Commonwealth of Virginia

State Corporation Commission

Report to the Commission on Electric Utility Restructuring of the Virginia General Assembly

And the Governor of the Commonwealth of Virginia

Status Report: The Development of a Competitive Retail Market for Electric Generation within the Commonwealth of Virginia

Pursuant to Section 56-596 of the Code of Virginia

August 29, 2003

HULLIHEN WILLIAMS MOORE
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STATE CORPORATION COMMISSION

August 29, 2003

TO: The Honorable Mark R. Warner
Governor, Commonwealth of Virginia

The Honorable Thomas K. Norment, Jr.
Member, Senate of Virginia
Chairman, Commission on Electric Utility Restructuring
and
Members of the Commission on Electric Utility Restructuring

The State Corporation Commission is pleased to transmit its report regarding the advancement of competition in Virginia as required by Section 56-596 of the Virginia Electric Utility Restructuring Act.

This report, required annually by September 1, provides information on the status of competition in the Commonwealth, the status of the development of regional competitive markets, and the Commission's recommendations.

Respectfully submitted,

Hullihen Williams Moore
Commission Chairman

Clinton Miller
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Commissioner

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Executive Summary and Overview

It has been over four years since the Virginia General Assembly passed the Virginia Electric Utility Restructuring Act[1] ("the Act"); less than four years remain until the mid-2007 end of the transition period set forth in the Act. Section 56-596 of the Act requires the Virginia State Corporation Commission ("SCC") to report to the Commission on Electric Utility Restructuring ("CEUR") and the Governor by September 1 of each year on the status of competition in the Commonwealth, the status of the development of regional competitive markets and the SCC's recommendations to facilitate effective competition in the Commonwealth as soon as practicable. This section of the statute also requires the SCC to report any recommendations of actions to be taken by the General Assembly, electric utilities, suppliers, generators, distributors, and regional transmission entities that the SCC considers to be in the public interest.

The SCC offers this Report pursuant to the requirements of the Act. We also note that on December 30, 2002, the SCC submitted an Addendum to its status report issued September 1, 2002, that addressed the Federal Energy Regulatory Commission's ("FERC") Notice of Proposed Rulemaking ("NOPR") on Standard Market Design ("SMD").[2] That Addendum, entitled "Review of FERC's Proposed Standard Market Design and Potential Risks to Electric Service in Virginia" raised several concerns we had regarding electric industry restructuring and its likely impact on Virginians. In the December 2002 Addendum, the SCC stated:

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1 Title 56, Chapter 23 of the Code of Virginia.

2 Remedying Undue Discrimination Through Open Access Transmission Service and Standard Electricity Market Design, Notice of Proposed Rulemaking, 67 Fed. Reg. 55452 (2002) (to be codified at 18 C.F.R. pt. 35) (proposed July 31, 2002).

> Only if the Commonwealth <u>reverses</u> the Act's requirement to unbundle rates and <u>defers</u> the Act's requirement that Virginia's utilities join an RTE [regional transmission entity] can Virginia preserve state jurisdiction. If rates remain unbundled or control of the transmission system is transferred to an RTE, then Virginia's choice will likely have been made. It will be difficult -- if not impossible -- to reverse that choice.

In the months since the SCC issued its December 2002 Addendum to the September 1, 2002, status report, industry events have not lessened our concerns nor cause us to alter our recommendation that the General Assembly take action to preserve Virginia's authority to ensure reliable electric service at just and reasonable rates. Industry, federal regulatory, and legislative uncertainty continue and Virginia's ability to ensure control over its restructured electric utility industry cannot be assured. Consequently, the SCC believes that it is in the public interest to suspend portions of the Act by re-bundling rates and continuing the moratorium on the transfer of control of Virginia's electric transmission systems to federally-regulated regional transmission entities. We note that such a suspension will leave in place rules, procedures and systems that enable retail access. The SCC recommends suspension only as a means to best preserve Virginia's jurisdiction and only as long as necessary to provide Virginia policy makers a reasonably clear view of the likely nature of the transformed industry.

This Report consists of three parts. Part I is a description of evolving regional retail and wholesale markets prepared by Dr. Kenneth Rose, Senior Fellow, Institute of Public Utilities at Michigan State University. Part II reports on the status of retail access and competition in the Commonwealth. Part III presents and discusses recommendations to facilitate effective competition in Virginia that were raised by stakeholders responding to an annual SCC solicitation of potential recommendations. Part III also contains and discusses the SCC's recommendation that the Virginia General Assembly take action to preserve Virginia's jurisdiction relating to its electric utility industry by suspending elements of the Act.

Part I of this Report contains detailed data and information on restructured wholesale and retail electricity markets around the United States. The economic health of these markets is questionable. Three major generating companies have filed for bankruptcy protection thus far in 2003 and other generation providers face substantial financial difficulties. The industry credit crunch continues as does fallout from securities and trading scandals. At the same time that generating companies are facing these difficult financial conditions, Dr. Rose reports that there continues to be strong evidence that significant market power is being exercised in all wholesale markets that have been independently analyzed. The coincidence of these two phenomena -- the alleged exercise of market power that serves to increase market prices and thus the returns to generators, coupled with the widespread financial distress in the industry which should be alleviated by the exercise of market power -- is puzzling. These two coincident results, taken together, illustrate the difficulty of fashioning electricity markets that ensures both the provision of safe and reliable service and the vigorous competition needed to forestall any exercise of market power.

Dr. Rose's Part I also provides extensive descriptions of retail markets on a state-by-state basis. He reports that 16 states and the District of Columbia continue to allow retail access. Several states have decided to delay retail access, restrict retail access to only larger customers or otherwise curtailed their retail access efforts. Of the 17 jurisdictions that allow retail access, there is little, if any, effective retail competition for electric service in the residential and small commercial market. Although some states have significant switching for larger customers, except for Texas no state has substantial state-wide competitive penetration in markets for residential or small commercial accounts. Even here, switching rates average around 11% and 17% for residential and small commercial customers, respectively.

Texas market penetration is explained by requirements that customers not choosing to take service from a non-affiliated retail electric provider ("REP") were automatically transferred to their utility's affiliated REP. Smaller customers so transferred are charged a regulated rate known in Texas as the "price-to-beat." This regulated rate at one point reflected a 6% decrease from pre-restructuring regulated rates. Importantly, Texas purposely set the price-to-beat with some "headroom" allowing non-affiliated competitors to offer service at prices that both saved customers money and allowed the non-affiliated REPs to make a profit on the sale. The price-to-beat is adjusted as energy prices change. The Texas PUC has the tools to ensure that non-affiliated REPs can continue to serve profitably customers in significant numbers. This comes, however, at the cost of higher regulated charges if a customer chooses to remain with an affiliated REP.

Increased switching in Texas has led to claims about the ultimate test of the efficacy of the Texas restructuring: customer savings. The picture is quite muddled and turns on forecasts of what regulated rates would be in the absence of the restructuring, the years chosen as the basis for comparison and the impact of mandated rate reductions and changes in regulated fuel charges. It should also be noted that utilities have yet to finalize their stranded cost determinations and are required to do so in 2004 through a market valuation of assets.

Ohio is witnessing substantial retail residential market penetration but only in the FirstEnergy service territory. This is explained by widespread "opt-out" municipal aggregation. There is little penetration in the service territories of Ohio's other distribution utilities where prices are lower.

On the basis of the extensive information submitted by Dr. Rose in Part I of this Report, the SCC concludes that, while retail access is widely available in many jurisdictions, vigorous retail competition has yet to develop. This national result, when combined with results obtained here in the Commonwealth as detailed in Part II of this Report, leave us with substantial doubt as to the ability of retail electric competition to provide, at the present time, lower prices for Virginians than would have been charged under the traditional regulation of the industry.

The SCC's concerns are shared by others around the country. For instance, in Ohio the Dayton Daily News reported on May 13, 2003 that "*some critics urge that Ohio abandon deregulation as an experiment that isn't working. After two years and four months, no outside electricity marketers have become competitors as DP&L [Dayton Power & Light] hoped. This is attributed to DP&L's relatively low rates ...Some critics complain that electricity deregulation is a failed experiment with little chance of meeting the goal of lowering consumer prices.*" Ellis Jacobs, an attorney for the Community Action Partnership, said "*the Ohio General Assembly should consider abandoning deregulation. Other states are moving in that direction. Seven states without deregulation have now put that on the back burner. A number of states that deregulated, Nevada,* *Oklahoma, and California among them, have reversed course.*" David Hughes, executive director of Citizen Power, a regional utility watchdog organization, also believes "*The [Ohio] General Assembly should reinstitute regulation of electric generation prices and supply before the MDP ends. PUCO keeps glazing over the real story which is that there is virtually no competition in the electricity generation market.*"

New Jersey Citizen Action, a consumer advocacy group, states "*We don't see competition on the horizon and from the beginning citizens have said we don't want deregulation for the sake of deregulation. It's the worst of both worlds, we'll have higher rates and unregulated monopolies.*" On July 23, 2003, Electric Power Alert reported that "*They point to a recent decision by state utility regulators to increase rates for the state's largest utility – with other utilities soon to follow – along with an end to price controls in August under the state's deregulation law, as the reason consumers will see electric rates increase by 15 percent.*"

The Ashbury Park Press reported on June 26, 2003, that in New Jersey, "*There still are practically no alternative electricity suppliers looking to pick up residential customers. But regulators and advocates hope that a growing market of suppliers vying for the state's largest electricity consumers – industrial, commercial and institutional users – will eventually trickle down so homeowners can find good deals.*" Effective August 1, 2003, under a program adopted by the New Jersey Board of Public Utilities, large electricity users will be subject to electricity prices that change hourly and are influenced by market fluctuations. Hal Bozarth, Executive Director of the Chemistry Council of New Jersey, states "*Come August 1, the world as we knew it under the (electric) monopolies is over, and there will be rate shock of significant proportion.*"

As rate caps expire in Maryland, market observers warn that residents should expect to begin paying more for electricity. Mark Travieso, a state advocate for residential utility customers, said "*that consumers cannot expect to see a true competitive market that makes it worthwhile to switch energy providers.*"

Electric Power Alert reported on June 11, 2003, that "*The Connecticut legislature voted to permit consumer rates to increase and fees to be collected for utilities administering billions of dollars in energy contracts – in a move to keep the lights on and the possibility of retail electricity competition open in the future despite disappointing results thus far. The transition period for restructuring the state's market is set to end with contracts and price caps expiring in December. Lawmakers devised a plan to strike a balance between the cost increases and reliability, because competition just hasn't occurred. The legislation increases the amount ratepayers will pay by four to six percent – on top of an eight percent increase incurred from New England's standard market design charges – and ensures reliability through creating a system of procurement fees that allows the default server, Connecticut Light & Power, to charge customers for its management of contract bidding.*"

Part II of the Report focuses on activities in Virginia related to retail access and resulting competition in the electricity market over the past year. It also reviews the SCC's efforts to develop a proper infrastructure to accommodate competition and to prepare Virginians for consumer choice for generation, as directed by the Act.

During the past year the SCC has continued to implement the Restructuring Act. At the present time, about 2.9 million electricity customers in Virginia have the right to choose an alternative supplier of electricity. By January 1, 2004, when an additional

168,500 customers will gain the right to choose, nearly all of the customers of Virginia's investor-owned utilities and electric cooperatives will have the right to switch to a competitive supplier. The exception is the approximately 29,400 customers in the southwestern part of the Commonwealth exempted from the Act by legislation enacted by the General Assembly in 2003 and approximately 7,000 customers served by Powell Valley Electric Cooperative.

As we reported last year, the right to choose has not yet evolved into the ability to choose. While it is clear that the SCC, the utilities and the various stakeholders have effectively enabled almost universal retail access in Virginia, there is little competitive activity in the Commonwealth. We understand that many suppliers still perceive little economic incentive to enter the Virginia retail market. No competitive service provider is offering energy priced so that switching customers may save money. Currently, one supplier continues to serve about 2,300 residential customers and 22 small commercial customers in northern Virginia with an environmentally-friendly "green" power offer. This service is more expensive than Dominion Virginia Power's price-to-compare. Again, as detailed in Part I, this lack of activity is not unique to the Commonwealth; in other states currently offering retail access, few customers have the option to purchase power at a price lower than their incumbent's price to compare.

Over the past twelve months, the SCC, aided by the incumbent utilities and interested stakeholders, continued to make strides in preparing the Commonwealth for the arrival of competition for the generation component of electric service. Various work groups coordinated by the Staff have been assisting the SCC to provide the foundation for retail access by examining many issues, including competitive metering, supplier billing, default service, energy infrastructure, stranded costs, and regional transmission organizations ("RTO"). The SCC appreciates the time and effort of the respondents that have participated with these work groups.

The SCC has issued orders during the past year relating to issues such as competitive metering, supplier billing, market price/wires charge determination, regional transmission organizations, and several access programs within electric cooperative territories. In addition to the September 1 reports on the status of competition and the December 2002 Addendum, the SCC has issued reports addressing energy infrastructure information and stranded costs. Slow development of competitive activity and statewide budget constraints have caused the SCC to suspend its consumer education efforts for the present.

Part III of the Report consists of two sections. The first section includes a discussion of recommendations advanced by various stakeholders as means of facilitating effective competition in the Commonwealth as soon as practicable. The second section of Part III discusses the SCC's recommendation that a suspension of the Act is in the public interest because delaying implementation of the Act is a prerequisite to the preservation of Virginia's jurisdiction.

To assist development of a comprehensive list of recommendations to foster effective competition, the Staff sent a letter to over 70 interested stakeholders seeking their suggestions. In a letter dated April 16, 2003, Staff posed eight questions designed to stimulate respondents' thoughts on specific restructuring issues. Although the Staff's mailing list targeted stakeholders thought most affected by electric restructuring issues, responses were received from just twelve stakeholders. In a similar survey conducted in

2002, the SCC received sixteen responses. The twelve 2003 responses are included as Appendix III-A to this Report.

Generally, most of the comments received are similar to those expressed in last year's report and reiterated during the past year via various forums such as work group discussions. Respondents' recommendations, while discussed in detail in Part III, do not provide new ideas; the recommendations presented have already been considered by the SCC and the CEUR. Many of the twelve respondents continue to believe that the major obstacles to effective competition in Virginia include:

- The existence of low, capped rates of the incumbent utilities,
- The existence and method of determining wires charges,
- The recovery of yet-to-be-quantified stranded costs,
- The lack of a functional RTO, and
- The lack of effective customer demand response programs.

SCC Recommendation

Section 56-596 of the Act requires the SCC to report its recommendations to facilitate effective competition in the Commonwealth as soon as practicable, which shall include any recommendations of actions to be taken by the General Assembly, the SCC, electric utilities, suppliers, generators, distributors, and regional transmission entities it considers to be in the public interest. This year, the SCC has one recommendation, and it is not new.

Our concerns with the bedrock issues of electric service adequacy and electric service prices likely to be available to Virginians prompted the SCC to issue its December 2002 Addendum. In the December 2002 Addendum, we described the many serious problems likely to result from implementation of the FERC's proposed rules on Standard Market Design. These problems include the elimination of native load preferences, the questionable ability of FERC to oversee market monitoring efforts, the potential exercise of market power by wholesale suppliers, increased costs resulting from the use of locational market pricing in transmission-constrained areas, and regional resource adequacy requirements.

We were and continue to be particularly troubled by the potential loss of the ability of Virginia's electric utilities to provide priority transmission service to Virginia customers under a FERC designed and regulated wholesale power market platform. FERC believes that long-standing practices whereby local utilities favor local customers constitutes undue discrimination. Currently in Virginia, "native load" has priority. This means that if a Virginia electric utility has sufficient generation and transmission to serve its control area or native load customers (including certain wholesale customers such as cooperatives and municipals), the utility may use excess transmission capacity to facilitate other transactions. However, service to native load customers in its control area will be the priority in the event that service interruptions are required to maintain system integrity. Under the current system, wholesale transactions --- serving non-Virginia loads --- are curtailed first because native load customers have paid for that utility's transmission system in retail rates over time. Virginians are protected to a great extent.

In response to criticism levied by Virginia and other jurisdictions, on April 28, 2003, the FERC issued a "White Paper" entitled "Wholesale Market Platform." The FERC White Paper has been carefully studied by the SCC. In our opinion, the FERC White Paper neither clarifies nor alleviates our concerns with the SMD NOPR.

As outlined in this Report, the problems that are impeding the development of retail competition in Virginia and other regional markets continue unabated. Events in

2003 deepen our concern that problems are becoming increasingly complex and their implications irreversible. We face the likelihood that staying on the current path may cause such distress that the development of an effective competitive market at a future date will be foreclosed.

The continued lack of current and expected market activity leads directly to our recommendation that the Act be suspended in order to preserve Virginia's authority. It is in the public interest to avoid ceding jurisdiction over transmission, generation, reliability and, ultimately, the cost of power, to federal regulators and regional entities. The likelihood that increased prices may be required to foster competition and uncertainty regarding Federal direction with regard to RTOs poses additional uncertainty as to what will occur when capped rates end on July 1, 2007.

For these reasons, we renew our recommendation that the General Assembly suspend the Act. Suspension of the Act would require rebundling the components of retail electricity rates and continuing a moratorium on transfers of control over transmission assets to RTOs. However, the General Assembly could allow other aspects of the Act to continue to evolve while these two elements of the Act are temporarily suspended.

Pausing in the implementation of the Act is the best course if we are to preserve Virginia's ability to protect its citizens from the problems that are likely to result from the ceding of regulatory authority to FERC and regional transmission entities. The potential costs of adhering to a perceived schedule for the sake of implementing change outweigh the risks of delay. It is possible that any future benefit of retail access could be affected by a delay of retail access. However, we currently have the basic rules, systems, and procedures in place to harmonize retail access. If Virginia delays full implementation now and retail access proves successful elsewhere, we will be in position to implement retail choice quickly and effectively. This ability to respond quickly should minimize any loss to Virginians with a delay at this time.

In summary, the status of competition is not encouraging. There has been little change in market conditions around the country or in Virginia since we submitted the December 2002 Addendum. Though there are isolated instances in other jurisdictions of competitive activity among larger commercial and industrial customers, retail choice is not yet providing meaningful benefits or yielding sustained savings anywhere in the country. Even more distressing than the absence of sought-after competitive activity is the likelihood that the implications of the SMD NOPR will be detrimental to Virginia's electricity consumers.

A Note on the Northeast Blackout of 2003

If history is any guide, the Northeast Blackout of 2003 will be a watershed event in the evolution of the North American electric utility industry. As this Report is prepared, certain aspects relating to the proximate cause of the blackout are known; the root causes and long-term policy implications have yet to be determined. This has not deterred many restructuring debate partisans from drawing conclusions about the event's deeper meaning. At this juncture it is clear that a full and thorough investigation is required. Also, logic and prudence dictate that before one makes any conclusions about what is happening in real time, one should at least have a full understanding about past related events. What follows is a brief history of the 1965 Northeast Blackout and the ConEdison Blackout of 1977 and explanation of how that history relates to the current state of the industry.

Prior to the 1965 Northeast Blackout, the real cost of electric power had continually declined for about four decades. This trend was aided by the regulatory regime of price and entry regulation, technological improvements and the continued capture of scale economies. The capture of these scale economies was aided, in large part, by steadily expanding system integration. Just as individual power systems benefit from tying increasing loads to ever expanding power generation, the power systems themselves eventually interconnected with their surrounding neighbors. This allowed for integrated planning and operations on a multi-system basis through various types of power pooling arrangements and operating agreements.

By November of 1965 the U.S. electric utility industry had reached its apogee ---- things were going very well. The industry, by pursuing a strategy of growth and inter-system coordination subject to rate of return regulation, compiled an amazing set of statistics: Consumption of power leaped ahead at a 12% annual rate from 1900 to 1920; from 1920 to 1965, it grew at about 7% per year.[1] Such rapid rates of electricity consumption exceeded the growth rate for all energy sources together by a factor of 4 to 5 times. As consumption increased, the price of power declined: in 1965 cents, power used by residential customers dropped from about 90 cents per kWh in 1892 to a little more than 2 cents in 1965.[2]

As would soon be evident, the benefits of regional integration of power systems came at a cost. At 5:16:11 P.M. EST on the moonlit evening of November 9, 1965, a protective relay at the Sir Adam Beck Station of the Hydro-Electric Power Commission of Ontario caused a circuit breaker to operate, opening (disconnecting) one of five transmission circuits carrying power north toward Toronto. There was no electrical fault; the relay had been set in 1963 at a level too low to carry the load it needed to carry in 1965. The breaker operation quickly overloaded the remaining four 230 kV transmission lines running from Beck Station. Those lines opened, triggering an electrical disturbance that would, within four seconds, "island" four large sections of what was then known as the Canada-United States Eastern Interconnection. Eventually, the blackout affected 30 million people over an 80,000 square mile territory in about 20 major utility control areas. Some utilities, with limited "blackstart" capabilities and damaged equipment, needed more than 13 hours to restore service. Clearly, interconnection of systems had allowed the Beck disturbance to spread from one utility control area to another.

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1 See Richard F. Hirsh, The Electric Utility Industry in 1965: At the Pinnacle of Success before the Blackout. Available at http://blackout.gmu.edu/archive/essays/hirsh_1999.html

2 See Richard F. Hirsh, The Electric Utility Industry in 1965: At the Pinnacle of Success before the Blackout. Available at http://blackout.gmu.edu/archive/essays/hirsh_1999.html

The 1965 Northeast blackout was watershed event for the industry. By 1967, the Federal Power Commission produced a voluminous Report to the President entitled "Prevention of Power Failures".[3] The 12 recommendations called for greater coordination among interconnected power systems, including but not limited to, "early action ... to strengthen transmission systems serving the Northeast" and "to the extent they do not now [1967] exist, strong regional organizations be established throughout the nation, for coordinating the planning, construction, operation and maintenance of individual bulk power supply system".[4] The end result of this was the formation of the North American Electric Reliability Council ("NERC"), the various regional reliability councils and the formation of the New York ("NYPOOL") and New England ("NEPOOL") power pools. It should be noted that utilities in Pennsylvania, New Jersey and Maryland recognized the economic and operational benefits of interconnection long ago. PJM was formed in 1927 and operated as an integrated system until its recent transformation into an RTO enabling the transition to restructured electricity markets in its control area in the late 1990's.

Twelve years after the Northeast blackout, on the hot and muggy evening of July 13, 1977, a series of thunderstorms led to the eventual collapse of the Con Edison system serving metropolitan New York City. The differences between the 1977 blackout and the

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[3] *See* U.S. Federal Power Commission. July 1967a. Prevention of Power Failures. Vol. I--Report of the Commission. Washington, DC: U.S. Government Printing Office.
U.S. Federal Power Commission. June 1967b. Prevention of Power Failures. Vol. II--Advisory Committee Report: Reliability of Electric Bulk Power Supply. Washington, DC: U.S. Government Printing Office.
U.S. Federal Power Commission. June 1967c. Prevention of Power Failures. Vol. II--Studies of the Task Groups on the Northeast Power Interruption. Washington, DC: U.S. Government Printing Office.
Available at http://blackout.gmu.edu/archive/a_1965.html

[4] *See* U.S. Federal Power Commission. July 1967a. Prevention of Power Failures. Vol. I--Report of the Commission. Washington, DC: U.S. Government Printing Office, page 4.

1965 disturbance described above are many.[5] The 1965 Northeast blackout affected a much larger area and was caused by a much more benign condition --- exceeding the Beck station relay setting that had been set in 1963. In 1977, a moderately loaded ConEd system sustained several lighting strikes that tripped generation and disabled interconnections with a neighboring utility. These events overloaded remaining ties before in-city load could be shed or generation increased. The ConEd system became completely separated from its neighbors and collapsed.

Perhaps partially in response to the belief that actions taken after 1965 would prevent such a blackout and perhaps because of large scale rioting in New York City, the investigations into the 1977 event appear to have taken a different tone compared to that of the 1965 investigations. ConEdison was determined to have committed "operator error".[6] Like 1965, there were recommendations that called for greater ties to and coordination with neighboring electric utilities. There were also recommendations that applied specifically to ConEdison operating and control procedures. For example, at the hour of the 1977 blackout, ConEd was importing a historically large proportion of its electricity requirements due to economic circumstances brought on by the end of cheap oil following the oil embargo of 1973-1974. As a result of the 1977 event, operational changes were recommended to commence with the approach of thunderstorms. Such a

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5 May include a discussion about how new post oil embargo dispatch economics causes heavy power flows into Con Ed that evening. Oral history suggests that control room technologies and personnel were not equipped to manage the power system given these new economy based power flows. This is still an issue today as FERC is currently working a NYISO matter regarding how the extra costs associated with "thunderstorm alerts" in NYC will be allocated among LSEs serving customers in the Con Ed CA.

6 U.S. Department of Energy. Federal Energy Regulatory Commission. June 1978. "The Con Edison Power Failure of July 13 and 14, 1977." Washington, DC: U.S. Government Printing Office. (Document 2 of 4.) Chapter VII, Conclusions and Recommendations. Available at: http://blackout.gmu.edu/archive/pdf/usdept051_100.pdf

protocol, which exists to this day, unloads tie-lines with neighboring systems by increasing in-city generation even though imported power would be cheaper.

What can we learn from this brief history and what are the implications of this history as they relate to the 2003 Blackout? Even though this is written before the likely massive inquiries are complete, certain questions --- not answers --- are apparent. Before stating those questions one thing is very clear. The events of Thursday afternoon, August 14, 2003 resemble some key aspects of both the 1965 and the 1977 events, even though those two prior blackouts were very different.

Both the 1977 blackout and the 2003 event occurred on the afternoon of a hot and humid summer day. Such conditions cause higher electrical loads and also reduce the capacity of the system to deal with such loads. Electrical systems can carry more load in cooler weather --- other things being equal. The 1965 blackout occurred in November in mild weather with relatively light system loads. But, the 1977 blackout was contained to the Con Edison system serving metropolitan New York. There was no cascading of the 1977 event throughout the Eastern United States and Canada.

The 2003 event, like the 1965 event, was a cascading blackout. This major common characteristic is very unsettling, to say the least. Given this crucial similarity, it appears that the 2003 event may have been more like the 1965 blackout. Thus, while steps taken between 1965 and 1977 appeared to have prevented a cascading blackout in 1977, the real question that must be answered is whether policies and industry changes that have been put into effect or occurred since 1977 have returned the Eastern United States and Canada to pre-1965 levels of system reliability. Also, since there were no notable major blackouts in the Northeast for many years after 1977, one should logically focus inquiry on the recent major changes experienced by the electric industry in the Northeast.

After both the 1965 and 1977 blackouts numerous and extensive investigations where undertaken that provided many answers to key questions raised by those two events. Answers were eventually produced and procedural changes were implemented that endure to the present day.

In simplest of terms the SCC notes that cascading electrical failures were impossible in the industry's earliest days because systems were not interconnected. As time progressed utilities began to take advantage of interconnection at the margin. Utilities realized that interconnection with a neighboring utility system could decrease costs and increase each system's individual reliability or at least a modeled calculation of that reliability. With the Northeast Blackout of 1965 it became apparent to many that interconnection also had reliability risks. Note that even the then existing relatively weaker ties built to deliver the benefits of integration at the margin allowed for a cascading failure to impact multiple systems. As a result of the 1965 event, actions were taken to enhance inter-utility coordination and minimize reliability risks. By 1977, these actions may have prevented the ConEdison Blackout of 1977 from spreading to other systems.

The objective of the restructuring of the industry over the last 10 years has been to improve the performance of the electric system by separating production (generation) from transport (transmission). Proponents believe that generation can be made to be competitive and, as a result, prohibitions against entry into the generation sector have been removed. There is also a belief that the existing transmission system has been and continues to be run in an inefficient manner. Restructuring proponents claim that utility reliance on local, affiliated generation is discriminatory and inefficient even though this operating strategy has reliability implications as such practices serve to unload the ties between systems. This reliance on local sources served to reduce the need to transmit power over long distances and instead required that utilities provide preference to transmission service needed to serve native load customers from local generating stations. Transmission among utility systems over long distances was put in second place behind transmission service for native load customers.

The FERC's current vision of a restructured wholesale electricity market implies an operating mode that seeks to minimize electricity costs over vast interconnected regions requiring more power flows than the current bulk transmission system was designed to handle. In contrast to the industry's historical integration at the margin, the FERC's vision is one of complete system integration. This means that electrical ties between and among regions will be more heavily loaded than in the past. Indeed, since ties are more likely to be loaded under a variety of operating conditions, heavily loaded ties may possibly have played a part in the 2003 event.

In response to the 2003 Blackout, there have been increased calls for greater investment in the bulk transmission system. Interconnection at the margin has benefits and it has costs. The amount of transmission plant and the kind of interconnection required to fully and reliably integrate large parts of the North American electric system has a different set of costs and benefits. This level of integration requires a bulk transmission system that is often characterized as being analogous to this nation's interstate highway system. It is nearly ubiquitous and very expensive. The key question is whether the costs and risks of constructing and operating such infrastructure will produce benefits in the form of operating economies sufficient to cover the costs of network development. This question should be fully evaluated as part of a reasoned response to the events on August 2003.

ACRONYMS

ACC	Arizona Corporation Commission
AEI	American Energy Institute
AEP-VA	American Electric Power- Virginia
AP	Allegheny Power
BG&E	Baltimore Gas and Electric
BGS	basic generation service
BHE	Bangor Hydro-electric Company
CGV	Columbia Gas of Virginia
CMP	Central Maine Power Company
CSP	competitive service provider
CTC	competitive transition charge
DEDS	Dominion Energy Direct Sales
DEQ	Department of Environmental Quality
DVP	Dominion Virginia Power
ECN	Energy Cooperative of New York
EDI	electronic data interchange
ESCO	energy service company
FERC	Federal Energy Regulatory Commission
FREDI	First Regional Electronic Data Interchange
GISB	Gas Industry Standards Board
ICAP	installed capacity market of PJM
ICC	Illinois Commerce Commission
IEEE	Institute for Electrical and Electronic Engineers
KU	Kentucky Utilities
KW	kilowatt
LDC	local distribution company
LMP	locational marginal price
LTTF	Legislative Transition Task Force
MMU	Market Monitoring Unit of PJM
MPC	Montana Power Company
MPS	Maine Public Service Company
MPSC	Maryland Public Service Commission
MW	megawatt
NAESB	North American Energy Standards Board
NARUC	National Association of Regulatory Utility Commissioners
NEM	National Energy Marketers Association
NMPC	Niagra Mohawk Power Corporation
NOPEC	North East Ohio Public Energy Council
NOPR	Notice of proposed rulemaking
NOVEL	Northern Virginia Electric Cooperative
NU	Northeast Utilities
NYSEG	New York State Electric and Gas
O&R	Orange and Rockland

ODEC	Old Dominion Electric Cooperative
ODP	Old Dominion Power
PES	Pepco Energy Services
PE	Potomac Edison
PJM	Pennsylvania-New Jersey-Maryland Interconnection
PMW	Power Markets Week
POLR	provider of last resort
PSE&G	Public Service Electric and Gas Company
PUCO	Public Utilities Commission of Ohio
PUCT	Public Utility Commission of Texas
REC	Rappahannock Electric Cooperative
REP	retail electric provider
RG&E	Rochester Gas and Electric
ROA	retail open access
RTE	regional transmission entity
RTO	regional transmission organization
S&P	Standard & Poor's Ratings Service
SCC	State Corporation Commission
SERC	Southeastern Reliability Council
SOS	standard offer service
SPP	Southwest Power Pool
SWEPCO	Southwestern Electric Power Company
T&D	transmission and distribution
UBP	Uniform Business Practices
UHR	UHR Technologies
UCAP	unforced capacity market of PJM
VCCC	Virginia Citizens Consumer Council
VCFUR	Virginia Committee for Fair Utility Rates
VEC	Virginia Energy Choice
VEPA	Virginia Energy Providers Association
VIPP	Virginia Independent Power Producers
WGES	Washington Gas Energy Services
WGL	Washington Gas Light
WTU	West Texas Utilities

PART I

STATUS OF THE DEVELOPMENT OF REGIONAL COMPETITIVE MARKETS

2003 PERFORMANCE REVIEW OF ELECTRIC POWER MARKETS

2003 Performance Review of Electric Power Markets

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Review Conducted for the Virginia State Corporation Commission*

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*This report was conducted under contract with the Virginia State Corporation Commission as Part I (of three parts) of the Commission's annual report to the Virginia General Assembly on the advancement of a competitive retail electricity market in the Commonwealth of Virginia. The views expressed here are those of the author and do not necessarily reflect the views or opinions of the Virginia State Corporation Commission.

EXECUTIVE SUMMARY

Overall, the electric supply industry's struggles continue for a third year. The string of events began with the price run-ups in California and the West in 2000 and 2001, continued with Enron's disclosures and collapse in late 2001, was followed by disclosures of accounting improprieties and data misreporting, and has continued with the "credit crunch" the industry still faces. As if this was not enough to contend with, as this report was being finalized, the most widespread electrical blackout in North American history occurred. While the cause has not been determined at this time, it has already sparked a debate about possible causes and solutions and has renewed interest in federal energy legislation that was already under consideration by the U.S. Congress.

Retail Markets

The number of states that allow retail access remained at 16 states and the District of Columbia. New Mexico, Oklahoma, and West Virginia continue to postpone retail access at this time. Arkansas repealed its restructuring law this year. Nevada and Oregon allow retail access for large customers only and California, which of course allowed retail access at one time, suspended its program in September of 2001 and may also repeal its law.

Many retail markets remain relatively inactive, particularly for smaller residential customers. However, overall market activity for larger customers in some states is relatively stronger. The following summerize retail market activities in eleven jurisdictions.

Nearly all the customer switching to alternative suppliers in **Maryland** has been in Potomac Electric Power's service area. Almost 16 percent of the residential customers and over 21 percent of the nonresidential customers are enrolled with an alternative supplier in Potomac Electric's service area. There are no reported residential customers enrolled with an alternative supplier in any of the other service areas and only a very small percentage of the nonresidential customers have switched in two areas–neither exceeding two percent. Statewide, about four percent of all customers have chosen an electric supplier, less than four percent of all residential customers and about five percent of the nonresidential customers.

The **District of Columbia** is also served by Potomac Electric Power and has had similar, although lower, percentages of customer switching as in Potomac Electric's area in Maryland, at 11.4 percent residential, 16.5 percent non-residential, and 12 percent total for the District as a whole.

New Jersey conducted its second Internet auction to determine Basic Generation Service (BGS) for the state's distribution companies in February 2003. The auctions determined BGS supply for the period from August 1, 2003 through May 31,

2004. Beginning August 1, 2003, the auction-determined generation prices translated directly to the rates customers pay, when the rate caps and the discounts ended. The post-transition rates for all distribution territories in the state increased, largely due to deferred costs that the distribution companies could not recover during the transition period, but is now recovering from customers through the post-transition rates. New Jersey had some switching activity early in the state's retail access program, but customer switching across the state and across customer classes dropped to fractions of a percent and remained there as recently as the summer of this year. However, preliminary reports indicate that almost 60 percent of the largest customers in the state have switched to alternative suppliers. This is likely the result of these larger customers now having their prices based on PJM's hourly prices, unless they make provisions with a supplier of their choice, since the post-transition period began on August 1.

Pennsylvania had, at one time, the most active retail access program in the country. This changed dramatically by mid-2001, when many competitive suppliers reduced their offerings to customers or left the market entirely. As of May 2003, the entire state had only one competitive offer below the price-to-compare being made to residential customers. Residential switching continues to decline or remain flat, with all but Duquesne Light now below (in most cases, well below) ten percent of customers with an alternative supplier. In all areas, commercial customer switching is below 20 percent, however, Duquesne Light and PECO Energy have seen a recent modest increase in the percentage of customers switching. For industrial customers, all areas are well below ten percent, except Duquesne Light, which is at about 35 percent of the customers with an alternative supplier.

In **Maine**, the Commission has completed three sets of competitive bids and has a fourth underway to determine standard offer service providers and prices. While, as the Commission noted, the first two bidding experiences met with "mixed results," currently all standard offer service prices for all customers classes for the three principle T&D utilities in the state have been procured through the competitive bidding process.

There has been no switching to competitive providers by residential and small commercial customers in Bangor Hydro-Electric Co.'s (BHE) area and large customer switching has dropped to below 40 percent (after reaching well over 80 percent in 2002). Although Central Maine Power Co. (CMP) had no switching to competitive providers by residential and small commercial customers, large customer switching was nearly 80 percent in June of 2003. Maine Public Service Co.'s (MPS) current standard offer price for residential and small commercial customers has increased by 35 percent between early 2001 and when the price went into effect in March of 2003. Commercial and industrial standard offer prices have increased 37 percent and 56 percent, respectively. This may explain, at least in part, why most commercial customers (68 percent of the load) and nearly all the industrial customers (between 97 percent and 100 percent of the load since early 2002) in MPS are now served by competitive providers and are not on the standard offer price. About two-thirds of the residential and small commercial load remains on standard offer service. (Last year, the total number of customers served by MPS was reported at 35,467 residential, 193 medium, and sixteen large customers. MPS is in northern Maine and not part of the ISO New England control area and does not have the same access to suppliers that other parts of the state have.)

The standard offer price has also increased for residential and small commercial customers since 2000 for two other distribution areas, increasing 22 percent in BHE's area and by 21 percent for customers in CMP's area.

While there has been an increase in residential customer activity since last year in **Massachusetts**, statewide, it is still less than three percent of the customers that have switched to a competitive supplier. The larger customer categories continue to show considerably more activity, however, there has been a marked decrease since the fall of 2002, especially for the large commercial and industrial customer group, which has fallen below 20 percent. Small and medium commercial and industrial customer groups also declined, both to less than ten percent of customers in each category.

For all customer groups, the most active customer switching, or "migration," in **New York** State is in the Orange and Rockland Utilities and Rochester Gas and Electric service areas. Most of this activity is concentrated among non-residential customers. This pattern of activity holds for both 2002 and 2003. With a few exceptions, most areas had modest gains in the percent of customers switching to alternatives in 2003 compared to 2002. Statewide, for all customer categories, customer migration was 5.3 percent for the state.

Illinois retail access for residential customers began on May 1, 2002. Also in May of 2002, the Illinois legislature extended the current freeze on electricity rates until 2007. At this time, there are no residential customers that have switched to an alternative supplier in the state. Also, several distribution companies are reporting no activity in their areas for all customer categories, including, AmerenCILCO Co., AmerenUE Co., Interstate Power and Light Co., and MidAmerican Energy Co. Three companies, AmerenCIPS Co., Commonwealth Edison Co., and Illinois Power Co., have had some customer switching to an alternative "Delivery Service," primarily among larger customers. However, statewide, nearly half of these Delivery Service Customers chose the Power Purchase Option, an unbundled, market-based generation option that non-residential customers subject to transition charges must be offered and is supplied by the incumbent utility.

Michigan started retail access in January 2002. While there is little activity among residential customers, there has been some activity with larger customer groups, particularly with industrial customers in Consumers Energy's territory and with commercial customers in Detroit Edison's territory.

According to the **Ohio** Commission, as of December 2002 a total of 756,411 residential customers and 848,702 customers of all classes had switched to an alternative electric supplier in Ohio. Cleveland Electric Illuminating Company had the highest percentage of all customers switching to alternatives of Ohio electric distribution companies and for all customer classes except industrial. Switching of its residential, commercial, and for total customers were all about 60 percent for each category. Ohio Edison had the highest percentage of industrial customers at over 30 percent. Toledo Edison also had relatively high percentage of customers switching, with residential, commercial, and total customer categories at about 40 percent and industrial customers at 20 percent switching to alternative suppliers. These three companies are part of FirstEnergy Corporation serving northern Ohio and had the highest regulated rates among investor-owned utilities prior to restructuring and, consequently, have higher prices-to-compare than other utilities in the state. For the other five distribution companies, no category exceeded five percent customer switching. Columbus Southern Power, Dayton Power and Light, Monongahela Power, and Ohio Power Company reported no residential customers had chosen an alternative supplier. Cincinnati Gas and Electric had less than three percent residential customer switching.

Ohio continues to have the highest residential switching in the country. However, as of December 2002, the state's aggregation program accounts for over 93 percent of residential, over 88 percent of the commercial and over 19 percent of the industrial customer switching in Ohio and over 92 percent of all customer switching in the state.

At this time there is only one competitive offer being made to residential customers in one distribution company's territory, Cincinnati Gas and Electric–from Dominion Retail, Inc. No other offers are currently being made to residential customers in any other part of the state. The total number of residential offers has decreased from eight in January 2001, to three in May 2002, to the one currently being made (July 2003).

Due to the apparent early success of its retail markets, **Texas** has attracted a great deal of attention across the country. Since its beginning in January of 2002, the Texas retail market has been one of the more active in terms of offers to residential customers and savings opportunities. In June 2003, residential customers had between four and nine competitive providers offering between four to eleven competitive offers (this count does not include the affiliated REP standard service at the "price-to-beat" rate). All five areas had at least three offers below the price-to-beat rate, two areas had six offers, and one area had seven offers below the price-to-beat. As measured by the lowest offer, residential customers had an opportunity to save between eight percent and 24 percent off the price-to-beat rate. All service areas, except that of WTU/AEP Texas North, had three renewable, or "green," offers (all the green offers were from the same power provider).

According to the Texas Commission, commercial and industrial customers also appear to have a large variety of offers from which to choose. They report that there were, as of September 2002, approximately 19 REPs serving commercial and industrial customers in all service territories open to competition.

Almost eight percent of all residential customers were served by a non-affiliated REP by December 2002. Both Oncor (TXU) and CenterPoint (Houston area, formerly Reliant Energy HL&P) service areas had over ten percent of residential customers being served by non-affiliated REPs in June of 2003. CPL (AEP Texas Central) had the highest percentage of secondary voltage customers (primarily smaller commercial and industrial customers, most of which are eligible for the price-to-beat) receiving power from competitive REPs. Over eleven percent of all customers in this category were with a competitive REP in December 2002.

The Commission also notes that although less than ten percent of all secondary voltage customers (68,133 customers) have switched, as reported for September 2002, the customers who have switched are among the largest customers in this customer class since about 25 percent of the MWh (about 1.8 million MWh) used by secondary voltage level customers were supplied by nonaffiliated REPs. Over 18 percent of commercial and industrial customers taking service at primary or transmission voltage levels (larger commercial and industrial customers, many of which are not-eligible for the price-to-beat) were receiving service from a non-affiliated REP in December 2002. In September, approximately 50 percent of the MWhs (1.7 million MWh) used by these customers were served by REPs not affiliated with the TDU in the customer's area.

