP) and CREPs
Retail Competition Transition	2003-2006	AEP Texas Central Company	CPL Retail Energy (AREP) and CREPs
Full Retail Competition	2007-2008	AEP Texas Central Company	REPs

Critical Factors

Three primary factors were examined to determine their impact on retail electric rates from 1995 to 2008. These include changes in the state-regulated utility wires charges, changes in fuel costs, and inflation. Explanations of how each of these factors fit into the analysis are provided below.

Changes in State-Regulated Utility Wires Charges

After the introduction of retail competition in 2002, retail electric prices paid by residential customers in Texas included the costs of services that are competitive, primarily generation supply, and the cost of services that are regulated or non-competitive, primarily transmission and distribution services. Since the utility distribution and transmission systems of Texas utilities remain regulated by the PUCT, fluctuations in the level of utility wires charges are not salient when examining the impact of retail competition on overall electricity prices. To isolate the impacts of retail competition on electricity prices, these non-competitive costs were removed from the entire analysis. From 1995 to 2001, the entire rate paid by customers for regulated utility service was non-competitive. For purposes of this study, those costs that remained non-competitive or regulated by the PUCT after the introduction of retail competition in 2002 were removed from the analysis during the 1995 to 2001 pre-retail competition period.

Fuel Costs

The cost of generating electricity is directly related to the underlying cost of fuel used to produce electricity. The vast majority of today's electricity in the ERCOT region (approximately 70 percent) is generated using natural gas.[11] In other words, the cost of providing retail electric service will increase or decrease as natural gas prices increase or decrease, given that natural gas plants generally operate on the margin in ERCOT and consequently set the market price for power in the region. Prior to the introduction of retail competition, the investor-owned utilities in Texas recovered their fuel costs pursuant to fuel factors included as part of their rates. The electric utilities could request periodic adjustments to these fuel factors to recover their projected fuel costs, subject to reconciliation in the future. For the three utility service areas examined, these fuel adjustments were impacted largely by changes in natural gas and coal prices. Since fluctuations in fuel costs impact retail electricity rates irrespective of whether retail competition exists, the impact of fuel costs must be accounted for when isolating the impacts of retail competition on electric rates. This was accomplished by holding fuel prices at 1995 levels throughout the entire analysis period.

Inflation Adjustment

Inflation is the general rise in the level of prices for goods and services during a period of time. It can occur regardless of whether those goods and services are competitive. Inflation can generally be thought of as a decrease in the value of currency. In other words, one can purchase more of the same goods or services with 1995 dollars than one can with 2008 dollars. In order to compare pre- and post-retail competition electricity prices, adjustments for inflation must be made so prices can be compared in real rather than nominal

[11] There are many reasons for the predominance of natural gas as a fuel source for generation facilities in ERCOT, one of the most notable being the legislatively established goal set in 1999 for natural gas generation in the State. *See* Public Utility Regulatory Act, § 39.9044

terms. For the purposes of this study, real prices were measured in 1995 dollars.

Analysis Time Periods

As previously stated, this study analyzed prices from 1995 to 2008. During that time period, the electricity market underwent two fundamental changes. The first change occurred in 2002, when the Texas retail electric market opened to competition. The second occurred at the end of 2006 when the transitional PTB rates ended and full retail competition began. As the result of these changes, the analysis was segmented into three time periods. The "Pre-Retail Competition Period" covers the period from 1995 to 2001; the "Retail Competition Transition Period" covers the period from 2002 to 2006; and the "Full Retail Competition Period" includes the years 2007 and 2008. The underlying analysis and methodology varied for each of the three time periods.

Pre-Retail Competition Period (1995 to 2001)

This period began four years prior to the enactment of the legislation requiring certain areas of the State to transition to a competitive retail electric market. Therefore, it involved analyzing regulated rates that were in effect prior to retail competition. During this period, consumers were charged functionally bundled rates. In other words, distribution, transmission and generation supply were "bundled" into one tariff rate, leaving the consumer with little to no visibility as to how much of their total electric service bill resulted from each component.

After the introduction of customer choice in 2002, the cost of generation supply became the principal cost in the price of competitive retail electric service. To estimate the portion of the bundled utility rates that were related to generation supply prior to 2002, the generation supply costs were isolated and separated from other bundled rate component costs using a combination of a Functional Cost of Service Model and a Regulated Fuel Cost Model, both of which were developed specifically for this study. The Functional Cost of Service Model was developed utilizing the public filings of each of the three Texas utilities. This model enabled the separation of generation supply costs from each utility's total bundled service rate.

Since the analysis also required isolating the effect of the cost of fuel on generation supply prices, a Regulated Fuel Cost Model was constructed in order to estimate the impact that fluctuating fuel costs exerted on generation supply costs. The Regulated Fuel Cost Model was based on each utility's FERC Form 1 filings, which included specific operating data on each power plant.

Retail Competition Transition Period (2002 to 2006)

Customer choice for residential consumers began in January 2002.[12] The introduction of competition in the retail electric market afforded customers the ability to choose the company providing their retail electric service. Residential customers could choose to continue to take service from the company affiliated with the incumbent utility (the affiliated REP) and pay for electricity under the affiliated REP's PTB tariff, or choose to take service from a number of competitive REPs and pay a market-based price generally lower than the applicable PTB. This study examined both options available to residential customers during this time period.

Affiliated REP PTB Rate Option

Beginning in 2002, the traditional bundled rates of Texas utilities (analyzed for the 1995 to 2001 period) were functionally separated into distribution, transmission and generation supply cost components. As a result, the functional cost of service analysis for these unbundled rates was more straightforward than during the Pre-Retail Competition Period. The PTB, however, remained a bundled rate. For consumers taking service under the PTB tariffs, generation supply costs were determined by computing transmission and distribution cost components using distribution and transmission service rates that took effect in 2002, and subtracting those transmission and distribution costs from the overall PTB service costs. This analysis was performed using the Price-to-Beat Supply Price Model.

In order to isolate the cost of fuel on the generation supply portion of the PTB rate, a model was constructed to predict how changes in natural gas prices impacted the fuel factor adjustment that was part of the PTB tariff. This model is referred to as the PTB Fuel Factor Model. During the Retail Competition Transition Period, the affiliated REP was permitted to request adjustments in the fuel factor based on changes in the price of natural gas, but no more than two times each year. Accordingly, the relationship between the fuel factor and natural gas prices was well established under the PTB.

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[12] All customers of the five investor-owned utilities in ERCOT were eligible to choose a REP beginning in January 2002. In the latter part of 2001, up to five percent of the electrical load of each investor-owned utility in the ERCOT region was eligible to participate in a pilot program in which customers were able to choose their electricity provider.

Competitive REP Generation Supply Option

For customers who opted to receive retail electric service from a competitive REP, the determination of the generation supply cost embedded in the retail price was more complex. This analysis began by developing average retail offer prices using historical postings of retail offers obtained (not including the PTB rate) from the PUCT's "Power to Choose" website.[13] The average retail offer prices were developed for each of the three utility service areas analyzed and for each month of the 2002 to 2006 time period. Finally, the applicable utility's transmission and distribution rates were subtracted from the retail offer prices to determine the customer's generation supply price. This analysis was performed using the REP Actual Supply Price Model.

In order to forecast how retail market prices would have changed had fuel costs remained at 1995 levels, a Forecast REP Supply Price Model was used. This model utilizes historic relationships between wholesale prices of electricity and retail offer prices, as well as the historic relationship between the affiliated REP's PTB rate and competitive REP offer prices.

Full Retail Competition Period (2007 to 2008)

The year 2007 marked the first full year of data available from a "fully" competitive retail electric market. The PTB rate expired at the end of 2006 and was no longer available to residential customers. As a result, the generation supply prices paid by all residential customers for competitive retail electric service were the result of market forces. Similarly, the distinction between affiliated REPs and competitive REPs no longer existed. The analysis for this time period was similar to the analysis conducted for customers taking supply from a competitive REP during the previous Retail Competition Transition Period.