The Commission reported that as of the end of September 2002, 400,837 individual customer premises were being served by a REP other than the incumbent affiliated REP in their service area. This was approximately 6.8 percent of all customers in areas of the state open to retail access. Of these premises, the Commission reported that 319,297 (80%) are residential customers, 71,691 (18%) are commercial and/or industrial customers that take service at the secondary voltage level (predominately smaller commercial customers eligible for the price-to-beat), and 1,322 (less than 1%) are larger commercial and industrial customers taking service at the primary and transmission voltage level and the remaining are lighting accounts.

Customers without a price-to-beat available from the affiliated REP, are essentially in the market and were encouraged to choose to purchase power from the affiliated REP or a competitive REP. As seen nationally, because these customers use large amounts of power and have a strong incentive to consider alternatives, they are usually the most active shopping group and are usually the more sought after customers by retail suppliers. In addition, the Texas Commission required affiliated REPs to give the non-price-to-beat customers advance notice of the rate they would be charged on January 1, 2002, if they did not negotiate other arrangements with the affiliated REP or switch to a competitive REP. The Commission reports that the default offers of the affiliated REP were generally either a very high fixed price offer or a passthrough of market prices, both of which may be considered risky options for most retail customers. This likely provided added incentive for these customers to shop for the best available price, since the default offers may lead to rates higher than those in effect before retail access began. As of December 2002, approximately eight percent of non-price-to-beat customers remained on this default pricing offer, or approximately 92 percent of these customers negotiated a competitive contract with either the affiliated REP or a non-affiliated REP.

The Commission calculates the total annual savings for residential customers at approximately $900 million in 2002 as compared to what they paid in 2001. This residential customers' savings is based on the price-to-beat rates in effect on January 1, 2002, when the savings ranged from eight percent to 18 percent compared to the rates in effect on December 31, 2001. The Commission also calculates that approximately $225 million of this reduction is related to the statutorily mandated six percent reduction in rates and $675 million of this reduction is attributable to reductions in fuel costs and the expiration of fuel surcharges. These two factors alone, therefore, account for all the $900 million savings.

Residential customers had savings opportunities in all areas open to retail access that ranged between eight percent and 24 percent in June 2003. If the price-to-beat rate increases from the beginning of competition on January 1, 2002 through June 2003 are compared with the percentage savings of the lowest-priced offers to residential customers by area, no offer would have offset the increase over that period. Thus, a similar calculation of rate impact for that period would show that customers had paid more since competition began. It is likely, however, that rates would have gone up under regulation as well, due to likely fuel cost adjustments. Therefore, it is uncertain what price impact retail access has had on customers versus what would have occurred with continued regulation.

Wholesale Markets

As noted, the disturbing industry news has resulted in a continuation of declining credit ratings and falling share prices for many energy companies. This "credit crunch" has impacted the ability of suppliers to raise capital and forced companies to cut back on their energy trading operations and plant investments. Standard & Poor's (S&P) noted that "familiar themes continue to dominate the bleak credit picture" for the industry. S&P cites four factors contributing to this trend: (1) accounting practices and disclosure, (2) the plethora of federal and state investigations, (3) failing confidence in future financial performance, and (4) investments outside the traditional regulated utility business, principally merchant generation facilities and related energy marketing and trading activities. As a result, the ratings trend for the investor-owned utility industry (which include electric, gas, pipeline, and water companies) is continuing on a negative slope, which began in early 2000, and actually accelerated in the first quarter of 2003, according to S&P. They noted that there were "an unprecedented 50 downgrades among holding companies and operating subsidiaries, compared with just three upgrades during the first three months of 2003." S&P also indicates that it expects the negative credit momentum to continue in 2003, although they expect the pace of negative ratings to moderate.

Three major energy producers have filed for bankruptcy protection in 2003, Xcel Energy Inc.'s NRG Energy, PG&E Corp.'s National Energy Group, and Mirant Americas Generation LLC, which includes nearly all of Mirant's wholly owned subsidiaries in the U.S. Other companies, including Dynegy Inc, have announced capital restructuring plans to allow time to improve their financial conditions. Both NRG Energy and Mirant have contract commitments with distribution companies that may significantly affect retail customer supply and prices.

The continuing credit crunch combined with the economic slowdown, has led to a cut back in investment in future generating capacity. The recent cutbacks followed a period of several years of the largest capacity expansion in the industry in over half a century. In 2002, 57,200 MW of gas-fired capacity was added with more than 50,000 MW expected again for 2003. This followed the 1999 through 2001 period when a total of 77,700 MW was added. This compares with the period 1986 through 1998 when a total of 53,900 MW of gas-fired capacity was added for the entire period. Coal capacity additions, in contrast, is expected to be only 12,800 MW between 2000 to 2009. No new plants entered construction during the first quarter of 2003.

There is a very close correlation between the spot market prices of electricity and natural gas prices. Since natural gas is the marginal fuel in most of the country and also because it is common practice to index power transactions to a natural gas price index. Power markets around the country, including PJM, New England, New York, Midwest, Texas, and Western markets, were significantly impacted in early 2003 from the spike in natural gas prices. If natural gas prices continue to remain at current levels or surge higher, this will almost certainly have a significant impact on power prices across the country.

In general, there continues to be strong evidence that significant market power is being exercised in wholesale markets that have been independently examined. The following summerize regional wholesale market events.

The principal wholesale market facilitator in the **mid-Atlantic region**, PJM Interconnection, is arguably the most developed in terms of number of market products developed and offered to participants and trading activity in these markets. Earlier analyses of overall market performance showed evidence of significant market power, particularly during peak hours of the day. In its most recent market assessment of 2002, PJM's Market Monitoring Unit (MMU) suggests that PJM's market are, in general, functioning well and without excessive market power. However, the MMU's method for assessing the markets likely understates the extent of the markup above competitive levels that suppliers can exert. The MMU did conclude that there was an exercise of market power in PJM's capacity credit market during the first quarter of 2001.

In March 2003, ISO **New England** began implementing its own version of a wholesale Standard Market Design (similar to FERC's "SMD"). This includes using Locational Marginal Pricing (LMP) for transmission congestion management, day-ahead and real-time energy markets, and using monthly and long-term Financial Transmission Right (FTR) auctions.

According to ISO New England, approximately 29 percent of the total megawatt hours produced in the region in 2002 was from natural gas generators, this was up considerably from 13 percent in 2000. This increasing use and reliance on natural gas for power generation is causing concern in the region. ISO New England issued a White Paper that examined current and future use of natural gas for power generation and natural gas supply availability in the region. The study notes that the recent power plant building boom in the region is expected to add nearly 10,700 MW of new capacity between 1998 and 2005–all of it natural gas-fired capacity. It is expected that 41 percent of New England's total electricity production will be gas-fired in 2003 and could reach 49 percent by 2010. This problem is particularly acute in the Boston area "load pocket." The Boston subarea is expected to have 65 percent of its electricity generated by natural gas in 2003 and is forecasted to increase to 80 percent by 2010.

The western power markets has been the focus of considerable attention since the 2000 to 2001 power crisis. In its 2002 Annual Report, the **California** ISO estimates that the 2002 average markup was $5.69 per MWh or 17 percent above costs. They note that the markup approached 35 percent in the summer months (May and July). The California ISO also began estimating a volume-weighted, twelve-month rolling average of short term markups, or the "twelve month competitiveness index." The intent is to measure the degree of market power during the market's transition to a new structure–of adequate supply and demand response. Since the ISO estimates that the index was above $5 per MWh for each month in 2002 and peaked at nearly $51 per MWh, they then conclude that during 2002 "some market power persists in the short-term market." They assume that the market is "workably" competitive if the index is below $5 per MWh.

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Overview of Electric Restructuring Activities in the U.S.

Introduction

The electric supply industry's struggles continue for a third year. Beginning with the price run-ups in California and the West in 2000 and 2001, continuing with Enron's disclosures and collapse in late 2001, disclosures of accounting improprieties and data misreporting, and the continuing "credit crunch" in the industry. Many retail markets remain relatively inactive, particularly for smaller residential customers. However, market activity for larger customers has remained relatively stronger in some states. Also, there continues to be strong evidence that significant market power is being exercised in all markets that have been independently examined.

This section summarizes some recent important events in the industry, the impact these events are having on wholesale markets and the industry, and federal regulatory actions. This section concludes with an explanation of how market performance is measured in wholesale and retail markets. The next six sections examine different regions of the country in terms of price and other factors to provide an indication on how the wholesale markets are performing in the regions. The regions examined here are the Mid-Atlantic (PJM), New England, New York, Midwest, Texas, and the West. The state retail markets are investigated in each regional section.

Overview of State Electric Restructuring Activities

Currently, 16 states[1] and the District of Columbia allow retail access (see Figure I.1). Three states that passed an electric restructuring law, however, have opted to delay restructuring. New Mexico, Oklahoma, and West Virginia have decided to delay or postpone retail access at this time, either pending further investigation or other

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[1]Arizona, Connecticut, Delaware, Illinois, Maine, Maryland, Massachusetts, Michigan, New Hampshire, New Jersey, New York, Ohio, Pennsylvania, Rhode Island, Texas, and Virginia.

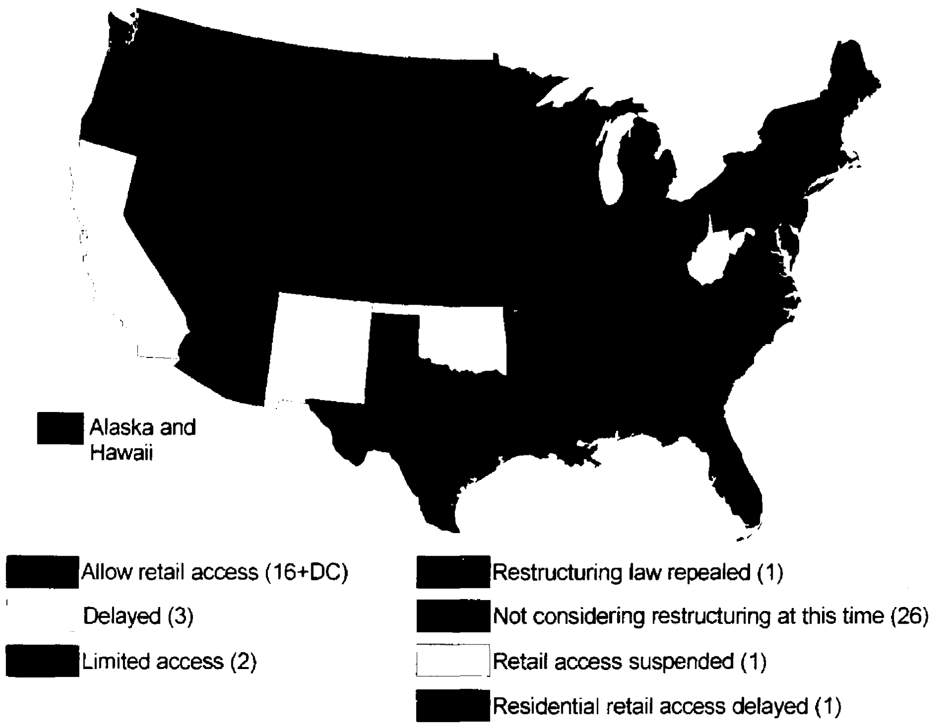

Figure I.1. Current status of state retail access.

action. West Virginia had planned a long transition period to full retail access, but has not yet proceeded to implement its restructuring law, and is not expected to anytime soon. Arkansas has repealed its restructuring law. Nevada and Oregon allow retail access for large customers only and California, which of course allowed retail access at one time, suspended its program in September of 2001 and may also repeal their law.

Continuing power industry turmoil

The electric supply industry has not had a continuation of the revelations and scandals as dramatic as those that plagued the industry beginning with Enron Corporation's collapse in late 2001 and the subsequent accounting scandals and investigations that revealed improper accounting treatment of partnerships and subsidiaries and their market manipulation schemes. However, while the jarring headlines are gone (for now) there has been continued fallout and ramifications from these events and the investigations of these events that has kept the industry in a state of turmoil. As noted in last year's report, in addition to the Enron collapse, other firms were involved in "round trip" or "wash" sales. In these types of trades, a company sells power to another company or to its subsidiary with a simultaneous purchase of the same product at the same price to artificially inflate revenue and trading volume. A Federal Energy Regulatory Commission (FERC) initial staff investigation report released in August 2002[2] gave examples of possible negative impact on the market of such trades, stating that "wash trading provides the illusion of a deep market (that is, more volume than absent wash trades), which may lead buyers to assume they are getting a competitive price and trading in a liquid market when in fact they are not."[3]

150 power traders[4] and marketers were ordered in May of 2002 by FERC[5] to disclose details of any "round trip," "wash," or "sell/buyback" trades they may have engaged in the western markets during the years 2000-2001. The FERC Order asked the respondents to admit or deny that their company had engaged in any wash, round

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[2]The Federal Energy Regulatory Commission, report prepared by the FERC staff, "Initial Report on Company-Specific Separate Proceedings and Generic Reevaluations; Published Natural Gas Price Data; and Enron Trading Strategies," Fact-Finding Investigation of Potential Manipulation of Electric and Natural Gas Prices, Docket No. PA02-2-000, August 2002, pp. 58-59.

[3]FERC Staff Fact-Finding Investigation of Potential Manipulation of Electric and Natural Gas Prices, August 2002, p. 58.

[4]See Attachment A to May 21, 2002 "Fact-Finding Investigation," Sellers of Wholesale Electricity and/or Ancillary Services In the U.S. Portion of the WSCC During 2000-2001.

[5]Federal Energy Regulatory Commission, "Fact-Finding Investigation of Potential Manipulation of Electric and Natural Gas Prices, Docket No. PA02-2-000," May 21, 2002.

trip or sell/buyback trading activities. The FERC investigation revealed that a number of companies were engaging in these transactions.

The FERC staff issued their final report in March of 2003 on their findings of price manipulation in the western markets during the crisis.[6] FERC staff was asked by the Commission to investigate whether any entity manipulated electric or natural gas short-term prices in the West or exercised undue influence over these prices and whether this resulted in unjust and unreasonable rates in long-term power sales contracts. Staff concluded that the electricity and natural gas markets in California are "inextricably linked." When the spot price for gas increased dramatically, it facilitated unprecedented electricity prices increases. The problems in the gas market were due, in part, to manipulated natural gas price indices compiled by trade publications. This was done by market participants through reporting false data and wash trading. Market participants, FERC staff found, provided false natural gas prices and trade volume information to industry publications that then used the data to compile price indices. This included fabricating trades, inflating trade volumes, omitting trades, and adjusting the price of trades. The primary reason for providing false information were to influence gas prices, enhance financial positions or purchase obligations, and to create the impression of a more liquid market. Market participants that sold power in California or were affiliated with a seller would benefit since the price for power was based, in part, on natural gas spot prices. Importantly for most of the U.S., FERC staff notes that natural gas is the marginal fuel in the West, as it is for most of the country (see below), thus forward gas prices affect forward power prices.

The FERC staff concluded that EnronOnline gave Enron proprietary knowledge of market conditions of which others in the market did not have access. Staff estimated that Enron's speculative profits through EnronOnline exceeded $500 million in 2000 and 2001. Staff also concluded that California electricity spot market prices were affected

[6]The Federal Energy Regulatory Commission, report prepared by the FERC staff, "Final Report On Price Manipulation In Western Markets, Fact-Finding Investigation of Potential Manipulation of Electric and Natural Gas Prices, Docket No. PA02-2-000, March 2003.

by economic withholding and inflated bidding. The FERC staff investigation did not address physical withholding of generation to raise prices since FERC is addressing that issue separately. FERC staff found that one supplier, "engaged in a high-volume, rapid-fire trading strategy," referred to as "churning," significantly increased the price of natural gas. The inflated gas prices significantly affected index prices and California spot wholesale power prices.[7]

FERC staff states that wash trades were common on EnronOnline to create a false sense of liquidity and can distort prices. Enron also had affiliates on both sides of wash-like trades to boost volatility and raise prices. Staff analyzed an Enron experiment to test a strategy and an actual manipulation using EnronOnline. They found that even though the price change was relatively small, $0.1/MMBtu, Enron earned more than $3 million from the manipulation because of its large financial position.

FERC staff identified various "entities" that appear to have participated with Enron regarding price manipulation strategies, profit sharing arrangements, economic withholding, and inflated bidding. They also found evidence that the Palo Verde electric price index was manipulated and that Pacific Northwest spot power prices were also inflated.

Based on their findings, FERC staff made numerous recommendations for the Commission to consider to address the issues raised in their investigation.

Industry Credit Outlook Remains "Bleak"

As documented in last year's report, the disturbing industry news resulted in declining credit ratings and falling share prices for many energy companies. This "credit crunch" has impacted the ability of suppliers to raise capital and forced companies to cut back on their energy trading operations and plant investments. Standard & Poor's

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[7]FERC Staff Final Report on Price Manipulation in Western Markets, March 2003, p. ES-5.

(S&P) noted that "familiar themes continue to dominate the bleak credit picture"[8] for the industry. This includes constrained access to capital due to

> . . . investor skepticism over accounting practices and disclosure; the plethora of federal and state investigations; failing confidence in future financial performance that has created a liquidity crisis for some companies; and investments outside the traditional regulated utility business, principally merchant generation facilities and related energy marketing and trading activities.[9]

As a result, the ratings trend for the investor-owned utility industry (which include electric, gas, pipeline, and water companies) is continuing a negative slope, which began in early 2000, and actually accelerated in the first quarter of 2003. S&P noted that there were "an unprecedented 50 downgrades among holding companies and operating subsidiaries, compared with just three upgrades during the first three months of 2003." S&P also indicates that it expects the negative credit momentum to continue in 2003, although they expect the pace of negative ratings to moderate.

S&P notes that some companies are decreasing or discontinuing their investments in unregulated businesses, including merchant generation, energy trading, and international investments–strategies that were intended to help them deal with competitive markets and to enhance shareholder value. The large number of downgrades, they note, has caused the average rating for the U.S. power sector as a whole to slip into the mid-'BBB' area (companies considered to have an "adequate capacity to meet its financial commitments"). They do not expect the industry to fall below that level and state that "companies that continue to emphasize a vertically integrated structure should hang onto an 'A-' average"[10] (an 'A' rating is given to companies with a "strong capacity to meet its financial commitments").

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[8]Standard & Poor's, "Downside Rating Trend Continues For U.S. Utilities in First Quarter," April 24, 2003, p. 1.

[9]Standard & Poor's, "Downside Rating Trend Continues," p. 1.

[10]Standard & Poor's, "Downside Rating Trend Continues," p. 3.

Three major energy producers have filed for bankruptcy protection in 2003, Xcel Energy Inc.'s NRG Energy, PG&E Corp.'s National Energy Group, and Mirant Americas Generation LLC, which includes nearly all of Mirant's wholly owned subsidiaries in the U.S. Other companies, including Dynegy Inc, have announced capital restructuring plans to allow time to improve their financial conditions.

NRG Energy is under contract to supply 45 percent of Connecticut Light & Power's electricity to its 1.1 million customers. Because of its critical importance to New England's power supply, ISO New England asked FERC to ensure that the company either continues to supply the power or finds an alternative means to supply the power to the area.[11] In June 2003, FERC ordered NRG to continue to deliver power to CL&P until a final ruling can be made. NRG claims to be losing $500,000 a day under a contract which is set to expire at the end of the year. A U.S. appeals court in July 2003 refused to temporarily halt the FERC order that required NRG Energy to honor its contract with CL&P until its final ruling.[12]

Mirant has 19,000 MW of U.S. generating capacity with over 10,000 MW committed to supply contracts–including about 6,000 MW from Maryland and Virginia plants for Potomac Electric Power's customers in Washington D.C. (approximately 700,000 customers).[13] The uncommitted capacity is sold on the spot market. Mirant sells power to Potomac Electric Power at below-market prices under a four year contract arranged when Mirant bought the company's power plants in 2000.[14]

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[11]Utility Spotlight, "New England ISO Asks FERC Move On CL&P Power Supply from NRG," July 21, 2003.

[12]*Reuters*, "Court Rejects NRG Request to Halt FERC Order," July 16, 2003.

[13]*Reuters*, "Bankruptcy Seen Threatening Mirant Power Contracts," July 15, 2003.

[14]*The Washington Times*, "Bankruptcy of PEPCO Power Supplier May Increase Washington-Area Electric Bills," July 16, 2003.

Washington Gas Energy Services also has contracts with Mirant to provide power to 79,000 customers in D.C. and Maryland.[15]

At this point, it is uncertain how these specific contract difficulties will be resolved. It is clear, however, that they stem, at least in part, from the higher production costs caused by higher natural gas prices and resulting higher power prices. A protracted period of higher natural gas prices or occasional substantial price spikes will lead to attempts to renegotiate existing contracts and higher prices as contracts expire, regardless of the financial health of the company supplying the power. Higher prices may also lead additional companies to financial problems that have long-term (and unhedged) supply commitments. These conditions have also led some suppliers to request an increase in the fixed price of default or standard offer service in restructured states and the regulated price under fuel adjustment mechanisms in non-restructured states.

Natural Gas Capacity and Natural Gas Prices

The continuing credit crunch due to the factors just discussed, combined with the economic slowdown, has led to a cut back in investment in future generating capacity. Despite the recent cutbacks, this was after a period of several years of the largest capacity expansion in the industry in over half a century. In 2002, 57,200 MW of gas-fired capacity was added with more than 50,000 MW expected again for 2003.[16] This followed the 1999 through 2001 period when a total of 77,700 MW was added. This compares with the period 1986 through 1998 when a total of 53,900 MW of gas-fired capacity was added for the entire period. Coal capacity additions, in contrast, is expected to be only 12,800 MW between 2000 to 2009.[17] No new plants entered construction during the first quarter of 2003.

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[15]*The Washington Times*, Bankruptcy of PEPCO Power Supplier, July 16, 2003.

[16]EPRI, "Energy Market and Generation Response," June 2003.

[17]EPRI, p. 2.

Figure I.2 compares the spot power prices in several U.S. mid-continent power markets and natural gas markets. This shows the close correlation between the spot market prices. As noted, natural gas is the marginal fuel in most of the country. This correlation in the spot markets for electricity is also not surprising considering that it is common practice to index power transactions to a natural gas price index. As will be seen in the regional section of this report, markets around the country (PJM, New

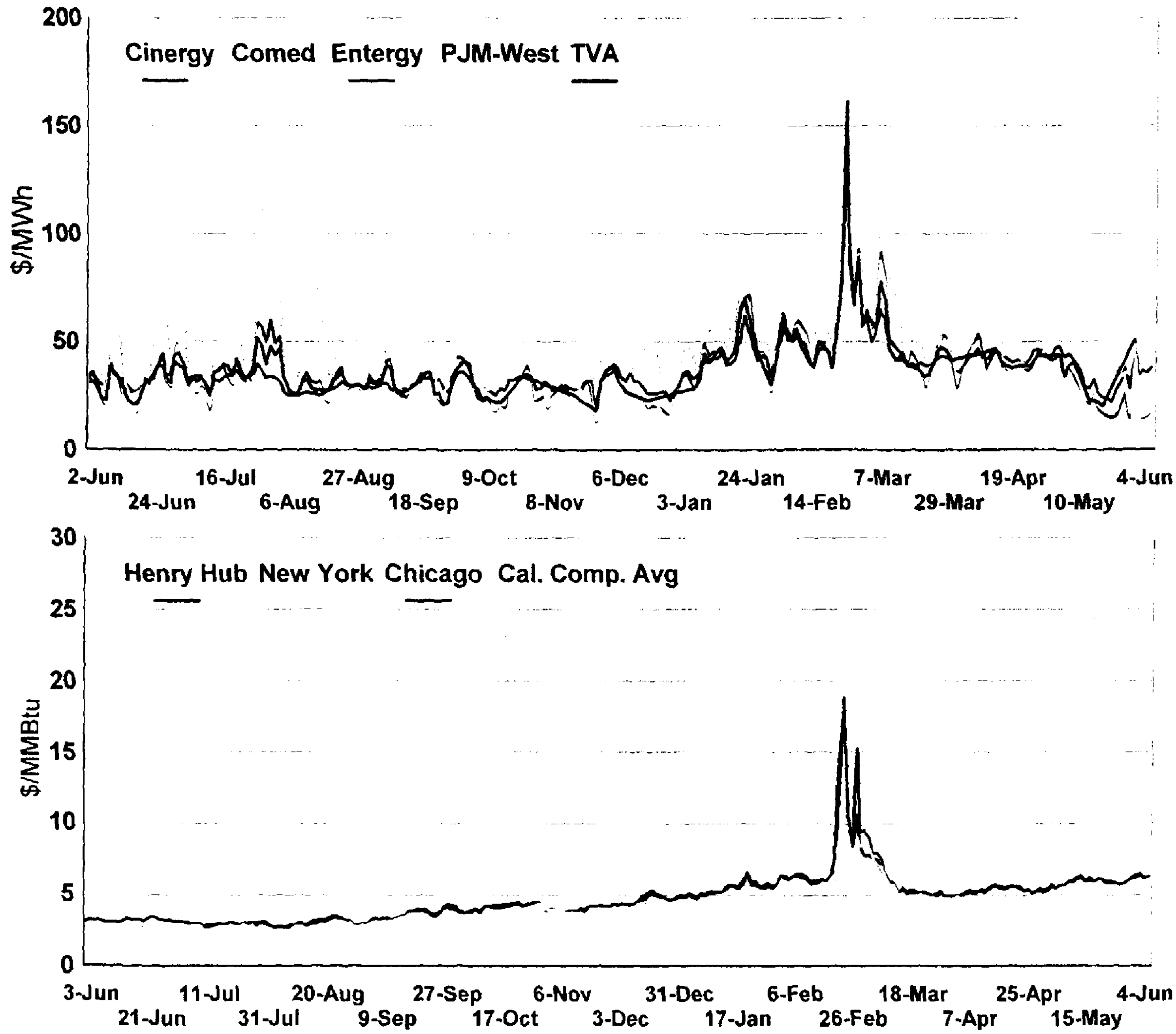

Figure I.2. Comparison of spot power prices and natural gas prices.
Sources: Data from IntercontinentalExchange, Inc. various trading hubs and U.S. Department of Energy, Energy Information Administration.

England, New York, Midwest, Texas, and Western markets), were significantly impacted in early 2003 from the spike in natural gas prices.

If natural gas prices continue to remain at current levels or surge higher, this will almost certainly have a significant impact on power prices across the country.

FERC's Standard Market Design

On July 31, 2002, the Federal Energy Regulatory Commission (FERC) issued a Notice of Proposed Rulemaking (NOPR) on "Standard Market Design" (SMD). FERC stated that it believed that SMD was needed because there are inconsistent market rules across the country. These inconsistencies, they believed, have resulted in higher costs to customers, less investment in infrastructure, discrimination by transmission owners against alternative suppliers, and market manipulation. Another FERC goal was to create "seamless" wholesale power markets across the country allowing market participants to transact easily across transmission grid boundaries.

FERC allowed comments to be filed on the various parts of the NOPR, held several workshops on related issues, and also held workshops in Washington and around the country to present what the Commission wanted to accomplish and to receive feedback from others. On April 28, 2003, FERC issued a White Paper, "Wholesale Power Market Platform."[18] FERC notes in the White Paper that any final rule will focus on the formation of regional transmission organizations (RTOs) and independent system operators (ISOs) and that they have "good wholesale market rules in place." The phrase "standard market design" does not appear anywhere in the White Paper. Also, the requirement that utilities create or join an Independent Transmission Provider (ITP) has been dropped. FERC anticipates that the final rule will require utilities to join an RTO or ISO, however. Importantly for states, particularly those that objected to FERC requiring a standard design for all jurisdictional regions, a final rule

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[18]Federal Energy Regulatory Commission, White Paper, "Wholesale Power Market Platform," issued April 28, 2003. Also issued was Appendix A, "Comparison of the Proposed Wholesale Market Platform with the RTO Requirements of Order No. 2000."

would allow phased-in implementation that would be "tailored to each region" and allow modifications within each region when beneficial to customers or it can be demonstrated that the costs of any feature outweighs its benefits.

FERC states in the White Paper that it believes that the following elements need to be in place for wholesale markets to function well.

- Regional independent grid operation. A final rule will reaffirm FERC Order 2000's goal of regional independent grid operation and the required RTO characteristics for independence, scope and regional configuration, operational authority, and short-term reliability. FERC had proposed in the NOPR that all transmission owners and operators that have not yet joined a Regional Transmission Organization (RTO) be required to contract with an independent entity to operate their transmission facilities, an Independent Transmission Provider (ITP). FERC eliminated this proposed requirement that utilities create or join an ITP since RTOs and ISOs are continuing to develop and take geographic shape across the country. They note almost all utilities have already joined or committed to join an RTO or ISO. However, a Final Rule would require public utilities (excluding FERC-jurisdictional electric power cooperatives that serve only retail load) to join an RTO or ISO.

- Regional transmission planning process. A final rule will also reaffirm Order 2000's requirement that RTOs and ISOs produce technical assessments of the regional grid and support state siting authorities or multi-state entities with necessary studies. How this will be done will be decided by the region.

- Fair cost allocation for existing and new transmission. Existing grid costs (except costs associated directly with a customer) will continue to be recovered from customers through rates. Rates should permit customers to have access to the entire region at a single rate, not cumulative charges for transmission service for each service area crossed ("pancake" rates). Regional state committees may propose a uniform regional rate for transmission service (or "postage stamp" rates) or the committee may propose different access charges that depend on where power is taken off the grid, such as based on the transmission owner's service area (or "license plate" rates). New transmission expansion would be recovered based on a regional pricing policy–that, in FERC's words "may be informed (sic) by the appropriate regional state committee." Presumably, these rates would still require FERC approval.

- Market monitoring and market power mitigation. Order 2000 did have requirements for monitoring, but not market power mitigation. Each RTO or ISO would be required to have an independent market monitor. FERC believes that market power mitigation should limit the exercise of market power, but not suppress prices below what is needed to attract investment in the area. RTO or ISO policy should include limits on bidding flexibility where there is "localized" market power and prevent market manipulation strategies. FERC had proposed in the NOPR to put in place "regulatory backstops" to protect customers against the exercise of market power when structures do not support a competitive market by requiring independent monitoring and assessment of wholesale power markets in each region.

- Spot markets to meet customers' real-time energy needs. FERC expects that most power will be bought and sold through long-term bilateral contracts between buyers and sellers. For last-minute sales or purchases for system reliability, however, FERC would require in a final rule that RTOs or ISOs use a real-time market to resolve energy imbalances. They would also be required to have a day-ahead market and a market for various ancillary services, when the market is ready. The day-ahead market must be designed to work reliably with the congestion management system. This is similar to what had been proposed in the NOPR, requiring markets for bid-based, security-constrained spot energy markets operated on a real-time and day-ahead trading basis and for the procurement of ancillary services.

- Transparency and efficiency in congestion management. FERC had proposed in the NOPR to require all ITPs to use Locational Marginal Pricing (LMP) to manage congestion on the transmission system, as three ISOs are currently doing (PJM, New York, and New England). They are now indicating that transmission congestion should be managed with an approach developed by each region, of course, subject to FERC approval. The approach should avoid manipulation, use the grid efficiently, and promote the use of the lowest cost generation.

- For RTOs and ISOs that choose to use LMP to manage congestion, FERC will require that firm transmission rights (FTRs) be made available to customers. FTRs are designed to allow customers an opportunity to hedge against the possibility of paying a congestion charge that occurs under LMP. Holders of FTRs would be entitled to receive revenues from transmission congestion costs. FTRs would be allocated according to existing contracts and existing service arrangements. FERC would not override RTO or ISO transmission rights arrangements that have already been approved. This is similar to the Congestion Revenue Rights (CRRs) that FERC had proposed in the NOPR, except that they are reverting back to the terminology already used by some RTOs and ISOs, the requirement is contingent on the RTO or ISO choosing LMP, and auctions of FTRs will not be required, as FERC had proposed (and stated they preferred) after a transition period.

- Resource adequacy approaches. Each region with an RTO or ISO will determine how it will ensure that the region has sufficient resources to meet customer demand. The approach and the level of resource adequacy will be decided by the states in the region, including a mix of generation, transmission, energy efficiency, and demand response. Approaches include state imposed requirements on load serving utilities or through RTO or ISO operated capacity markets. FERC had proposed in the NOPR that the RTO or other regional entity must forecast the region's future resource needs, facilitate regional determination of an adequate future level of resources, and assess the adequacy of the plans of load-serving entities to meet the regional needs. Each load-serving entity would have been required to meet its share of the future regional need through a combination of new generation and demand reduction. The resource adequacy and the regional transmission planning requirement in the NOPR raised considerable concern among many states that it would infringe on state jurisdiction. FERC did not assert jurisdictional authority in the NOPR over siting of transmission and generation facilities, however, states have been generally concerned about the potential loss of their siting jurisdiction sometime in the future and many states were concerned that a federal resource adequacy requirement would be a step toward further loss of jurisdiction. In the White Paper, FERC states "nothing in the Final Rule will change state authority" on these matters. FERC also stated that they will not include a minimum level of resource adequacy. FERC adds that an "RTO or ISO may implement a resource adequacy program only where a state (or states) asks it to do so, or where a state does not act."

The transmission pricing reforms that FERC had proposed in the NOPR to create a nondiscriminatory and standard transmission tariff for all customers was not part of the White Paper. The proposed reforms would have combined three types of current transmission service -- integrated network service and firm and non-firm point-to-point service -- into a new "Network Access Service." This would have been used to recover embedded costs of the transmission system. FERC had noted that since this would have been to standardize transmission tariffs, which will remain regulated in any case, it was not part of market design. FERC had believed that streamlining the transmission tariff would prevent discriminatory or preferential treatment that is now given to some existing transmission customers. This included the transmission portion of the bundled rate for retail customers, and became a significantly controversial issue with states who were concerned that FERC was asserting jurisdiction in an area that had been primarily a state-jurisdictional issue.

In the White Paper, FERC indicated that *non-price* terms and conditions of the RTO or ISO tariff will apply equally to all users, including those taking service to meet their obligation to serve bundled retail customers. But FERC said it will not assert jurisdiction over the transmission *rate* component of bundled retail service.

In general, FERC has indicated that a final rule will provide more flexibility than what was originally proposed in the NOPR. While that allows states and regions to design market rules and mechanisms that are more appropriate for their area, this does place the burden on states to determine these design features. However, these wholesale market design features will have to be approved by FERC and conform to its specifications.

How wholesale market performance is measured

Among the principal reasons[19] for the movement away from regulation and toward generation competition was the belief that competition would provide better incentives to control costs and that these cost savings would be passed on to consumers–resulting in lower prices for all customer classes.

The examination of the performance of the wholesale markets in this report is based on the extent to which this goal of developing a competitive market is being met. Ideally, the economic textbook case of a perfectly competitive market, there would be many suppliers vying for business. Potential new entrants would encounter few or no entry barriers and this ease of entry[20] would provide an additional incentive to existing suppliers to control costs and offer competitive prices to retain customers. No single

[19]Other reasons include increased use of innovative technologies in generation and more customer options in terms of price, fuel source, and service.

[20]For example, no or little sunk investment costs, where either the investment costs are low or the capital invested can be easily redeployed to another enterprise.

supplier or group of suppliers could exercise any control over the price or manipulate it in any significant way. In other words, in a *perfectly* competitive market, suppliers are "price takers" and base their choice of the quantity to supply to the market on this market-determined price. In this perfectly competitive market case, the market price will approximate the marginal cost of supply at the market-clearing quantity.

The ability of a supplier or group of suppliers to raise and maintain the price above what would occur in a competitive market is referred to as their market power. Market power is the degree of price leveraging ability a supplier or suppliers have for "price making" ability, rather than being the price takers of the perfectly competitive market. The more a firm can charge a price that exceeds the marginal cost and exert its influence upon the price, the greater the firm's degree of market power.[21] The price-taking competitive firm that has no market power cannot pick its own price or influence it in any significant way. However, there are upper bound limits on price that hold even in the extreme case of market power of an unregulated monopolist that faces no meaningful threat of market entry from rival firms. Such limits reflect that the price cannot exceed what consumers are willing to pay for the product (that is, it cannot exceed demand at the quantity the monopolist wants to produce), nor can a monopolist charge a price that is sufficiently high that it creates a strong incentive for other firms to find ways around the entry barriers to the market or that encourages consumers to seek alternatives.

Of course, experience tells us that markets are routinely less than ideal or perfect. Suppliers often have at least some degree of control over the price. When this control is relatively modest, as with many markets, no corrective action is required or

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[21]This can be estimated with the "Lerner Index," which is defined as:

(Price - Marginal Cost)/Price

which measures the markup of price over marginal cost (as a percentage of price). The larger the Lerner Index, the greater the firm's market power. If the Lerner Index equals 0.5, then 50 percent of the price is the mark-up above marginal cost; if it equals 0.02, then just two percent of the price is mark-up above marginal cost. If the Index equals 0.5, it may indicate significant market power and require some action; if it is only 0.02, it is unlikely to raise any calls for governmental action.

taken. For example, if a manufacturer can raise and maintain the market price ten percent above a competitive level, and is able to do so without using any illegal anti-competitive practices (such as price fixing or in collusion with other firms),[22] this relatively modest impact on price is not likely to lead to calls for corrective regulatory action. Indeed, some corrective actions may cause more harm than good by deterring new entrants or imposing additional compliance costs. Also, with low entry barriers, over time the higher price will draw the attention of potential new suppliers who will drive the price down closer to the competitive level when they enter the market. Problems arise when the price control is relatively large and has persisted, or has the potential to persist, for a long time.

How much control or price leverage a firm has is based on three factors: the overall demand characteristic of the product, the market concentration or market share of the firm, and the supply characteristics. These three factors together determine how much market power a firm can exercise. No single factor by itself would indicate a firm has considerable market power. For example, if a firm had a substantial market share, say 80 percent of the market, but entry or increased output from other firms was relatively easy and customers had suitable alternatives to the firm's product, then its actual market power potential may in fact be very low.

Unfortunately, in electric markets all three factors clearly play a role. Demand for electricity is very inelastic, particularly in the short-run (less than one year) since customers have few practical alternatives and the long life of major electrical appliances makes it difficult to respond to price changes quickly for most customers. Markets are very concentrated for most geographic regions, even for multi-state wholesale regions. Market entry from other firms requires time to build new generation and is limited from outside the area by transmission constraints, which also require time to relieve. Also, mass storage of electricity for later use during peak hours is generally impractical for

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[22]These and other anti-competitive practices to raise the price are illegal under Federal law. However, the unilateral exercise of market power by itself is not illegal.

many regions of the country.[23] As economic theory would predict, because during peak hours supply is often very inelastic, that is, the quantity supplied is not very responsive to the price, markets are relatively concentrated, and demand is also very inelastic, market power has been very significant, particularly during peak hours.

The way a supplier can exercise market power in electric power markets, if they have some degree of price leverage,[24] is to either physically or economically withhold output from the market. Physical withholding is the actual withdrawal of capacity, such as claiming that a plant or plants are down for maintenance or withdrawing capacity for other reasons. Economic withholding is bidding a relatively high price with the expectation that either the plant or plants will not be selected for dispatch, or if they are selected, the owner will receive a much higher price than the marginal cost. In either case, withholding is profitable because the revenue lost from the idled capacity is more than made up for by the increased revenue gained by the operating plants that receive the higher price.

For each of the regions examined in the following sections, when there are analyses of wholesale market performance available, they are summarized and presented in the wholesale discussion. Unfortunately, at this time, not all regions have had a rigorous and independent market performance analysis conducted.

How retail market performance is measured

The actual prices paid by retail customers that choose a competitive supplier are not made public. Measuring an actual price trend, and the potential benefits to consumers, is therefore not always directly observable. The review of retail markets summarizes what we can observe in the markets, in terms of offers being made to residential customers, the potential savings opportunities these offers present, the

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[23]Pumped hydro storage, obviously, requires hydro resources to be available, and when it is available, it is usually not a significant portion of the total capacity required to meet demand.

[24]If a firm has no or very little market power, then raising the price will mean the loss of all or a substantial number of the firm's customers.

number of suppliers in the area, the type of offers being made, and the percent of customers that have selected an alternative supplier, among other factors. These performance measures are, when available, included in the regional summaries in the subsequent sections.

These potential performance indicators in isolation do not determine whether a retail market and its design are succeeding or failing. Rather, considered in tandem with an assessment of wholesale market developments, these indicators present a picture of how retail markets are evolving. Since these markets began relatively recently, and the transition period continues for most areas, markets are still evolving. Therefore, the purpose of this report is not to judge success or failure of competition overall, but to present facts to assess the state of retail and wholesale markets today.

Retail market performance is highly dependant on prices in the wholesale market. Most retail markets have overall price constraints that seldom fluctuate along with changing conditions in the wholesale market or are adjusted after a considerable time lag. The retail standard offer, or the "price-to-compare," is the price for generation service paid by a retail customer who does not select a competitive supplier. These customers continue to receive power supplied by the distribution company that still owns generation, an affiliated generation owner, an unaffiliated supplier or suppliers, or some combination of all of these generation sources.

The standard offer or price-to-compare is the benchmark or "price-to-beat" not only to inform customers to allow them to make a choice, but is also an indicator for use by competitive suppliers considering entry into a retail market. The effect of the retail price constraints depends on the amount of the available "headroom," which is the difference between the generation price-to-compare and the cost to procure power to serve retail customers.

As is illustrated in Figure I.3, the generation charge or price-to-compare, relative to the cost to competitive suppliers to obtain or generate power, will determine the amount of "headroom" available for alternative suppliers to compete. The distribution companies in Figure I.3 have the same beginning regulated price, discount,[25] and transmission and distribution charges. In this hypothetical example, the customer charges are greater for distribution company one on the left side of the figure than distribution company two on the right. To collect the same net present value for both

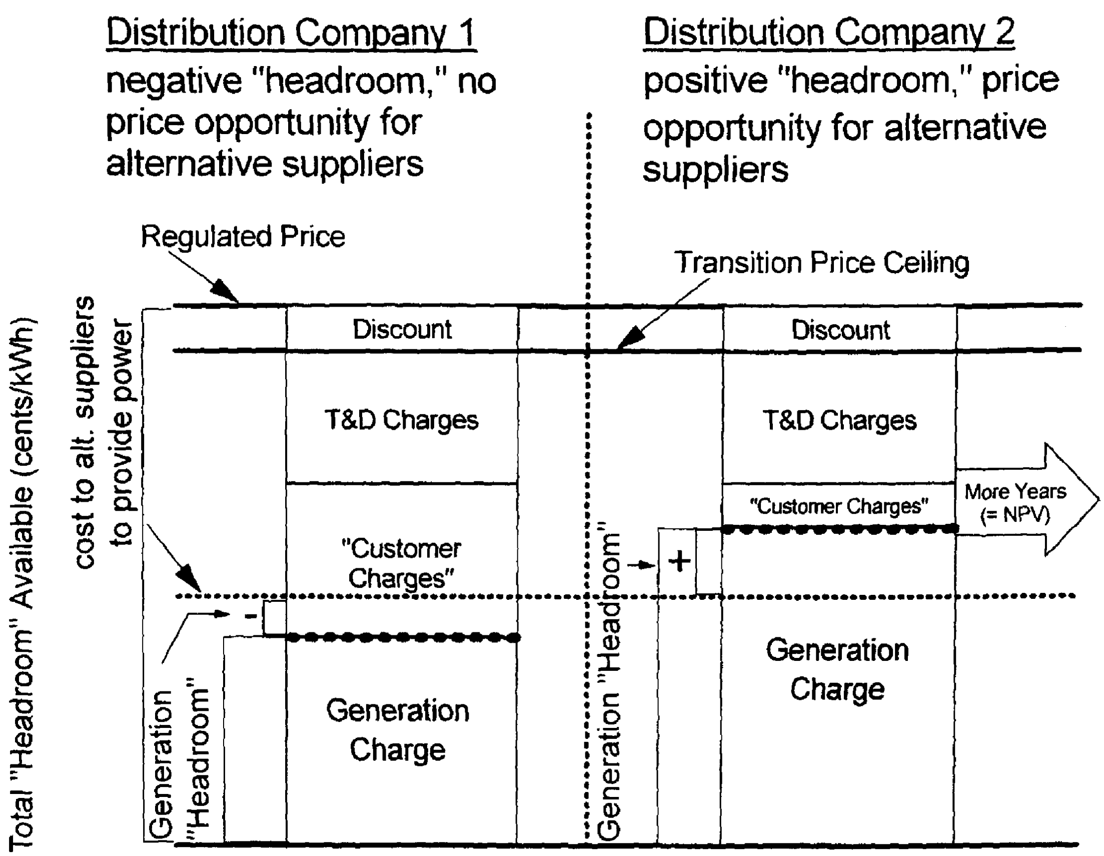

Figure I.3. Examples of two different distribution companies with different generation cost and with the same cost of procuring power for alternative suppliers.

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[25]Not all states have a discount, of course.

companies (assuming they are the same for both companies), the transition period runs longer for distribution company two. However, the larger customer charge (or "CTC") for distribution company one results in the generation charge being reduced (in order to remain under the price ceiling[26]), in this case, below the cost to alternative suppliers to either procure power in the wholesale market or to generate it themselves–this cost is represented by the dotted line running across the figure.

Alternative supplier costs also include marketing, risk management, overhead, and normal return-on-investment costs, not only the direct cost of the power. In this first example, alternative suppliers will have to charge a price above what customers would pay if they stayed with the distribution company, therefore, in this case, there is "negative headroom." In the case of distribution company two in Figure I.3, the generation charge or price-to-compare is above the cost to alternative suppliers to provide power, meaning there is "positive headroom" and an opportunity for these suppliers to entice customers away from the distribution company or default provider.

If there is sufficient headroom, suppliers are able to offer customers an opportunity to save and can entice customers away from the price-to-compare (illustrated by distribution company two).[27] However, the headroom may be too small to cover all the costs of supplying the retail customers, be nonexistent, or even negative–that is, where the cost of securing and delivering power to the retail customer exceeds the retail price charged by the distribution company (as illustrated by

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[26]Another way of considering this is to start with the previously regulated rate, then subtract the discount (if any), T&D charges, and the customer charges. Then, what is left over is available for the generation charge.

[27]Of course, as demonstrated by the existence of "green" suppliers, who offer power generated to some degree by renewable or "clean" energy resources, price is not the only consideration customers use to select a supplier. Other factors include reliability, fuel source, and contract terms. While a small subset of customers are willing to pay a premium for these other factors, price is still the dominant consideration for most customers.

distribution company 1).[28] Assuming alternative suppliers do not want to operate at a loss for too long, they will not enter or will leave a market under these conditions. In general, of the relative factors of retail price for generation and the wholesale cost of power, the wholesale cost is more volatile. Price fluctuations and volatility, or the future threat of it, can increase the cost to alternative suppliers and be a determining factor in a decision to participate or continue to participate in a market.

Obviously, if the beginning-regulated rate is relatively lower to start with, the amount of available overall headroom (that is, what is available for all the price components) will be relatively low when compared with a higher-rate distribution company. Also, if wholesale prices are relatively high compared to what customers are paying for the price-to-compare, then fewer suppliers will enter the market. This lack of headroom is the primary reason that many retail markets currently have very little activity and, where there is retail market activity, it is primarily in states or distribution companies that were relatively higher cost before restructuring began.

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[28]An extreme example of negative headroom is California, which led one distribution company (PG&E) to the filing for bankruptcy protection and severe financial difficulties for another. Distribution companies in other states, for example, Massachusetts and Pennsylvania (GPU), have received upward adjustments to the standard offer price to recover the increased cost of obtaining power in the wholesale market (made necessary because the distribution companies sold their own generating capacity). In the Pennsylvania/GPU case, a settlement reached in June of 2001 allows GPU to defer for ratemaking and accounting purposes the difference between what it can charge customers for generation under the rate cap and its actual cost to supply electricity. The deferral provision of the settlement allows GPU to retain unrecovered generation costs on its books until 2010. Overall customer rates will not increase (the rate cap was extended through 2007), but the "shopping credit" or price-to-compare will increase. The settlement ends the Competitive Transition Charge (CTC) in 2015. GPU stated that it lost $47 million on electricity supply in Pennsylvania in 2000 and estimated it would lose an additional $250 million in 2001 without rate relief.

SECTION II
Electric Restructuring Activity in the Mid-Atlantic Region

Wholesale Market and PJM Interconnection[1]

PJM Interconnection, L.L.C.'s (or PJM) origins date back to 1927 when three companies formed the first power pool, the "Pennsylvania-New Jersey Interconnection." In 1956, three more companies were added and the pool became the "Pennsylvania-New Jersey-Maryland" Interconnection (the beginning as "PJM"). In 1981 PJM added two members, bringing membership to eight companies. Today PJM claims to operate the largest wholesale electric market in the world and coordinates the movement of electricity throughout the mid-Atlantic states. Figure II.1, is a map of PJM's and PJM West's control areas. PJM's control area currently has 25.1 million people in it, 614 generation sources of various fuel types, more than 76,000 megawatts of generating capacity, 329 million megawatt-hours of annual delivered energy, 20,000 miles of transmission lines, and more than 245 participants in its markets.

Because of its history as a coordinated power pool, PJM was able to quickly develop into an Independent System Operator (ISO) and perform the market coordination it does today. For this reason PJM is currently the most developed wholesale market in the U.S. and has considerable information on its operations. In addition to operating and monitoring its electricity markets, PJM also plans transmission and generation expansion for the area. There are currently plans under consideration to expand PJM as far west as Iowa and south to include practically all of the state of Virginia.

PJM Markets

PJM operates a number of different power markets, including: day-ahead and real-time energy markets; daily, monthly, and multi-monthly capacity credit markets;

[1]The introduction and explanatory material presented here on PJM's operations and markets is from various PJM publications on their website, www.pjm.com.

several ancillary service markets; and monthly FTR auction markets. PJM introduced nodal energy pricing with market-clearing prices on April 1, 1998 and nodal, market-clearing prices based on competitive offers on April 1, 1999 (LMP). PJM implemented a competitive auction-based FTR market on May 1, 1999. Daily capacity markets were introduced on January 1, 1999 and were broadened to include monthly and multi-monthly markets in mid-1999. PJM implemented the day-ahead energy market and the regulation market on June 1, 2000.

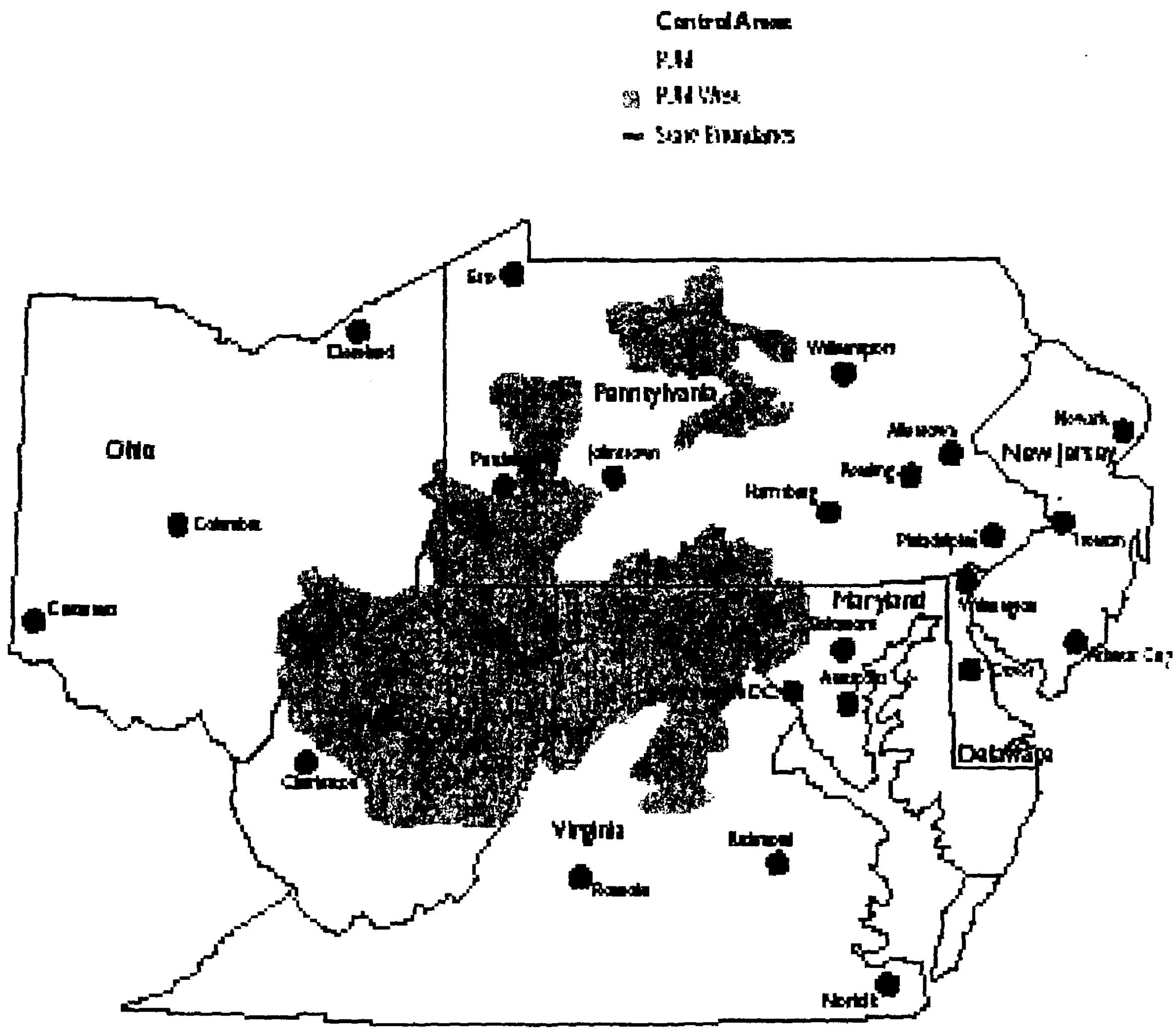

Figure II.1. The PJM and PJM West control areas.
Source: PJM.

Energy Markets

The day-ahead energy market is a forward market in which day-ahead locational marginal prices (LMPs) are calculated for each hour of the next operating day based on generation offers, demand bids, and bilateral transactions submitted in the day-ahead market. The real-time energy market is based on current day operations in which real-time LMPs are calculated at five-minute intervals based on the actual system operating conditions. Figure II.2 plots PJM's monthly weighted average LMPs for April 2002 to May 2003. As discussed in Section I, the impact of higher natural gas prices in early 2003 can be seen in the February and March weighted average prices.

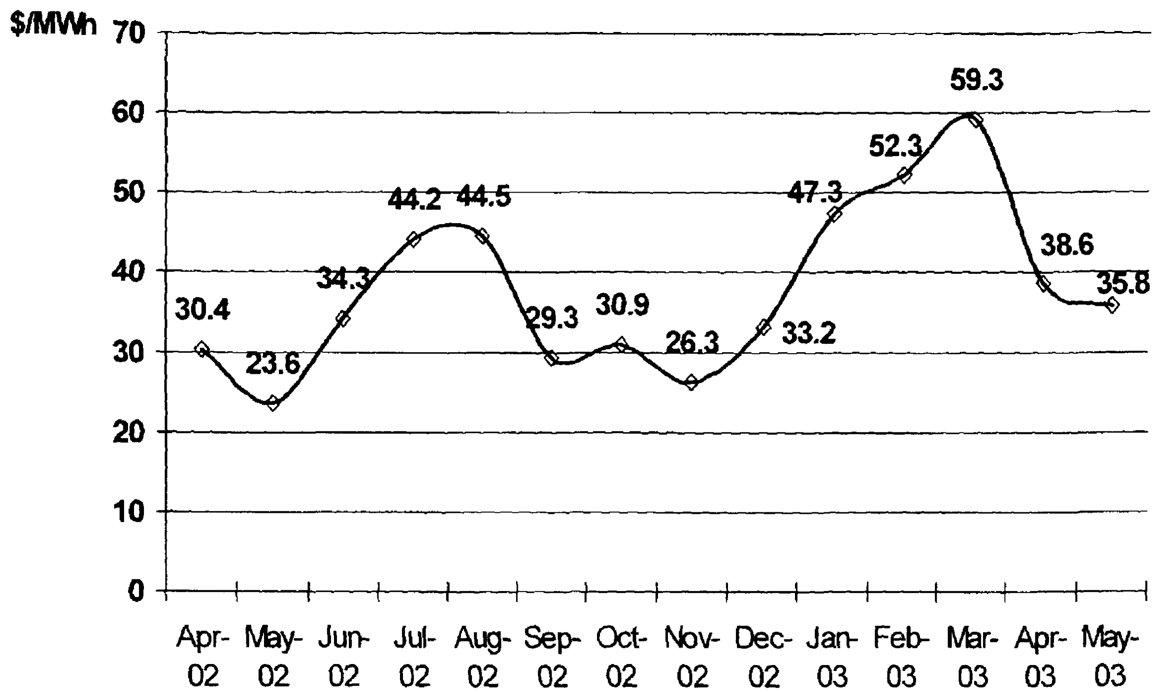

Figure II.2. PJM monthly weighted average LMPs, April 2002 to May 2003.
Source: PJM.

Buyers and sellers of energy in PJM can decide whether to meet their energy needs through self-supply, bilateral purchases from generation owners or market intermediaries, through the day-ahead market or the real-time balancing, or spot market. Energy purchases can be made over any time frame from instantaneous real-time balancing market purchases to long term, multi-year bilateral contracts. Purchases may be made from generation located within or outside the PJM control area. Generation owners can sell their output within the PJM control area or outside the control area and can use generation to meet their own loads, to sell into the spot market or to sell bilaterally. Generation owners can sell their output over multiple time frames from the real-time spot market to multi-year bilateral arrangements.

Capacity Markets

Under PJM rules, each load-serving entity (LSE) has the obligation to own or acquire capacity resources equal to the peak load that it serves plus a reserve margin. LSEs can acquire capacity by buying or building units, by entering into bilateral arrangements with terms determined by the parties, or by participating in the capacity credit markets operated by PJM. Collectively, these arrangements are now known as the Unforced Capacity Market (UCAP). The PJM capacity credit markets (CCMs) provide a mechanism to balance the supply of and demand for capacity not met through the bilateral market or through self-supply. Capacity credit markets are intended to provide a transparent, market-based mechanism for new, competitive LSEs to acquire the capacity resources required to meet their capacity obligations and to sell capacity resources when no longer needed to serve load. PJM's daily capacity credit markets enable LSEs to match capacity resources with changing obligations caused by daily shifts in retail load. Monthly, multi-monthly, and interval capacity credit markets enable longer-term capacity obligations to be matched with available capacity resources. Prices and performance, including a significant problem with manipulation of the capacity credit markets, are discussed below.

Ancillary Services: Regulation Market

Regulation is one of six ancillary services defined by the FERC in Order No. 888. Regulation is required to match generation with short-term increases or decreases in load that would otherwise result in an imbalance between the two. Longer-term deviations between system load and generation are met via primary and secondary reserves and generation responses to economic signals. Market participants can acquire regulation in the regulation market in addition to self-scheduling their own resources or purchasing regulation bilaterally. The market design implemented by PJM provides incentives to owners based on current, unit specific opportunity costs in addition to the regulation offer price. The market for regulation permits suppliers to make offers of regulation subject to a bid cap of $100 per MW, plus opportunity costs. A regulation market was introduced on June 1, 2000, and modified on December 1, 2002.

Ancillary Services: Spinning Reserve

Spinning reserve is an ancillary service defined as generation synchronized to the system and capable of producing output within 10 minutes. Spinning reserve can be provided by a number of sources including steam units with available ramp (incidental spinning), condensing hydro units, condensing combustion turbines (CTs), CTs running at minimum generation, and steam units scheduled a day ahead to provide spinning reserves. PJM introduced a market for spinning reserves on December 1, 2002.

Fixed Transmission Rights

A Fixed Transmission Right (FTR) is a financial instrument that entitles the holder to receive compensation for Transmission Congestion Charges that arise when the transmission grid is congested in the day-ahead market and differences in day-ahead Locational Marginal Prices (LMPs) that result from the dispatch of generators out of merit order to relieve the congestion. Each FTR is defined from a point of receipt (where the power is injected onto the PJM grid) to a point of delivery (where the power is withdrawn from the PJM grid). For each hour in which congestion exists on the transmission system between the receipt and delivery points specified in the FTR, the holder of the FTR is awarded a share of the Transmission Congestion Charges collected from the market participants.

FTRs are designed to provide a hedge against congestion charges in the day-ahead market for firm transmission service customers, who pay the costs of the transmission system, including any congestion charges. PJM provides three ways to acquire FTRs: the annual FTR auction, the monthly FTR auction, and the FTR secondary market. The annual auction uses a multi-round auction process that offers for sale the entire transmission entitlement available on the PJM system on a long-term basis. The proceeds from the annual FTR auction are allocated through the Auction Revenue Rights (ARRs) mechanism. The ARRs are allocated to network transmission customers and to firm point-to-point transmission service customers for the annual planning period. ARR holders can elect to directly convert an ARR into an FTR instead of bidding in the auction. PJM completed the first annual auction of FTRs in May 2003. The monthly FTR auction offers for sale any residual transmission entitlement that is available after FTRs are awarded from the annual FTR auction and also allows market participants an opportunity to sell FTRs they are holding. Before the annual auction was instituted, FTRs were allocated annually to firm transmission service customers and remaining FTRs were auctioned in the monthly auction. The FTR secondary market is a bilateral trading system that facilitates trading of existing FTRs between PJM members.

FTRs are financial entitlements that enable holders to receive revenues (or charges) based on transmission congestion measured as the hourly energy locational marginal price differences in the day-ahead market across a specific path. An FTR does not represent a right to physical delivery of power. FTRs can protect transmission service customers, whose day-ahead energy deliveries are consistent with their FTRs, from uncertain costs caused by transmission congestion in the day-ahead market. Transmission customers are hedged against real-time congestion by matching real-time energy schedules with day-ahead energy schedules. FTRs can also provide a hedge for market participants against the basic risk associated with delivering energy from one bus or aggregate to another. An FTR holder does not need to deliver energy in order to receive congestion credits. FTRs can be purchased with no intent to deliver power on a path.

The hourly value of an FTR is based on the FTR megawatt reservation and the difference between day-ahead LMPs at the point of delivery and the point of receipt designated in the FTR. An FTR *obligation* is positive when the path designated in the FTR is in the same direction as the congested flow. However, an FTR obligation is negative (a charge or liability) when the designated path is in the opposite direction of the congested flow. An FTR *option* is also positive when the path designated in the FTR is in the same direction as the congested flow, but an FTR option's value is zero when the designated path is in the direction opposite to the congested flow. The option is intended to eliminate the risk from holding an FTR when transmission congestion occurs in the opposite direction of the path specified in the FTR.

FTRs are issued through PJM's simultaneous feasibility test that determines the amount of FTRs for each participant based on anticipated power transactions and transmission requirements and the system's ability to accommodate these requirements. When the actual system conditions result in more congestion than what was expected, there may be an insufficient number of FTRs issued to cover all actual congestion, a condition referred to as "unhedgeable congestion." It is unclear at this time just how much congestion on the PJM system is "unhedgeable."

While this situation may be occasional, there are transmission system constraints, such as with a number of "load pockets" scattered throughout PJM and in other parts of the country that could result in significant congestion charges. It is also not clear just how common and pervasive these types of constrained conditions are throughout the country. The western U.S., for example, has many isolated load pockets, including some large urban areas that are separated by long distances. Supporters of the LMP/FTR concept have argued that the process sends the correct economic incentive to build generation in the transmission-constrained area or to find ways to relieve the congestion with additional transmission capacity. However, critics have argued that adding additional transmission lines may require the siting of new transmission rights-of-ways, which is always difficult and costly. Even additional capacity on existing rights-of-ways are often difficult and costly as well. Moreover, as critics note, it is already known that additional generation is likely needed in the area and that additional transmission capacity would ameliorate the congestion problem, so the additional cost from the LMP "incentive" is superfluous and will only result in higher costs for customers.

Market Performance

An overview of how wholesale market performance is analyzed and the issues involved are presented in Section I. Specific analyses of PJM's markets are presented in this subsection.

In an analysis summarized in previous years' reports, it was noted that Erin T. Mansur[2] had found that market imperfections in the PJM spot energy market (which account for 10 percent to 15 percent of the market) for the period April through August of 1999 totaled $224 million. She estimated that total costs in PJM were 41 percent higher than would have occurred with perfect competition. When bilateral contracts are added (an additional 30 percent of the market) the sum of the spot market and bilateral contract costs is $827 million, or a 48 percent increase over competitive costs. She calculated a load-weighted Lerner Index of 0.293 (29 percent of the price) for the spot energy market and 0.323 (32 percent) when bilateral contracts are included.[3] These were considerably larger than PJM's Market Monitoring Unit's (MMU) estimate of an average markup of about 0.02 (2 percent) for April through December of 1999 and the year's maximum markup in July of 0.08 (8 percent). Mansur's study remains the most recent independent analysis of PJM's markets.

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[2]Erin T. Mansur, "Pricing Behavior in the Initial Summer of the Restructured PJM Wholesale Electricity Market," University of California Energy Institute (PWP-083), April 2001.

[3]Her methodology is similar to Borenstein, Bushnell, and Wolak, "Diagnosing Market Power in California's Deregulated Wholesale Electricity Market" and Wolak, "What Went Wrong with California's Re-structured Electricity Market?"

In PJM MMU's reports of the year 2001[4] and 2002,[5] the markups or Lerner indices are also much lower than Mansur's or as reported in other markets. The average markup for both 2001 and 2002 was calculated to be 0.02 (2 percent), with a maximum monthly markup of 0.05 (5 percent) for January 2001 and 0.04 (4 percent) for July 2002. The minimum monthly market was less than 0.01 (less than 1 percent) for November 2001 and again for several months in 2002. The MMU also calculated monthly markups assuming that there is a 10 percent markup over cost, since generators in PJM are allowed to provide cost-based offers with up to a 10 percent markup over cost. An adjusted markup calculation removes the assumed potential 10 percent increase over cost and results in the average markup for 2001 and 2002 to increase to 0.11 (11 percent) with a monthly maximum of 0.13 (13 percent) in January 2001 and again in July 2002 and a minimum of 0.09 (9 percent) for October 2001 and 0.10 (10 percent) for several months in 2002.

As noted last year, it appears that these markup calculations are based on "cost-based offers" as the marginal cost rather than an estimate of marginal cost based on the resource costs, as others have done. If this is the case, then this will likely understate the markups (or Lerner) index.[6] This is because suppliers are bidding an offer price that is not necessarily their marginal cost. A supplier with market power will, by definition, bid at a price that is above their marginal cost. Since marginal cost is usually not known directly, it can be estimated based on resource costs (fuel, operation and maintenance costs, etc.) of production. For example, Bushnell and Saravia (May 2002) estimate a "competitive benchmark" for the marginal cost, which is the estimated market price if there was a perfectly competitive market. This is estimated to be the

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[4]Market Monitoring Unit, PJM Interconnection, L.L.C, "PJM Interconnection State of the Market Report 2001," June 2002.

[5]Market Monitoring Unit, PJM Interconnection, L.L.C, "2002 State of the Market Report," March 5, 2003.

[6]Recall that the markup or Lerner index is calculated as:
(Price - Marginal Cost)/Price. If the marginal cost is overestimated, the markup will be understated.

incremental cost[7] of the lowest cost unit that is not needed to serve demand. This difference in how the marginal cost is estimated likely accounts for a considerable amount of the widely different markup estimates of Mansur's from the PJM MMU's.

In a different analysis, the MMU concluded that there was an exercise of market power in PJM's capacity credit markets during the first quarter of 2001.[8] As explained above, Load Serving Entities (LSEs) in PJM must either have their own capacity or purchase capacity credits from a supplier that does own capacity. If a Load Serving Entity does not have their own capacity or the capacity credits, then they must pay a Capacity Deficiency Rate of $177.30 per MW-day. During the summer of 2000 and early in 2001, prices in the daily capacity credit market jumped from zero or near zero to about $177, the Capacity Deficiency Rate, as shown in Figure II.3. During this time, there were also price spikes to $354 per MW-day–since market rules require the capacity deficient party to pay twice the Capacity Deficiency Rate on a day when the overall market is deficient. The MMU concluded that one supplier ("Entity 1") was unilaterally able to exercise undue market power during the first quarter of 2001 through the use of economic withholding, that is, withholding capacity by offering the capacity at prices greater than the Capacity Deficiency Rate. The MMU points out that this company held more net capacity than the total excess capacity in the market. The MMU stated that it believed because of changes in the underlying market conditions, actions by market participants, and rule changes proposed by PJM and approved by FERC, prices in the daily, monthly, and multi-monthly markets have declined, as can also be seen in Figure II.3.

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[7]Since actual marginal cost is unknown, "incremental cost" is used to refer to the estimated marginal cost based on the resource costs of production.

[8]PJM Interconnection, L.L.C., Market Monitoring Unit, "Report to the Pennsylvania Public Utility Commission, Capacity Market Questions," November 2001.

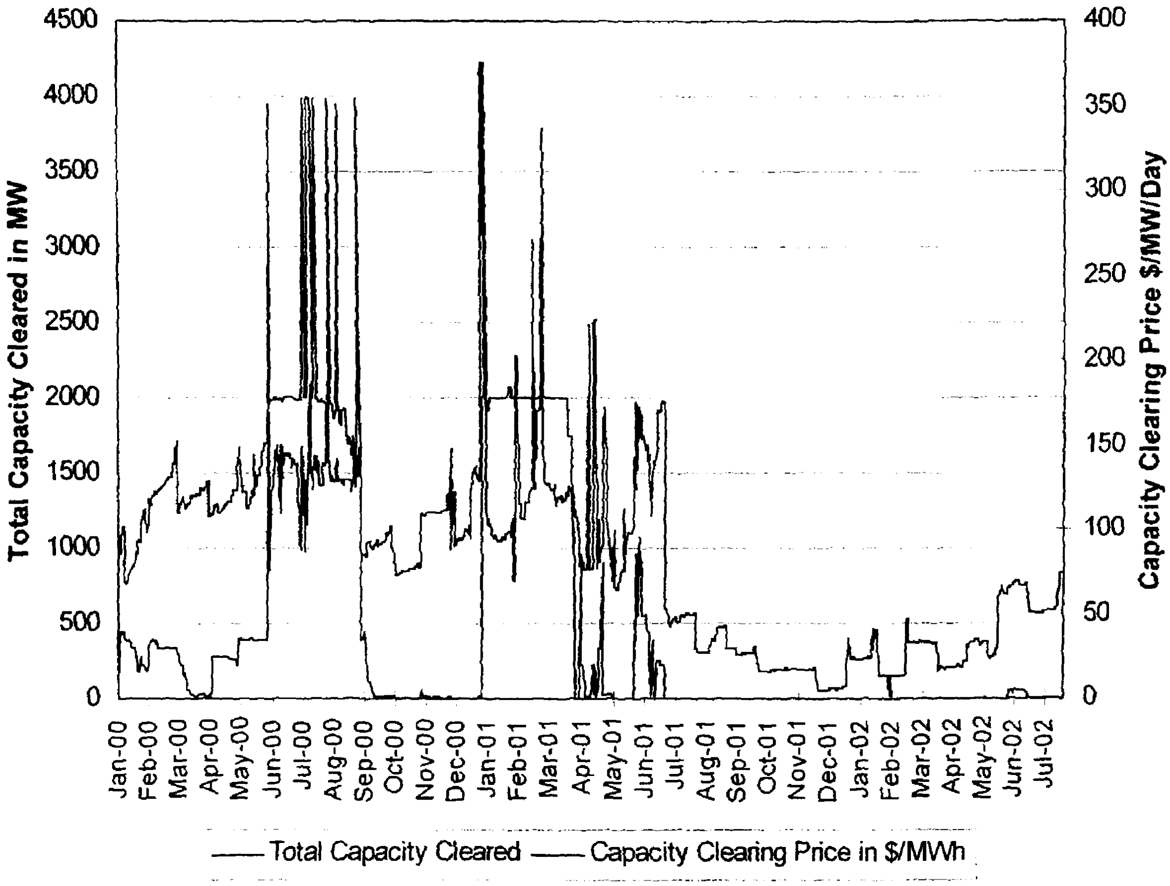

Figure II.3. PJM daily capacity market prices and MWs cleared.
Source: PJM data.

In a letter to financial analysts in December 2001, PPL Corporation's executive vice president and chief financial officer identified PPL EnergyPlus, L.L.C. (an energy marketing affiliate of PPL Corp.) as "Entity 1" in the PJM MMU report.

In an "Investigation Report," the Pennsylvania Public Utility Commission[9] concluded:

> that there is reason to believe that anticompetitive or discriminatory conduct including the unlawful exercise of market power and the threat of future recurrences of similar conduct is preventing the retail customers in this Commonwealth [of Pennsylvania] from obtaining the benefits of a properly functioning and workable competitive retail electricity market.[10]

The Commission noted that 36 licensed electric suppliers have exited the Pennsylvania market by surrendering their licenses and only seven have entered.

The Pennsylvania PUC referred the matter to the Pennsylvania Attorney General, the United States Department of Justice, and FERC and authorized the Commission's Law Bureau to intervene in any proceedings.

After a year long review, the Pennsylvania Attorney General concluded (in a press release) that:

> . . . the price increase was actually caused by the PJM's (sic) increase in the amount of capacity each firm selling electricity was required to hold. While PPL benefitted by being a holder with extra capacity to sell, it did not cause the conditions that led to the price increase."
>
> 'We agree with the [Pennsylvania] PUC that PPL had market power in the first quarter of 2001,' [Attorney General] Fisher said. 'However, our extensive investigation determined that PPL did not violate antitrust laws in acquiring that market power.'[11]

The Pennsylvania Attorney General closed its antitrust investigation with this finding.

The capacity credit market's problems combined with the energy market prices in early 2001 was clearly a significant factor that caused the drop-off in retail market

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[9]Pennsylvania Public Utility Commission, "Investigation Report," Re: Investigation Upon the Commission's Own Motion With Regard to PJM Installed Capacity Credit Markets, Docket No. I-00010090, Public Meeting held June 13, 2002.

[10]Pennsylvania Public Utility Commission, "Investigation Report," pp. 3 - 4.

[11]Pennsylvania Attorney General, Press Release, "AG Fisher closes antitrust case involving PPL; Determines that electric company did not violate laws," June 18, 2003.

activity in Pennsylvania and other PJM states. The highest "shopping credit" or price-to-compare for generation service in Pennsylvania at that time was in PECO Energy's territory, at 5.67 cents/kWh.[12] When energy prices are over $50/MWh, as it averaged during December of 2000 and again in August of 2001, adding $10/MWh for capacity[13] would place the total cost over $60/MWh or 6 cents/kWh, well above the fixed PECO Energy price-to-compare. Alternative suppliers that need to secure capacity to serve a retail load in PJM would face a loss of at least 0.33 cents/kWh for each kilowatthour sold. Even when energy prices are in the $30 to $40/MWh range as they averaged from January through May of 2001, the margin for a gain would be very thin and risky given the price volatility in both the energy and capacity markets. This also leaves very little room for marketing costs, administrative costs, cost of risk management, or an adequate profit.

Figure II.4 compares the capacity ratio (residual demand divided by capacity) and Lerner index relationship for California, New England, and PJM for the same time period of May to December 1999. The California regression line exceeds a Lerner index of 0.2 at about only .35 capacity ratio and is over 0.4 just before .60 capacity ratio is reached. However, while both New England and PJM remain below a Lerner index of 0.1 through about .65 capacity ratio, both regressions lines rise very quickly and exceed a Lerner index of 0.2 by .70 capacity ratio and reach a higher peak than California's regression line at just over .80 capacity ratio. The overall pattern is nearly identical for PJM and New England and all three markets have a similar pattern of moderate to low Lerner indices when residual demand is relatively low and Lerner indices rising quickly to very high levels as residual demand increases. While this data is now somewhat dated, it does provide a representation of how the level of the markup is, as explained in Section I, largely a function of the supply/demand constraints.

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[12]Current annual average price-to-compare for regular residential service.

[13]The PJM Market Monitoring Unit in its report on the 2000 market issued in 2001, states that "[a] maximum capacity market price of $160/MW-day is equivalent to a net energy price differential of $10/MWh for a 16-hour forward market standard energy contract."

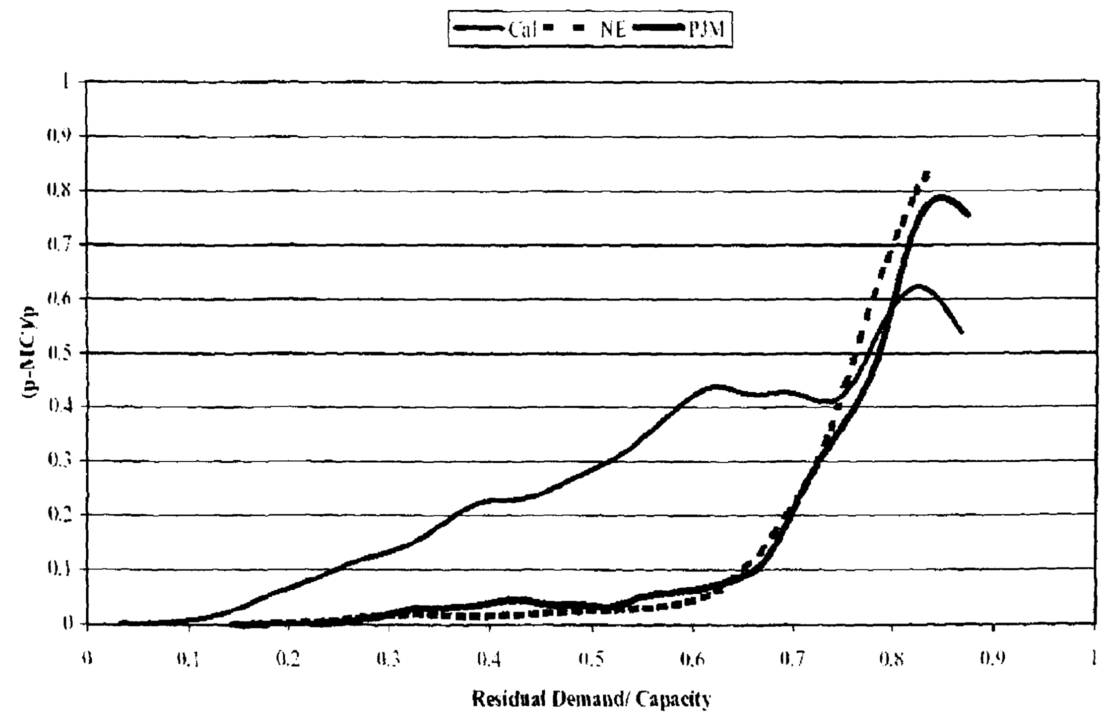

Figure II.4. Comparison of California, New England, and PJM relationship between demand level and Lerner index.
Source: Bushnell and Saravia, "An Empirical Assessment of the Competitiveness of the New England Electricity Market," May 2002.

Retail Markets

Maryland

As summarized in Table II.1 below, nearly all the customer switching to alternative suppliers in Maryland has been in Potomac Electric Power's service area. Almost 16 percent of the residential customers and over 21 percent of the non-residential customers are enrolled with an alternative supplier in Potomac Electric's service area. There are no reported residential customers enrolled with an alternative supplier in any of the other service areas and only a very small percentage of the non-residential customers had switched in two areas–neither exceeding two percent. Statewide, about four percent of all customers have chosen an electric supplier, less than four percent of all residential customers and about five percent of the non-residential customers.

Table II.1. Maryland percentage of customers enrolled with an electric supplier

Utility	Residential	Non-Residential	Total
Allegheny Power	0	0	0
Baltimore Gas & Electric	0	0.5%	0.1%
Conectiv Power Delivery	0	1.6%	0.2%
Potomac Electric Power	15.7%	21.4%	16.2%
Total	3.8%	5.1%	3.9%

Source: Maryland Public Service Commission, for month ending April 25, 2003.

Two areas had offers to residential customers, as summarized in Table II.2. As might be expected, most of the offers to residential customers were in the Potomac Electric area. Potomac Electric's area also had the only offer that was below the price-to-compare for the state. Four areas had no offers.

Table II.2. Competitive offers to residential customers in Maryland.

Utility	Number of Competitive Suppliers	Total Number of Offers from Competitive Suppliers	Number of Offers Below the Price-to-Compare
Allegheny Power	0	0	0
Baltimore Gas & Electric	1	2	0
Choptank Electric Cooperative	0	0	0
Conectiv Power Delivery	0	0	0
Potomac Electric Power	2	3	1
Southern Maryland Electric Cooperative	0	0	0
Total for State	2	5	1

Source: Maryland Attorney General, May 14, 2003.

District of Columbia

The District of Columbia is also served by Potomac Electric Power and, as Table II.3 shows, has had similar, although lower, percentages of customer switching as in Potomac Electric's area in Maryland.

Table II.3. Percent of customers served by alternative suppliers in the Dist. of Columbia.

	Residential	Non-Residential	Total
April 2003	11.4%	16.5%	12.0%

Source: District of Columbia Public Service Commission, May 2003.

New Jersey

As reported in the two previous years' reports, New Jersey had some activity early in the state's retail access program. One utility, Conectiv, reached almost 12 percent of the non-residential customers and almost six percent of residential customers being served by alternative suppliers, as reported for November 2000. Two other utilities had about six percent of the non-residential customers that had chosen an alternative, also reported for November 2000. About one year later, by October 2001, all customer switching by non-residential and residential customers had dropped to less than one percent for all companies. As Table II.4 shows, customer switching across the state and across companies reportedly remain at fractions of a percent from January through July of 2003. Current indications are, for reason explained below, the largest customers in New Jersey are now choosing suppliers at relatively higher rates.

Table II.4. Percent of customers served by competitive suppliers.

Distribution Company	Residential		Non-Residential		Total	
	Jan 2003	July 2003	Jan 2003	July 2003	Jan 2003	July 2003
Conectiv	0.091	0.081	0.756	0.307	0.171	0.108
JCP&L	0.037	0.037	0.048	0.044	0.038	0.038
PSE&G	0.062	0.055	0.044	0.039	0.059	0.052
Rockland	0.000	0.000	0.000	0.000	0.000	0.000
Statewide Total	0.058	0.052	0.137	0.076	0.068	0.055

Source: New Jersey Board of Public Utilities, January 15, 2003 and July 29, 2003.

In February 2002, the New Jersey Board of Public Utilities (BPU) approved the results of a Basic Generation Service (BGS) auction to meet the electric demands of customers who have not selected an alternative electric supplier or who are dropped by a third-party supplier. More than twenty companies participated in the auction held on the Internet from February 4 to February 13, 2002. During this auction firms bid simultaneously to supply capacity, energy, and ancillary services to customers at a competitive price per kWh for the period of August 1, 2002 through July 31, 2003. This auction was conducted under the requirement of New Jersey's restructuring law that utilities facilitate competition of the supply of electricity to customers who have not switched companies under deregulation. The auction set lower than expected prices for the utilities' BGS. GPU's price was 4.87 cents per kWh compared to the customers' previous rate of 5.06 cents per kWh. Conectiv's price was set at 5.12 cents per kWh compared to its previous customer rate of 5.17 cents charged from January to August of 2001.[14] The prices for Rockland and PSE&G were 5.82 cents per kWh and 5.11 cents per kWh, respectively.

The price results of the 2003 "Fixed Price" auction, held in February 2003, for BGS for small to medium-sized customers are shown in Table II.5. Another separate auction determined hourly energy prices for approximately 1,750 larger customers, with prices based on PJM's hourly prices. Again, Internet auctions determined BGS for all the state's distribution companies. This was to provide BGS supply for the period from August 1, 2003 through May 31, 2004. The fixed price auction (for the smaller customers) concluded after 14 rounds of bidding and had 15 winning bidders sharing approximately 15,500 MW of load. The auction for hourly service (for larger customers) had 15 rounds with eight bidders for the 2,500 MW of available load. New Jersey is currently the only state in the country using such an Internet-based auction procedure. (Maine, as summarized in Section III, uses a competitive bidding process for its "standard offer" generation service.) Except for Rockland, all prices where somewhat higher than those determined in the previous year's auction.

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[14] Compiled with News release, New Jersey Board of Public Utilities, February 15, 2002; Reuters, February 15, 2002; Ashbury Press, February 16, 2002; PSEG Fact Sheet, November, 2001 and Restructuring Weekly.