A summary of the models employed during each time period for each analysis are shown in Table 6. More detailed descriptions of each model are presented in the remainder of this report.

[13] www.powertochoose.com

Table 6 - Intelometry Analysis Models

Time Period	Retailer	Functional Separation	Fuel Cost Adjustment
Pre-Retail Competition (1995-2001)	Regulated Utility	Functional Cost of Service Model	Regulated Fuel Cost Model
Retail Competition Transition (2002-2006)	Affiliated Retail Electricity Provider (AREP)	Price-to-Beat Generation Price Model	PTB Fuel Factor Model
	Competitive Retail Electricity Provider (CREP)	REP Actual Generation Price Model	REP Forecast Generation Price Model
Full Retail Competition (2007-2008)	Retail Electricity Provider (REP)	REP Actual Generation Price Model	REP Forecast Generation Price Model

Modeling Details

This section describes the core models constructed in order to perform the overall analysis. The specific models include the Functional Cost of Service Model, the Regulated Fuel Cost Model, the Price-to-Beat Supply Price Model, the PTB Fuel Factor Model, the REP Actual Supply Price Model, and the REP Forecast Supply Price Model.

Functional Cost of Service Model

From 1995 to 2001, residential consumers paid for electric service pursuant to functionally bundled rates. In other words, the costs of distribution, transmission and generation services provided by the regulated utility were generally bundled into a single tariff rate. Given this bundling, a residential consumer could not determine how much of the total rate was derived from each component. In order to determine the portion of a residential customer's tariff rate that related to generation supply, a Functional Cost of Service Model was constructed. This model was developed by first analyzing utility FERC Form 1 filings to determine the portion of total costs attributable to distribution, transmission and generation. Utility unbundled cost of service filings made in 2000 with the PUCT were also analyzed to corroborate the FERC Form 1 data and to determine how overall generation supply costs were allocated specifically to the residential rate class of each utility.

Overall Cost of Service

From 1995 to 2001, each of the three utilities analyzed in the study filed annual reports with the Federal Energy Regulatory Commission ("FERC"). Part of these submissions included detailed reporting of accounting data filed through FERC Form 1. FERC Form 1 is a standardized filing that requires the utilities to submit detailed financial, sales and cost information. FERC Form 1 uses the Uniform System of Accounts ("USOA") to define how various costs should be grouped. For most costs, these accounts allowed for a determination of whether a particular cost is attributable to distribution, transmission or generation supply. For general costs that could not be clearly attributed to one of these functions, other data filed in FERC Form 1 was used to develop allocation factors. This model generated the percentage of overall costs attributable to generation supply for each utility for the 1995 to 2001 period. A summary of this data is shown in Table 7.

Table 7
Overall Costs Attributable to the Generation Function

	1995	1996	1997	1998	1999	2000	2001
Reliant HL&P	77.0%	77.0%	76.1%	74.1%	76.7%	76.7%	76.7%
TXU Electric Company	81.5%	81.5%	79.5%	81.8%	79.3%	79.7%	76.2%
Central Power and Light	72.4%	72.4%	72.2%	71.2%	69.7%	76.1%	80.6%

Note: Data for 1995 was unavailable for all three utilities, so 1996 data was used as a proxy. 2000 and 2001 data was unavailable for Reliant HL&P, so 1999 data was used as a proxy.

Residential Cost of Service

The process discussed above resulted in an estimation of the portion of the utilities' overall costs that were attributable to generation supply during the period preceding retail competition. This estimation was at the utility level, that is, it included costs for all customers, not just residential customers. In order to determine which portion of the generation supply costs should be allocated to the residential class, utility rate case filings were reviewed to determine how costs were allocated to various rate classes.

As part of the process to implement the restructuring of the electric market and the introduction of retail competition, each of the utilities filed an Unbundled Cost of Service ("UCOS") study in early 2000 to support the separation of the transmission and distribution function from the generation supply function. In these UCOS filings, both Reliant HL&P and TXU Electric provided historical test-year costs for the year ending September 30, 1999. These costs were functionalized according to distribution, transmission and generation functions. These functionalized costs were further allocated to each rate class, including an allocation for residential customers. An analysis was conducted to determine the ratio of the residential allocation of overall generation supply costs to the company's total allocation of generation supply costs. This factor was then applied to the overall generation supply cost percentages developed in the previous step to estimate the percentage of total residential electricity costs that were allocated to the generation supply function. Since CPL did not provide detailed test-year costs in its UCOS filing, an average of the results from Reliant HL&P's and TXU Electric's respective filings was used as a basis for CPL's residential allocation. A summary of these analysis results is shown in Table 8.

Table 8
Residential Costs Attributable to the Generation Function

	1995	1996	1997	1998	1999	2000	2001
Reliant HL&P	72.9%	72.9%	72.0%	70.1%	72.6%	72.6%	72.6%
TXU Electric Company	79.2%	79.2%	77.2%	79.4%	77.0%	77.4%	74.0%
Central Power and Light	69.4%	69.4%	69.2%	68.2%	66.8%	73.0%	77.2%

Note: Residential allocation data was unavailable for CPL, so an average residential allocation of TXU Electric and Reliant HL&P was used as a proxy.

Residential Generation Supply Costs

After completing the analysis using the Functional Cost of Service Model, the total electricity cost for a residential customer using 1,000 kWh per month was obtained from historical utility price data available from the PUCT. Applying the allocation factors for the portion of total residential costs attributable to the generation supply function from the previous analysis yielded the estimated price in cents/kWh that residential customers paid for generation supply from each utility from 1995 to 2001. The results are shown in Figure 3 through Figure 5.