Table II.5. Price results from the 2003 "Fixed Price" auction for small to medium-sized customers (cents/kWh).

Distribution Company	10 Month	34 Month
Conectiv	5.260	5.529
JCP&L	5.042	5.587
PSE&G	5.386	5.560
Rockland	5.557	5.601

Source: New Jersey Board of Public Utilities, February 2003.

Beginning August 1, 2003, the auction-determined generation prices translated directly to the rates customers pay. This was when the rate caps and the discounts ended and the post-transition period began. The New Jersey Board of Public Utilities determined the post-transition, non-generation portion of rates for customers in July 2003. Beginning August 1, 2003, excluding the BGS portion, all Conectiv customer classes had an average rate increase of approximately 4.7 percent. The estimated average BGS increase for all fixed-price customer classes is about 3.4 percent, resulting in a total rate increase of 8.1 percent. The average residential customer had an increase of approximately 6 percent on their monthly bill (the average residential bill would increase from $85.77 per month to $90.93 per month). This includes deferred balances accrued by Conectiv during the transition period when the rate cap was in effect and the company could not recover all of its costs incurred to supply its customers (which New Jersey's restructuring law allows recovery after the four-year transition period). The Board also determined that Rockland's (a company that also had deferred balances) rates for the average residential customer would increase by 15.4 percent. This includes the estimated 11.3 percent increase in BGS charges and resulted in a monthly bill increase from $85.21 per month for the average residential customer to $98.36 per month. The Board also authorized PSE&G (again with deferred energy costs) an increase of approximately 15 percent for the residential customer class. The Board modified the rate design in a proposed settlement to assure that the majority of residential customers receive no more than a 15 percent increase on an overall annual basis, including BGS prices. For Jersey Central Power & Light, the Board approved an average annual increase in rates of approximately 3.5 percent for the typical residential customer. All these rate increases became effective August 1, 2003.

As noted, for approximately 1,750 larger customers, prices are based on PJM's hourly prices, unless these customers make provisions with a supplier of their choice. Preliminary indications are that for 1,766 of these larger customers state-wide, over 1,000 customer accounts have switched, or 57 percent of the customers. By company, the preliminary numbers are approximately 61 percent, 60 percent, 56 percent, and 43 percent for Conectiv, JCP&L, PSE&G, and Rockland, respectively. Obviously a dramatic change from the numbers reported in Table II.4 and most likely the result of the change to PJM hourly prices if a supplier is not selected by these customers.

Pennsylvania

Pennsylvania had, at one time, the most active retail access program in the country. In early 2000, PECO Energy alone, then the most active service area in the state (and the country), had 29 offers being made to residential customers–about 20 of which were below the price-to-compare. Every service area in the state had at least two offers to residential customers that were below the price-to-compare. This changed dramatically by mid-2001, when many competitive suppliers reduced their offerings to customers or left the market entirely (see the above discussion on the effect the capacity credit market had on retail suppliers). Table II.6 shows, as of May 2003, the entire state had only one offer below the price-to-compare, in Duquesne Light's service territory. Last year, in May 2002, the state had three such offers, all in PECO Energy's service territory. Overall, the state remains about as it was last year in terms of total number of residential offers, at 29 this year compared with 33 total offers last year. This year (as of May 2003), as with last year's survey (May 2002), each service territory had at least three residential offers.

Table II.6. Competitive offer summary for Pennsylvania.*

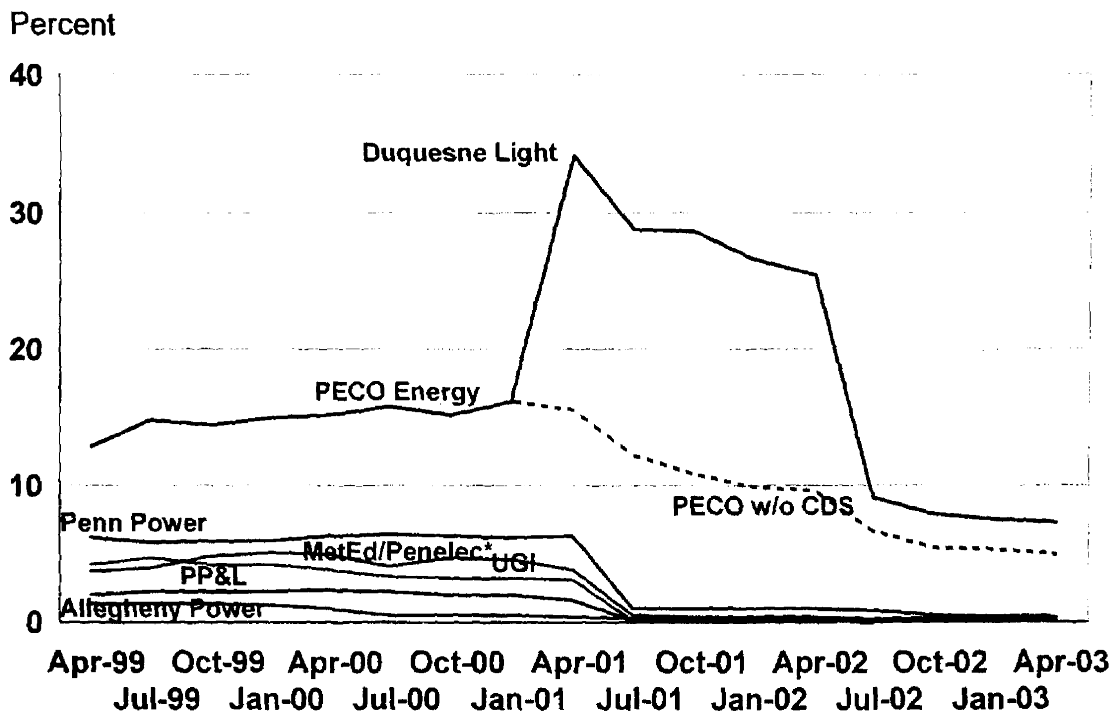
Utility	Number of Competitive Suppliers	Total Number of Offers from Competitive Suppliers	Number of Offers Below the Price-to-Compare
Allegheny Power	2	3	0
Duquesne Light	3	4	1
Met Ed	2	3	0
PECO Energy**	6	7	0
Penelec	2	3	0
Penn Power	2	3	0
PPL Utilities	2	3	0
UGI	2	3	0
Total for State	7	29	1

*For Regular Residential Service.
**Does not include the "Competitive Discount Service" (CDS), which is priced at 0.12 cents/kWh less than PECO Energy's Price-to-compare, or at a two percent discount. This is only available to preselected customers, not available to new customers.
Source: Pennsylvania Office of Consumer Advocate, May 2003.

Figures II.5, II.6, and II.7 plot the customer switching activity for Pennsylvania back to the first quarter of retail access in the state for residential, commercial, and industrial customers, respectively. The decrease that occurred in 2001 in retail market activity can be seen in all three customer groups. Residential switching continues to decline or remain flat, with all but Duquesne Light now below (in most cases, well below) ten percent of customers with an alternative supplier. With commercial customers, all areas are below 20 percent, however, Duquesne Light and PECO Energy have seen a recent modest increase in the percentage of customers switching. For industrial customers, all areas are well below ten percent, except Duquesne Light, which is at about 35 percent of the customers with an alternative supplier.

Figure II.8 shows the decline in customer switching in the state in terms of total load. The peak was reached in April of 2000, at 8,320 MWs, fell to 5,509 MWs in July

2000, then fell again to 2,039 MWs in July 2001. Since then, total load served by an alternative supplier has climbed back to 2,621 MWs in April 2003.



*MetEd and Penelec were formerly part of GPU.
Data Source: Pennsylvania Office of Consumer Advocate

Figure II.5. Residential customer switching in Pennsylvania.

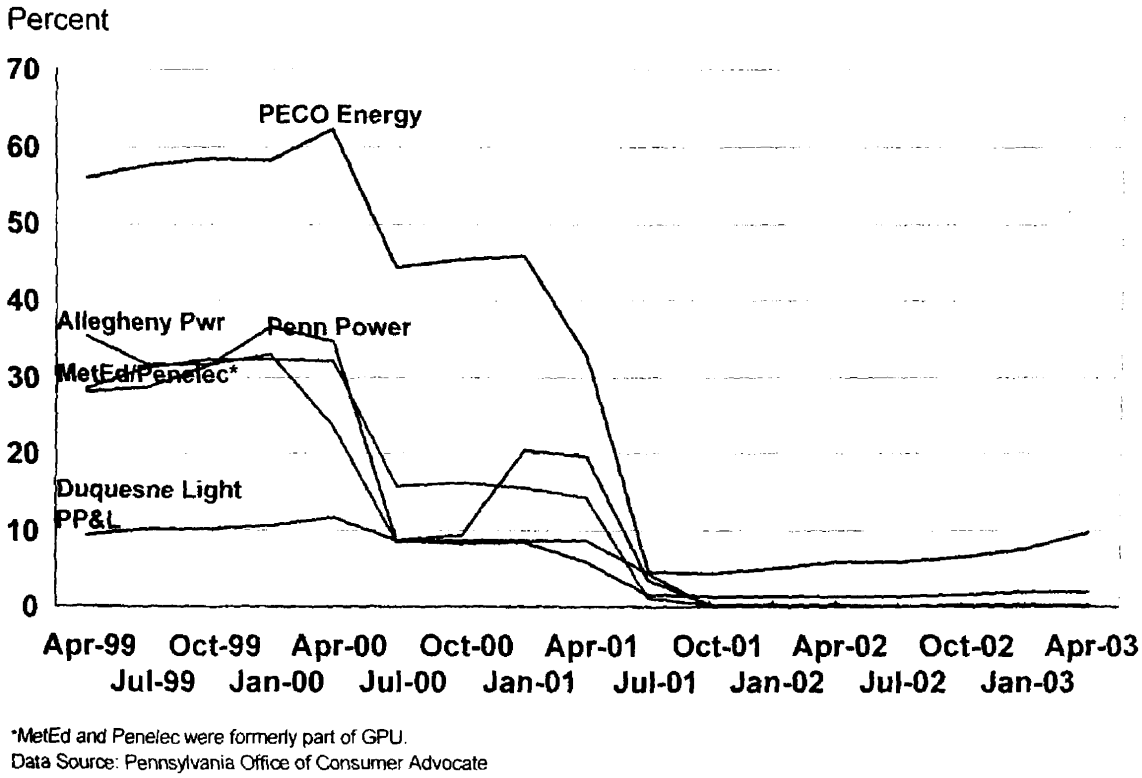


Figure II.6. Commercial customer switching in Pennsylvania.

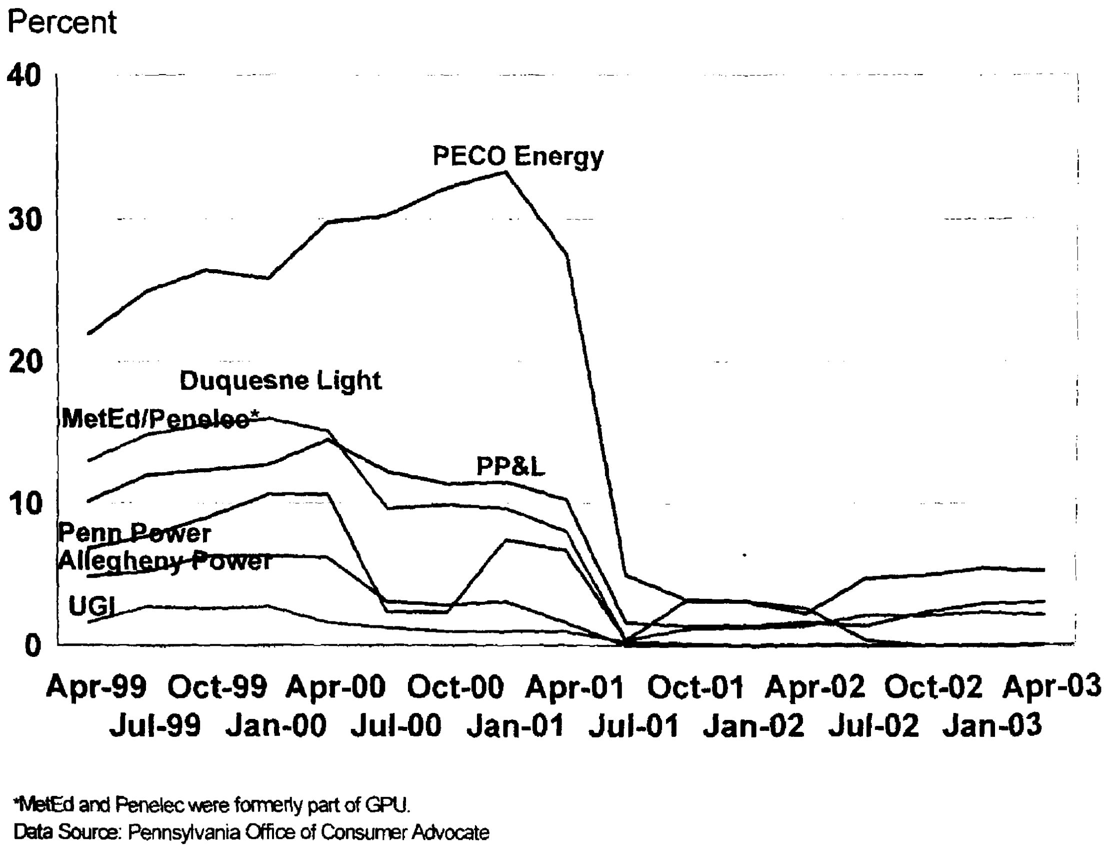
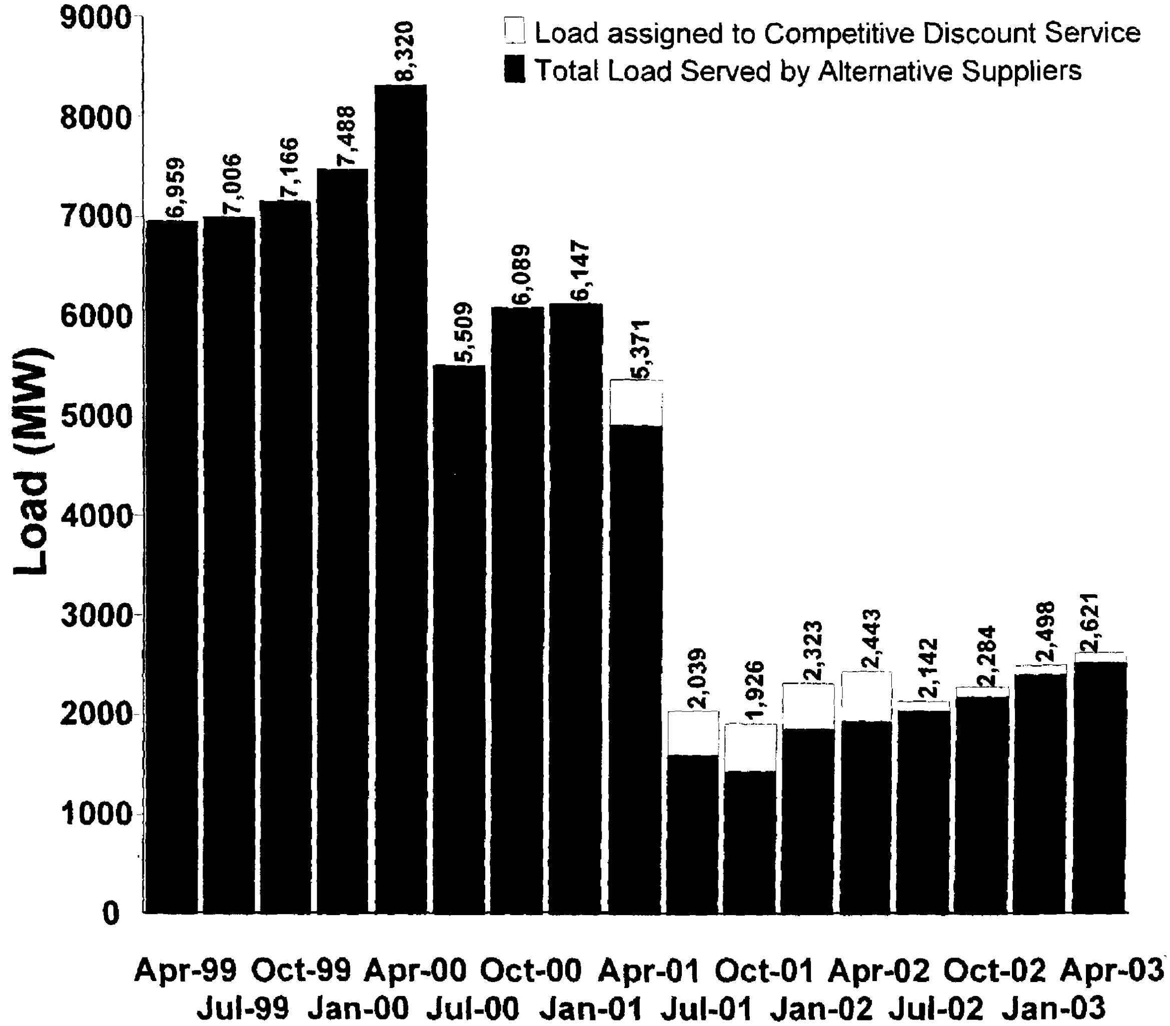


Figure II.7. Industrial customer switching in Pennsylvania.



Data Source: Pennsylvania Office of Consumer Advocate

Figure II.8. Pennsylvania total load served by alternative suppliers.

Section III
New England

Wholesale Market and ISO New England

ISO New England, Inc. was created in 1997 and operates the six-state New England region's[1] bulk electric power system and wholesale electricity markets. ISO New England developed out of the New England Power Pool (NEPOOL) that was created in 1971 from the integration of most of New England's utilities and municipal systems. This was primarily to enhance the region's system reliability in response to the northeast's 1965 blackout. ISO New England has interconnecting transmission lines connecting it to New York State and Quebec and New Brunswick in Canada. These lines are for the sale and purchase of electricity between the regions and for reliability purposes.

The New England power system serves about 6.5 million customers in an area with a population of 14 million people. The total market value is $4.5 billion, with $1.5 billion cleared in the spot market. There are over 350 power plants and over 8,000 miles of high-voltage transmission lines. New England system is a summer peaking system with peak demand in summer typically between 19,000 MW and 23,000 MW and winter peak demand between 17,000 MW and 19,000 MW. On August 14, 2002 a peak demand of 25,348 MW was reached, which is the current record peak demand for the region. The normal weather summer peak has increased by 20 percent over the last ten years.

ISO New England began managing the region's restructured wholesale power markets in May of 1999. In March 2003, the region began implementing its own version of a wholesale Standard Market Design. This includes using Locational Marginal Pricing (LMP) for transmission congestion management, day-ahead and real-time energy markets, and using monthly and long-term Financial Transmission Right (FTR)

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[1]The six states in ISO New England's region are Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont.

auctions to allow market participants to hedge against the possibility of paying transmission congestion charges under LMP in the day-ahead market.

The New England power market trades about 75 percent of its electricity under bilateral contracts and 25 percent in the real-time market.

The ISO currently has about 31,000 MW of total capacity and maintains an operating reserve margin of about 1,700 MW. The region is expecting to add approximately 3,500 MWs within the next year (as of May 2003). The region's electricity supply has increased by about 40 percent within the past five years.

According to ISO New England, approximately 29 percent of the total megawatt hours produced in the region in 2002 was from natural gas generators, this was up considerably from 13 percent in 2000. Nuclear and coal generated 26.6 percent and 12.3 percent, respectively, in 2002.

This increasing use and reliance on natural gas for power generation is causing concern in the region. ISO New England issued a White Paper that examined current and future use of natural gas for power generation and natural gas supply availability in the region.[2] The study notes that the recent power plant building boom in the region is expecting to add nearly 10,700 MW of new capacity between 1998 and 2005–all of it natural gas-fired capacity. It is expected that 41 percent of New England's total electricity production will be gas-fired in 2003 and could reach 49 percent by 2010. The study notes that, except for Texas,[3] "New England is by far the most dependent region in North America on natural gas for power generation." In addition, because of insufficient pipeline capacity in the region, studies by ISO New England indicate that approximately 2,800 MW to 3,900 MW of gas-fired generation would be unserved by

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[2]ISO New England Inc., "Natural Gas and Fuel Diversity Concerns in New England and the Boston Metropolitan Electric Load Pocket," prepared by Levitan & Associates, Inc., July 1, 2003.

[3]Texas (ERCOT region) is 44 percent natural gas-fired generated, according to Energy Information Administration numbers presented in Table 3 of the White Paper on page 13. They also note that Texas is in a region that has ready and ample natural gas supplies, while New England must rely on supply basins that are between 750 to 4,000 miles away.

pipelines during a peak winter day as soon as by the winter of 2004/2005. This is due to the coincident natural gas and electric generation requirements during the heating season.

This problem is particularly acute in the Boston area "load pocket." The Boston subarea is expected to have 65 percent of its electricity generated by natural gas in 2003 and is forecasted to increase to 80 percent by 2010. If a single power plant that is critical to the sub-area's electric supply, the Salem Harbor plant, is converted to natural gas, that subarea's electricity generated with natural gas could rise to 94 percent. Salem Harbor is a 745 MW coal- and residual fuel oil-fired power plant with four units located about 15 miles north of Boston; it accounts for about 21 and 23 percent of the Boston area's current winter and summer generating capacity, respectively. Because of its fuel use and location, it is subject to state and federal environmental regulations for nitrogen oxides, sulfur dioxide, carbon dioxide, and mercury emissions. Compliance options include switching to natural gas use or retiring the plant. Because transmission constraints limit the amount of power that can be sent from outside the subarea, either of these options would have a major impact on the subarea's fuel diversity and supply resources.

ISO New England's monthly average prices are charted in Figure III.1. This is the monthly average, on-peak monthly average, and off-peak monthly average prices

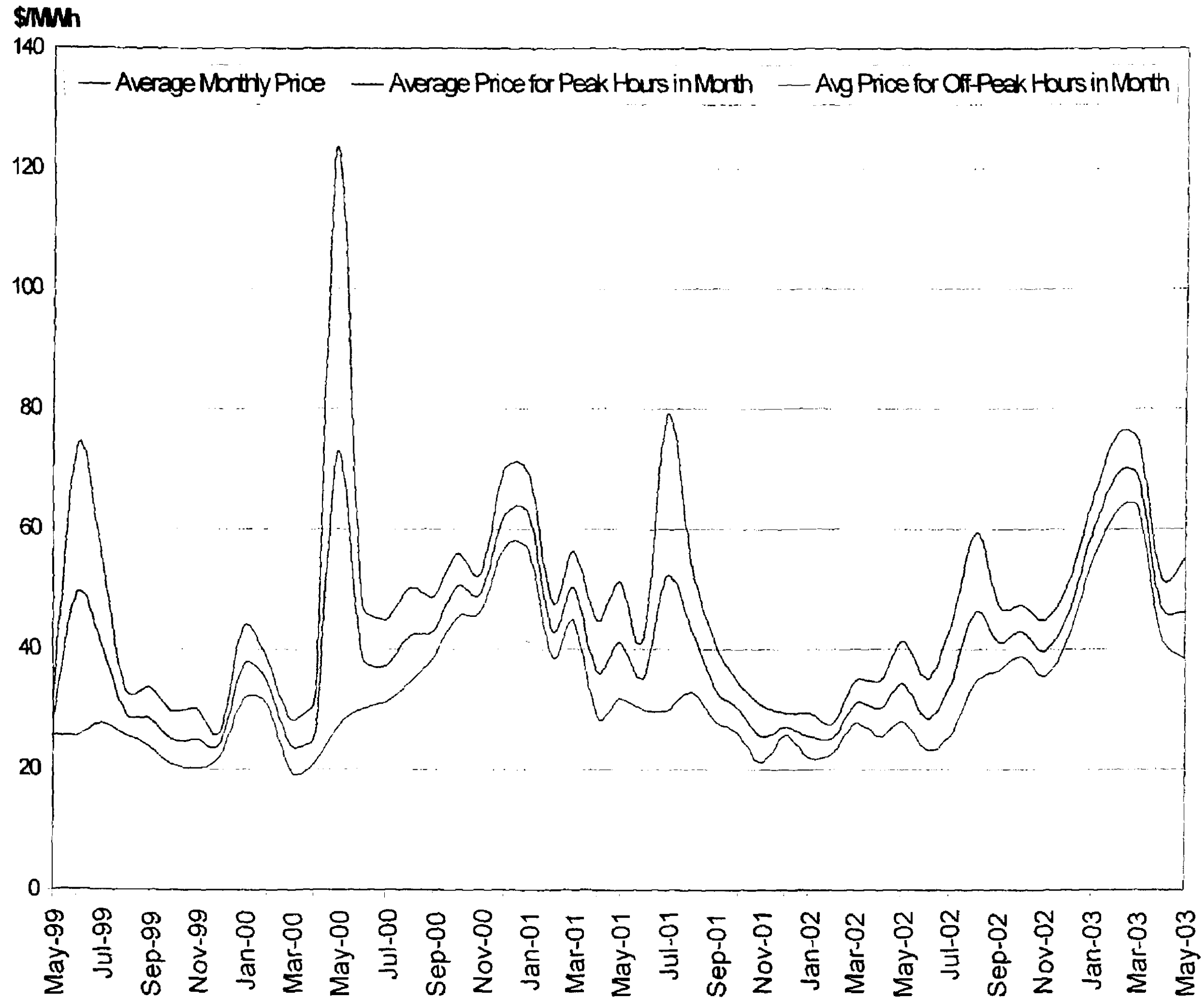

Figure III.1. Average monthly, average monthly peak, and average monthly off-peak prices in ISO New England, May 1999 through May 2003.
Source: ISO New England, June 2003.

for May 1999 through May 2003.[4] The impact on prices from the hot weather in late July and early August of 2001 can clearly be seen and, as seen with most other power markets, the impact from the higher natural gas prices in early 2003. The ISO New England White Paper noted this strong link between natural gas and electricity prices and the potential negative impact this could have in terms of higher and more volatile prices due to the region's increasing dependence on natural gas.

Market Performance Analyses

Last year's report summarized a study of the New England ISO market by Bushnell and Saravia[5] that used a similar "competitive benchmark analysis" as was used in the June 2002 Borenstein, Bushnell, and Wolak analysis of the California market (also summarized last year). This competitive benchmark is the estimated price that would result if all firms acted as price-taking firms–that is, no firm exercises market power.[6] (The basis for examining wholesale market performance is discussed in Section I.) The study examined the period of May 1999 through September 2001. The results of the Lerner index estimation are summarized in Figure III.2 (this is an estimation using ISO New England, Energy Clearing Prices). The results are similar to

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[4]For May 1999 through February 2003, prices are the monthly average clearing price, monthly average on-peak price, and monthly average off-peak price. For March 2003 through May 2003, the period when ISO New England began its Standard Market Design, prices are the average real-time LMP (the average hourly real-time hub or zone LMP for the month), on-peak LMP (the average real-time hub or zone LMP for peak hours in the month, where peak hours are hours ending 8:00 AM to 11:00 PM Monday through Friday excluding holidays), and off-peak LMP (average real time hub or zone LMP for the off-peak hours in the month).

[5]James Bushnell and Celeste Saravia, "An Empirical Assessment of the Competitiveness of the New England Electricity Market," Center for the Study of Energy Markets (CSEM WP-101), University of California Energy Institute, Berkeley, California, May 2002.

[6]This is based on an estimated incremental cost of the cheapest unit that is not needed to serve demand in a given hour.

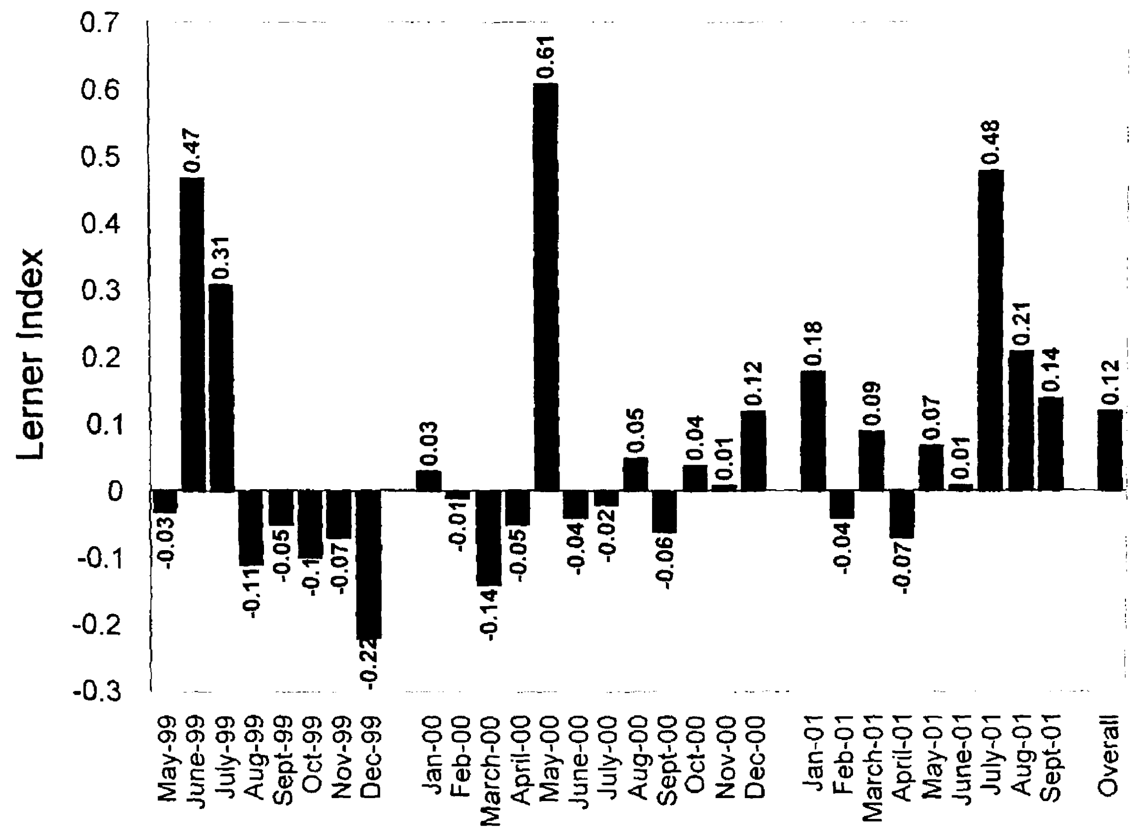

Figure III.2. Monthly Lerner index for New England electricity market, May 1999 to September 2001.
Source: Bushnell and Saravia, "An Empirical Assessment of the Competitiveness of the New England Electricity Market," May 2002.

the California estimation with relatively higher indices during the summer months, but without the sustained periods of very high monthly markups lasting several months.

Bushnell and Saravia also graphed the relationship between demand and the Lerner index for May to September for 1999, 2000, and 2001, which is shown in Figure III.3. The graph is flatter than for California and for a wider range of demand, indicating that for up to moderate levels of demand, the Lerner index (and market power markup) is lower. However, at high levels of demand, the index rises quickly and reaches values that are similar to the California result. A comparison of California, New England, and PJM Lerner Indices were presented in Section II of this report.

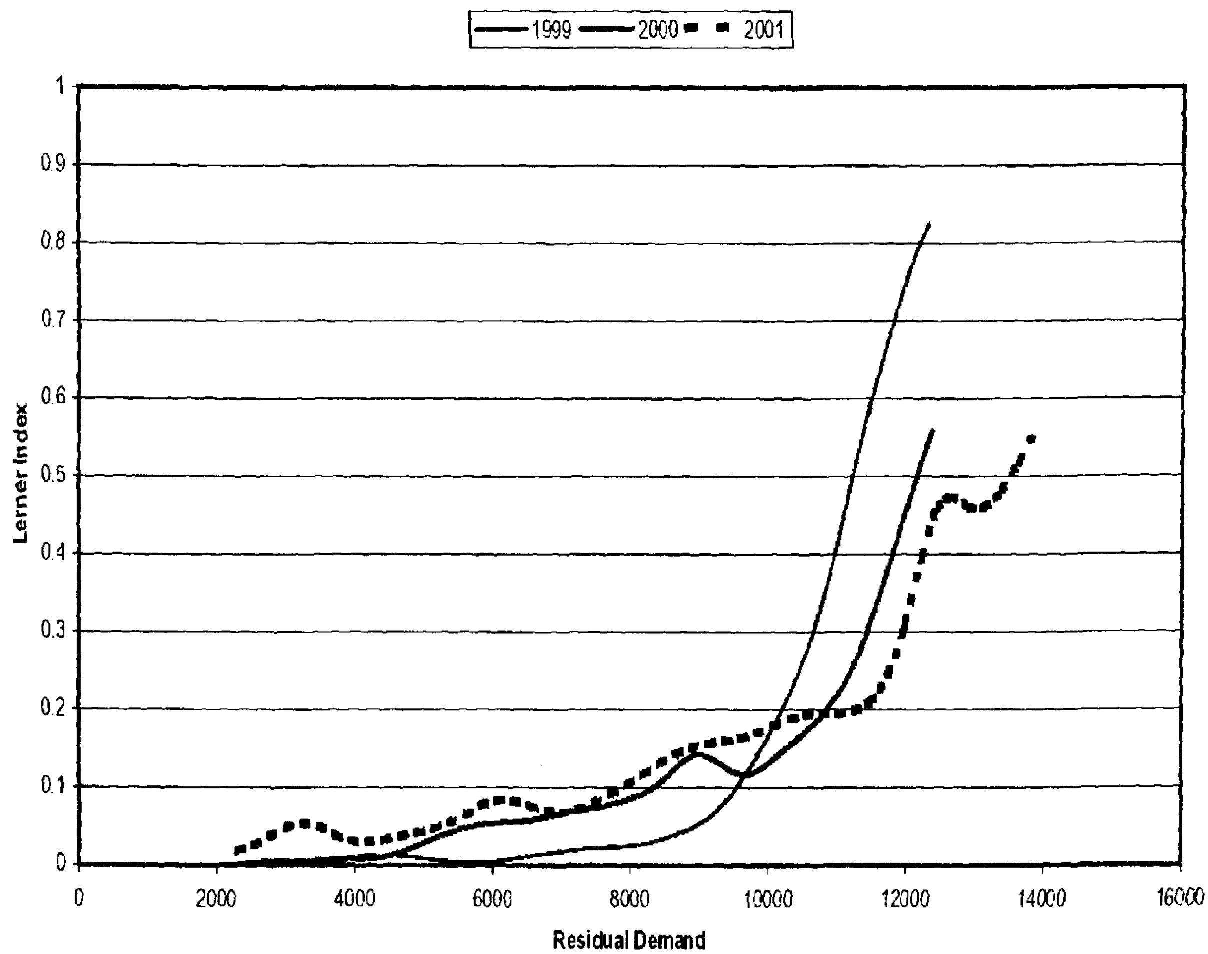

Figure III.3. The relationship between the level of demand and the Lerner index for New England.
Source: Bushnell and Saravia, "An Empirical Assessment of the Competitiveness of the New England Electricity Market," May 2002.

The authors pronounce the overall results "encouraging," but caution:

> The results described above occur in a market with many layers of continued regulation. The vertical integration of some suppliers and the transition contracts imposed on others provide a powerful mitigating influence on the incentives of these firms to exercise market power. Any new contracts that replace those imposed during the transition will be set at terms determined by market conditions, rather than regulatory proceedings. The pending expiration of transition periods and potential consolidation of supply portfolios will reverse this effect.[7]

Another analysis by the Independent Market Advisor to ISO New England,[8] takes a different approach by examining attempts to exercise market power by suppliers through withholding generating resources from the market. Their analysis tries to differentiate anti-competitive withholding of supply resources from what could be regarded as ordinary competitive behavior. In their "withholding analysis," they calculate an "output gap" that is defined as the difference between a unit's capacity that is economic to supply at the prevailing market price and the capacity that is actually supplied. They conclude from their analysis that the New England wholesale market is "workably competitive." They find "little evidence of persistent economic or physical withholding," but that "it cannot exclude the possibility that discrete instances of physical withholding occurred."

The Independent Market Advisor also examined the highest-priced hours during the summer of 2001 to determine whether market rules or procedures, unjustified actions by the ISO, or withholding by suppliers contributed to the inflated prices. They find that the majority of these high-priced hours "were warranted based on the deficiency in internal resources" in the region. Market rules that may have allowed prices to be set at unjustifiably high levels when a deficiency did not exist were

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[7]Bushnell and Saravia, p. 21.

[8]David B. Patton, Robert A. Sinclair, and Pallas M. LeeVanSchaick, "Competitive Assessment of the Energy Market in New England," Independent Market Advisor to ISO New England, Potomac Economics, Ltd., May 2002.

addressed by the ISO's pricing reforms. Based on their analysis, they state that "no clear evidence was found that economic or physical withholding substantially contributed to inflating the energy prices in these hours."

The Independent Market Advisor's economic withholding analysis is based on calculating a proxy marginal cost or "reference price" for each unit. This is to make the comparison with what would be economic for the unit to supply at the market price given the unit's marginal cost and what was actually supplied by that unit. In Appendix B of their report, they note that the reference price is calculated "based on an average of bids accepted in-merit for each unit." The assumption is that, in the absence of market power, suppliers will bid their marginal costs into the market. However, if there is supplier market power, which is at least part of the objective of which the analysis was to determine, then this method of calculating the reference price will likely overestimate the actual marginal cost and result in underestimating the "output gap" and possible economic withholding.[9] This is because the relatively higher reference price (that is, what is being used for the marginal cost proxy) will result in fewer units being judged as withholding, since the reference price is higher than the market clearing price. In these cases, it is expected that the units will not sell power for less than what it costs to produce the power.

To test the results from the reference price, the Independent Market Advisor also estimates the output gap using an "alternative" competitive benchmark or reference price based on the variable production costs for each unit.[10] While, as expected, the output gap increases with the alternative benchmark, the results still show a relatively modest amount of "output gap"–reinforcing the Advisor's conclusion that the New

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[9]This is a fundamental difference between the two studies reviewed here. The Bushnell and Saravia study uses a "competitive benchmark analysis" which is based on a variable production cost estimate. The ISO New England Independent Market Advisor's "withholding analysis" is based on a benchmark (the first benchmark, not the "alternative" which is closer to Bushnell and Saravia's benchmark) calculated from supplier bids. Both are attempting to estimate supplier marginal costs, but with fundamentally different results.

[10]Independent Market Advisor, pp. 27 - 29.

England market is "workably" competitive and had only insignificant attempts to raise prices through economic withholding during the study period. However, the analysis is done using 110 percent of the variable production cost estimate and only for fossil units with "low out-of-merit frequency;" out-of-merit units are those that are dispatched even though the unit's bid price exceeded the market clearing price. The analysis is not presented using all units or for different variable production costs levels to test the sensitivity of the alternative benchmark.

A Lerner index or market power markup is not calculated in the Independent Market Advisor analysis that could have allowed a comparison with the Bushnell and Saravia study. Such an index, presumably, could have been calculated based on the reference prices they calculate.

It should be noted that both these studies pre-date ISO New England's implementation of Standard Market Design, which began March of 2003. This may impact the New England's market performance over time.

Retail Markets

Five of the six New England states have retail access, Connecticut, Maine, Massachusetts, New Hampshire, and Rhode Island, and were among the first states to pass restructuring legislation and implement retail access. The five retail access states have been reviewed in previous reports–Maine and Massachusetts are updated below.

Maine

Maine's Restructuring Act required complete divestiture of transmission and distribution (T&D) utilities' generation assets. Maine chose to have the T&D utilities supply standard offer generation service to retail customers through a competitive process conducted by the Maine Public Utilities Commission. This has been done through a competitive bidding process or, if bids are insufficient or unacceptable to the Commission, through wholesale contracts. The T&D utilities themselves cannot participate in the bidding to become the standard offer provider and affiliates of the T&D utilities cannot provide more than 20 percent of the standard offer service in the affiliated T&D utility's service territory. Maine has one type of default service, the standard offer service, for each of the three primary retail customer classes.[11] This standard offer serves all customers in the class that are not receiving power from a competitively-obtained supplier.

The Commission has, at this time, completed three sets of competitive bids and has a fourth underway.[12] Table III.1 summarizes the results of the three completed competitive bids that Maine has conducted. The Commission refers to the first two bidding experiences as meeting with "mixed results." For Maine Public Service (MPS), the bidding process has been able to obtain successful bidders in the first two years. However, MPS is in northern Maine and not part of the ISO New England control area. The Commission notes that while there has been some competition in this area, "there has been a limited number of suppliers active in the market."[13] Also, the standard offer rate has been increasing since early 2001. The MPS current standard offer price for residential and small commercial customers has increased by 35 percent between early 2001 and the price that went into effect in March of 2003. Commercial and industrial standard offer prices have increased 37 percent and 56 percent, respectively. This may explain, at least in part, why most commercial customers (68 percent of the load) and nearly all the industrial customers (between 97 percent and 100 percent of the load since early 2002) in MPS are now served by competitive providers and are not on the

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[11]The primary customer classes in Maine are Residential and Small Commercial (demand less than 20kW, 25kW, and 50kW, for Central Maine Power (CMP), Bangor Hydro-Electric (BHE), and Maine Public Service (MPS), respectively), Commercial (greater than 20kW, 25kW, or 50kW for CMP, BHE, and MPS, respectively, but less than 400kW for CMP and less than 500kW for BHE and MPS), and Industrial (demand greater than 400kW for CMP and greater than 500kW for BHE and MPS). Maine also uses the corresponding categories, as in Table III.1, Residential and Small Non-Residential, Medium Non-Residential, and Large Non-Residential.

[12]This information is from an undated and untitled Maine Public Utilities Commission paper posted on the Commission's website. The first section is titled, "Detailed Summary of Standard Offer Bid Processes and Results."

[13]Maine Public Utilities Commission, "Standard Offer Study and Recommendations Regarding Service After March 1, 2005," December 1, 2002, p. 8.

standard offer price. However, about two-thirds of the residential and small commercial load remains on standard offer service. (Last year, the total number of customers served by MPS was reported at 35,467 residential, 193 medium, and sixteen large customers.) Customer switching by company are shown in Figures III.4, III.5, and III.6.

Table III.1. Summary of Maine's standard offer bidding process.

<table>
<tr><th></th><th>Year 1: for service beginning March 2000</th><th>Year 2: for service beginning March 2001</th><th>Year 3: for service beginning March 2002</th></tr>
<tr><td><u>Bangor Hydro-Electric Co. (BHE)</u>
Residential & Small Non-Residential</td><td rowspan="3">All bids rejected – BHE directed by Commission to procure power in wholesale market for all 3 classes</td><td rowspan="3">All bids rejected – BHE directed by Commission to procure power in wholesale market for all 3 classes</td><td>3 year contract accepted for residential and small non-residential customers</td></tr>
<tr><td>Medium Non-Residential</td><td rowspan="2">1 year contract accepted for medium and large non-resid. customers</td></tr>
<tr><td>Large Non-Residential</td></tr>
<tr><td><u>Central Maine Power Co. (CMP)</u>
Residential & Small Non-Residential</td><td>2 year contract accepted for residential and small non-residential</td><td>no bid – contract continues for this class</td><td>3 year contract accepted for residential and small non-residential customers</td></tr>
<tr><td>Medium Non-Residential</td><td rowspan="2">Bids rejected – CMP directed by Commission to procure power in wholesale market for medium and large non-residential customers</td><td rowspan="2">Bids rejected – CMP directed by Commission to procure power in wholesale market for medium and large non-residential customers</td><td rowspan="2">1 year contract accepted for medium and large non-residential customers</td></tr>
<tr><td>Large Non-Residential</td></tr>
<tr><td><u>Maine Public Service Co. (MPS)</u>
Residential & Small Non-Residential</td><td>1 bidder chosen</td><td rowspan="3">three year term contract for all 3 standard offer rate classes (until 2/28/04)</td><td rowspan="3">no bid – contract continues for all classes</td></tr>
<tr><td>Medium Non-Residential</td><td>service split 80/20 between 2 bidders</td></tr>
<tr><td>Large Non-Residential</td><td>1 bidder chosen</td></tr>
</table>

Source: From information in "Detailed Summary of Standard Offer Bid Processes and Results," Maine Public Utilities Commission.

While the bidding process for Bangor Hydro-Electric (BHE) was unsuccessful the first two years at finding acceptable bids for all customer categories, Central Maine Power (CMP) was only successful for residential and small non-residential customers. By the third year, all customer categories for both companies were served by acceptable standard offer prices found through the competitive bidding process. The standard offer price has increased for residential and small commercial customers since 2000, increasing 22 percent in BHE's area and by 21 percent for customers in CMP's area. There has been no switching to competitive providers by residential and small commercial customers in either BHE's or CMP's areas (see Figures III.4 and III.5 below), consequently, all of these customers are on standard offer service. (There have been no direct offers to residential customers in the service areas of BHE and CMP since July 2001.) The contract for these customers has been in effect since March of 2002 and will remain in effect until February 2005. Currently all standard offer service prices for all customers classes for the three principle T&D utilities in the state have been procured through the competitive bidding process.

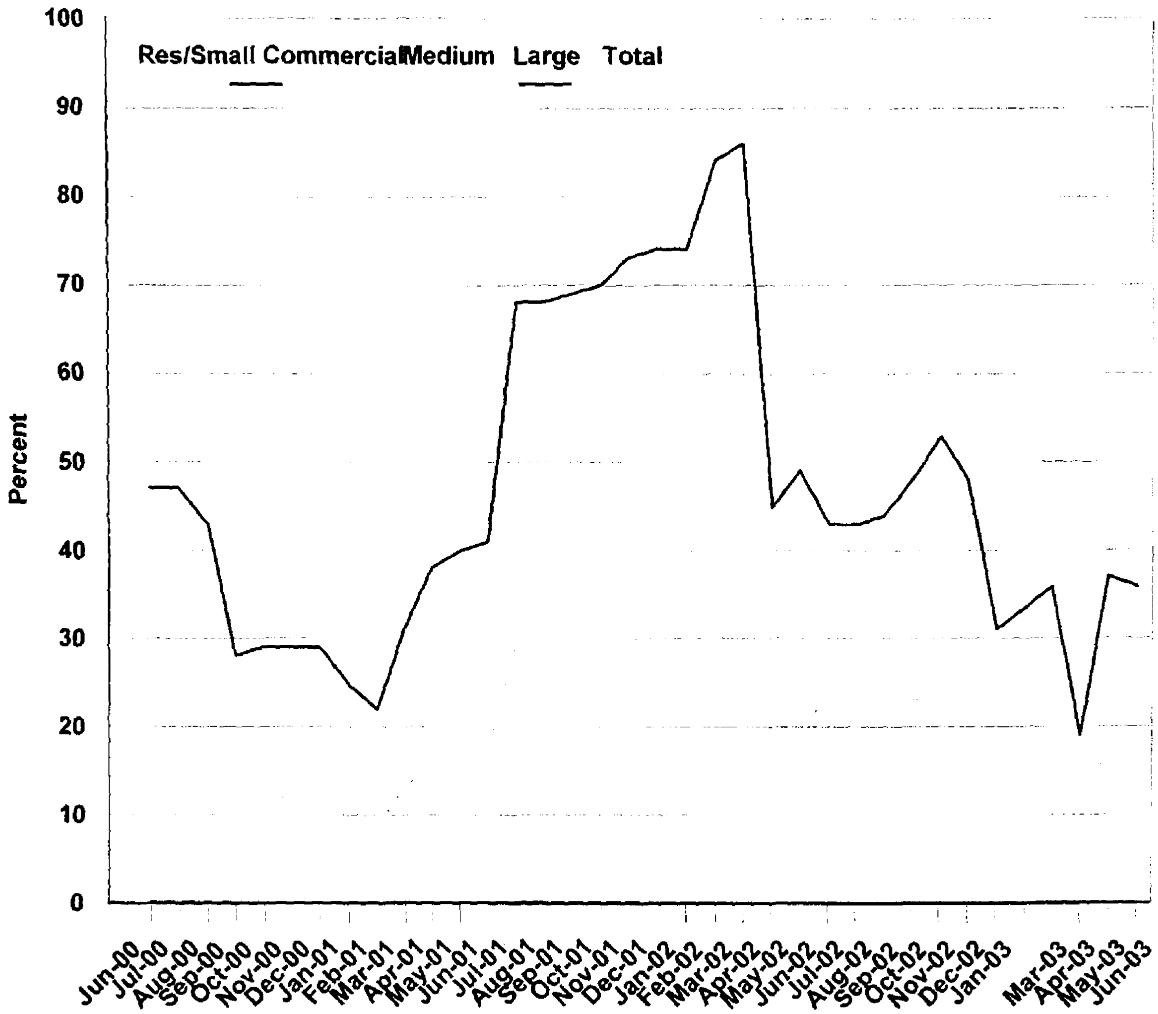

Figure III.4. Percentage of load served by competitive providers in Bangor Hydro-Electric Co.'s (BHE) service territory. (Note: No data was reported for February 2003.) Source: Maine Public Utilities Commission, June 2003.

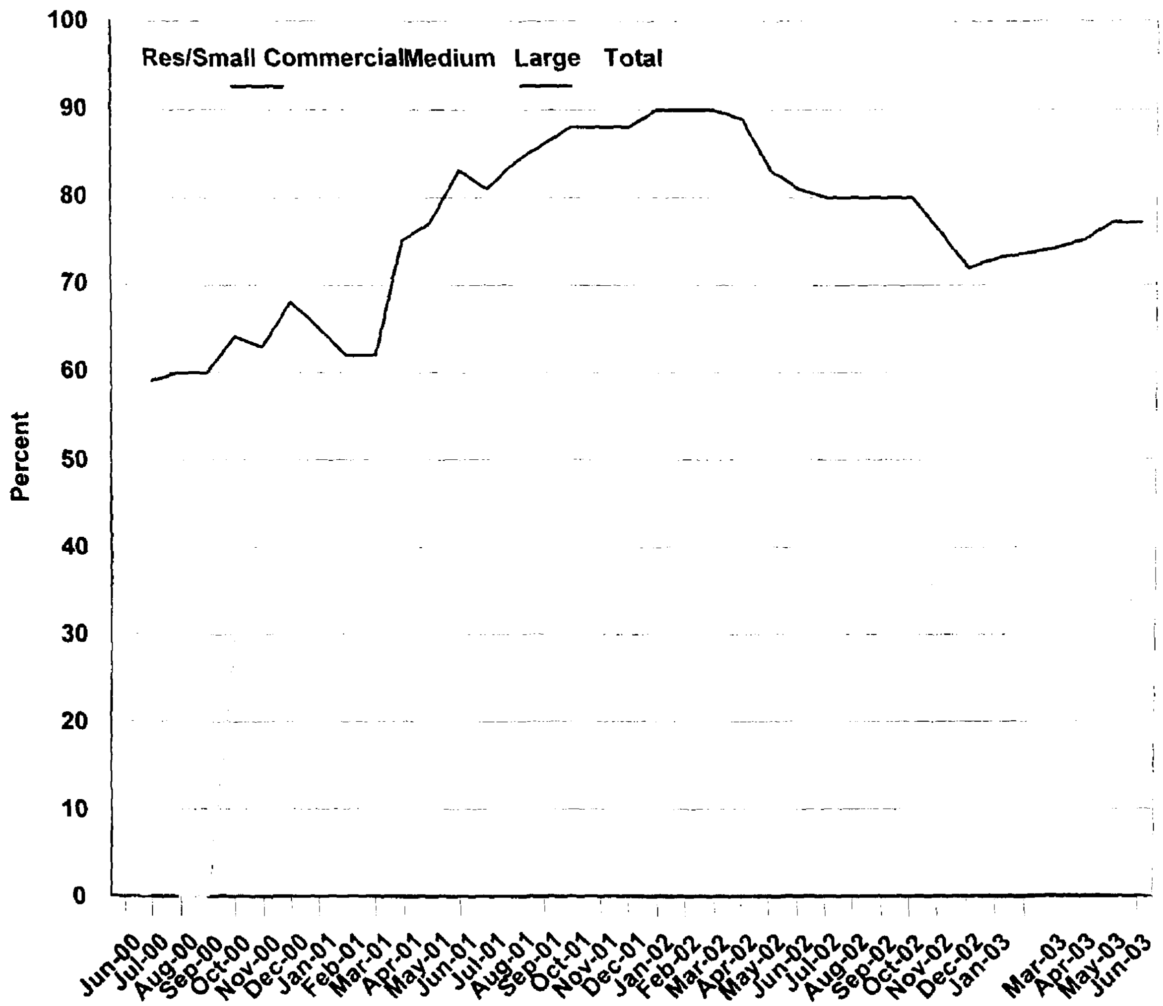

Figure III.5. Percentage of load served by competitive providers in Central Maine Power Co.'s (CMP) service territory. (Note: No data was reported for February 2003.)
Source: Maine Public Utilities Commission, June 2003.

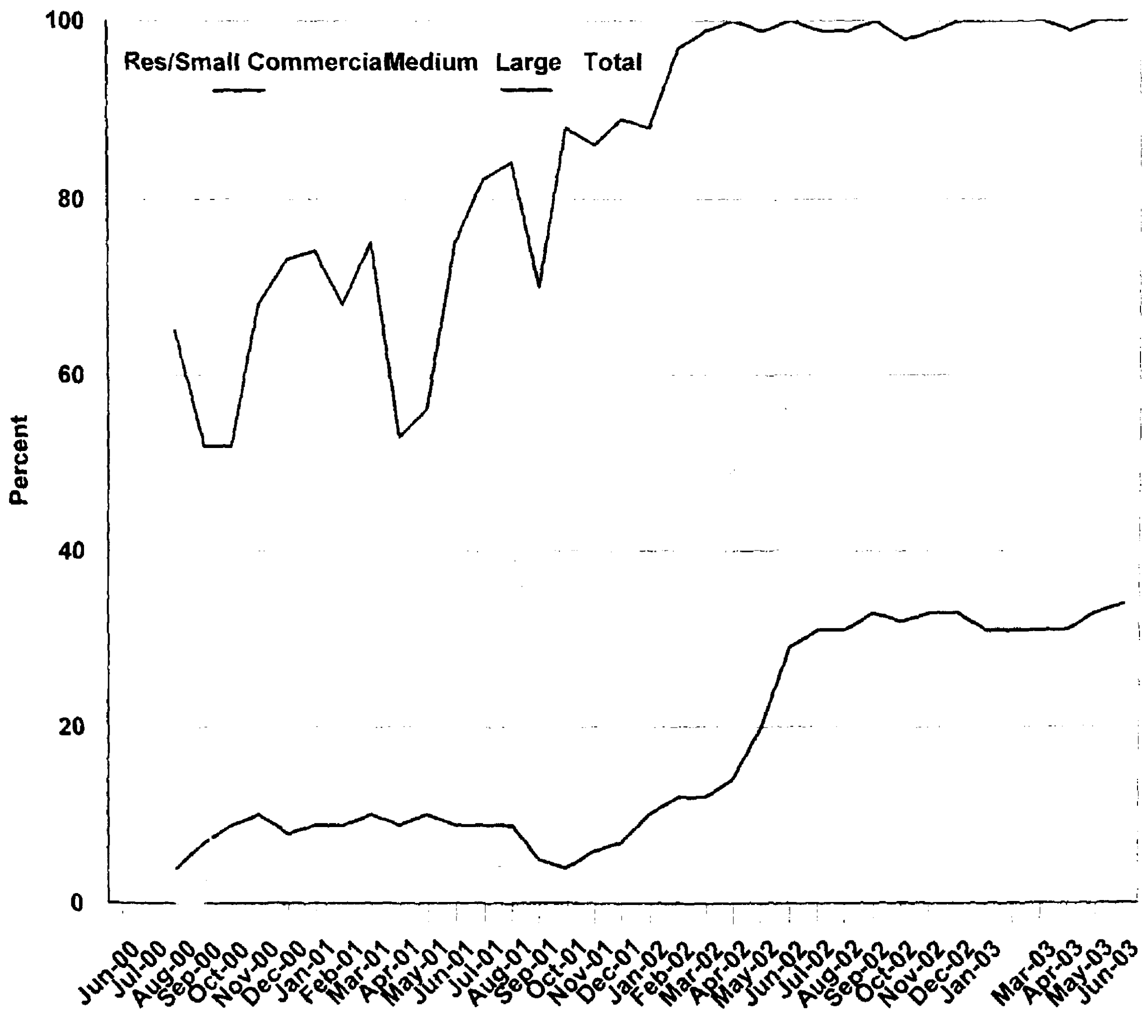

Figure III.6. Percentage of load served by competitive providers in Maine Public Service Co.'s (MPS) service territory. (Note: No data was reported for February 2003.) Source: Maine Public Utilities Commission, June 2003.

Massachusetts

The Massachusetts Electricity Restructuring Law, passed in 1998, provides three electric generation service options to consumers: (1) standard offer service provided by distribution companies, a transition generation service available to each distribution company's customers through February 2005, and assigned to customers who had not selected a competitive supplier as of March 1, 1998; (2) default service provided by distribution companies, customers who move into a distribution company's service territory after March 1, 1998, are not eligible to receive standard-offer service and are placed on default service until they select a competitive supplier (which is higher cost that the standard offer); and (3) competitive generation service provided by competitive suppliers.

While there has been an increase in residential customer activity since last year, statewide, it is still less than three percent of the customers that have switched to a competitive supplier. Figure III.7 shows the trends since April 1999 of the percent of customers choosing a competitive supplier by customer categories. The larger customer categories continue to show considerably more activity, however, there has been a marked decrease since the fall of 2002, especially for the large commercial and industrial customer group, which has fallen below 20 percent. Small and medium commercial and industrial customer groups also declined, both to less than ten percent of customers in each category. The pattern is similar in terms of kilowatt-hours, as shown in Figure III.8 below.

Figure III.9 is a cross section of customer switching activity for April 2003 to show where the activity is in terms of customer groups and kWhs by distribution companies. Commonwealth Electric (Comm Elec) clearly had the most activity for every customer group. For the larger customer groups, Massachusetts Electric (Mass Elec) had the second highest customer and kWh percentages. In terms of kWhs, all companies had large commercial and industrial customer switching above ten percent.

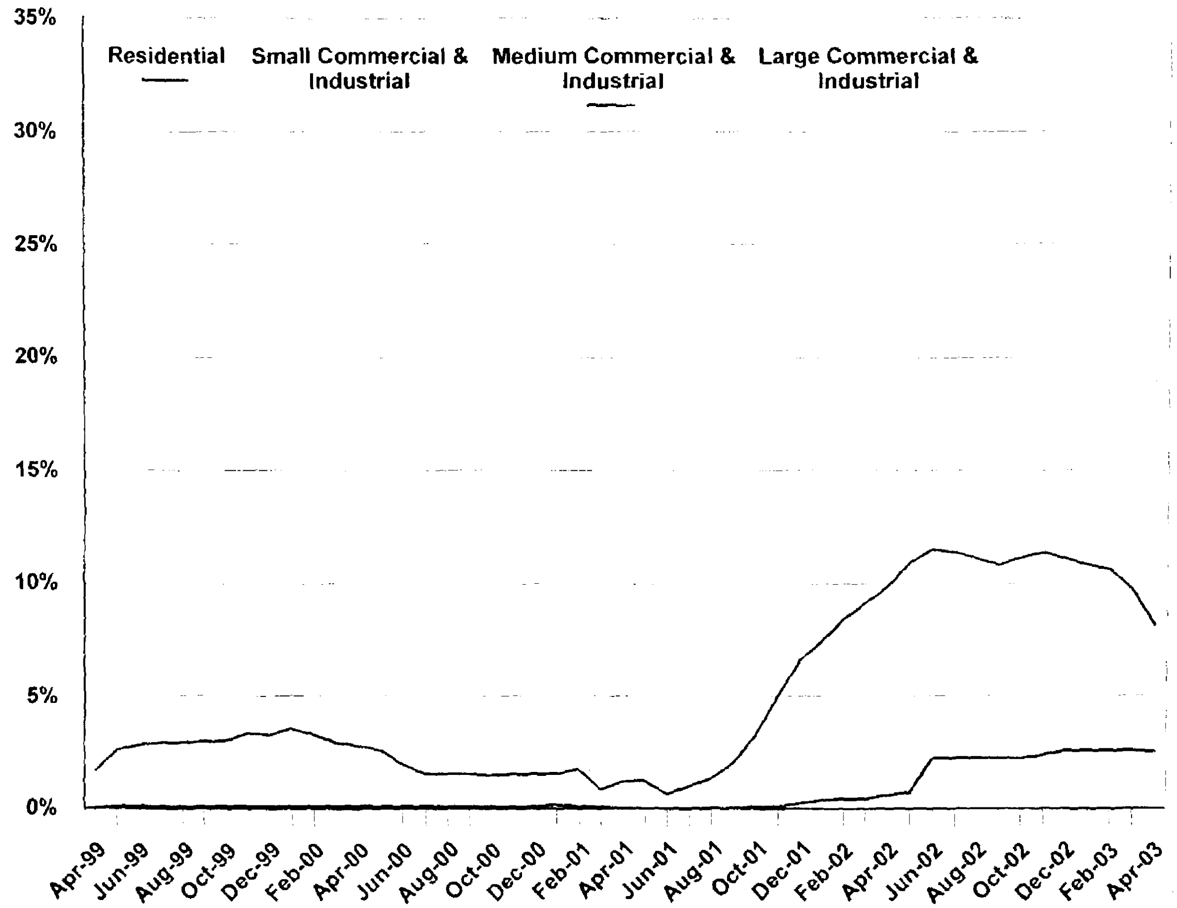

Figure III.7. Massachusetts percent of customers served by competitive generation, April 1999 to April 2003.*
Source: Massachusetts Division of Energy Resources, "Electric Power Customer Migration Data," April 1999 through April 2003 reports.
*The percentage calculated for Large Commercial & Industrial customers for July 2002 was omitted because it appeared to be incorrectly recorded.

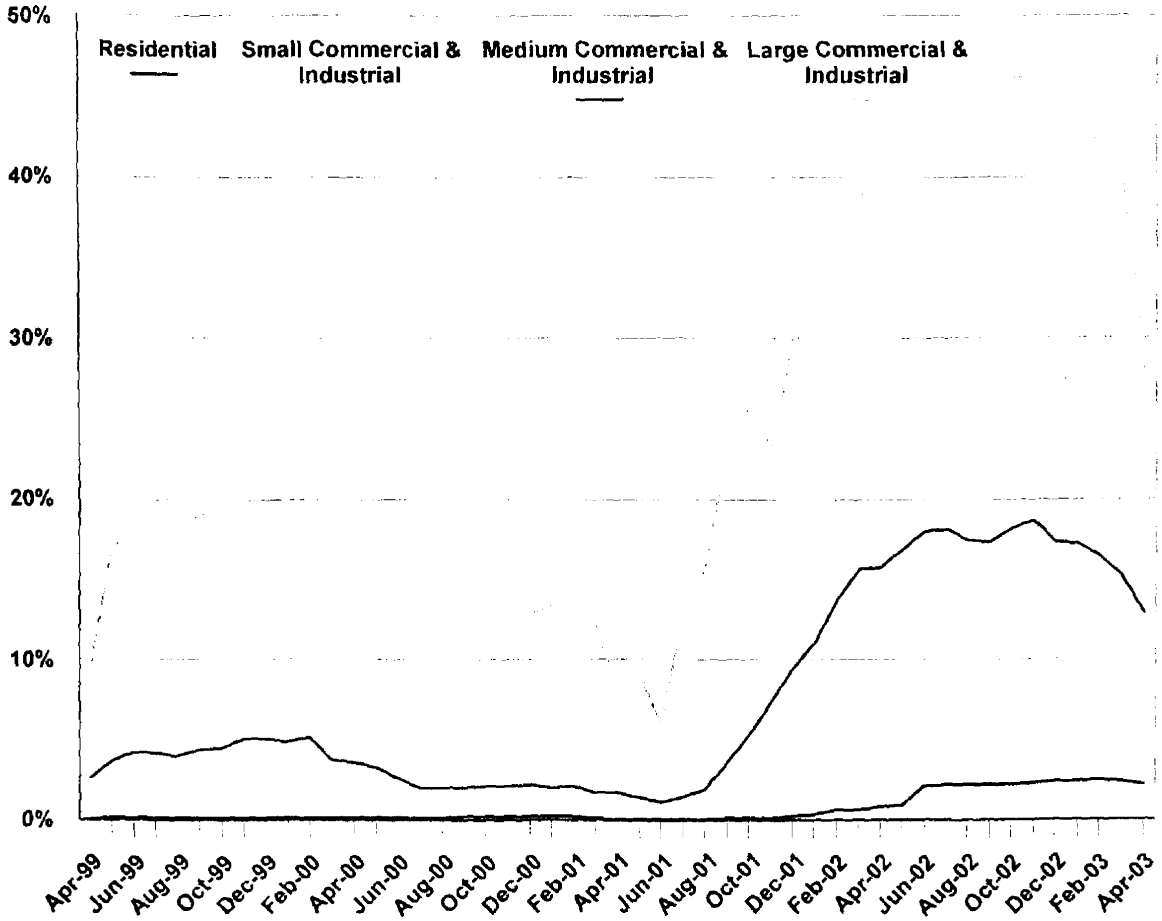

Figure III.8. Massachusetts percent of kWhs provided by competitive generation, April 1999 to April 2003.
Source: Massachusetts Division of Energy Resources, "Electric Power Customer Migration Data," April 1999 through April 2003 reports.

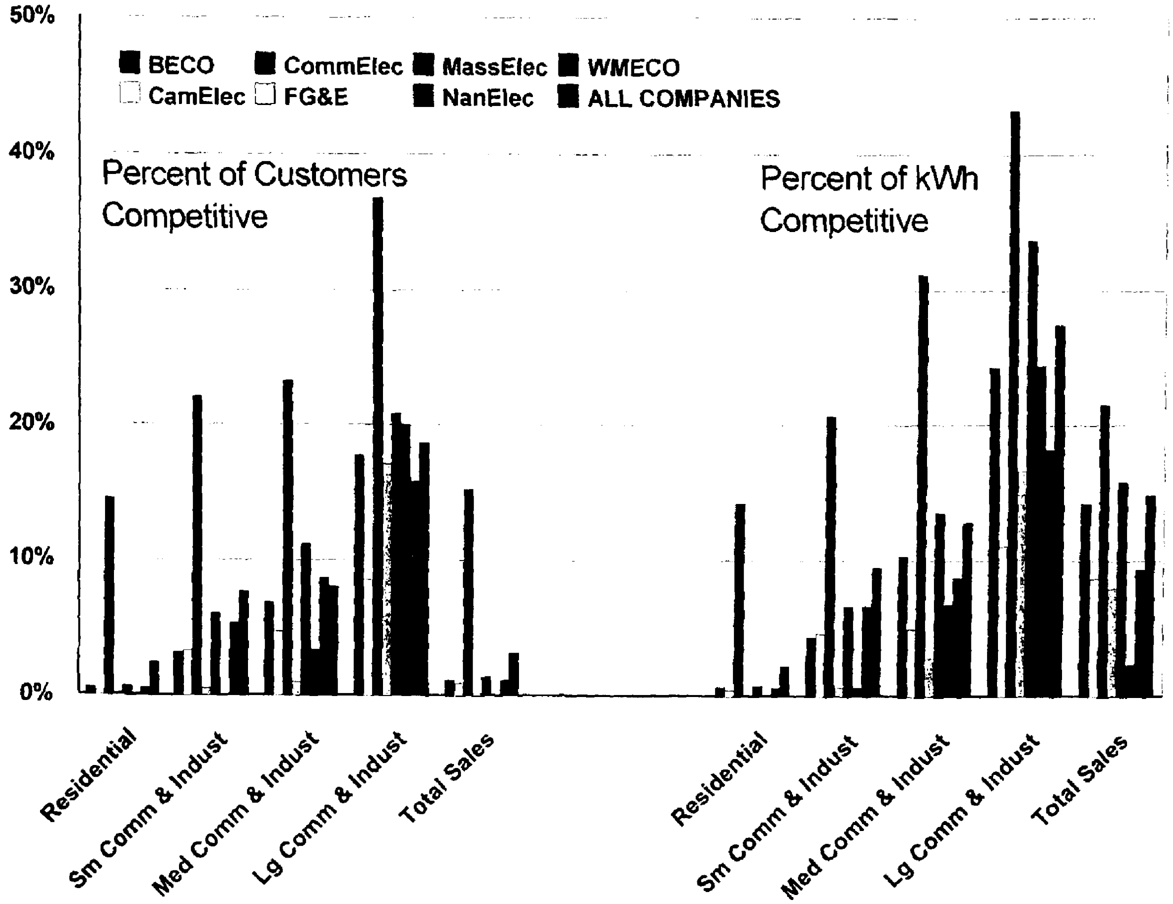

Figure III.9. Massachusetts company comparison by percent of customers and kWhs, April 2003.
Source: Massachusetts Division of Energy Resources, "Electric Power Customer Migration Data," April 2003 report.

Section IV
New York

Wholesale Market

Figure IV.1 shows the load weighted monthly average prices for the Day Ahead Market of the New York ISO from May 2001 to May 2003. As with other power markets around the country, the impact from the higher natural gas prices in early 2003 can be seen, when prices reached $75 per MWh in February and March of 2003. Prices retreated to below $50 per MWh in May. However, the price trend appears to be increasing since the low was reached in December 2001 of less than $24 per MWh. Natural gas wellhead prices were about three and one-half dollars per Mcf in December 2001 and had dropped below three dollars in September and October of that year Natural gas prices had spiked the previous winter of 2000/2001, peaking in January of 2001 at almost seven dollars per Mcf – which may, in part, explain the general downward trend from May 2001 to December 2001.[1]

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[1]Natural gas wellhead prices are from the Energy Information Administration, U.S. Department of Energy.

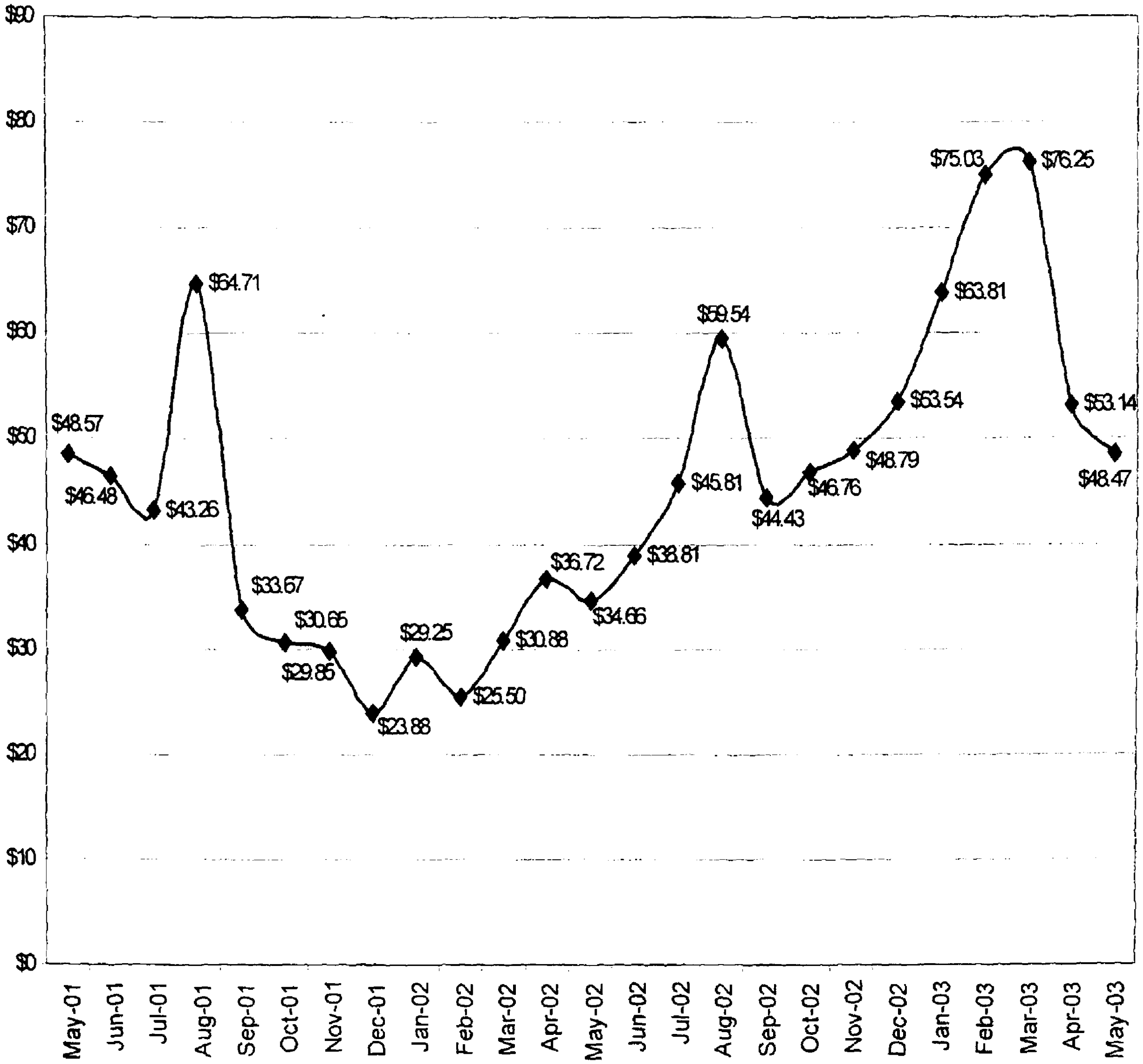

Figure IV.1. Load weighted monthly average Day Ahead Market prices ($/MWh), May 2001 through May 2003.
Source: New York ISO, May 2001 through May 2003 reports.
*The May 2003 price is the load weighted monthly average Locational Based Marginal Price for the Day Ahead Market.

Retail Market

Figure IV.2 summarizes customer switching, or "migration," in New York State and compares the 2002 percentages with 2003. The first graph in Figure IV.2, of all customer groups, shows that the most active shopping in the state is in the Orange and Rockland Utilities and Rochester Gas and Electric service areas.[2] As the other two graphs show, most of this activity is concentrated among non-residential customers. This pattern of activity holds for both 2002 and 2003. With a few exceptions, most areas had modest gains in the percent of customers switching to alternatives in 2003 compared to 2002. Since non-residential customers are the most active in the state, the percent of customer load that has migrated to alternative suppliers, as shown in Figure IV.3, is generally higher and, except for the Long Island Power Authority's area, distributed across the state's service territories. Non-residential customers in Rochester Gas and Electric's service area in particular, moved to over 65 percent of load for May 2003, the highest percentage for any area, customer group, and for both years. For residential customers, however, the Orange and Rockland Utilities and Rochester Gas and Electric service areas remain the most active for both years.

[2]The full company names that are abbreviated in the figures are as follows: CH is Central Hudson Gas & Electric Corp.; Con Ed is Consolidated Edison Company of New York, Inc.; LIPA is Long Island Power Authority; NMPC is Niagara Mohawk Power Corp.; NYSEG is New York State Electric & Gas Corp.; ORU is Orange and Rockland Utilities, Inc.; and RGE is Rochester Gas and Electric Corp.

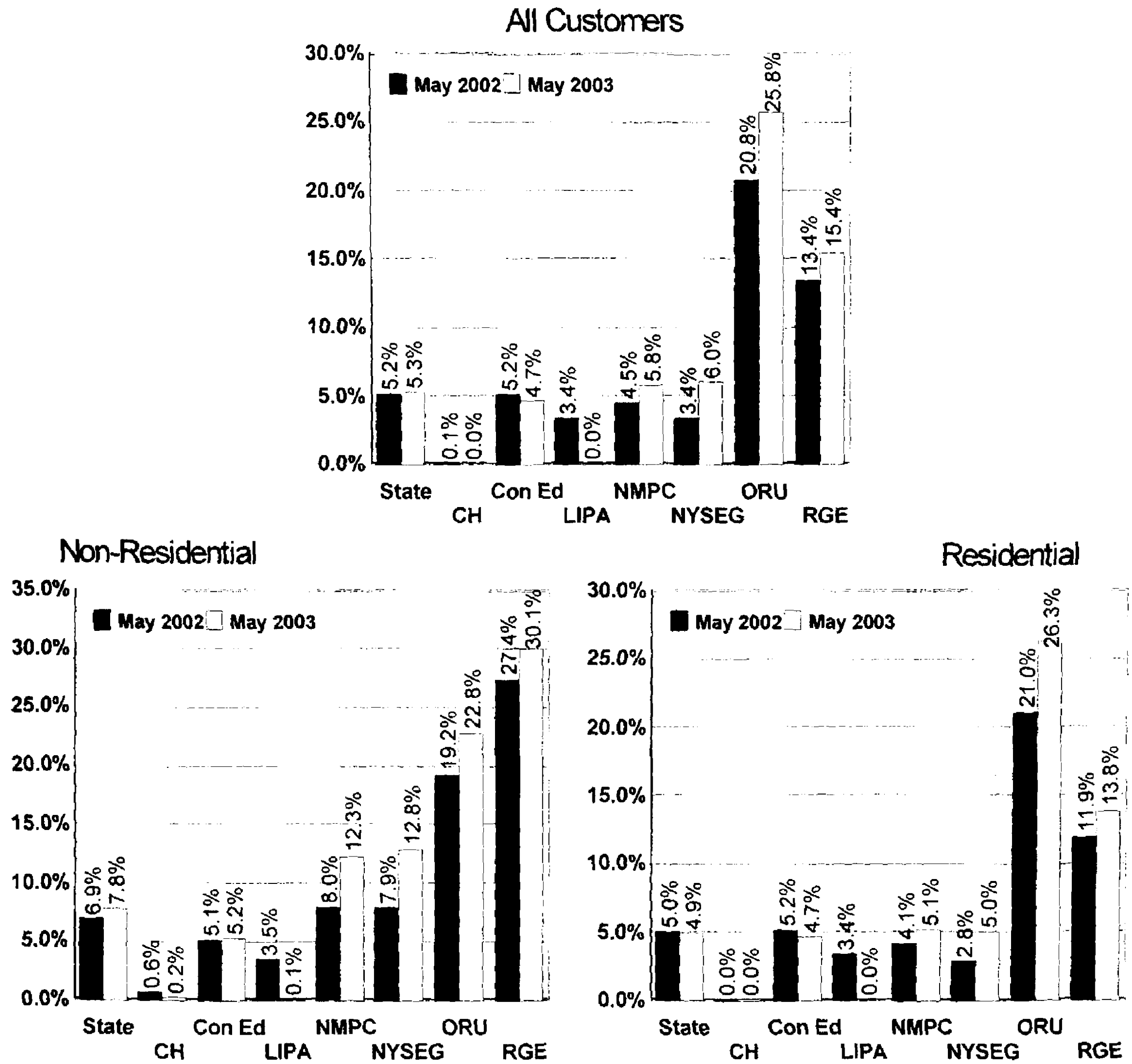

Figure IV.2. Percent of customer accounts migrated to alternative suppliers, by utility for all customers, non-residential customers, and residential customers, May 2002 and May 2003.

Source: New York State Public Service Commission, May 2002 and May 2003 migration reports.

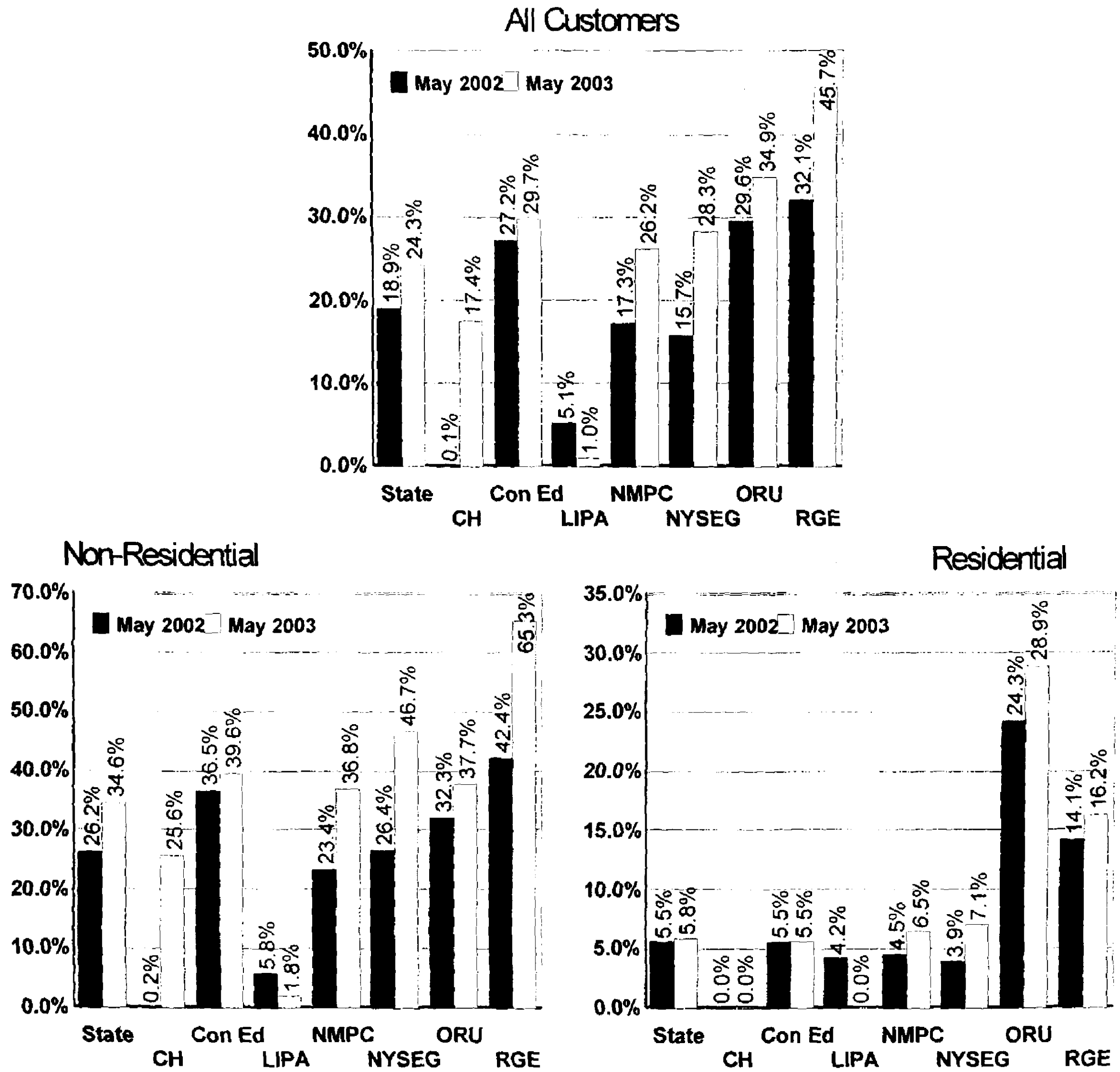

Figure IV.3. Percent of customer load migrated to alternative suppliers, by utility for all customers, non-residential customers, and residential customers, May 2002 and May 2003.
Source: New York State Public Service Commission, May 2002 and May 2003 migration reports.

Section V
Midwest

Wholesale Market

The Midwest is an area that has an extensive transmission system that interconnects the utility systems throughout most of the region. Historically, however, the region has operated as independent utility systems, not as a single tightly coordinated system as other systems in the country have. PJM and New England, for example, operated for a long period as a coordinated system or power pool before they became an ISO. With the transmission system in the Midwest, these independent utility systems have been able to coordinate their systems to support increasing volumes of wholesale sales in the last two decades. However there are some areas with transmission "bottlenecks," that limit the amount of power transfers within the region.

A significant part of the Midwest region formed the Midwest ISO (MISO), which was founded in February 1996, to begin the process of forming a more tightly integrated regional system. MISO became the first FERC-approved RTO in December of 2001 and began operation in Feb. 2002 as a transmission provider. MISO covers an area that has 122,000 MWs of generation capacity with 111,000 miles of transmission lines. It covers a large area of the country that includes all or parts of 15 states and into Canada, or 1.1 million square miles, and with 16.5 million customers. Figure V.1 is a map that highlights the MISO's geographic area.