Figure 3

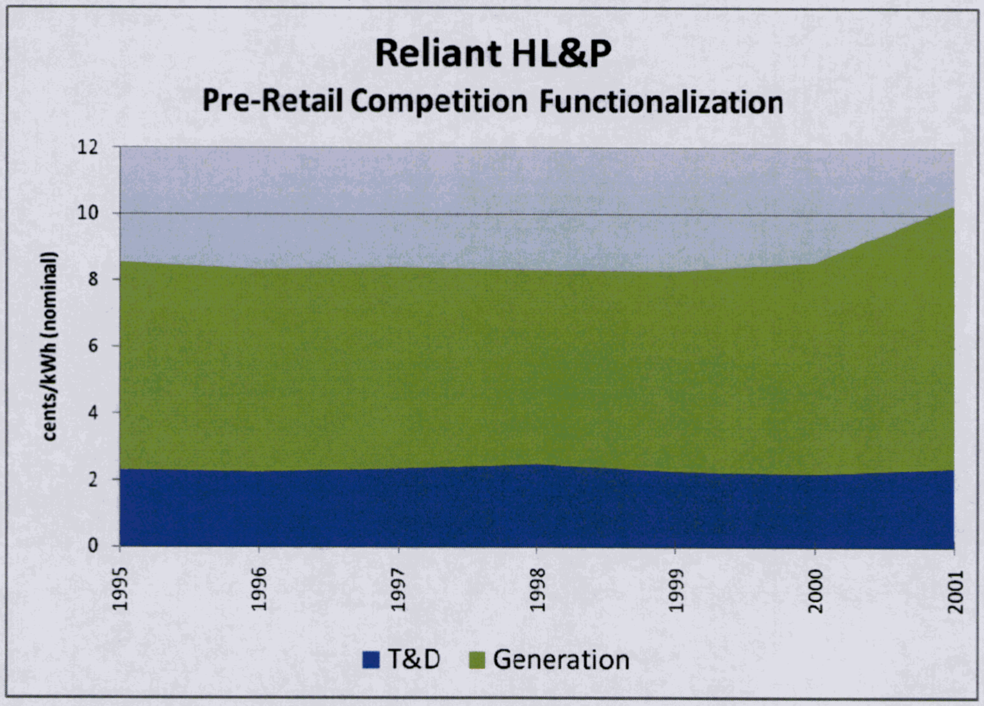


Figure 4

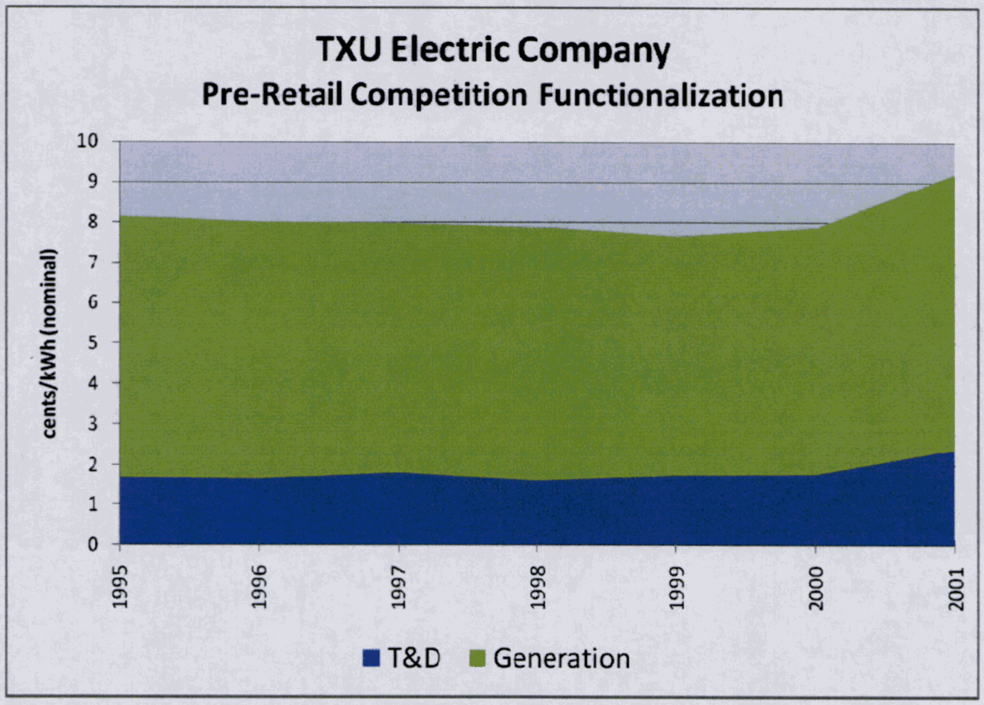
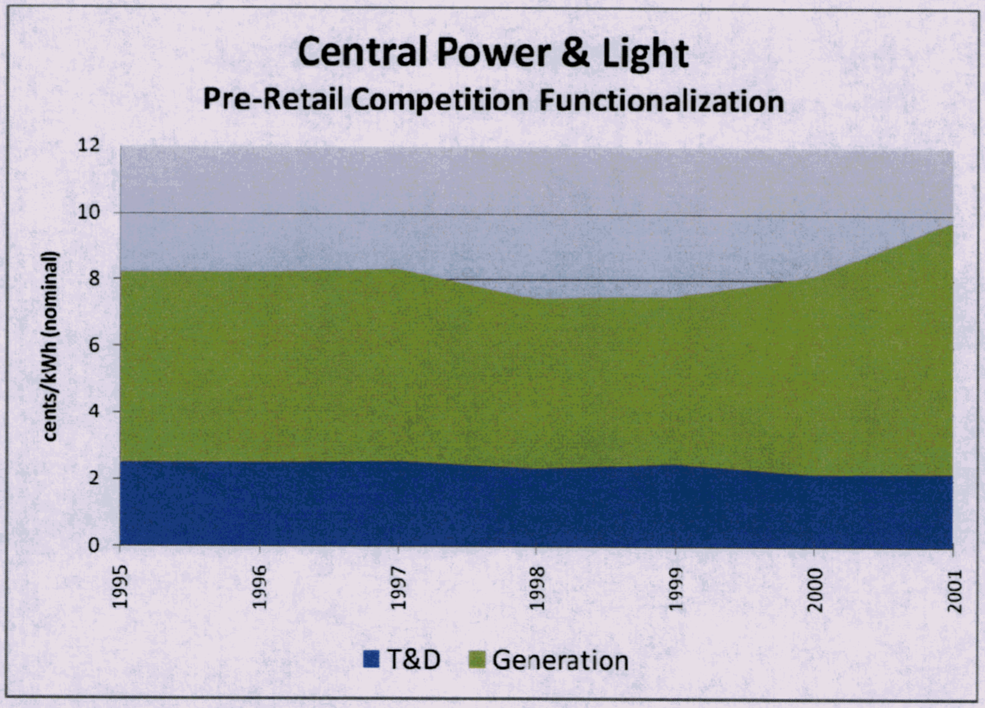


Figure 5



Regulated Fuel Cost Model

The Regulated Fuel Cost Model was developed in order to calculate how actual generation supply prices from 1995 to 2001 would have changed had fuel prices stayed constant at 1995 price levels. Each utility's FERC Form 1 filing during the Pre-Retail Competition Period included detailed operational data for each power plant in the utility's generation fleet. This data included the total quantity of fuel consumed, as well as the average cost of fuel burned in each power plant. From this data, each utility's actual fuel costs were computed on a cents/kWh basis and a model was constructed that allowed for a recalculation of the utility's average fuel costs. This model was constructed in a fashion that allowed for the utility's overall fuel costs to be computed based on different prices for natural gas, coal and lignite.

The next step in constructing the Regulated Fuel Cost Model was to determine market prices for natural gas, coal and lignite from 1995 to 2001. Daily natural gas prices were obtained from *Platts*, while coal and lignite prices were extracted from FERC Form 423. FERC Form 423 is a monthly report addressing the cost and quality of fuels used for steam generating plants greater than 50 MW. The report includes the quantity, price and British thermal unit (Btu) content of bituminous, sub-bituminous or lignite coal. This data was extracted from the FERC reports and then summarized into a monthly price for coal and lignite.

With the fuel cost model and fuel cost data compiled, the natural gas and coal prices for 1995 were extracted from the data. The model was then run using 1995 prices for natural gas and coal during the entire period from 1995 to 2001. The result is an estimate of each utility's fuel cost, assuming that fuel prices during the Pre-Retail Competition Period stayed at 1995 price levels. The estimated change in fuel costs was then used to adjust the utility's rate for generation supply for each year. The results are shown for each utility below.