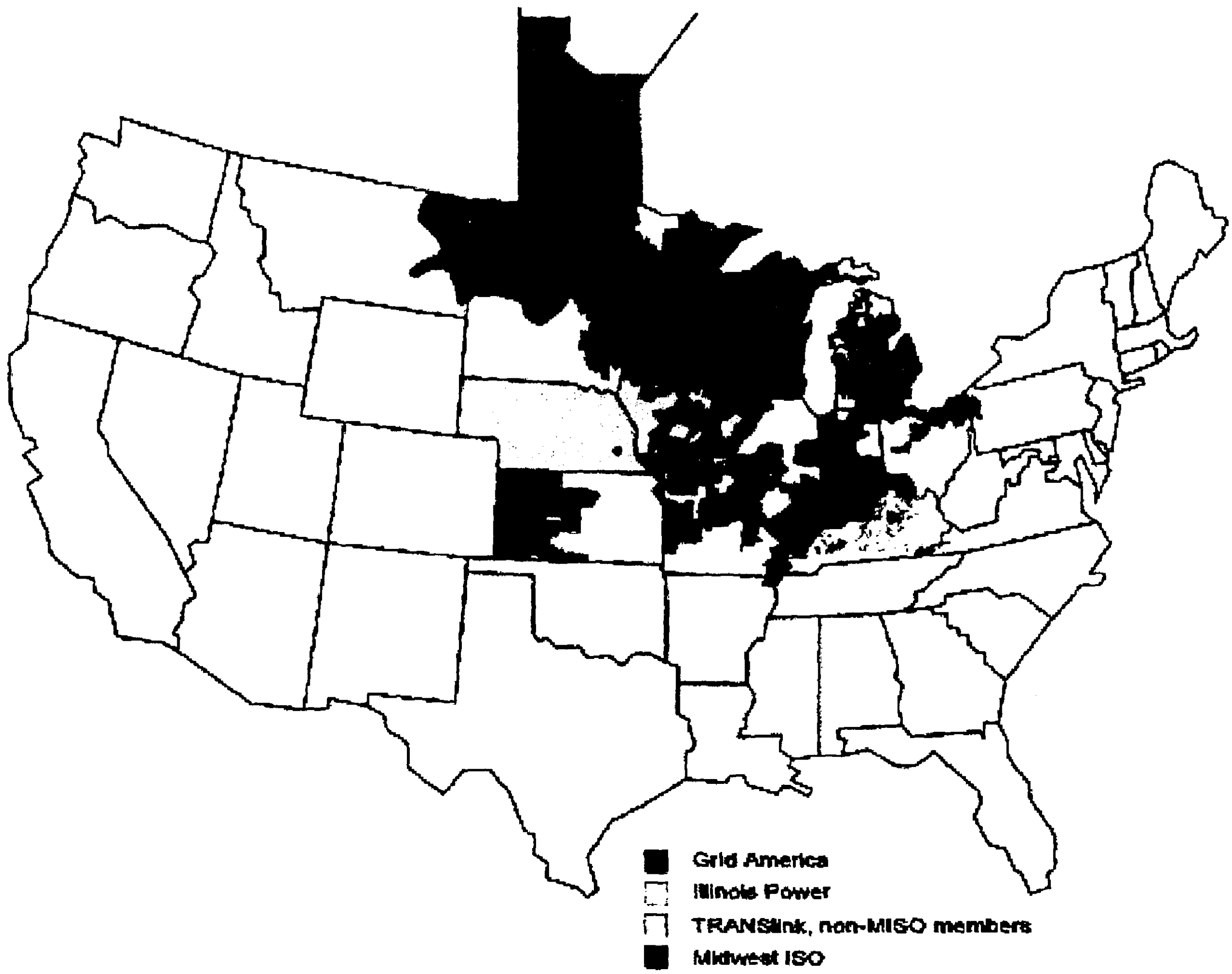

Figure V.1. The Midwest ISO region.
Source: Midwest ISO.

Currently, MISO is responsible for short-term reliability and interchange schedules. It now uses transmission loading relief (TLR) for congestion management, but plans to implement an LMP and FTR model, similar to other RTOs or ISOs. While there is currently no centralized market, MISO is planning to operate day-ahead and real-time energy markets. As a result, most transactions in the region are bilateral. The market launch date is, at this time, March 31, 2004 and market trials are scheduled to run from November 1, 2003 through February 2004. MISO also is the provider of last resort for ancillary services and market monitoring is done only for spot energy markets.

All of the currently operating and fully functional ISOs or RTOs, New England, New York, PJM, Texas, and California, had previous histories of at least some coordination or are within the boarders of a single state. It is proving to be more difficult to form a functioning RTO without this history and one that crosses multiple state lines.

PJM, MISO, and TVA are attempting to form a "joint and common energy market" to coordinate power flows across the three regions.

Figure V.2 plots the weighted average daily prices for several Midwestern trading hubs for June 2002 through June 2003. The data is from IntercontinentalExchange, an electronically traded OTC commodity market (the same data used in the overview for the natural gas price comparison). The prices generally move in tandem, except PJM-West, which is now more closely tied with eastern markets (primarily PJM). PJM West now covers parts of western Pennsylvania and Maryland, northern Virginia, most of West Virginia, and into southeastern Ohio. The plan is for PJM-West to extend beyond these areas and into more of the Midwest–including most of Ohio and into northern Illinois to the Iowa-Illinois border, with portions of Indiana and Michigan.

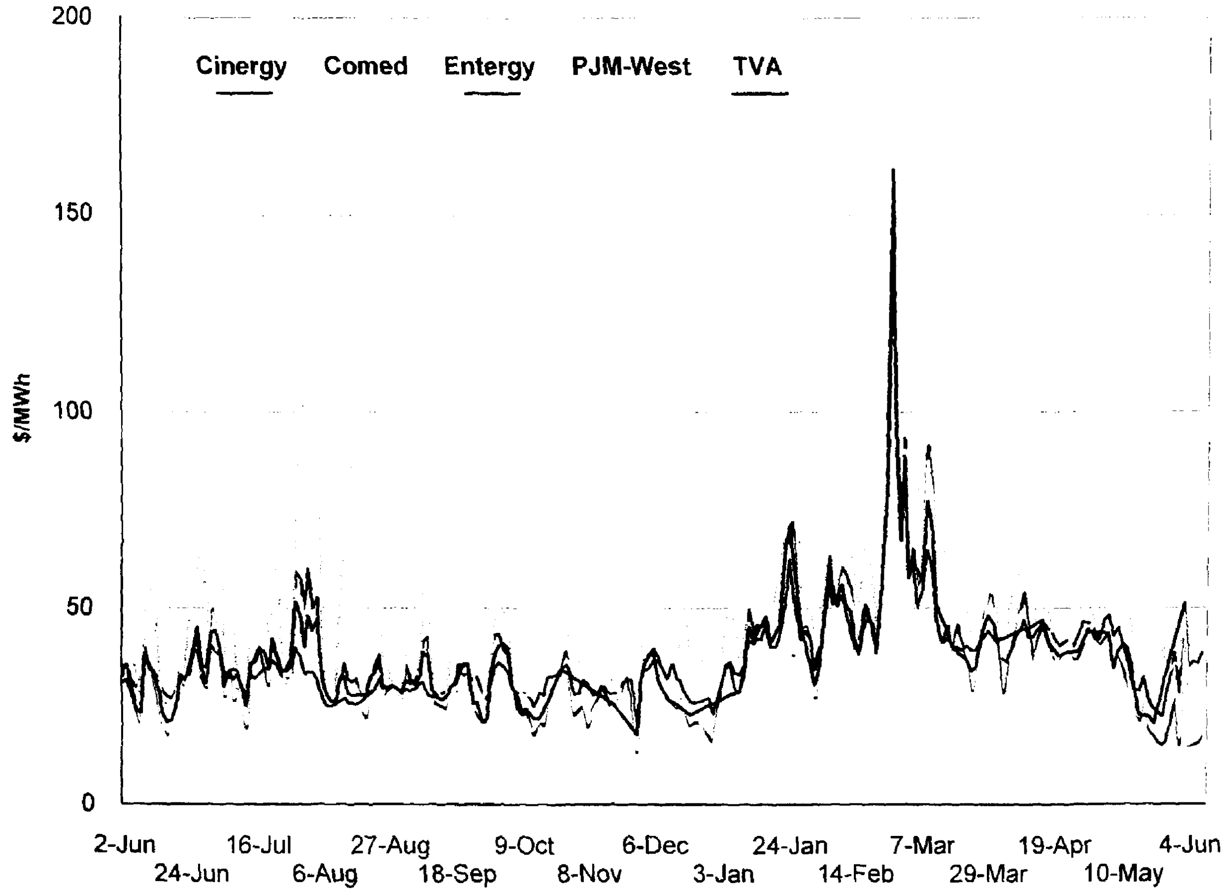

Figure V.2. Midwest trading hub daily prices, June 2002 to June 2003.
Source: IntercontinentalExchange, Inc., www.intcx.com.

Retail Markets

Three states in the Midwest have retail access, Illinois, Michigan, and Ohio. The status of each state is briefly updated below.

Illinois

Illinois retail access for residential customers began on May 1, 2002. Also in May of 2002, the Illinois legislature extended the current freeze on electricity rates until 2007. At this time, there are no residential customers that have switched to an alternative supplier in the state. Also, several distribution companies are reporting no activity in their areas for all customer categories, including, AmerenCILCO Co., AmerenUE Co., Interstate Power and Light Co., and MidAmerican Energy Co. Three companies, AmerenCIPS Co., Commonwealth Edison Co., and Illinois Power Co., have had some customer switching, primarily among larger customers. Table V.1 contains the percent of customers that are receiving "delivery services." This includes Interim Supply Service, Power Purchase Option, and Retail Electric Supplier customers. The Illinois Commerce Commission (ICC) defines Interim Supply Service as a tariffed short-term service available to delivery services customers who have no source of electric supply and Power Purchase Option (PPO) as an unbundled, market-based generation option that non-residential customers subject to transition charges must be offered. Both Interim Supply Service and PPO are supplied by the incumbent utility.[3] Currently, according to the ICC, only two utilities, Commonwealth Edison and Illinois Power, charge transition charges to customers who receive delivery services.

The ICC reports that during 2002 over 40 percent of Commonwealth Edison's delivery services customers switched to PPO. About 75 percent of AmerenCIPS' delivery services customers and about 99 percent of Illinois Power delivery services customers under one MW were taking PPO service. About 80 percent of Illinois

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[3] Illinois Commerce Commission, "Assessment of Competition in the Illinois Electric Industry in 2002," April 2003.

Power's larger-use delivery services customers (greater than one MW) switched to PPO. Table V.2 shows the percentage of delivery service customers using PPO by utility and demand level. The ICC has previously noted that reliance on PPO may be cause for concern for the long-term development of the market, primarily because of the temporary nature of the PPO. They note, however, that electric utilities will cease offering PPO by the end of 2006, when the statutory "Mandatory Transition Period" ends.

Table V.1. Percentage of customers receiving delivery services, May 2003.

	Residential	Commercial	Industrial	Total		
AmerenCIPS Company	0.0%	1.5%	12.8%	0.2%		
	Residential	Small C&I	Large C&I	Govern mental	Other	Total
Commonwealth Edison Company	0.0%	5.6%	59.2%	15.8%	0.0%	0.6%
	Residential	Demand Less Than 1 MW	Demand Greater Than 1 MW	Total		
Illinois Power Company	0.0%	1.6%	32.5%	0.2%		

Source: Illinois Commerce Commission, May 2003.

Table V.2. Percentage of Delivery Service Customers on Power Purchase Option, 2002.

Utility	Less Than 1 MW	Greater Than 1 MW
AmerenCIPS	75.4	54.5
Commonwealth Edison Co.	41.8	46.1
Illinois Power	99.4	80.3
Total	45.4	48.2

Source: Illinois Commerce Commission, "Assessment of Competition in the Illinois Electric Industry in 2002," April 2003.

Michigan

Michigan started retail access in January 2002. Table V.3 shows the percent of sales that have switched to alternative suppliers for Michigan's two largest investor-owned companies. While there is little activity among residential customers, there has been some activity with larger customer groups, particularly with industrial customers in Consumers Energy's territory and with commercial customers in Detroit Edison's territory.

Table V.3. Percent of sales (MWh), end of first quarter 2003.

	Consumers Energy	Detroit Edison
Residential	0.0%	0.006%
Commercial	5.3%	12.9%
Industrial	11.6%	7.8%
Total	5.6%	7.4%

Source: Michigan Public Service Commission staff, Department of Consumer & Industry Services, "Status of Electric Competition In Michigan: First Quarter 2003 Update," May 2003.

Ohio

Ohio's restructured electric generation market began January 1, 2001. The state remains in a transition period or a "market development period," which for most utilities continues until the end of 2005, during this time incumbent distribution utilities continue to provide standard offer service to customers who do not choose an alternative supplier and to those customers whose chosen supplier defaults in providing service. Also during this period customers receive standard offer service at prices approved by the Public Utilities Commission of Ohio (PUCO) and residential customers receive a five percent rate reduction on the distribution utility's unbundled generation service component. After the market development period, standard offer service may be provided at market rates, that could be obtained by competitive bidding for either the customer accounts or the load. A distribution utility, that offers both competitive and non-competitive services, is required to form separate affiliates and meet accounting requirements determined by the

PUCO. The utility needs to obtain approval of the PUCO for the corporate separation plan.

In August 2001, the PUCO approved rules for allowing electric demand aggregation by local governments. These rules require local governments to obtain majority support of the community to act as an aggregator. Under Ohio's law the customers are automatically enrolled with the community's chosen supplier unless a customer returns an "opt-out" card mailed to all eligible customers. The North East Ohio Public Energy Council (NOPEC) formed an electric buying group that represents 112 communities in Northeast Ohio with more than 350,000 residential customers in eight counties. This is the largest public aggregation of electricity customers in the U.S.

According to the PUCO, as of December 2002 a total of 756,411 residential customers and 848,702 customers of all classes had switched to an alternative electric supplier. The percentages of customers that switched to an alternative supplier for each distribution company is shown in Figure V.3. Cleveland Electric Illuminating Company[4] had the highest percentage of all customers switching to alternatives of Ohio electric distribution companies and for all customer classes except industrial. Switching of its residential, commercial, and for total customers were all about 60 percent for each category. Ohio Edison had the highest percentage of industrial customers at over 30 percent. Toledo Edison also had a relatively high percentage of customers switching, with residential, commercial, and total customer categories at about 40 percent and industrial customers at 20 percent switching to alternative suppliers. For the other five distribution companies, no category exceeded five percent customer switching. Columbus Southern Power, Dayton Power and Light, Monongahela Power, and Ohio Power Company reported no residential customers had chosen an alternative supplier. Cincinnati Gas and Electric had less than three percent residential customer switching.

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[4]The full company names of the abbreviations used in the figures are as follows: CEI, Cleveland Electric Illuminating Co.; CG&E, Cincinnati Gas and Electric Co.; CSP, Columbus Southern Power Co.; DP&L, Dayton Power and Light Co.; Mon Pwr, Monongahela Power Co.; Ohio Ed, Ohio Edison Co.; Ohio Pwr, Ohio Power Co.; Toledo Ed, Toledo Edison Co.

In terms of megawatt-hour sales, shown in Figure V.4, the pattern is similar for Cleveland Electric Illuminating, Ohio Edison, and Toledo Edison, except for industrial sales for Toledo Edison which was below five percent. Also, there was considerably more activity for commercial and industrial sales for Cincinnati Gas and Electric and for Dayton Power and Light. It should be noted that Cleveland Electric Illuminating, Ohio Edison, and Toledo Edison (all part of FirstEnergy Corporation serving northern Ohio) had the highest regulated rates among investor-owned utilities prior to restructuring and, consequently, higher prices-to-compare than other parts of the state.

Customer aggregation by local governments in the area of Toledo and by Northwest Ohio Aggregation coalition and NOPEC in other areas contributed to substantial switching in the services areas of Cleveland Electric Illuminating, Ohio Edison, and Toledo Edison. As of December 2002, aggregation programs account for over 93 percent of residential, over 88 percent of the commercial and over 19 percent of the industrial customer switching in Ohio and over 92 percent of all customer switching in the state. Table V.4 summarizes the aggregation program switching.

Table V.4. Aggregation activity in Ohio, December 2002.

	Customer Switching through Aggregation	Total Customer Switching	Percent Switching through Aggregation
Residential	704,701	756,411	93.16%
Commercial	80,501	91,171	88.30%
Industrial	214	1,120	19.11%
Total	785,416	848,702	92.54%

Source: Source: Public Utilities Commission of Ohio, Division of Market Monitoring & Assessment.

As noted in last year's report, under an agreement with the PUCO and various parties, FirstEnergy agreed to make available 1,120 MW of "Market Support Generation" (MSG) to non-affiliated marketers, brokers and aggregators for sales to retail customers during the "market development period," which runs for five years beginning January 1,

2001. This capacity was made available on a first-come-first-served basis to competitive suppliers for committed capacity sales to FirstEnergy's customers. Of the total MSG capacity, 500 MW is reserved for residential customers. Total power allocations for the three northern Ohio FirstEnergy companies are 560 MW from Ohio Edison, 400 MW from Cleveland Electric Illuminating, and 160 MW from Toledo Edison. Prices for the capacity are based on customer class and increase each year that the capacity is made available. Industrial and commercial customer prices are the same for all three FirstEnergy companies, beginning at $26.23/MWh and $30.83/MWh respectively in 2001 and rising to $31.88/MWh and $37.19/MWh respectively in 2005. Residential customer prices for the MSG capacity are $30.03/MWh for Toledo Edison, $31.19/MWh for Ohio Edison, and $31.64 for Cleveland Electric Illuminating. These prices rise to $36.28/MWh, $37.69/MWh, and $38.24/MWh respectively in 2005. It is believed that these prices are initially below market prices for each customer class.

At this time there is only one offer being made to residential customers in one distribution company's territory, Cincinnati Gas and Electric–from Dominion Retail, Inc. No other offers are currently being made to residential customers in any other part of the state. The total number of residential offers has decreased from eight in January 2001, to three in May 2002, to the one currently being made (July 2003).

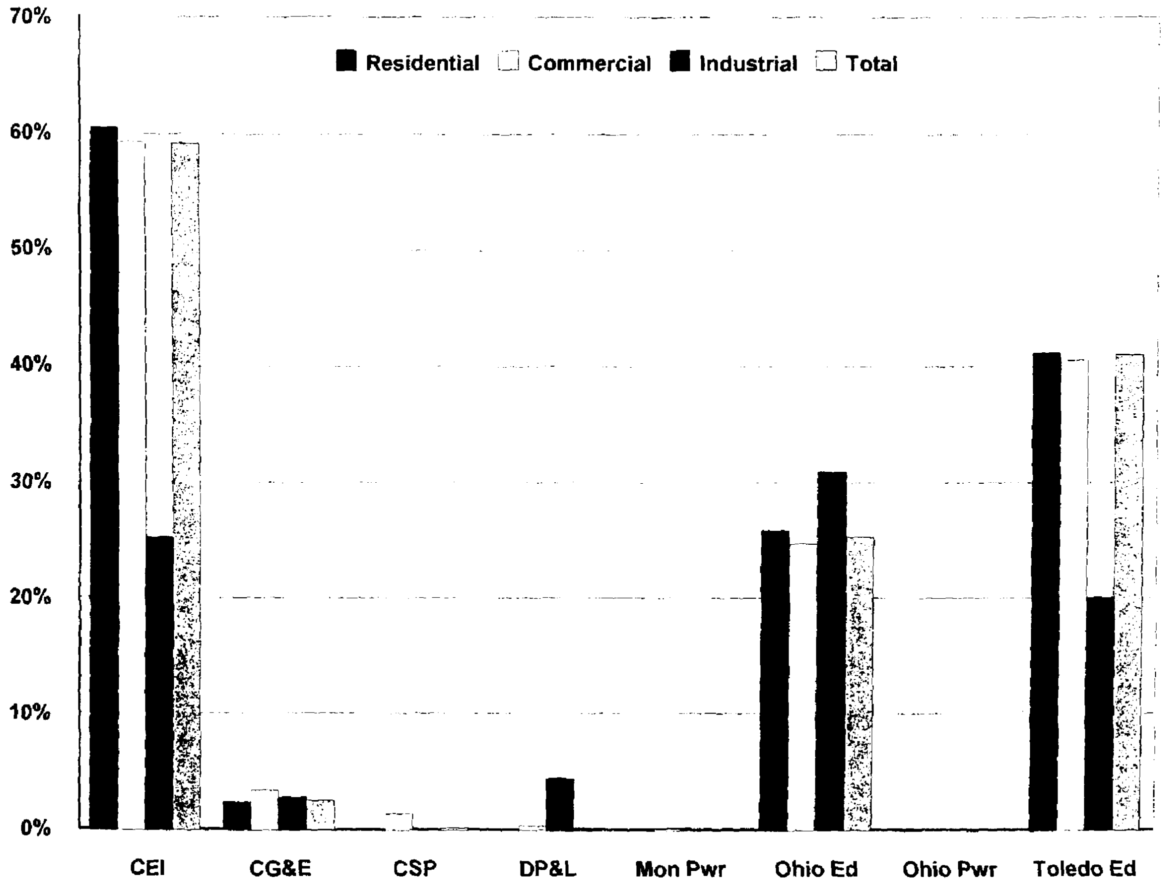

Figure V.3. Percent of customers that switched to alternative electric suppliers, December 2002.
Source: Public Utilities Commission of Ohio, Division of Market Monitoring & Assessment.

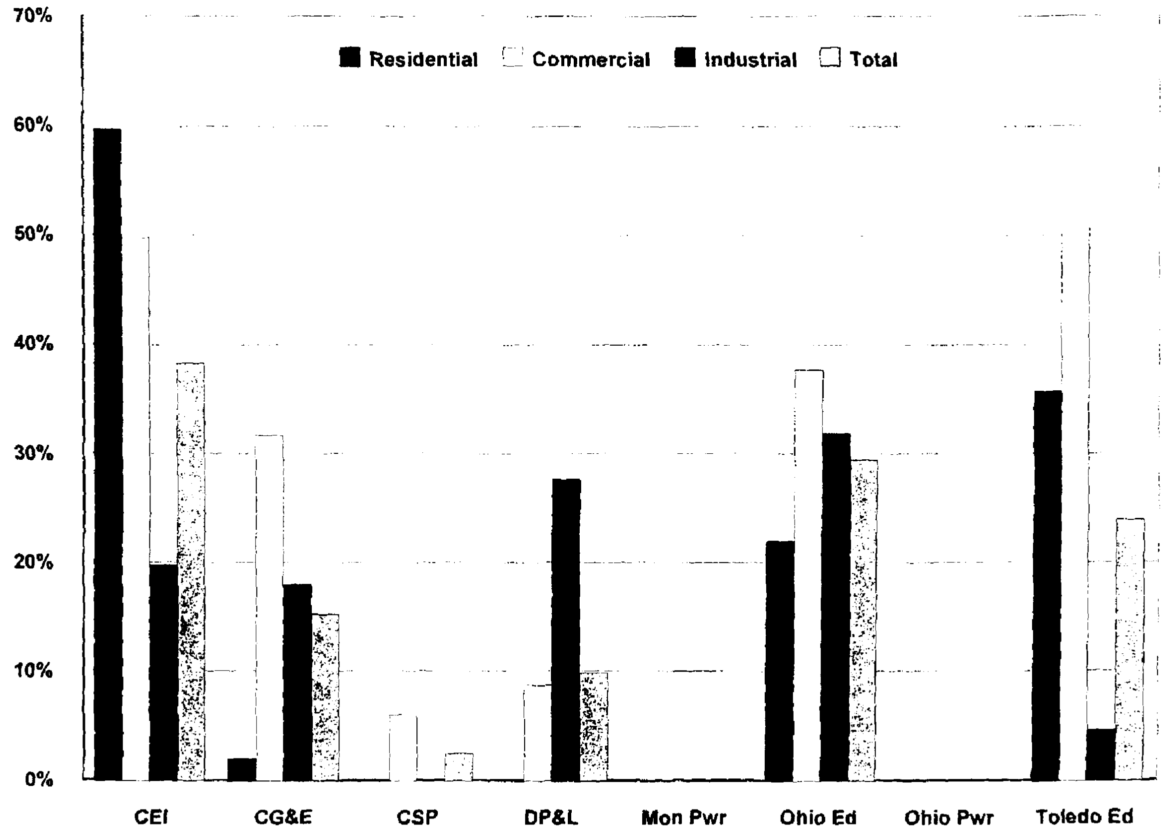

Figure V.4. Percent of megawatt-hour sales that switched to alternative electric suppliers, December, 2002.
Source: Public Utilities Commission of Ohio, Division of Market Monitoring & Assessment.

Section VI
TEXAS

Due to the apparent early success of its retail markets, Texas has attracted a great deal of attention across the country. Since its beginning in January of 2002, the Texas retail market has been one of the more active in terms of offers to residential customers and savings opportunities. This early success has led some to proclaim Texas as the model for both its retail access program and its wholesale market design. Because of the attention both the Texas wholesale and retails markets have received, this section is more extensive in this year's report than other regions that have been covered extensively in previous years.

Wholesale Market and the Electric Reliability Council of Texas

The Electric Reliability Council of Texas, Inc. (ERCOT) administers Texas' power grid and serves approximately 85 percent of the state's electric load, an area that includes about twelve million people. ERCOT is an independent, not-for-profit organization responsible for the transmission of electricity and is one of ten regional reliability councils in the North American Electric Reliability Council (NERC). It is one of two reliability regions that are also an ISO, PJM being the other. ERCOT has approximately 70,000 megawatts of generation and over 37,000 miles of transmission lines. ERCOT covers approximately 75 percent of the land area in Texas.

The Texas Public Utility Commission (the Commission) has primary jurisdiction over ERCOT activities and, because ERCOT is located completely within the borders of a single state, FERC does not have any jurisdiction. This provides ERCOT and Texas more latitude and flexibility in designing their wholesale power markets than other states that would also require FERC approval and oversight. Some believe that this also provides Texas with a better opportunity to coordinate the ERCOT portion of the state's retail and wholesale markets since both are state jurisdictional and the FERC is not involved. Outside of the ERCOT region, transmission access and pricing and wholesale generation markets are under the jurisdiction of the FERC. Retail pricing and market operations remain under the jurisdiction of the Texas Public Utility Commission.

In May 1999, the Texas Legislature passed a bill to allow electric choice or retail access, which began for most consumers in January 2002. This required ERCOT to change its structure and functions. ERCOT is unusual among the existing RTOs and ISOs since it must deal with both retail and wholesale electric restructuring. ERCOT is still responsible for transmission reliability and open wholesale access, but is now also charged with overseeing the transactions related to the state's restructuring of the electric industry–including the development and operation of the ERCOT portion of Texas' competitive retail market. Restructuring of the electric industry in Texas makes ERCOT the central controller of the majority of the state's energy market activities, including power scheduling and troubleshooting.

ERCOT's market relies primarily on bilateral contracts between buyers and sellers of electricity traded. In contrast to other markets in the U.S. where there is either a central power exchange or sizable day ahead and/or real-time markets that are administered by the independent system operator. Two concerns the Commission has expressed with having such reliance on the bilateral market are price discovery and liquidity.[1] A broader market, they note, could provide greater liquidity and price transparency, and provide better information about future supply and demand conditions. The existing market design, they claim, also presents gaming opportunities for market participants that could probably be eliminated by redesigning the market.

ERCOT Market Operations

As noted, ERCOT's wholesale market is a market where participants use bilateral forward contracts almost exclusively, with zonal congestion management and the system operator running a minimal real-time balancing market. The Market Oversight

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[1]Public Utility Commission of Texas, Report to the 78th Texas Legislature, "Scope of Competition in Electric Markets in Texas," January 2003. Much of the details about the Texas markets, unless otherwise indicated, are from this Texas Commission report and from various ERCOT sources.

Division of the Texas Public Utility Commission noted that ERCOT is the only operating ISO/RTO-based wholesale market in the U.S. that uses only bilateral forward contracting among market participants. ERCOT's residual energy market for balancing energy, representing three percent to five percent of total demand, is for the reliability of the Texas electric grid. The Texas Commission has identified problems with its wholesale market design and has been formally considering changes.

Prices in the bilateral market that represents the bulk of delivered energy in Texas are based on mutual agreement or long-term contract between the parties, and are not known by ERCOT. These agreements are incorporated into base energy schedules which are submitted to ERCOT on a daily basis and account for about 95 percent to 97 percent of the end-user electric energy requirements in ERCOT.

Ancillary Services

ERCOT has operated day-ahead ancillary service markets and the real-time balancing energy market since July 31, 2001. The following are ERCOT's five ancillary services (and the total amount required each day): Regulation Up (1,200 MW), Regulation Down (1,800 MW), Responsive (spinning) Reserves (2,300 MW), Non-Spinning Reserves (1,250 MW), and Replacement Reserves (as needed). Market participants can self-provide their ancillary service requirements or allow ERCOT to procure these services on their behalf.

During the first year of operation as a single control area, ERCOT usually procured from ten percent to 20 percent of the ancillary service capacity required. Market participants chose to provide their own ancillary services rather than expose themselves to unknown market clearing prices from the ERCOT auction. According to the Commission, prices for ancillary services procured by ERCOT were below $20 per MW for more than 95 percent of the time, from August 2001 through July 2002.

Capacity Adequacy

ERCOT currently has no formal capacity market comparable to PJM's capacity credit market. The Texas Commission is developing a generation adequacy rule which likely will use a mechanism that differs from capacity credit markets in the northeast region of the U.S. ERCOT utilities have traditionally sought to maintain a planning reserve margin of 15 percent. Because the system cannot rely on imports, due to its isolation from surrounding interconnections, relatively high reserve margins are thought necessary. However, in mid-2002, the ERCOT Board approved a 12.5 percent reserve margin requirement.

In 2000 and 2001, the reserve margins at peak were 14 percent and 21 percent, respectively. From 1995 to January 2001, 22 new generating plants, totaling more than 7,600 MW, were built in the ERCOT region. This represents 10.9 percent of total generating capacity; during this same period, peak demand grew by 24.5 percent. The Texas Commission reports[2] that statewide (ERCOT and non-ERCOT regions of the state) 55 plants for a total of 21,685 MW were completed from 1995 through early 2002. Also, in early 2003 it was reported that 12 plants with a total of 8,781 MW were under construction, 16 plants with a total of 8,047 MW had been announced or planned, and 13 plants totaling 7,180 MW had been delayed. (Earlier Commission numbers indicated that more than 9,700 MW of announced new generation capacity had been delayed and more than 4,400 MW had been cancelled.) These capacity additions have been mostly natural gas combined cycle plants and wind turbines. American Electric Power (AEP) and CenterPoint Energy announced in the fall of 2002 that they plan to mothball a total of 7,000 MW of older, less-efficient generating capacity. ERCOT is currently expecting its 2003 reserve margin to be over 32 percent and remain above 23 percent through 2008.[3]

The Commission has opened a rulemaking project to determine whether the adequacy of reserve margins should be left to market forces, or whether other means should be created to help ensure a minimum reserve margin.

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[2]These data on new plants in Texas are from a presentation by Commissioner Brett A. Perlman, "Setting a New Agenda for the Restructured Electric Industry," at the "Give Your Customers a Break" Seminar, Atlanta, Georgia, August 8, 2003.

[3]Commissioner Brett A. Perlman presentation, "Setting a New Agenda for the Restructured Electric Industry," August 8, 2003.

The Commission also notes that transmission constraints limit the deliverability of some generation resources, especially wind power from West Texas. The Commission states that so much wind power has been added that the existing transmission system is not always capable of delivering all of the power available from the wind projects. Transmission projects are planned to relieve the bottlenecks, but they report that significant new facilities are required, which will take up to five years to complete.

ERCOT introduced monthly and annual Transmission Congestion Rights (TCRs) auction markets in February of 2002. TCRs were implemented in ERCOT along with the implementation of direct assignment of interzonal congestion charges. ERCOT initially adopted a simple flow-based transmission right approach and flow-based congestion charges.

Bilateral Market Prices

Figure VI.1 shows the daily power and natural gas prices in ERCOT from January 2001 to September 2002. Since August 2001, power prices have remained below $50 per MWh. The figure also shows how power prices in ERCOT, similar to most of the country, is very dependent upon natural gas prices (except for a period during the summer of 2001). The reason, as discussed in the overview section of this report, is because natural gas-fueled generation is often the marginal unit dispatched for most power regions, including ERCOT.

The Commission attributes the price spikes for several days in August 2001 to transmission congestion that occurred on these days. They note that prices in 2002 have been usually below $40 per MWh, even during the summer months. The Commission attributes this to the significant amount of new generation built in ERCOT over the last several years, along with lower than expected demand due to the nationwide economic slowdown, and cooler weather during the peak demand periods.

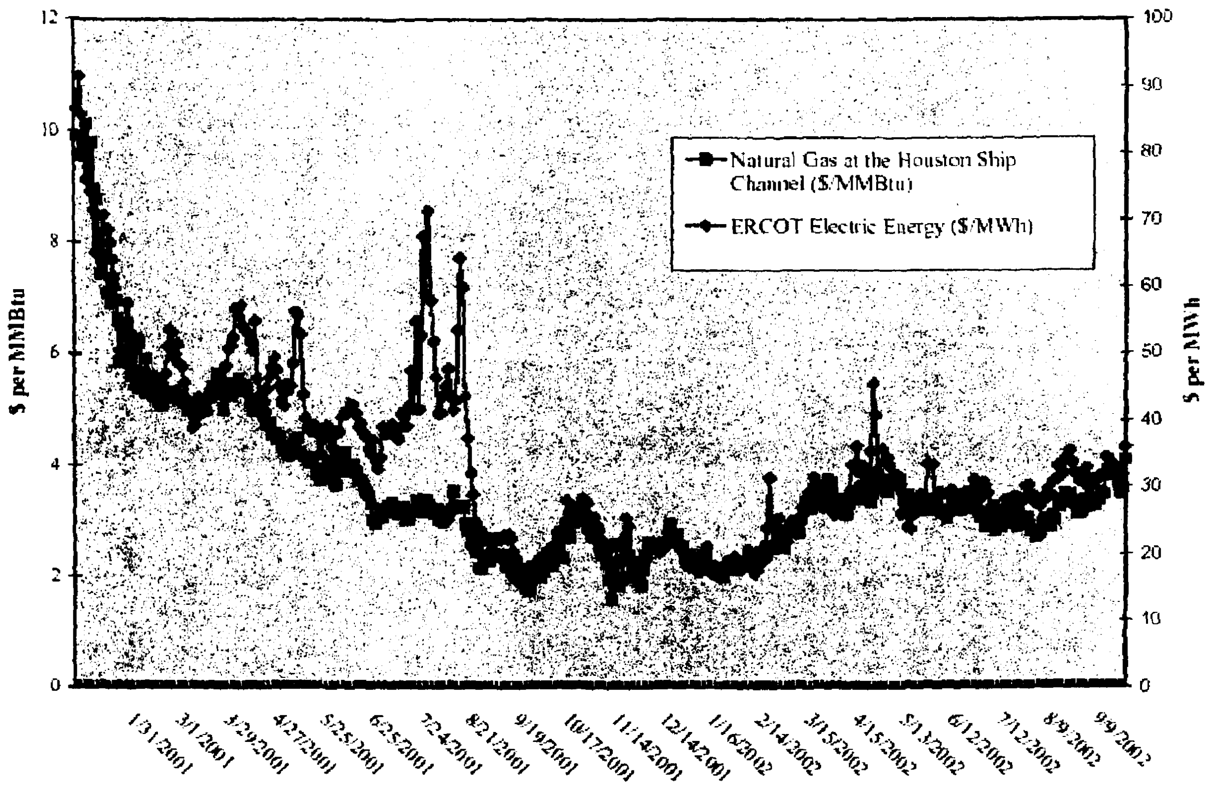


Figure VI.1. Daily ERCOT Energy Prices and Natural Gas Prices.
Source: Public Utility Commission of Texas, January 2003, p. 78.

<u>Real-Time Balancing Energy Market</u>

As noted, ERCOT does not have a central power exchange or sizable day ahead or real-time energy markets administered by an independent system operator. However, ERCOT does have a balancing energy market designed to maintain the balance between load and generation and to resolve transmission congestion. Balancing energy makes up the difference between the total ERCOT electricity requirements and the sum of the base energy schedules. The real-time balancing energy market process accepts bids in ascending order of price until the total quantity required is obtained. The bid price of the last quantity accepted for Balancing Energy Service sets the Market Clearing Price of Energy (MCPE) for that 15-minute interval.

Figure VI.2 is a chart of the ERCOT weighted average prices for energy from August 2001 through July 2002. The Commission reports that the average daily price

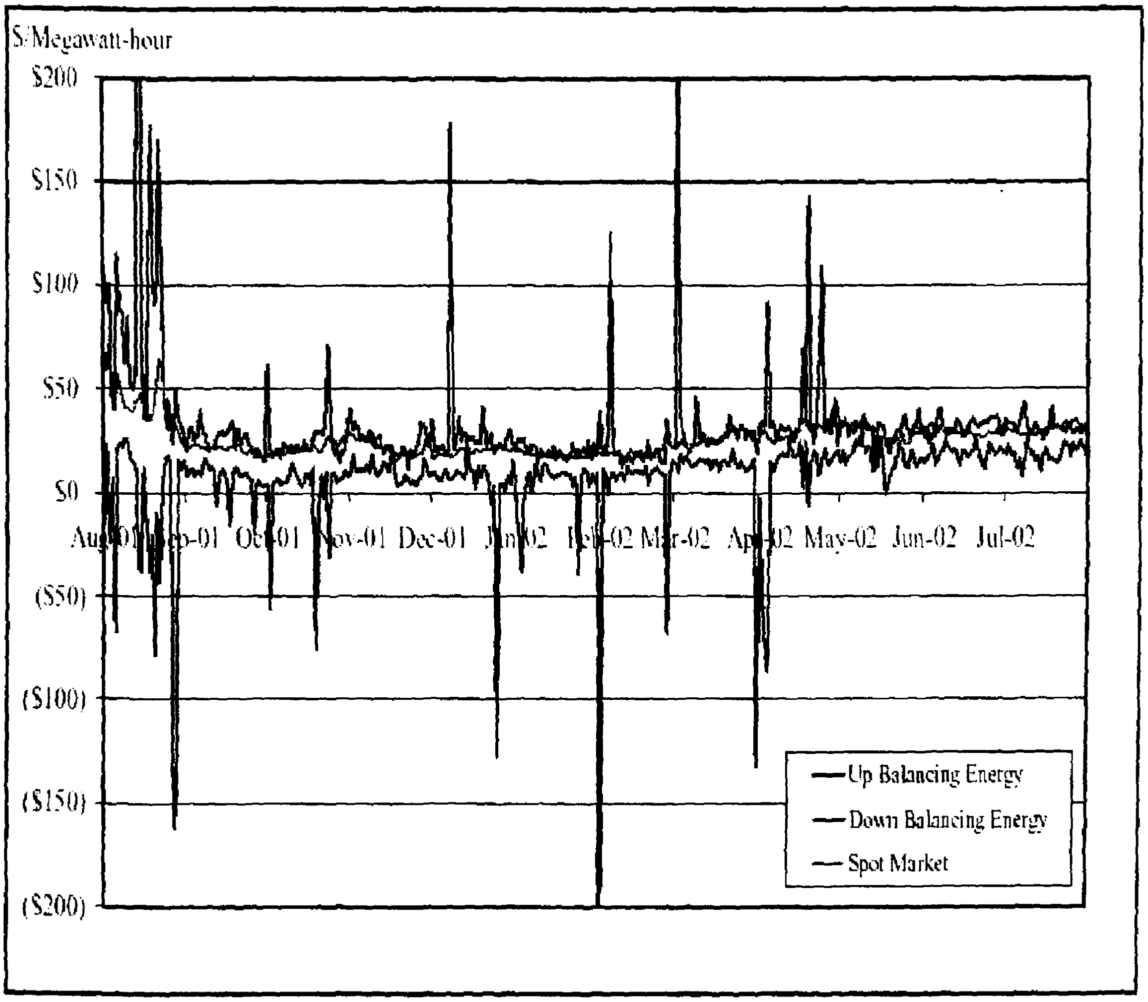


Figure VI.2. Weighted average price for Energy, August 2001 to July 2002.
Source: Public Utility Commission of Texas, January 2003, p. 80.

for balancing energy was within the plus or minus $50 per MWh range 90 percent of the time. The Commission also reports that nearly 277 million MWh of energy were consumed in ERCOT from August 2001 through July 2002, but less than five percent of total energy was transacted through the balancing energy market. The negative prices for down balancing energy represents the amount that ERCOT will pay the generator to reduce its output while ERCOT assumes the operational and financial responsibility to serve the load that was dedicated to the amount of reduced generation.

Figure VI.2 also shows the ERCOT energy spot market prices, as reported in Megawatt Daily, for comparison with the prices for up balancing energy and down balancing energy. Up balancing energy tends to be higher with occasional spikes than the spot market, while the down balancing energy tends to be lower than the spot market with downward spikes. The Commission attributes the price spikes to several possibilities, including a generator "forgetting" to place bids that resulted in a "lean" bid stack to misjudging weather conditions and not having the resources available.

Texas Retail Market

Overview

As noted, Texas passed their restructuring bill in June of 1999 and retail competition began for all customers of investor-owned utilities in the Electric Reliability Council of Texas (ERCOT) region on January 1, 2002. For areas served by municipal utilities and electric cooperatives, competition is allowed if the governing body of the city or cooperative opts for retail competition. Metering services for commercial and industrial customers will be open to competition beginning January 1, 2004. For residential customers, metering services are regulated until September 1, 2004 or until 40 percent of customers have switched to an alternative supplier, whichever is later.

The Legislature delayed retail competition for utilities in the non-ERCOT regions of Texas, in the El Paso Electric service area until September 2005, (the end of the rate-freeze period from El Paso Electric's bankruptcy proceeding in 1995) and in the Southwestern Public Service Company service area (in the Panhandle region of Texas) until 2007 at the earliest. The Southwestern Public Service Company service area is described as a transmission-constrained area that has limited access for alternative power generation companies and retail providers to serve customers.[4] The Public Utility

[4]The Legislature required Southwestern Public Service Company to conduct an analysis on the need for additional transmission infrastructure and on plans to interconnect with other power regions.

Commission of Texas delayed the start of full customer choice for the Entergy, Southwestern Electric Power Company (SWEPCO), and a small portion of West Texas Utilities Co.'s (WTU)[5] service area that is located within the Southwest Power Pool region. The Commission delayed competition for the Entergy and SWEPCO service areas because of three concerns: (1) a lack of independence in the administration of transmission service and uncertainty about the market rules for these areas; (2) a lack of testing of the technical systems needed to accommodate retail choice; and (3) a lack of necessary market institutions and lack of open and non-discriminatory access to the transmission grid.