Figure 6

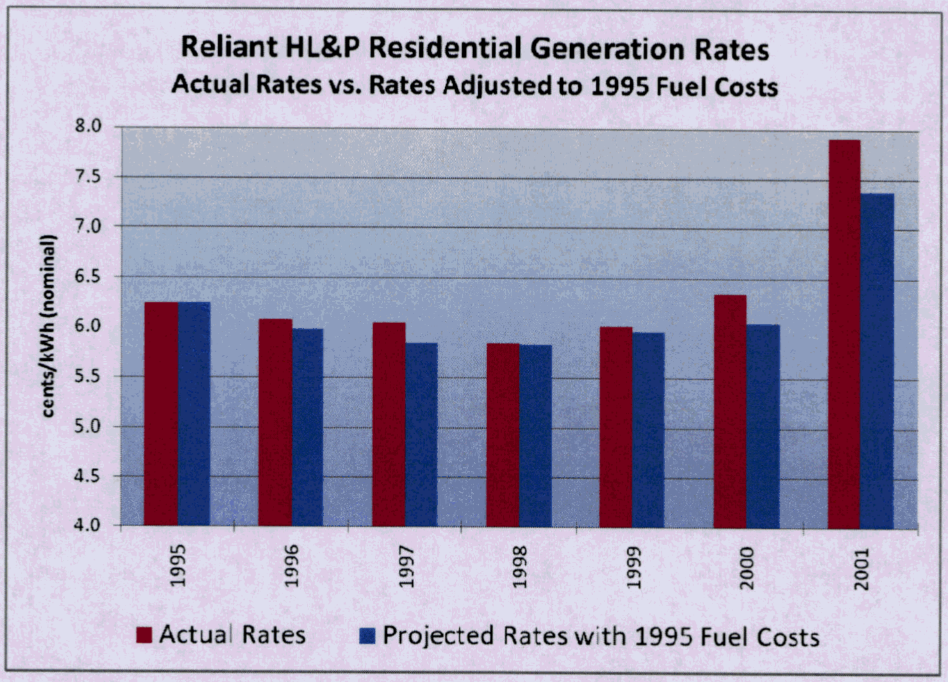


Figure 7

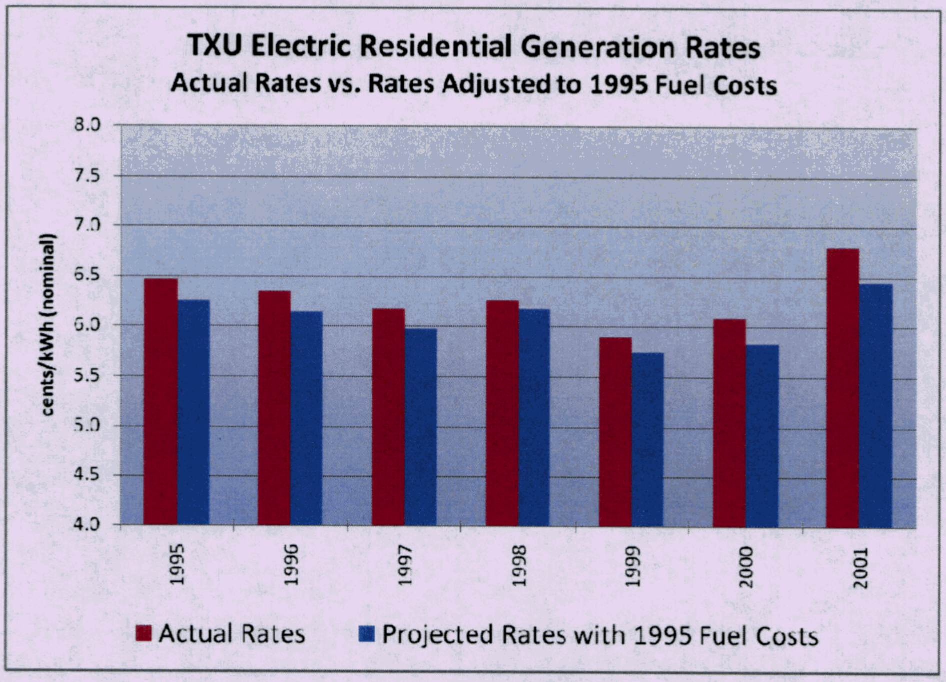
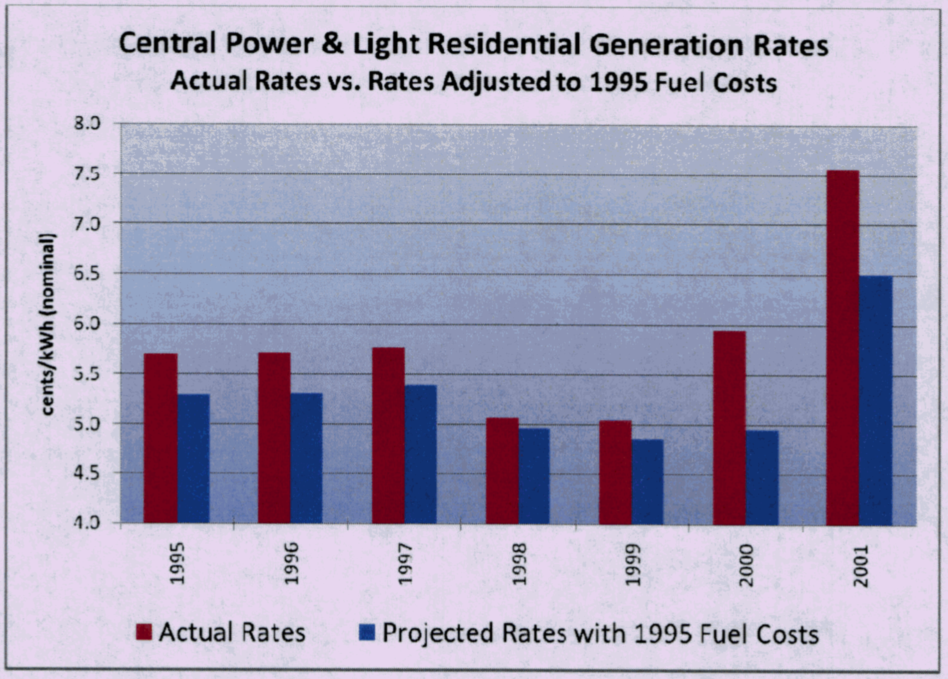


Figure 8



Price-to-Beat Generation Price Model

In order to smooth the transition to a fully competitive retail electric market, the enabling statute for retail competition created a Retail Competition Transition Period from 2002 to 2006. During this transitional period, residential customers could choose to continue to take electric service from the affiliated REP pursuant to a regulated PTB rate, or to select a competitive REP that offered a market-based price for retail electric service. In both cases, the price offered to residential consumers included transmission, distribution and generation components bundled into one total price. However, unlike during the Pre-Retail Competition Period, the costs attributable to transmission and distribution services provided by the still-regulated utility in this period were segregated and reflected in the utility's non-bypassable charges for delivery services in its filed tariffs. Using these tariff charges, the portion of the PTB rate that is associated only with generation supply was calculated.

This calculation was performed by first calculating the entire monthly cost of electricity for a residential customer who took service on the PTB rate.[14] Next, the total monthly cost for transmission and distribution service provided by the regulated utility was calculated using the utility tariffs. The cost associated with PTB generation supply was then calculated as the total cost of PTB electricity less the total transmission and distribution charges for each month.

Price-to-Beat Fuel Factor Model

No more than twice a year, the affiliated REP was permitted to seek adjustments in the fuel factor included in the PTB to reflect significant changes in the market price of natural gas. The adjustment to the fuel factor was based primarily on a calculation of the closing forward 12-month NYMEX Henry Hub natural gas price.[15]This ability to adjust the PTB fuel factor based on changes in the market price of natural gas reflected the direct relationship between the price of natural gas and the price of wholesale power in ERCOT. This relationship is clearly visible in Figure 9. As a result, a model was constructed to predict what the PTB fuel factor would have been for each utility had different natural gas prices existed from 2002 to 2006. The PTB Fuel Factor Model was then run using 1995 NYMEX Henry Hub natural gas prices

[14] The PTB rate was computed using the affiliated REP's filed PTB tariff, assuming a residential customer using 1,000 kWh per month.

[15] Texas Administrative Code, Title 16, Part 2, Chapter 25, Subchapter B, Rule 25.41.

for the years 2002 to 2006. The result of this analysis is a PTB fuel factor based on 1995 natural gas prices.

Figure 9

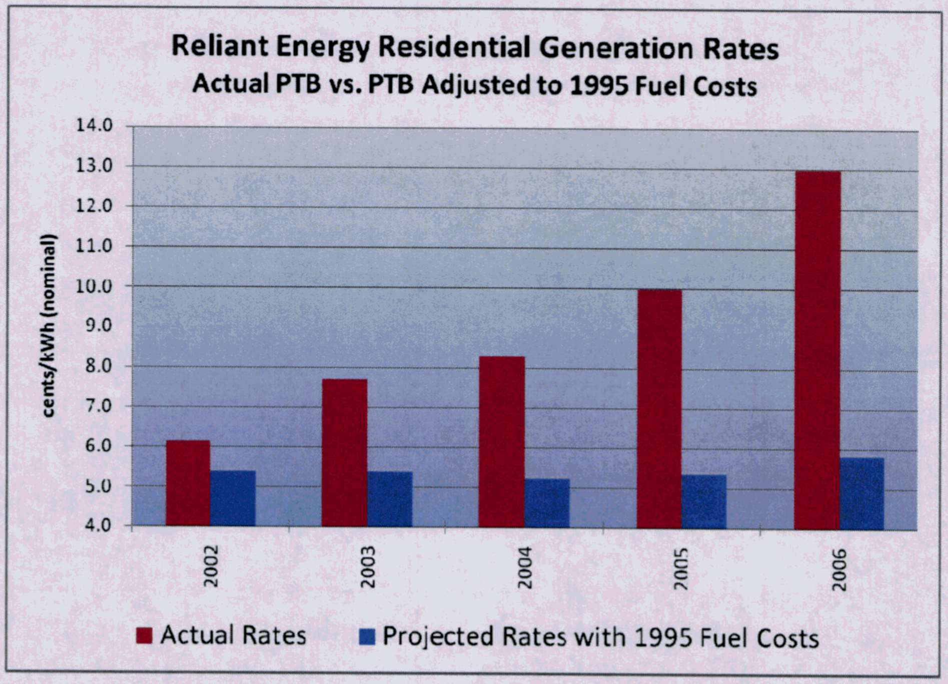


Figure 10

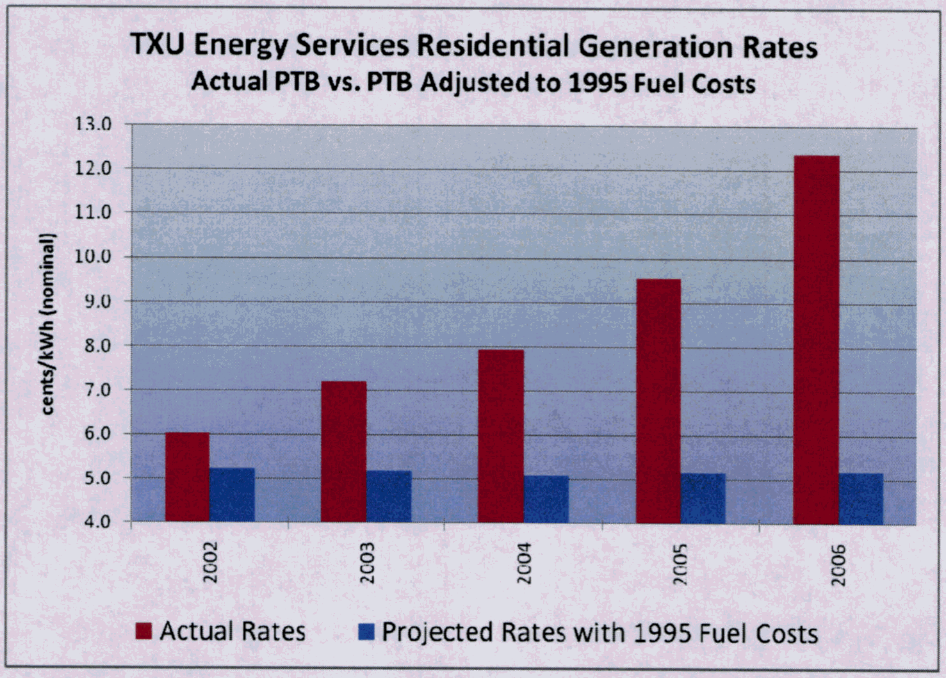
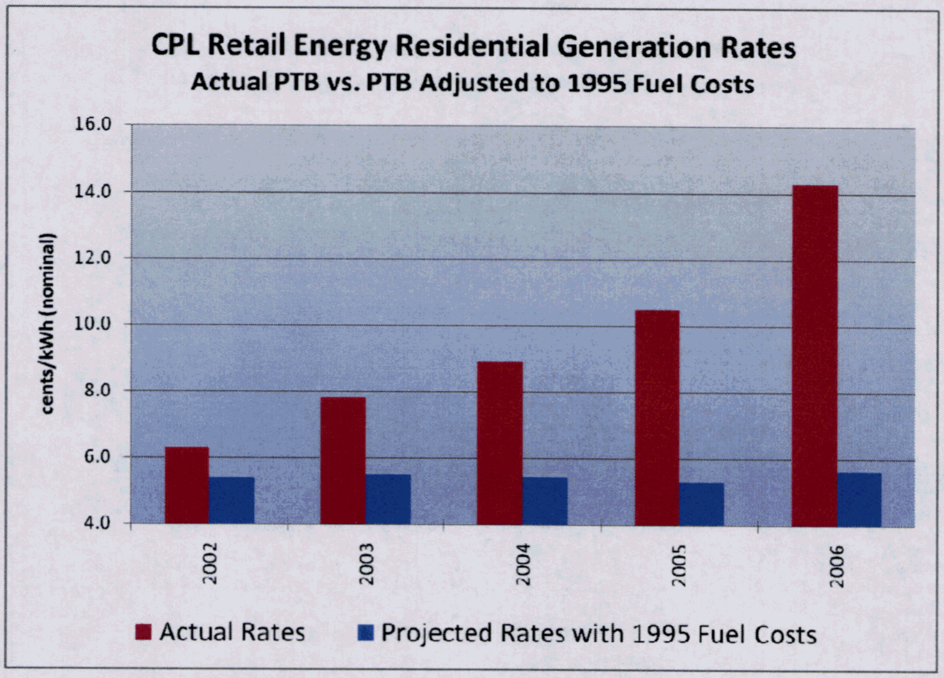


Figure 11



REP Actual Generation Price Model

For customers who chose a competitive REP for retail electric service, the determination of the generation supply portion of the retailer's market-based offer was more complex. The PUCT maintains a history of competitive REP offers that were posted on its Power to Choose website. The offers presented in those postings varied in both characteristic and contractual terms. For example, various postings reflected a retail product based on 100-percent renewable energy, while others reflected only base renewable requirements to satisfy regulatory mandates. Similarly, some offers were designated as "variable" (e.g., the price could change from month to month), while other offers were characterized as "fixed" for a specified term (e.g., six months, 12 months, etc.). Not all of the characteristics, including the contract term, of a retail electric product were clearly delineated in the Power to Choose website postings. To the greatest degree practical, each competitive REP offer in each month was reviewed, and if it appeared that the offer was a standard product (not renewable) for a fixed 12-month price term, it was averaged into a total "CREP Offer" price for that month.

The prices posted by competitive REPs on the Power to Choose website represented the total price for retail electric service. In other words, the utility's regulated transmission and distribution charges were embedded in these retail prices. To adjust the retailer's offer price to reflect only the competitive portion of the price, the utility's transmission and distribution charges were computed for each month and subtracted from the retailer total offer price. The result is the estimated portion of the competitive REP's offer price for each month that primarily relates to generation supply.

REP Forecast Generation Price Model

The REP Actual Generation Price Model results in an estimate of the actual average generation supply prices embedded in the offers available to customers who switched to a competitive REP in the 2002 to 2008 timeframe. The price paid by a competitive REP for generation supply was significantly influenced by the wholesale market price for power. In turn, the wholesale market price for power was greatly influenced by the underlying cost of fuel used to generate power. In order to estimate competitive REP offer prices based on the assumption that natural gas prices remained at 1995 levels throughout the 2002 to 2008 period, a REP Forecast Generation Price Model was constructed.