Investor-owned utilities were required to separate their business functions into three distinct companies: a power generation company (PGC), a transmission and distribution utility (TDU), and a retail electric provider (REP). PGCs operate as wholesale providers of generation services, such as independent power generators. REPs operate as retail providers of electricity and energy services and have primary contact with retail customers. TDUs remain regulated by the Commission, and are required to provide non-discriminatory access to the transmission and distribution grid at rates and terms of access prescribed by the Commission.

The "Price-to-Beat"

Customers who did not choose a new retail electric provider, or REP, by January 1, 2002 were automatically transferred to their utility's affiliated REP. Residential and small non-residential electric customers (with a peak demand of 1 MW or less) who remain with the affiliated REP are charged a regulated rate, called the "price-to-beat." Commission rule generally required a 6% reduction from the rates in effect on January 1, 1999 for residential and small commercial customers, with adjustments for the setting of a final fuel factor for the integrated utility as of December 31, 2001. The reduction applied to customers who did not choose a REP and continue to take service from the

[5]WTU is now also known as AEP Texas North, an affiliate Retail Electric Provider (REP) of AEP's Texas local distribution utilities. AEP Texas Central, also is still known by its former names CPL, Central Power and Light Company, or CPL Retail Energy.

affiliated retail electric provider. The affiliated REPs are required to sell electricity at the price-to-beat until January 1, 2007.

Similar to Pennsylvania's "shopping credits" and some other states' price-to-compare, Texas purposefully set the price-to-beat with some "headroom," that is, allowing the difference between the price-to-beat and the costs incurred by non-affiliated REPs (see the discussion in the overview section of this report) to be sufficient to allow competitors to profitably offer prices to customers for their services and offer sufficient savings off the price-to-beat so that customers are encouraged, by the potential savings, to consider alternative suppliers. The Commission found, as other states have, that if the price-to-beat or the fuel factors were not adjusted to reflect changes in the market price of electricity, the price-to-beat could fall below the costs of alternative REPs and competition in the retail market will not develop and decline (negative headroom). For this reason, the price-to-beat is adjusted to reflect changes in natural gas and purchased energy market prices. If the price of natural gas futures changes by more than four percent, Commission rule permits the affiliated REP to request adjustments to their fuel factor. Also, if headroom diminishes from changes in the market price of purchased power as measured by one-year and three-year contract prices, the affiliated REP may also request an adjustment to the price-to-beat.

Affiliated REPs, that is, the incumbent utility, can offer rates lower than the price-to-beat beginning January 1, 2005, or earlier if at least 40 percent of residential or small-commercial customers switch to competitors.

The price-to-beat rates for residential customers for each affiliated REP are shown in Table VI.1. In the case of First Choice/TNMP, CPL/AEP Texas Central, and WTU/AEP Texas North, base rates changed a level other than six percent due to changes in rates between January 1, 1999 and December 31, 2001 that resulted from merger proceedings. (See the sideline note on company names in Texas.)

Table VI.1. Price-to-Beat rate comparison (cents per kWh).

Affiliated REP	December 31, 2001	January 1, 2002	September 2002	June 2003
TXU	9.67	8.25	8.66	9.70
Reliant/CenterPoint	10.40	8.62	9.12	10.10
First Choice/TNMP	10.57	8.66	9.15	10.10
CPL/AEP Texas Central	9.57	8.80	9.52	10.92
WTU/AEP Texas North	9.98	8.88	9.73	11.34

Source: Public Utility Commission of Texas, January 2003 and, for the June 2003, ENERGYguide.com.

The Commission reports that because of significant increases in the price of natural gas during the winter of 2000-2001, the fuel factor portions of the 2001 rates rose significantly and also required fuel surcharges to recover past uncollected fuel expenses. At the end of 2001, natural gas prices fell significantly, resulting in reductions in the fuel factor portion of the price-to-beat rates. Also, the fuel surcharges that were in place during 2001 terminated in December 2001. As a result, customers received in excess of a six percent reduction in their total rates as compared to rates in effect on December 31, 2001. Natural gas prices dropped in the early months of 2002, but began to rise significantly in

Due to mergers; the required unbundling of investor-owned utilities into three companies – (1) power generation company (PGC), (2) transmission and distribution utility (TDU), and (3) retail electric provider (REP); and other structural changes that companies in Texas have undergone in recent years, the names of companies have been changed or new names created. In this report, where possible, the names of the companies reported by the Commission along with the figures supplied are used in the tables and graphs. In the text, the company's pre-retail access utility name is also given. Here is a summary of the utility, REP, or new names that are used:

- Central Power and Light Co. / CPL / AEP Texas Central
- HL&P / Reliant Energy / CenterPoint Energy
- Texas-New Mexico Power Co. / TNMP / First Choice Power
- TXU Electric & Gas / Oncor
- West Texas Utilities Co. / WTU / AEP Texas North.

March and April of 2002. All of the affiliated REPs (except TXU-SESCO) subsequently requested adjustments to their price-to-beat fuel factors in order to reflect increases in the price of natural gas in the range of 16 percent to 24 percent. Reliant Resources filed for a second adjustment in November 2002 to reflect a further seven percent increase in natural gas prices (that was approved by the Commission in December 2002). Figure VI.3 charts the changes in the bundled rates before retail access and the price-to-beat rates after (the slide is from a presentation of Chairman Rebecca Klein of the Texas Commission in May 2003).

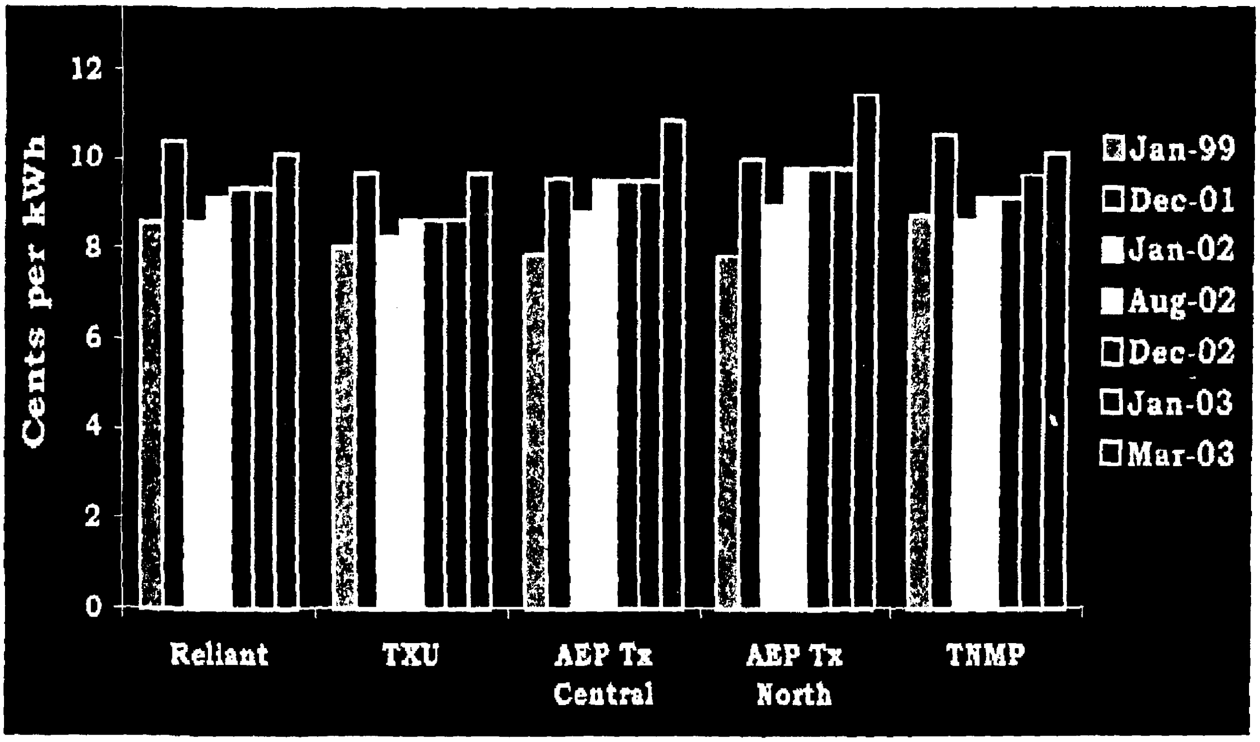


Figure VI.3. Pre-retail access bundled rates and the "price-to-beat," January 1999 to March 2003.
Source: Slide from presentation of Chairman Rebecca Klein, Public Utility Commission of Texas, Competitive Retail Markets in Texas and Market Design," Electric Power Supply Association, State Issues Meeting, May 6, 2003.

Provider of Last Resort (POLR) Service

In areas of the state where retail access is in effect, the Commission designates REPs to serve as providers of last resort or a POLR. The Commission adopted POLR rules in October 2000 that required the selected POLR to charge a fixed rate that could not be changed over the term of the POLR contract. Each POLR was required to offer a standard retail service package for each class of customers designated by the Commission at the approved fixed, non-discountable rate. In the event that a REP failed to serve its customers, the POLR must offer the standard service package to those customers with no interruption of service. The standard service package must also have been available to any requesting customer. In addition, under the original POLR rule and customer protection rules, only the POLR had the authority to disconnect customers for nonpayment of electric services. Other REPs could only cancel a nonpaying customer's contract and transfer that customer to the POLR.

POLRs were originally to serve two types of customers: (1) customers of a REP that chose to exit the market without making arrangements to transfer those customers to another REP, and (2) non-paying customers of a REP. For the first set of customers, POLRs faced the risk of potentially being required to serve a large number of customers from an exiting REP with little notice and at a fixed rate that was set far in advance of the switch. For the second set of customers, POLRs faced the risk of serving customers that had already demonstrated an inability or unwillingness to pay their provider for energy consumed. The Commission states that the combination of these risks led to the high rates initially set for the POLRs for 2002. Several parties appealed the orders and contracts with the POLRs alleging that the rates were not just and reasonable, and that the Commission erred in the process it used to select POLRs and set the rates for POLR service.

The Commission's new POLR rules remove non-paying customers from the class of customers served by the POLR. REPs no longer transfer non-paying residential and small commercial customers to the POLR, as of September 2002. Instead non-affiliated REPs transfer them to the affiliated REP for service at the price-to-beat. The affiliated REP has authority to disconnect the customers if the customer does not establish any required deposit with the affiliated REP, or subsequently does not pay a bill of the affiliated REP. All REPs have authority to disconnect large commercial and industrial customers for non-payment, unless an existing contract provides for different treatment.

This structure will remain in place until October 1, 2004. After that, all REPs will have the authority to disconnect non-paying customers, if protections are in place for retail customers. The primary purpose of the POLR service is now to serve customers of a REP that exited the market without making arrangements to transfer their customers to another REP.

The original POLR rules chose a sealed-bid competitive bidding process to set the POLR rates. The Commission conducted a bid for each customer class in each designated service area, but only one REP submitted a bid. The Commission accepted the bids of TXU Energy Services to provide POLR service in the majority of the state. The Commission designated non-bidding REPs to serve as POLRs and set the rates for the remaining areas of the state where no bid was received through negotiation and in contested case proceedings. The initial rates for POLR service, whether approved by bid, negotiation, or contested case proceeding, were substantially above the price-to-beat in all areas.

Under the revised POLR rules, the Commission compares bids for POLR service on price alone and the selected rates are to be adjusted monthly to reflect changes in wholesale market prices. If no bids are submitted or all bids are rejected, the new rule requires the Commission to select POLRs by a lottery. The selected POLRs would provide service at specific rate levels determined under the rule. For service beginning January 1, 2003, only affiliated REPs were eligible to bid or be selected by lottery. Bids could also not exceed 125% of the price-to-beat for residential and small commercial customers.

The Commission noted that the competitive process it envisioned has yet to perform adequately. Only Reliant Resources submitted a POLR bid under the new process and was selected as POLR for most areas of the state. TXU Energy Services, First Choice Power, and AEP did not submit bids under the revised rule. The Commission held a lottery for the areas where Reliant did not bid.

The 2002 and 2003 POLR rates for Texas service areas are in Table VI.2.

Table VI.2. POLR rates for 2002 and 2003 (cents per kWh).

Service Area	2002 POLR Rates	2003 POLR Rates
Reliant/CenterPoint	11.96	10.83
TXU/Oncor	10.54 - 11.05	10.00
WTU/AEP Texas North	12.86	12.37
CPL/AEP Texas Central	12.22	11.08
TNMP/First Choice Power	12.13	10.99

Source: Public Utility Commission of Texas, January 2003, p. 44.

Customer Choices

Texas continues to have the most active market in the country for residential customers in terms of offers and savings opportunities. In June 2003, as summarized in Table VI.3, residential customers had between four and nine competitive providers offering between four to eleven competitive offers (this count does not include the affiliated REP's standard service at the price-to-beat rate). All five areas have at least three offers below the price-to-beat rate, two areas had six offers, and one area had seven offers below the price-to-beat. As measured by the lowest offer, residential customers had an opportunity to save between eight percent and 24 percent off the price-to-beat rate. All service areas, except that of WTU/AEP Texas North, had three renewable, or "green," offers (all the green offers were from the same power provider).

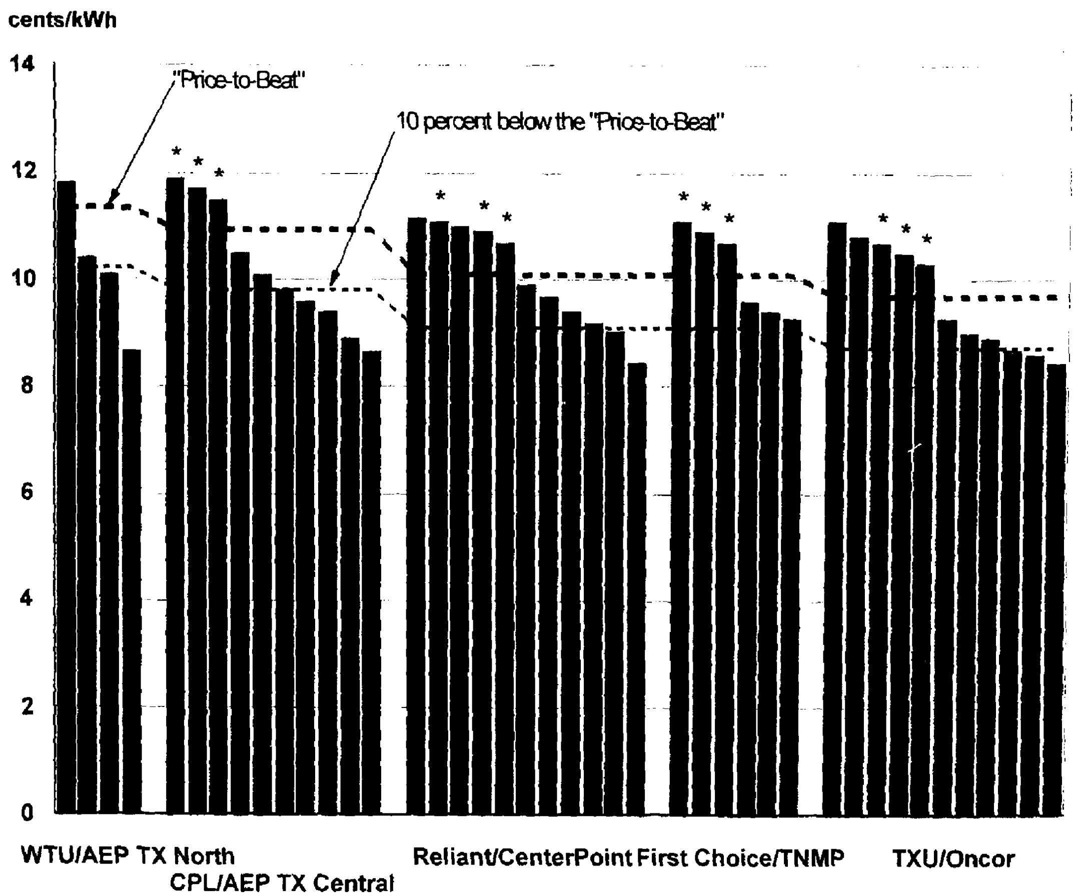
Table VI.3. Residential competitive offer summary for Texas, June 2003

Utility	Number of Competitive Suppliers	Total Number of Offers from Competitive Suppliers	Number of Offers Below the Price-to-Compare	Number of Green Offers	Savings with Best Offer*
TXU/Oncor	9	11	6	3	13%
CPL/AEP Texas Central	8	10	7	3	21%
WTU/AEP Texas North	4	4	3	0	24%
Reliant/ CenterPoint	9	11	6	3	16%
TNMP/ First Choice Power	4	6	3	3	8%

*Calculated by comparing the Price-to-beat with the lowest offer in cents/kWh.
Source: Based of offers from ENERGYguide.com, collected in June 2003.

Figure VI.4 graphs all the residential offers in the five service territories made in late June 2003. This shows that all but one service area had offers at greater than ten percent savings.

According to the Commission, commercial and industrial customers also appear to have a large variety of offers from which to choose. They report that there were, as of September 2002, approximately 19 REPs serving commercial and industrial customers in all service territories open to competition. As seen in other states, while residential offers are sometimes publicly available, the commercial and industrial market operates mostly under individual contracts. These customers often negotiate the type of service (firm vs. interruptible, short term vs. long term), and choose the amount of risk of price volatility (fixed price vs. indexed) they desire to accept. Customers who have negotiated contracts with the pricing tied to natural gas or power market prices enjoyed extremely low prices early in 2002 when natural gas prices (and power prices) dropped dramatically. Customers who have negotiated fixed price contracts have been able to avoid the subsequent increase in prices that have occurred this year, albeit at a price that reflects their REP absorbing that risk. Generally, however, all customers have enjoyed prices in 2002 that were significantly below the regulated rates they paid in 2001.



*Indicates an offer that is in part or entirely from renewable resources.

Figure VI.4. Residential offers in Texas retail markets, June 2003.
Source: Based on offers from ENERGYguide.com, collected in June 2003.

Customer Switching

As Figure VI.5 shows, almost eight percent of all residential customers were served by a non-affiliated REP by December 2002. Both Oncor (TXU) and CenterPoint (Houston area, formerly Reliant Energy HL&P) service areas had over ten percent of residential customers being served by non-affiliated REPs in June of 2003. Figure VI.6 shows that CPL (AEP Texas Central) had the highest percentage of secondary voltage customers (primarily smaller commercial and industrial customers, most of which are eligible for the price-to-beat) receiving power from competitive REPs. Over eleven percent of all customers in this category were with a competitive REP in December 2002.

The Commission notes that although less than ten percent of all secondary voltage customers (68,133 customers) have switched, as reported for September 2002, the customers who have switched are among the largest customers in this customer class since about 25 percent of the MWh (about 1.8

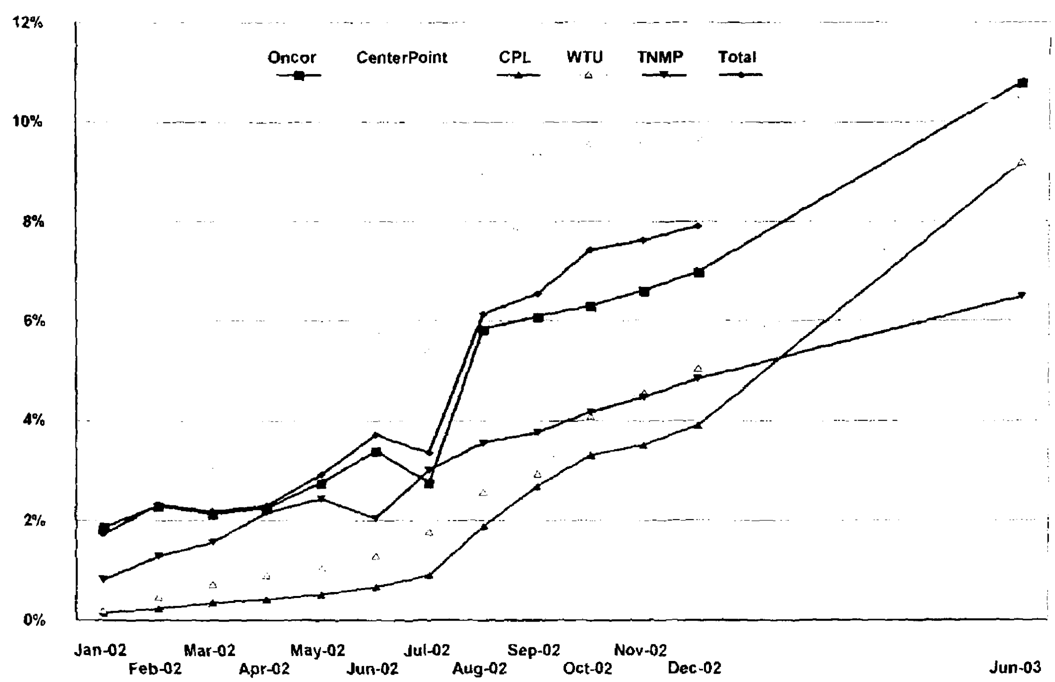


Figure VI.5. Percent of Residential Customers Served by Competitive REP, January 2002 to June 2003.

million MWh) used by secondary voltage level customers were supplied by non-affiliated REPs.

Over 18 percent of commercial and industrial customers taking service at primary or transmission voltage levels (larger commercial and industrial customers, many of which are not-eligible for the price-to-beat) were receiving service from a non-affiliated REP in December 2002 (Figure VI.7). In September, approximately 50 percent of the MWhs (1.7 million MWh) used by these customers were served by REPs not affiliated with the TDU in the customer's area. (The Commission does not report a break down by TDU area because of concern for confidentiality of market share information for these customers by the affiliated REPs. They note that the trends are similar across TDU areas with respect to the number of customers that are being served by non-affiliated REPs.)

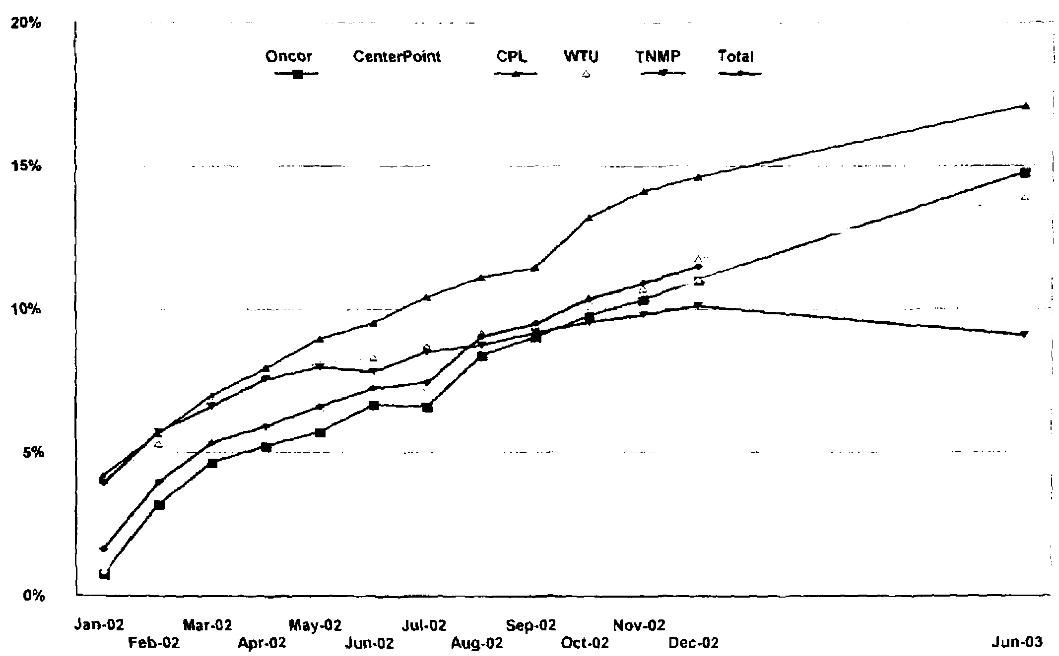


Figure VI.6. Percent of Secondary Voltage Customers Served by Competitive REP, January 2002 to June 2003.

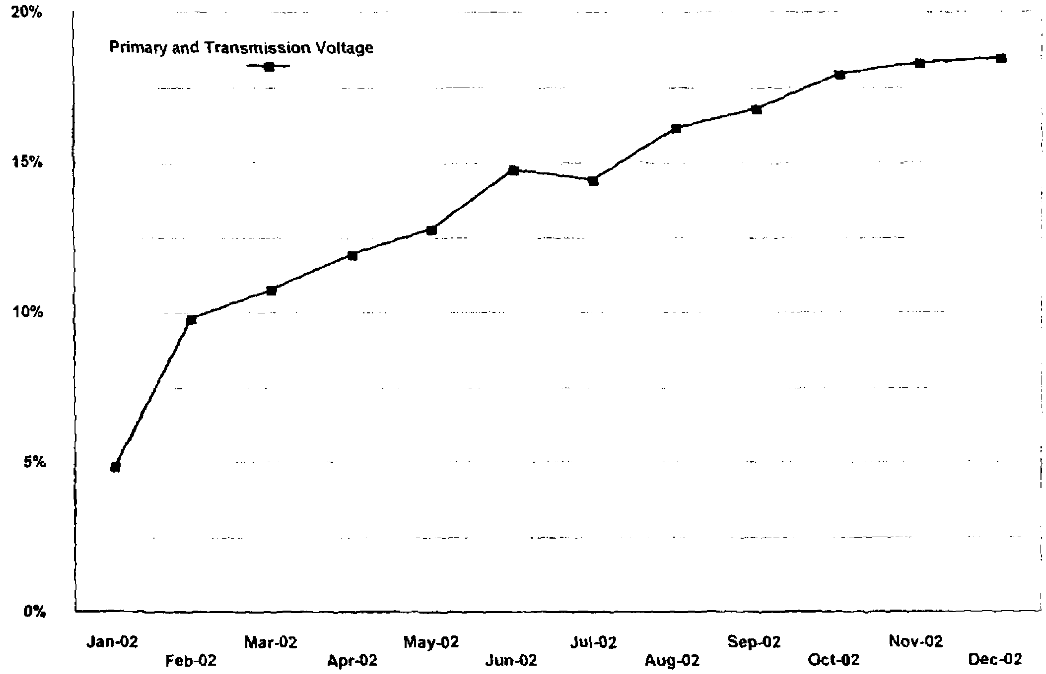


Figure VI.7. Percent of primary and transmission voltage customers served by competitive REP, January to December 2002.

The Commission reported that as of the end of September 2002, 400,837 individual customer premises were being served by a REP other than the incumbent affiliated REP in their service area. This was approximately 6.8 percent of all customers in areas of the state open to retail access. Of these premises, the Commission reported that 319,297 (80%) are residential customers, 71,691 (18%) are commercial and/or industrial customers that take service at the secondary voltage level (predominately smaller commercial customers eligible for the price-to-beat), and 1,322 (less than 1%) are larger commercial and industrial customers taking service at the primary and transmission voltage level and the remaining are lighting accounts.

The Commission also reports that a total of 6,070,477 megawatt hours (MWhs) were served by non-affiliated REPs in September 2002, approximately 25% of the total MWhs sold in the month. Commercial and industrial customers represent almost 20 percent of the customers who have switched, but they account for over 90 percent of the megawatt hours served by non-affiliated REPs in areas open to competition.

In September 2002, 69,424 residential customers (about 0.8%) were served by the POLR. However, these customers are included in the switching totals by the Commission, even though many of these customers were transferred to the POLR. This overstates the number of customers that chose to switch to another REP and is different than the method used by other states that report customer switching. Using the Commission's figures for September 2002 and adjusting for the inclusion of these POLR customers reduces the percent of residential customers from six percent to 4.7 percent.[6] As Figure VI.3 shows, the percent of all residential customers reported by December 2002 had reached almost eight percent. Since the number of POLR customers was not reported by the Commission for December, the adjustment for the month was not made.

Figure VI.8 show that as of May 2003, between 25 percent and 39 percent of load was served by non-incumbent or independent REPs. The highest percentage was for AEP Texas North's service area at 39 percent of the load from non-affiliated REPs and the second highest percentage was 36 percent of CenterPoint's load served by non-affiliated REPs. Affiliated REPs are often active in other service territories, however since the Commission does not report individual company market shares, it is not made public how successful affiliated REPs have been in other service areas. The lowest service area market share served by non-affiliated REPs was Oncor's (TXU), at 25 percent of the load served.

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[6]Six percent of 319,297 customers works out to 5,321,616.6 total residential customers. Subtracting the POLR customers that were reported to have switched (319,297 - 69,424), leaves 249,873. Then, 249,873 divided by 5,321,616.6 comes to 4.7 percent.

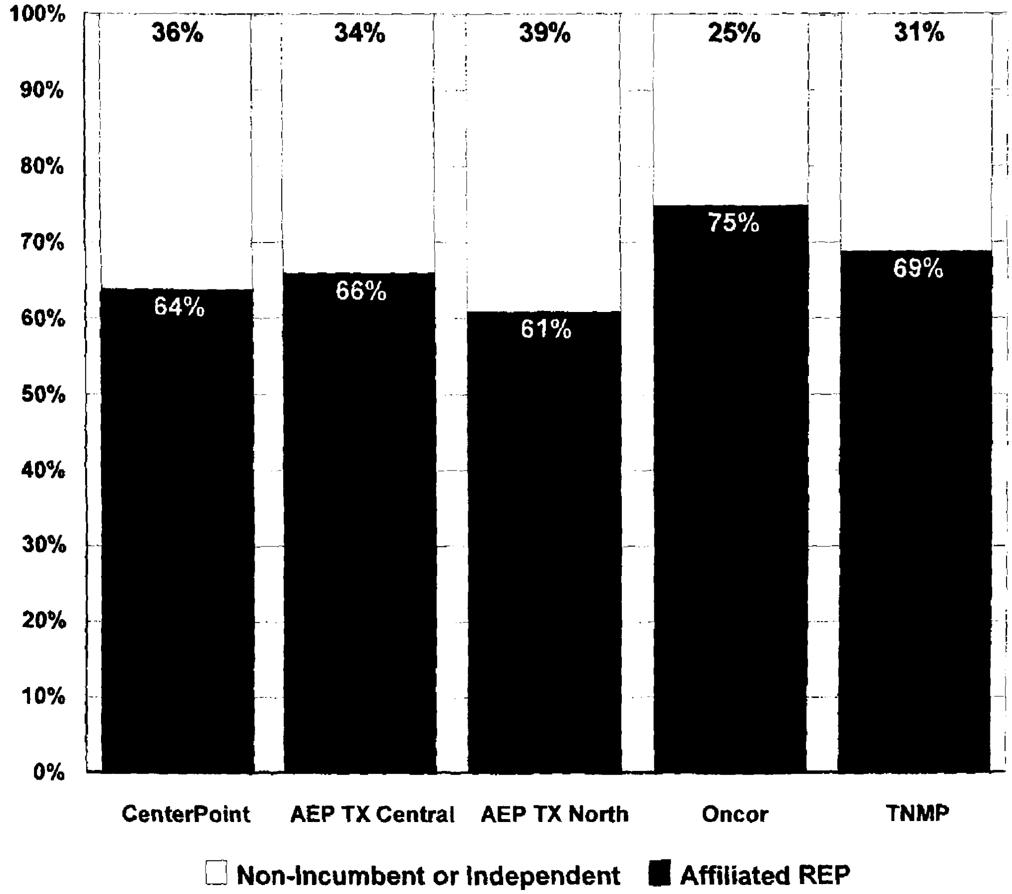

Figure VI.8. Affiliated and non-affiliated REPs' market shares by service area, percent of load (May 2003).
Source: Commissioner Brett A. Perlman presentation, "Setting a New Agenda for the Restructured Electric Industry," August 8, 2003.

Customers without a price-to-beat available from the affiliated REP, are essentially in the market and were encouraged to choose to purchase power from the affiliated REP or a competitive REP. As seen nationally, because these customers use large amounts of power and have a strong incentive to consider alternatives, they are usually the most active shopping group and are usually the more sought after customers by retail suppliers. In addition, the Texas Commission required affiliated REPs to give the non-price-to-beat customers advance notice of the rate they would be charged on January 1, 2002, if they did not negotiate other arrangements with the affiliated REP or switch to a competitive REP. The Commission reports that the default offers of the affiliated REP were generally either a very high fixed price offer or a pass-through of market prices, both of which may be considered risky options for most retail customers. This likely provided added incentive for these customers to shop for the best available price, since the default offers may lead to rates higher than those in effect before retail access began. As of December 2002, approximately eight percent of the non-price-to-beat customers remained on this default pricing offer, or approximately 92 percent of these customers have negotiated a competitive contract with either the affiliated REP or a non-affiliated REP.

Customer savings

The Commission reports that because of a combination of excess generation capacity, lower natural gas prices, and implementation of the price-to-beat rate reduction mandated by restructuring law, retail customers in Texas paid significantly less for electricity in 2002 when compared to the regulated rates in effect in 2001. The Commission calculates the total annual savings for residential customers at approximately $900 million in 2002 as compared to what they paid in 2001. Low-income residential customers have received an additional $68 million in discounts, or an average reduction of $136 per customer, through the end of October 2002.

They also estimate that through August of 2002, commercial customers have saved, in total, approximately $420 million compared to rates in effect in 2001 and industrial customers appear to have saved at least $225 million compared to rates in effect in 2001. They note that many of these customers, especially cities and other government entities, have done this through aggregating with other customers.

The residential customers' savings of approximately $900 million are based on the price-to-beat rates in effect on January 1, 2002, when the savings ranged from eight percent to 18 percent[7] compared to the rates in effect on December 31, 2001 (see Table VI.1 and Figure VI.3). They note that approximately $225 million of this reduction is related to the statutorily mandated six percent reduction in rates and $675 million of this reduction is attributable to reductions in fuel costs and the expiration of fuel surcharges. These two factors alone, therefore, account for all the $900 million savings. In addition, as can be seen also in Table VI.1, the price-to-beat rates were *higher* for three affiliated REPs in June 2003, by 14.1 percent for CPL/AEP Texas Central, 13.6 percent for WTU/AEP Texas North, and 0.3 percent for TXU. The other two affiliated REPs had much more modest decreases from the December 31, 2001 rate than the January 1, 2002 price-to-beat rate, 4.4 percent for First Choice/TNMP and 2.9 percent for Reliant/CenterPoint. It should be noted also, as can be seen in Figure VI.3, that all the December 31, 2001 rates (the basis of comparison) were considerably above the January 1999, rates that were likely in effect when the restructuring law passed in May of that same year. All the price-to-beat rates remained substantially higher in June 2003 than the January 1999 regulated rates.

As shown in Table VI.3, residential customers have savings opportunities in all areas open to retail access, ranging between eight percent and 24 percent in June 2003. If the price-to-beat rate increases from the beginning of competition on January 1, 2002 through June 2003 are compared with the percentage savings of the lowest-priced offers to residential customers by area, no offer offsets the increase over that period. Thus, a similar calculation of rate impact for that period would show that customers had paid more since

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[7]By company, the reduction in rates from December 31, 2001 to the price-to-beat on January 1, 2002 was 14.7 percent for TXU, 17.1 percent for Reliant/CenterPoint, 18.1 percent for First Choice/TNMP, eight percent for CPL/AEP Texas Central, and 11 percent for WTU/AEP Texas North.

competition began. It is likely, however, that rates would have gone up under regulation as well, due to likely fuel cost adjustments. A comparison, therefore, of the percent increase in the price-to-beat to best offer is not a fair assessment of competition in Texas, only a reminder that the rate changes are substantially the result of fuel price changes and any increase or decrease should not be attributed to just retail access. Table VI.4 compares the percent increase in the price-to-beat since January 2002 and the percent savings on the best offer to residential customers in the area in 2003.

Table VI.4. Percentage increase in the price-to-beat since January 2002 and the percent saving on the best offer to residential customers in June 2003.

Affiliated REP	Increase in the Price-to-Beat from Jan. 2002 to June 2003	Savings on Lowest Priced Offer to Residential Customers, June 2003
TXU	17.6%	13%
Reliant/CenterPoint	17.2%	16%
First Choice/TNMP	16.6%	8%
CPL/AEP Texas Central	24.1%	21%
WTU/AEP Texas North	27.7%	24%

Other Issues

<u>Stranded Cost True-Up</u>

Utilities are required to finalize their stranded cost determination in 2004 through a market valuation of assets. The Commission is concerned that because of the current level of uncertainty and the lack of investor interest in wholesale generation companies, the market-based valuations of generation facilities or companies that own them may result in significant stranded costs for several companies. High stranded costs would, in turn, likely result in higher delivery charges from the TDUs. In Texas (as in many other states), the Commission noted that stranded costs are predominately related to nuclear generation assets' high capital costs.

The initial estimates of stranded costs were made during the cost separation cases filed by the utilities in April 2000. In large part due to high estimates of natural gas prices, the Commission found initial estimates of stranded costs to be negative, that is, estimates of the market value of the generation resources exceeded the net book value of the assets. As a result, the Commission did not establish interim CTCs and instead ordered the utilities to begin returning stranded cost mitigation to customers as a credit to the non-bypassable charges (the "excess mitigation credit," or EMC).

In December 2001, the Commission adopted a rule to establish the procedures by which formerly integrated utilities will conduct their true-up proceedings in 2004. The primary purpose of the true-up proceedings is to reach a final determination of the utilities' stranded costs as the new rule establishes the process for quantifying the stranded costs of the utilities, and the reconciliation of that amount with prior estimates is used to set rates. Several investor-owned utilities have appealed the true-up rule.

TXU and Entergy have both agreed to forego further stranded cost recovery, and will not be conducting true-up proceedings as a result of these settlements. Reliant, TNMP, and CPL are required, barring additional settlements, to finalize their stranded costs.

The rule amendments included a "transmission cost recovery factor," or TCRF, that permits a utility to receive expedited cost recovery of additional transmission investments, and include those costs in the non-bypassable rates that are charged to retail customers. The TCRF is to only recover the capital costs associated with new investments in transmission facilities, and is subject to reconciliation in the transmission utility's next transmission rate case. The Commission believes that the TCRF mechanism will encourage the timely construction of new transmission facilities needed to facilitate competition by reducing the risk to the transmission utility of making such investments. (This is similar to a FERC proposal issued in January of 2003.)

Capacity Auction

The Commission's rule on capacity auctions is intended to promote competition in the wholesale market by increasing the availability of generation and liquidity by requiring affiliated PGCs to sell entitlements to at least 15 percent of their Texas generation capacity. In compliance with the Commission's rule, monthly and annual generation capacity auctions have been conducted by incumbent utilities.

Market Monitoring

The Commission created a Retail Market Oversight Section in the Electric Division to coordinate monitoring of retail electric market issues. The responsibilities of the section include the monitoring of the day-to-day operation of the retail market in Texas, including monitoring the success of processing switch requests, move-in/move-out transactions, the exchange of meter data needed to bill retail customers, and billing issues that affect retail customers. This section also monitors compliance with Commission rules, transmission and distribution tariffs and the ERCOT Protocols, and participates in retail market design and implementation activities at ERCOT. This section also participates in the development of retail market protocols for the areas outside of ERCOT, and oversees the administration of the system benefit fund and low-income discount programs.

The Commission also has the Market Oversight Division (MOD) that has responsibilities that include monitoring the activities of wholesale market participants to ensure compliance with Commission rules and the ERCOT

Protocols and to prevent the exercise of market power and other anti-competitive behavior. MOD investigates market activities as necessary, and participates in market design and implementation activities at ERCOT to eliminate market design flaws as they are recognized. MOD staffing currently consists of nine full-time employees and graduate student interns in the Economics and Engineering programs at the University of Texas at Austin. MOD compiled a comparison of the market oversight staffs in the five operating competitive electric markets in the United States, and is reproduced in Table VI.5.

Table VI.5. Comparison of market monitoring staffing and budgeting.

Market Region	Market Size (Peak Demand, MWs)	2002 Full Time Equivalents	2003 Full Time Equivalents	2002 Budget (millions of dollars)
California ISO	43,000	14	16	3.0
New England ISO	26,000	11	14	1.9
New York ISO	32,000	21	30	4.8
PJM	54,000	12	NA	2.7
ERCOT	58,000	9	NA	0.6

Source: Public Utility Commission of Texas, January 2003, p. 52.
PUCT Table Notes: 2002 budget figures are estimates provided by each ISO and include the costs of consulting services. Figures for New York include resources for legal enforcement. New York indicated that their budget for 2003 will be increased to $6.5 million.

SECTION VII
West and California

In the previous two reports, details and analysis of the Western and California wholesale market crisis were examined. Some of those studies that were summarized are reproduced below along with some updated prices and findings from the California ISO.

The western power crisis began in late May of 2000 when the average California Power Exchange (PX) price jumped from just over $27 per MWh in April of 2000 to over $50 per MWh in May and then to $132 per MWh in June–on its way to a high of about $450 per MWh in January 2001. The last power emergency declared by the California ISO to occur in that train of events can be viewed as the end of the crisis period, in early July of 2001. After this period, wholesale prices leveled off and did not return to the levels reached during the crisis. The eventual decline in prices was due to the reversing of a similar combination of factors that lead to prices rising during the crisis. These included a return of hydro-capacity, reduced demand, and lower natural gas prices. (The combination of factors that caused the crisis in California is discussed in last year's report.) The FERC western-wide price cap was likely imposed too late (June of 2001) to have much of an impact on prices during the crisis.[1]

Figure VII.1 graphs monthly average prices from January 2000 through December 2002. This graph shows the full span of time of the price run-up in California and the relative calm in average monthly prices through the end of 2002. Figure VII.2 charts the daily western hub prices from June 2002 to June 2003. As seen in other

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[1]A FERC staff report ("Report on the Economic Impacts on Western Utilities and Ratepayers of Price Caps on Spot Market Sales," a paper prepared by the FERC staff, January 31, 2002) found that "after the Commission [FERC] issued its June 19 [2001] Order, prices in the spot market steadily declined throughout the time period at issue [late June through late November] and were well below the $92/MWh price cap." (p. 11.) The report concluded that "a wide variety of factors other than the price cap, such as conservation efforts, a downturn in the regional economy, and adequate supply given low demand, affected sales prices in both the spot and non-spot markets." (p. 4.)

power markets, the effect of the natural gas price spike in early 2003 can be seen, albeit, even more pronounced than other power markets. Also, the effect of warm weather in May in the West and in early June can also clearly be seen.