Calculation of REP Offer Spread

In order to predict the level of competitive REP offer prices if natural gas prices had remained at 1995 levels, it was first necessary to calculate the actual spread between retail offer prices and the wholesale price of electricity from 2002 to 2008. Since competitive REPs must include more than just the underlying wholesale cost of energy in their offer prices, the wholesale market price must undergo a number of adjustments and incorporate certain adders to be truly reflective of the underlying generation cost incurred by the competitive REP.

Forward on-peak wholesale market prices for the ERCOT region were obtained from *Platts* for the 2002 to 2008 timeframe. These market prices were then consolidated into a forward 12-month strip for each settlement date. This forward on-peak wholesale price represents the price if the same quantity of energy was purchased for all weekdays (exclusive of all holidays) between the hours of 6 a.m. and 10 p.m. The following adjustments were then made to adjust this on-peak forward market price to develop its equivalent retail generation cost:

- **Estimation of Off-Peak Forward Market Price:** Data was not readily available for the off-peak forward market price from 2002 to 2008. To estimate the forward market off-peak price, an analysis was conducted of the historic relationship between on- and off-peak prices using data from the ERCOT Market Clearing Price for Energy (MCPE). This relationship was then used to estimate the off-peak market price that would have existed with each on-peak price observation from *Platts*.

- **Calculation of Monthly Shape:** The kWh consumption of residential customers varies by season based on relatively predictable patterns. If the competitive REP offered a fixed 12-month price to the customer for all volume consumed during any month, the competitive REP must have anticipated this pattern in its pricing, as ERCOT wholesale prices also varied in relatively predictable seasonal patterns. The standard residential load profiles of each utility were used to shape the on- and off-peak monthly data into a weighted average annual forward market price.

- **Calculation of Basis Prices:** The forward market prices published by *Platts* represented a "sellers choice" product. That is, the seller of the contract had the choice as to which location within the ERCOT region to deliver the energy. However, the REP had to deliver the energy to the zone where the customer was located. The difference in pricing between these locations is often referred to as the "basis" price. The basis price from the seller's choice to each zone that covers the majority of each utility service area was computed using historical ERCOT Market Clearing Price of Energy (MCPE) data.

- **Calculation of Hourly Shape:** As discussed earlier, the forward market product represented the same volume every hour of either the on- or off-peak period. However, residential customer consumption patterns vary continuously. In addition, ERCOT's wholesale balancing energy market prices vary every fifteen minutes. The REP had to account for the difference in price between the fixed hourly volume forward market price and the hourly volumes actually consumed by customers. Historic utility load shapes for residential customers, along with historical ERCOT MCPE prices, were used to develop an hourly shaping factor for each utility.

- **Ancillary Services and ERCOT Fees:** The REP must procure ancillary services to support the transmission of energy and ensure the reliability of the ERCOT system. In addition, there are certain fees assessed by ERCOT to the REP as a market participant. Historical prices for these services were used to estimate the costs associated with ancillary services and ERCOT fees that were embedded into supplier offers.

- **Losses:** The REP must purchase additional energy and ancillary services to cover the transmission and distribution losses incurred in providing service to the residential customer. Historical losses for each utility were used to estimate this cost.

The sum of the forward market wholesale price and the costs associated with all of the above factors represent the retail commodity cost for each month during the 2002 to 2008 timeframe. In order to determine how retail offers corresponded to this retail commodity cost, the retail commodity cost was subtracted from the average retail offer price each month to develop the "spread" between retail and wholesale prices. The spread was then converted to a percentage of the retail offer price. Monthly spreads from 2002 to 2006 were then averaged over rolling 12-month periods to develop an average retailer spread for each utility service area during the Retail Competition Transition Period.

It is important that this spread not be equated with competitive REP profit or margin. There are many other costs and risks incurred by the REP that are encompassed in the difference between the retail supply price and the base retail commodity cost. The REP assumes the risk associated with changes in volume, changes in price, and changes in transmission and distribution prices, just to name a few of the risks that REPs bear. The competitive REP also assumes substantial operational, transactional and financial costs to support the business.

Calculation of REP Offer to PTB Spread

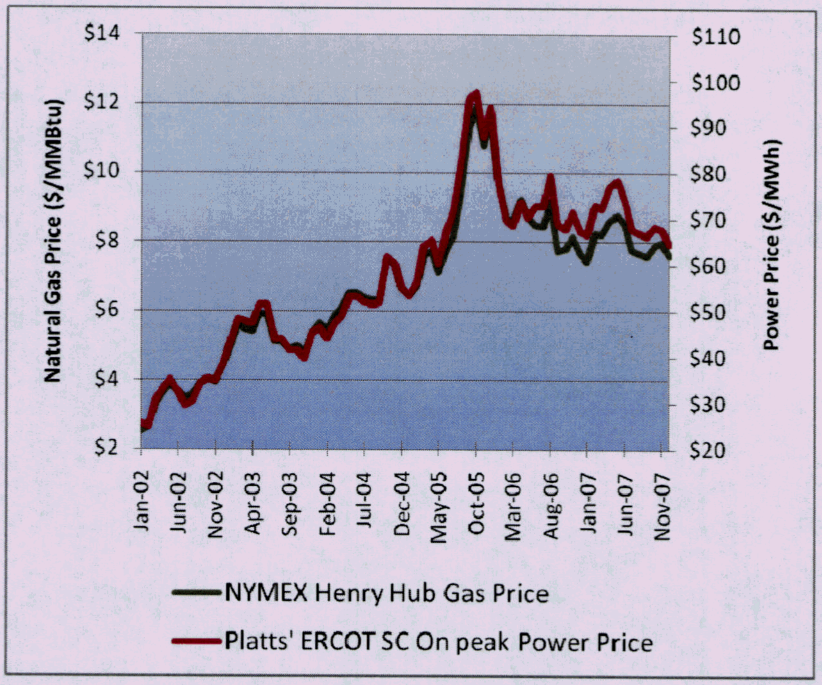
The analysis described above determines the average spread between retail offers and the base retail commodity cost. This spread can be used as one means to estimate what retail prices would have been if fuel costs had stayed at 1995 levels throughout the Retail Competition Transition Period and Full Retail Competition Period.

However, retail pricing strategies are more complex than a simple direct relationship to costs. During the 2002 to 2006 period, residential consumers could use the PTB rate, which was publicly available information in the affiliated REP's tariff, to determine whether a competitive REP's price offer would save them money. As a result, most competitive REPs, especially in the beginning of the Retail Competition Transition Period, priced at a discount to the PTB in order to entice residential customers to switch service from the affiliated REP. To account for this, the difference each month between the average retail offer price and the PTB was converted to a percentage basis. The monthly percentage differences from 2002 to mid-2006 were then averaged on a rolling 12-month basis to develop an overall retail offer to PTB spread. This REP Offer to PTB Spread, along with the REP Offer Spread, is used later in the Forecast Generation Price Model and will be described further in the subsequent section.

Estimation of Power Prices Based on Gas Prices

Approximately 70 percent of ERCOT's generating capacity is fueled by natural gas. As a result, there is a strong correlation between natural gas and wholesale power prices in the ERCOT region. This is evidenced in Figure 12, which depicts the average monthly settlement price for the forward 12-month natural gas and power contract.

Figure 12



In view of this strong relationship between natural gas and wholesale power prices, a model was constructed that used the historical relationship between natural gas and power prices to project what on-peak power prices would be if natural gas prices had remained at 1995 levels during the 2002 to 2008 time period.

Once this on-peak power price was generated, the same process previously described in calculating the REP Offer Spread was used to estimate the base retail commodity cost assuming natural gas prices had remained at 1995 levels. Specifically, the off-peak price of power was estimated using the derived on-peak price of power. The monthly shape, basis, hourly shape, ancillary services and losses were then added to the on- and off-peak price to derive the base retail commodity cost for each month between 2002 and 2008, assuming natural gas prices had stayed constant at 1995 levels.

Forecast of REP Price Based on 1995 Natural Gas Price Levels

The forecast for the base retail commodity cost developed in the previous step was scaled up each month based on the REP Offer Spread explained earlier. Separately, the forecasted PTB rate developed using the Price-to-Beat Fuel Factor Model was scaled down based on the REP Offer to PTB Spread. The maximum of these two figures was then used for each month as the forecasted retail offer price adjusted for 1995 fuel price levels.

Figure 13

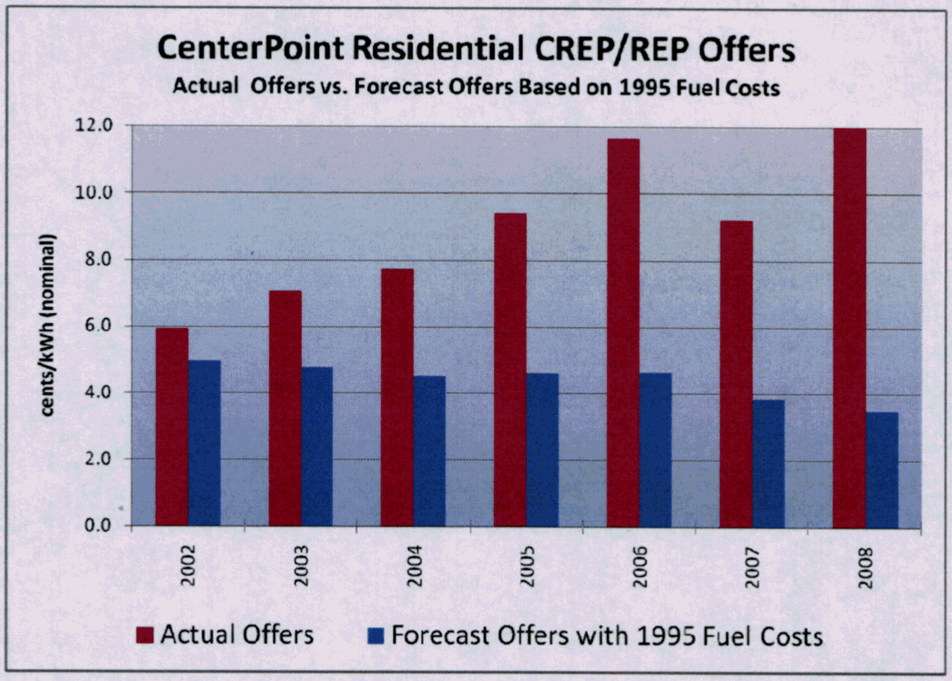


Figure 14

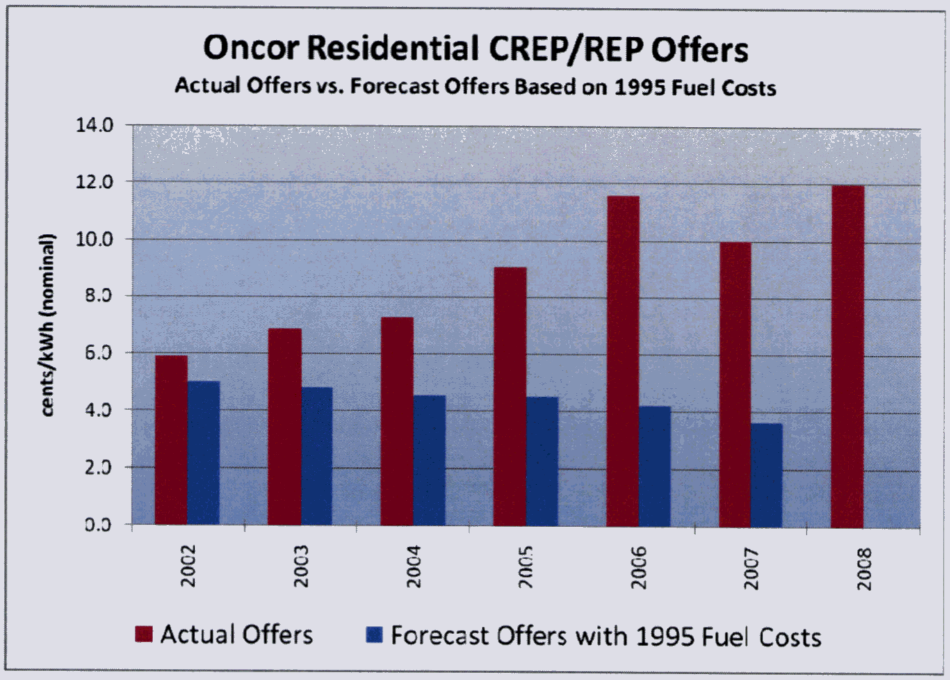
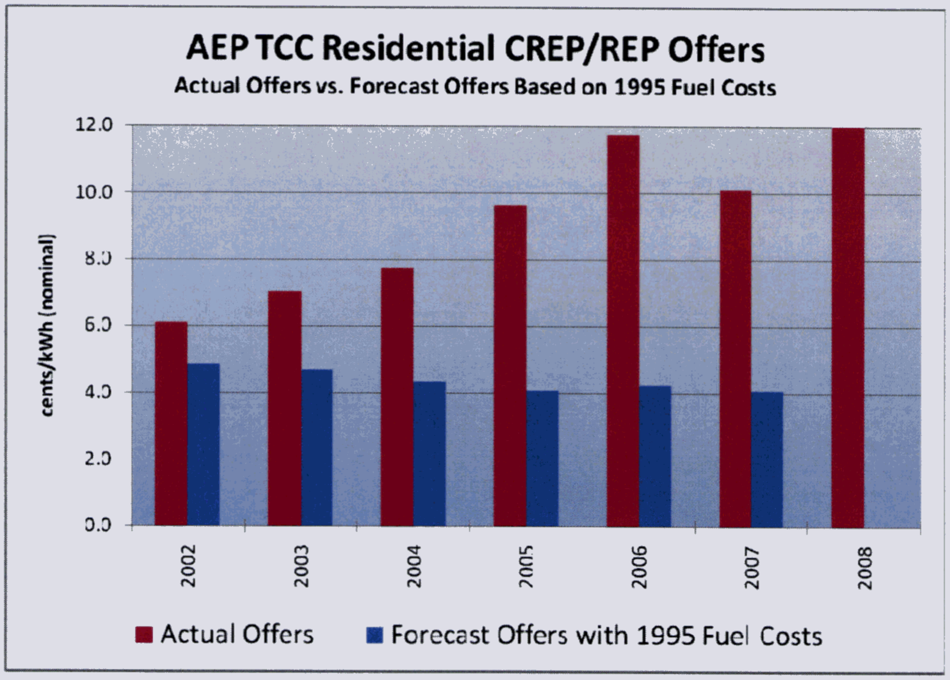


Figure 15



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Inflation Adjustment

With the removal of the regulated portion of the overall electricity price and the conversion of retail prices to their equivalent assuming fuel prices remained at 1995 levels, the last step was to compile the analysis and adjust for inflation. To adjust for inflation, the Consumer Price Index was used to convert each year's dollars into their 1995 equivalent. The final results for each utility from 1995 through 2008, converted to real 1995 dollars, are shown in Figure 16 to Figure 18.

Figure 16

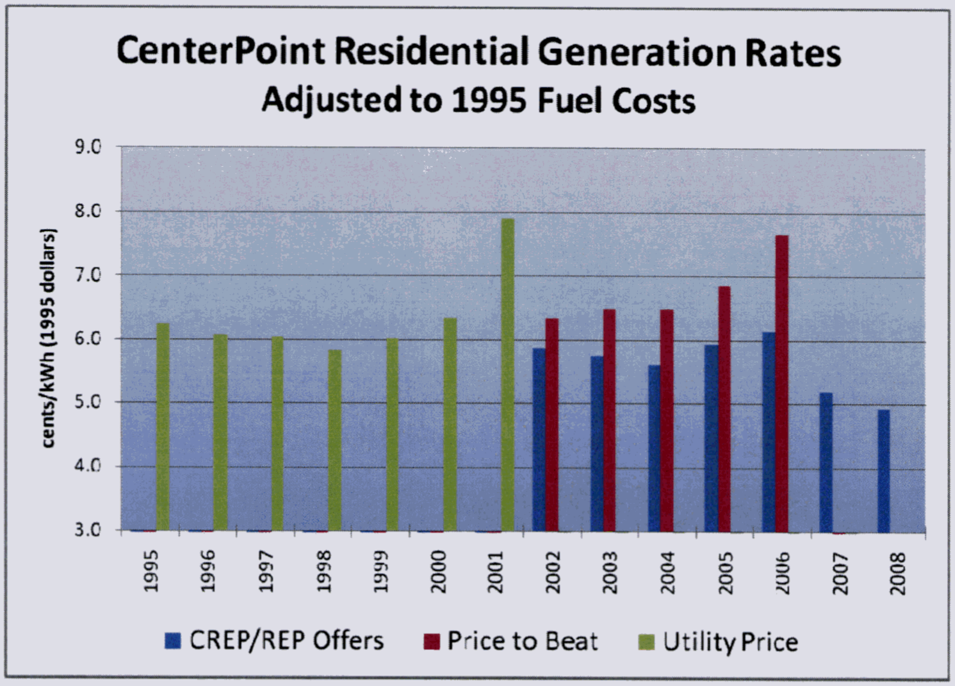

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Figure 17

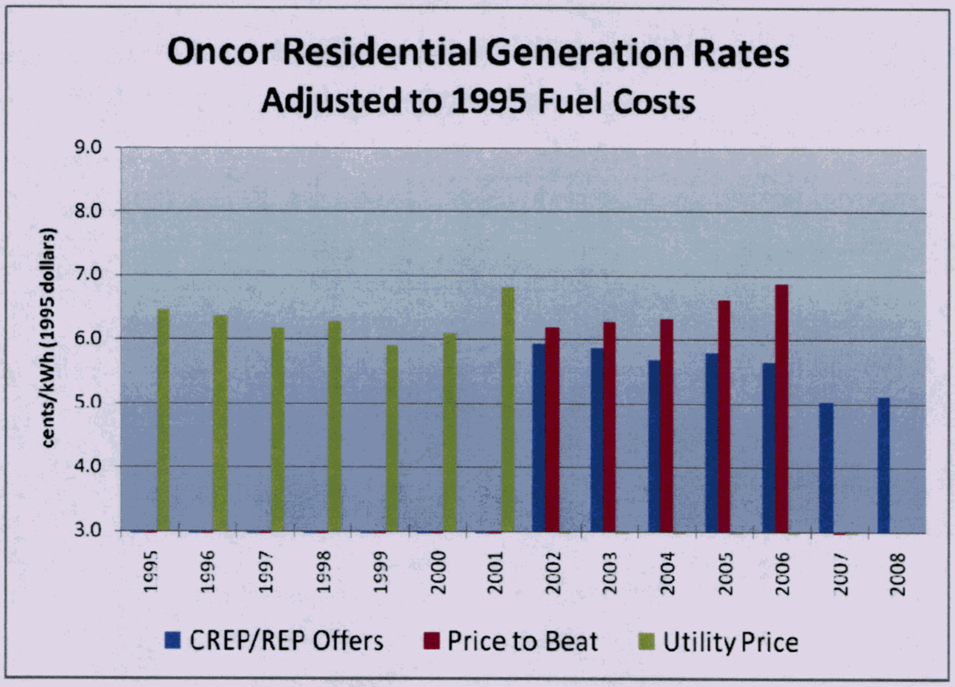
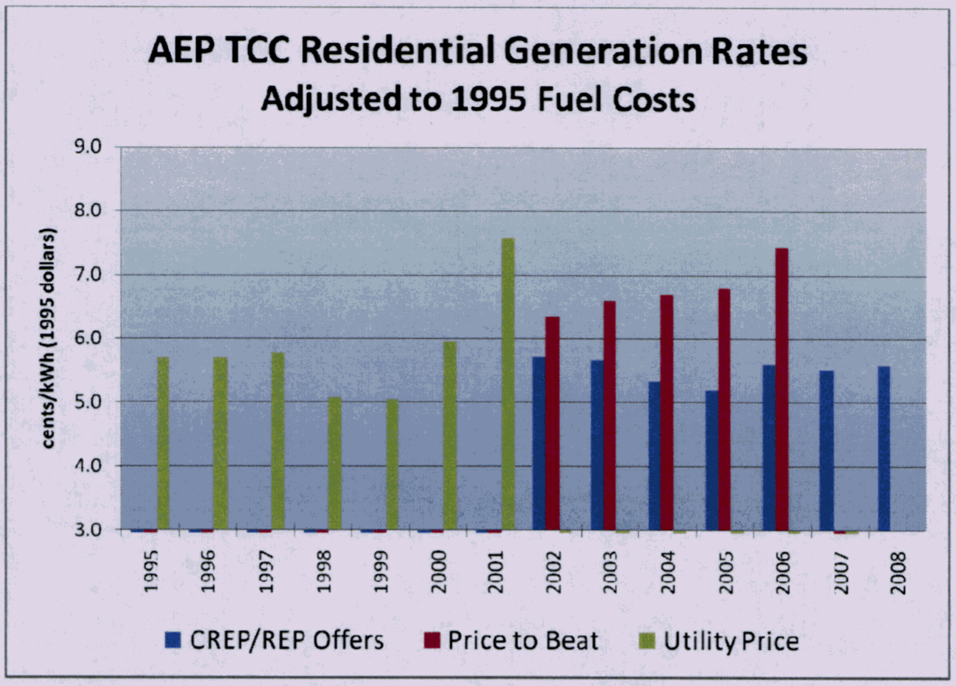


Figure 18



Conclusion

The introduction of retail electricity competition in the Texas electric market in 2002 has brought consumers an array of retail electric service and pricing options for meeting their electricity needs that did not exist previously. Consumers now have the ability to select from one of many 100-percent renewable energy products available in the market, and REPs continue to develop products and offerings to reflect consumer preferences and dynamic market conditions. This competitive market is in stark contrast to the one-size-fits-all paradigm that existed prior to 2002, when residential consumers had no choice in their electric service.

Although residential customers have paid more for electricity since the introduction of customer choice in Texas, this study demonstrates that retail competition is not responsible for the price increase. Other factors--notably the dramatic increase in natural gas prices—have exerted upward pressure on the price of retail electric service in the market in recent years.

When adjustments to regulated and competitive residential prices are made for factors that exist independent of competition (i.e., regulated wires charges, the price of natural gas and inflation), residential consumers in CenterPoint and Oncor's service areas experienced a decrease of more than 13 percent in the price of generation supply after the introduction of retail competition, while residential consumers in AEP TCC's service area experienced a nearly three percent decrease in the generation supply price. This reduction in the price of generation supply, which is the primary driver in the overall price of retail electric service, demonstrates that retail competition has applied downward pressure on residential electric prices in Texas.