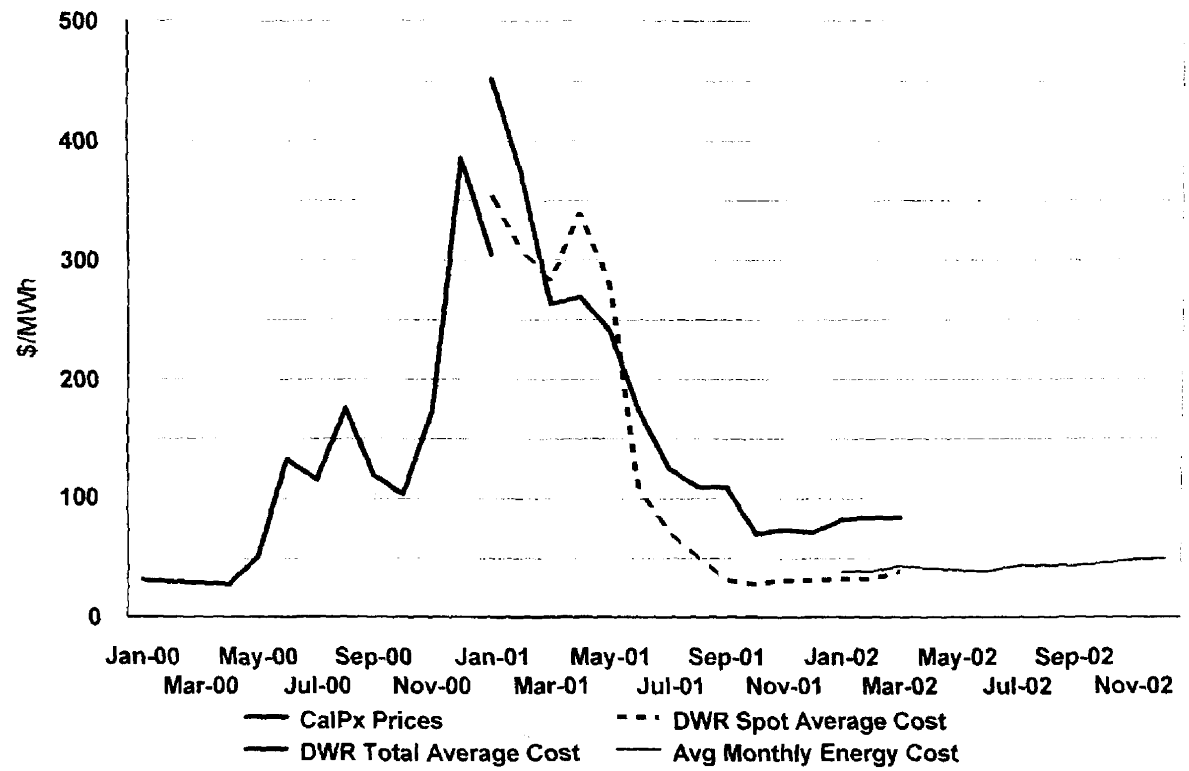

Figure VII.1. California power prices from January 2000 through 2002.
Sources: The California Power Exchange, California Department of Water Resources, and California ISO.

The California power market has been studied and analyzed more than any other power market in the country. There was evidence before the summer of 2000 suggesting that market power was significant during peak hours. Since growing demand in California was not matched with additional supply and significant existing hydro capacity was unavailable due to drought conditions, there is little doubt that scarcity played a role in the price run-up. It would be expected that the price would be

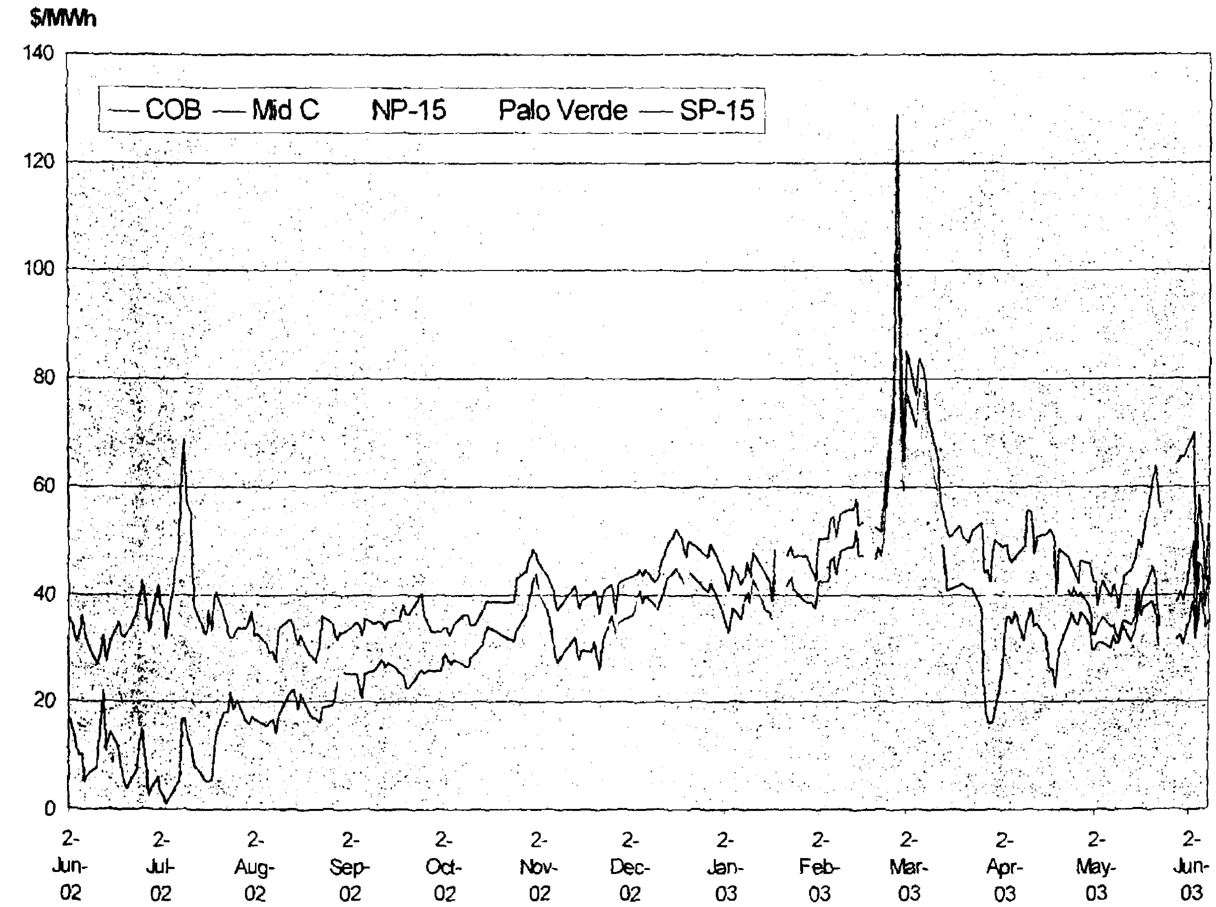

Figure VII.2. Western wholesale power hub prices.
Source: IntercontinentalExchange, Inc., www.intcx.com.

driven up to the marginal cost of the highest cost marginal unit needed to satisfy demand–a higher marginal cost than would be obtained during times of relatively plentiful supply. However, it is clear that actual prices exceeded, and often greatly exceeded, the expected highest marginal cost. Empirical evidence of market power has been found in several analyses of the California market. A summary of the more significant studies that were discussed last year are presented again here, followed by summaries of two new analyses of California's markets.

Before the Western power crisis of 2000 and 2001 began, a study by Borenstein, Bushnell, and Wolak[2] had found evidence of significant market power in the California wholesale electricity market. They estimated total payments in excess of competitive levels at $719 million for the 16 months of their study period–June of 1998 to September of 1999. If June of 1998 is excluded, the total payment in excess of competitive levels was determined to be $795 million.[3] They calculated the average markup of price over a competitive outcome at 15.7 percent or, excluding June '98, 18.3 percent. This markup occurred primarily during peak demand periods.

Dr. Anjali Sheffrin, the Director of the Department of Market Analysis of the California Independent System Operator, conducted a detailed analysis of market power and bidder strategy in California. [4] This study provides evidence that "many large suppliers actively engaged in strategic bidding efforts and that their activity had a direct impact on market prices." Dr. Sheffrin concludes that supplier "bidding strategy was not ad hoc, but consistent with a certain model of oligopoly pricing behavior" and that it "implies the systematic exercise of market power to maximize profit." Her findings are

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[2]Borenstein, Bushnell, and Wolak, "Diagnosing Market Power in California's Deregulated Wholesale Electricity Market," working paper of the Program on Workable Energy Regulation, University of California Energy Institute, Berkeley, California, March 2000, PWP-064.

[3]As a later study (discussed below) also shows, June of 1998 had prices *below* competitive levels. This was the third month of operation of the California Power Exchange and most of the capacity was still owned by the investor-owned utilities. During this time, the utilities' competition transition charges (CTCs) were calculated as the previous regulated rate minus the mandated discount, transmission and distribution charges, other customer charges, *and the Power Exchange price* (adjusted for customer class). This meant that the lower the PX price, the greater the CTC. After divestiture by the utilities and other suppliers entered the market, this incentive was removed.

[4]Anjali Sheffrin, "Empirical Evidence of Strategic Bidding in California ISO Real Time Market," March 21, 2001, California Independent System Operator and "What Went Wrong With California Electric Utility Deregulation?," presentation at "Current Issues Challenging The Utility Industry," held by the Center for Public Utilities, New Mexico State University, Santa Fe, New Mexico, March 26, 2001.

consistent with expected behavior of firms with considerable market power that can profitably use economic and physical withholding to raise prices. Five large in-state suppliers were found to use economic withholding 80 percent of the time and physical withholding less than 20 percent of the time. Her estimated average bid-cost markup was more than $100/MWh during some summer months. The total market power impact was estimated at approximately $6.2 billion from May of 2000 through February of 2001.

An analysis by Joskow and Kahn,[5] concludes that wholesale electricity prices in California "far exceeded" competitive levels from June through August of 2000. They could not explain the prices as the "natural outcome of 'market fundamentals' in competitive markets." This was due to the "very significant gap between actual market prices and competitive benchmark prices that take account of these market fundamentals." They estimate a competitive benchmark price of $62.60 per MWh for June 2000 (assuming a NOx price of $10/lb), which compares with the average PX price for the month of $120.20 per MWh. For July the competitive benchmark was $67.98 per MWh ($20/lb NOx price) and a average PX price of $105.72 per MWh. August and September competitive benchmark prices were $121.50 and $104.36 per MWh (both using a NOx price of $35/lb) respectively, when average PX prices were $166.24 in August and $114.87 in September. The market fundamentals accounted for in their analysis included higher natural gas and emission permit prices, increased demand, and reduced availability of imports. They also found evidence that suggests that the higher prices reflected the withholding of supplies by generators and marketers.

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[5]Joskow and Kahn, "A Quantitative Analysis of Pricing Behavior in California's Wholesale Electricity Market During Summer 2000," an AEI-Brookings Joint Center for Regulatory Studies Working Paper (01-01), January 2001.

Borenstein, Bushnell, and Wolak[6] estimated the monthly Lerner index for California from June 1998 through October 2000. These estimates are shown in Figure VII.3. The negative values in the first year of the ISO's operation were likely due to incentives of the investor-own utilities (that still owned most of their pre-restructuring generation) to have low energy prices–and thereby increase their competition transition charges or CTCs (as previously explained in footnote 3 of this section). In general, the Index spikes during the summer and early fall months when demand is at its peak and supplies are most constrained. They also correlated the hourly demand level for electricity with the corresponding Lerner Index for that hour,[7] as shown in Figure VII.4. This clearly demonstrates that as demand increases, when supplies become increasingly scarce, the ability of suppliers to leverage a higher price increases. At its peak, the Index is over 0.5 (that is, 50 percent of the price is markup above marginal cost) in all three years. At only about two-thirds of the peak demand, however, the Index is above 0.3 for all years. At lower levels of demand, as would be expected, suppliers have very little price leverage. It is interesting to note that all three years, including the crisis year of 2000, have a similar overall pattern. This confirms the expectation discussed above that when demand is relatively inelastic (that is, unresponsive to price as electricity generally is), the market is concentrated as it was in California at that time, and as the supply from other firms becomes more restricted as demand increases, the price leveraging ability of firms increases.

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[6]Severin Borenstein, James Bushnell, and Frank Wolak, "Measuring Market Inefficiencies in California's Restructured Wholesale Electricity Market," Center for the Study of Energy Markets, University of California Energy Institute, Berkeley, California, CSEM WP 102, June 2002.

[7]They used "kernel" regression to determine the curves for each year.

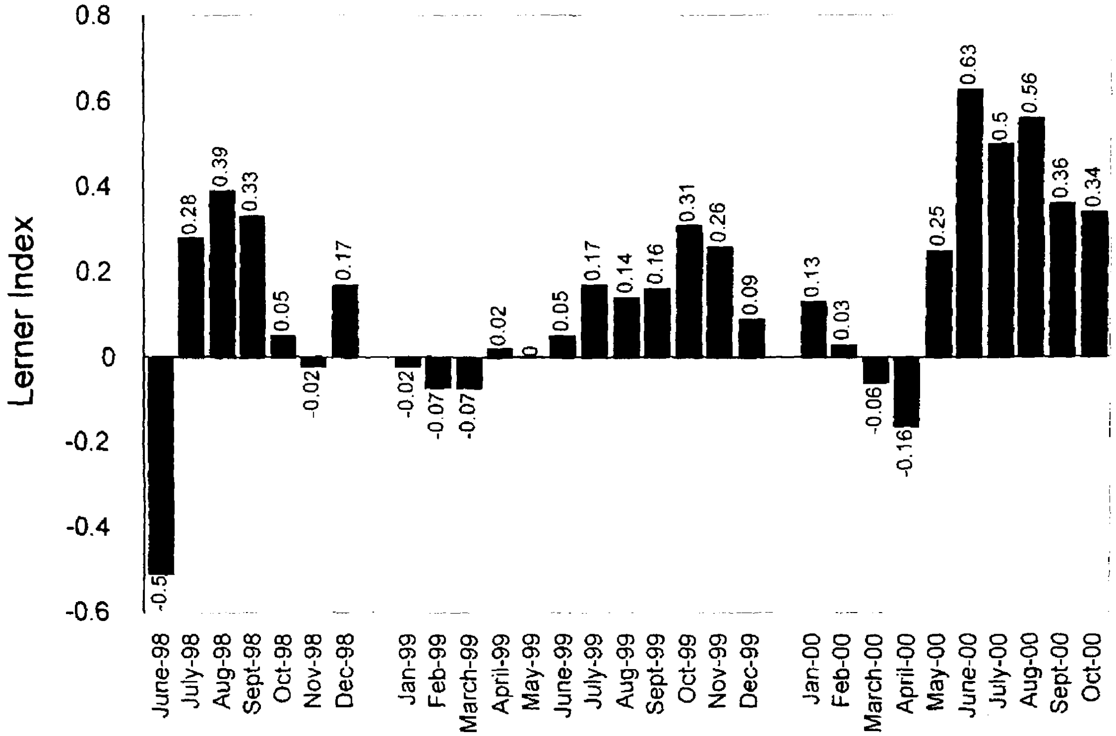

Figure VII.3. *California monthly Lerner Index for June 1998 through October 2000.* Source: Borenstein, Bushnell, and Wolak, "Measuring Market Inefficiencies in California's Restructured Wholesale Electricity Market," June 2002.

Borenstein, Bushnell, and Wolak also estimated supplier economic rents[8] due to the exercise of market power in California. They estimate that between the summers of 1998 and 2000, "oligopoly rents," increased more than ten fold from $425 million in 1998 and more than eleven times the 1999 estimate of $382 million, to $4.45 *billion* in 2000. They note that while a substantial portion of the rise in the wholesale cost of power, from $1.67 billion to $8.98 billion, was due to rising input costs and reduced imports, this also increased the amount of the market power exercised by suppliers as well.

[8]Economic rent is defined as what was paid to producers beyond what would have been the minimum amount required to have them continue to generate electricity.

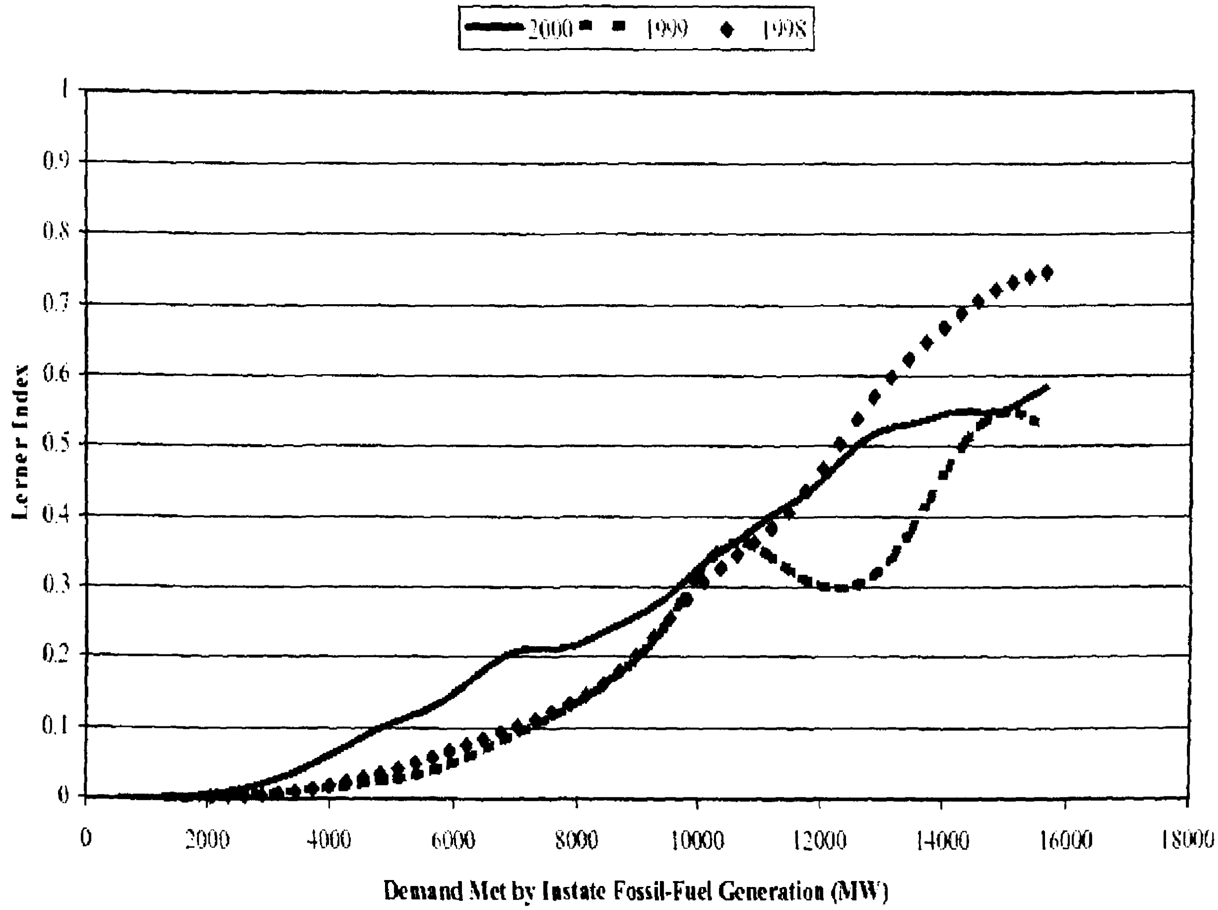

Figure VII.4. The relationship between the level of demand and the Lerner Index (market power markup estimate) for California.
Source: Borenstein, Bushnell, and Wolak, "Measuring Market Inefficiencies in California's Restructured Wholesale Electricity Market," June 2002.

An analysis by the California ISO[9] also shows that electricity suppliers in California exercised significant market power and were able to raise prices significantly above competitive levels. Figure VII.5 shows the markup of prices above a competitive market for the forward and real-time energy markets in California during 2000 and 2001. The area depicted in red is the estimated supplier market power markup. The California

[9]California Independent System Operator, "Third Annual Report on Market Issues and Performance: Market Monitoring, Investigative, and Compliance Activities," January – December 2001, January 2002.

ISO's report notes that the bulk of the markup observed after June is embedded in the long-term forward contracts entered into by the California Energy Resource Scheduler (CERS) during January through April 2001. Market power, they note, is therefore embedded in the long-term average costs for electricity. Supplier market power in the real-time market was substantially reduced after June of 2001, as shown in Figure VII.6. They note that this is because of more favorable supply/demand conditions, the imposition of a regional (western-wide) price cap by FERC, and forward purchases by the state.

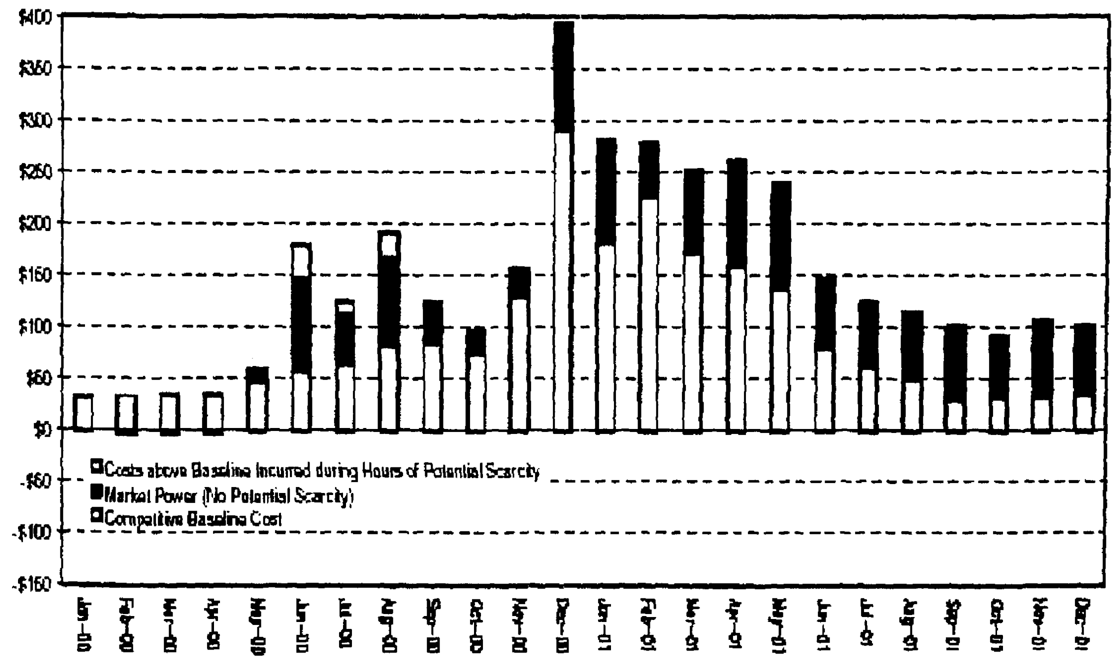

Figure VII.5. Price-cost markup of forward and real-time energy.
Source: California Independent System Operator, "Third Annual Report on Market Issues and Performance Market Monitoring, Investigative, and Compliance Activities," January – December 2001, January 2002.

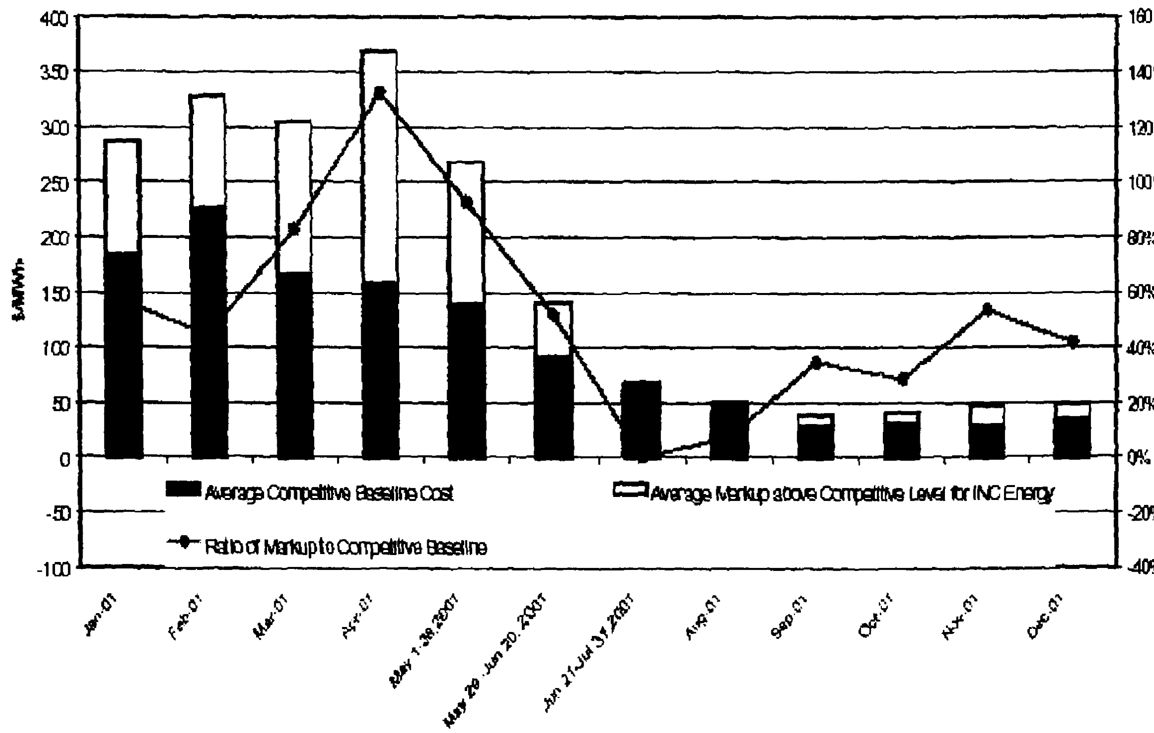

Figure VII.6. Price-cost markup in the real-time energy market.
Source: California Independent System Operator, "Third Annual Report on Market Issues and Performance Market Monitoring, Investigative, and Compliance Activities," January – December 2001, January 2002.

In its 2002 Annual Report,[10] California ISO estimates that the 2002 average markup was $5.69 per MWh or 17 percent above costs. They note that the markup approached 35 percent in the summer months (May and July from the graph). Figure VII.7 shows the California ISO's monthly markup estimates for 2002. The California ISO also began estimating a volume-weighted, twelve-month rolling average of short-term markups, or the "twelve month competitiveness index." The intent is to measure the degree of market power during the market's transition to a new structure–of adequate supply and demand response. The 2002 index is reproduced as Figure VII.8

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[10]California Independent System Operator, "2002 Annual Report On Market Issues and Performance," April 2003.

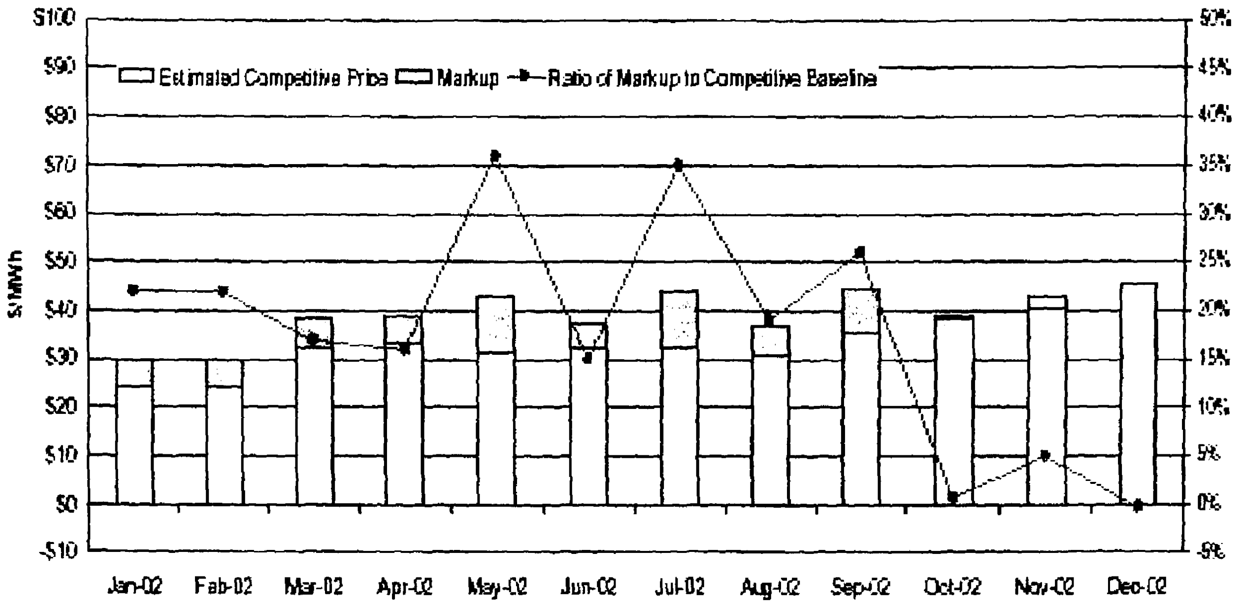

Figure VII.7. Price-to-cost markup in short-term energy market in 2002.
Source: California ISO, April 2003.

below. Since the ISO estimates that the index was above $5 per MWh for each month in 2002 and peaked at nearly $51 per MWh, they then conclude that during 2002 "some market power persists in the short-term market."[11] They assume that the market is "workably" competitive if the index is below $5 per MWh.

[11]California ISO, "Annual Report," p. 3-15.

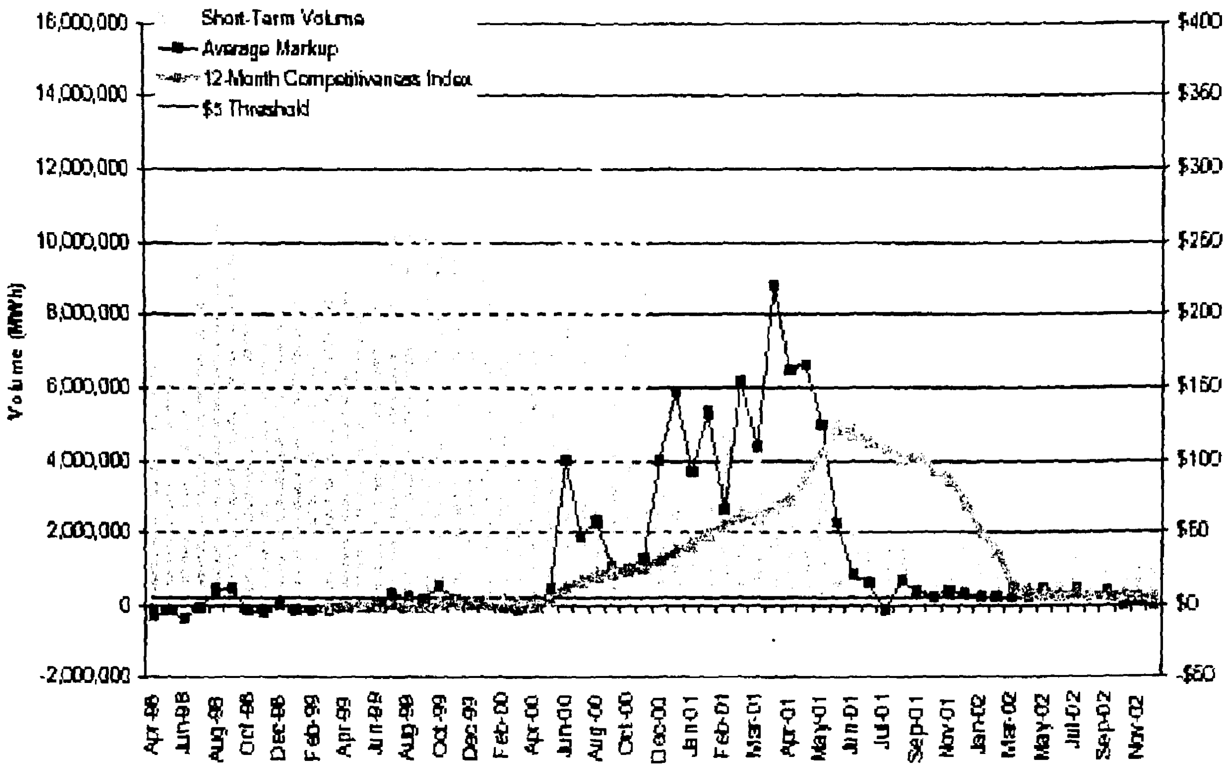

Figure VII.8. California ISO's Twelve-Month Competitiveness Index, April 1998 through December 2002.
Source: California ISO, "Annual Report," p. 3-15.

Biography

Dr. Rose has been working on energy and regulatory issues for more than nineteen years. He has testified or presented at many legislative and public utility commission hearings, proceedings, conferences, and workshops on electric industry issues and has testified before several committees of the U.S. House of Representatives on regulatory matters. Dr. Rose has worked primarily on studies concerning the electric industry and has directed or contributed to many reports, papers, articles, and books. Topics include Clean Air Act implementation, environmental externalities of electricity production, competitive bidding for power supply, regulatory treatment of uneconomic costs, market power and market monitoring, and other industry restructuring issues. He is a frequent presenter at conferences, workshops, and other instructional venues and has been quoted often in The New York Times, The Washington Post, The Wall Street Journal, other newspapers and in trade publications. Dr. Rose is a Senior Fellow at the Institute of Public Utilities at Michigan State University and lectures for the School of Public Policy and Management at The Ohio State University. Dr. Rose was a Senior Institute Economist at The National Regulatory Research Institute at Ohio State University from 1989 until October 2002. Prior to NRRI, Dr. Rose worked on many energy related issues at Argonne National Laboratory from 1984 to 1989. Dr. Rose received his B.S. (1981), M.A. (1983), and Ph.D. (1988) in Economics from the University of Illinois at Chicago.

PART II

STATUS OF RETAIL ACCESS AND COMPETITION IN THE COMMONWEALTH

PART II

Status of Retail Access and Competition in the Commonwealth

Executive Summary

The first part of our third annual report to the Governor and the Commission on Electric Utility Restructuring, provided a review of recent performance of electricity power markets throughout the United States. The electricity supply industry continues to struggle following price run-ups, disclosures of accounting and data improprieties, creditworthiness issues, and volatile fuel prices, particularly natural gas. Most of the retail markets remain inactive, especially for smaller residential and commercial customers.

Part II of the Report focuses on activities in Virginia related to retail access and competition in the electricity market over the past year. It also reviews the SCC's efforts to develop a proper infrastructure to accommodate competition and to prepare Virginians for consumer choice for generation, as directed by the Act.

During the past year the SCC has continued to implement the Restructuring Act. At the present time, about 2.9 million electricity customers in Virginia have the right to choose an alternative supplier of electricity. By January 1, 2004, when an additional 168,500 customers will gain the right to choose, nearly all of the customers of Virginia's investor-owned utilities and electric cooperatives will have the right to switch to a competitive supplier. The exception is the approximately 29,400 customers in the southwestern part of the Commonwealth exempted from the Act by legislation enacted by the General Assembly in 2003 and approximately 7,000 customers served by Powell Valley Electric Cooperative.

As we reported last year, the right to choose has not yet evolved into the ability to choose. While it is clear that the SCC, the utilities and the various stakeholders have effectively enabled almost universal retail access in Virginia, there is little competitive activity in the Commonwealth. We understand that many suppliers still perceive little economic incentive to enter the Virginia retail market. No competitive service provider is offering energy priced so that switching customers may save money. Currently, one supplier continues to serve about 2,300 residential customers and 22 small commercial customers in Dominion Virginia Power's northern Virginia with an environmentally-friendly "green" power offer. This service is more expensive than Dominion Virginia Power's price-to-compare. Again, as detailed in Part I, this lack of activity is not unique to the Commonwealth; in other states currently offering retail access, few customers have the option to purchase power at a price lower than their incumbent's price to compare.

Over the past twelve months, the SCC, aided by the incumbent utilities and interested stakeholders, continued to make strides in preparing the Commonwealth for the arrival of competition for the generation component of electric service. Various work groups coordinated by the Staff have been assisting the SCC to provide the foundation for retail access by examining many issues, including competitive metering, supplier billing, default service, energy infrastructure, stranded costs, and regional transmission organizations ("RTO"). The SCC appreciates the time and effort of the respondents that have participated with these work groups.

The SCC has issued orders during the past year relating to issues such as competitive metering, supplier billing, market price/wires charge determination, regional transmission organizations, and several access programs within electric cooperative territories. In addition to the September 1 reports on the status of competition and the December 2002 Addendum, the SCC has issued reports addressing energy infrastructure information and stranded costs. Slow development of competitive activity and statewide budget constraints have caused the SCC to suspend its consumer education efforts for the present.

INTRODUCTION

In this part of the State Corporation Commission's ("Commission" or "SCC") report to the Governor and to the Commission on Electric Utility Restructuring ("CEUR"), we provide an update regarding activities in Virginia related to competition in the electricity market. Since § 56-596 of the Virginia Electric Utility Restructuring Act ("Restructuring Act" or "Act")[1] directs us to file a report each September 1st, the section on the status of competition in the Commonwealth will provide a history of the transition to competition. Each year we will prepare a chronology and summary to detail the progress of competition and activities of interest during the past twelve months.

During the past year this Commission has continued with the scheduled implementation of the Restructuring Act. At the present time, 2.9 million electricity customers in Virginia have the right to choose an alternative supplier of electricity. By January 1, 2004, an additional 168,500 customers will gain the right to choose a supplier. In compliance with the Act and this Commission's Order in Case PUE-2000-00740, all electricity customers of Virginia's investor-owned utilities and electric cooperatives will be eligible to switch to a competitive supplier except for about 29,400 customers in the southwestern part of the Commonwealth[2] and approximately 7,000 customers served by Powell Valley Electric Cooperative.

As discussed later in this report, work began or continued during the past year to address restructuring issues such as those related to competitive metering, supplier billing,

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[1] Virginia Electric Utility Restructuring Act, Chapter 23 (§ 56 576 et seq.) of Title 56 of the Code of Virginia.

[2] Amending legislation passed by the 2003 Session of the General Assembly as House Bill 2637 to § 56-580 of the Code of Virginia, suspended application of the Restructuring Act to Kentucky Utilities operating in the Commonwealth as Old Dominion Power Company until such time as the utility provides retail electric services in any other service territory in any jurisdiction to customers who have the right to receive competitive retail electric energy.

default service, energy infrastructure, stranded costs, and regional transmission organizations ("RTO"), to name a few.

It remains disappointing, however, that more competitive service providers have not made offers of attractively priced energy options. As in many other states that offer retail access, competitive activity has dwindled in Virginia during the past twelve months. One supplier continues to serve a small portion of customers in northern Virginia with a limited renewable resource, but no other electricity supply offers have been made.

The following pages provide an overview of the continued transition to full retail access; the process used to develop wires charges and a price-to-compare; the status of our consumer education program; and details on a diverse list of activities and investigations devoted to the development of a competitive market.

ACTIVITY RELATED TO ACCESS

This section provides a review of activity during the past 12 months of the transition to full retail access in Virginia. In addition to supplying details on the number of customers who switched energy providers, there will also be discussions of the licensing of suppliers and aggregators, marketing activity, and customer complaints.

Transition to Full Retail Access (Phase-In)

The Commission Order in Case No. PUE-2000-00740 established the phase-in schedule for all investor-owned utilities and cooperatives and directed them to submit quarterly reports regarding the status of efforts to implement the phase-in of retail choice. Ten such reports have been submitted to the Commission staff ("Staff") as of July 2003, and a brief summary of the current status follows.

Allegheny Power ("AP"),[3] American Electric Power – Virginia ("AEP-VA") and Delmarva Power & Light ("Delmarva") implemented full customer choice within their respective Virginia service territories on January 1, 2002. In December 2001, these three local distribution companies ("LDCs") were granted approval of unbundled rates and associated tariffs that became effective on January 1, 2002. Price-to-compare information was provided along with a revised bill format to inform and assist each customer in evaluating options. All of these LDCs have completed adjustments to their computer and business systems and are ready to conduct electronic data interchange ("EDI")[4] tests with competitive service providers ("CSPs"), a topic discussed later in this report. To date, no CSP has registered with AP or

[3] Doing business in Virginia as the Potomac Edison Company ("PE").
[4] EDI standards and guidelines are established by the Virginia Electronic Data Transfer Working Group ("VAEDT"). The VAEDT is discussed later in this report.

AEP-VA to provide service within their respective Virginia territories. To date, one CSP is fully registered with Delmarva and another has completed EDI testing. The LDCs are prepared to accommodate customer choice when CSPs offer service within the companies' service areas.

Dominion Virginia Power ("DVP") implemented customer choice for one-third of its statewide commercial and industrial load and a third of its residential customers, primarily within its northern Virginia territory, on January 1, 2002. Another third of its customers, including residential customers in central Virginia were eligible to switch suppliers on September 1, 2002, and its remaining customers on January 1, 2003.

Similar to AEP-VA, AP and Delmarva, DVP was granted approval of its unbundled rates and associated tariffs effective January 2002. Price-to-compare information was provided along with a revised bill format.

DVP has completed adjustments to its EDI systems and has successfully completed testing with seven CSPs. To date, eleven CSPs and aggregators have initiated discussions or are in various stages of registering with DVP to provide service within DVP's Virginia territory. Only three CSPs have actually served customers since implementing full retail access. Two of those were the DVP affiliates that were carry-overs from the pilot program. The one CSP that had an offer in DVP's service territory this year, Pepco Energy Services ("PES"), withdrew its offer in May 2003, but continues to serve about 2,400 customers. Although PES is not currently mass marketing its service, it continues to enroll new customers to replace slots that become available as customers drop PES to return to DVP's capped rates. To date, all CSPs that served customers either in DVP's pilot program or under full access have been affiliates of an electric or natural gas utility.

The Commission Order in PUE-2000-00740 permitted the electric cooperatives ("Cooperatives") and Kentucky Utilities ("KU")[5] to phase-in implementation of retail access at their own pace provided it is completed by January 1, 2004. The distribution cooperatives have announced plans to develop the necessary business processes and systems to accommodate retail access by the dates shown below:

Northern Virginia	implemented 7/1/02
Rappahannock	implemented 1/1/03
Shenandoah Valley	implemented 4/21/03
Community	implement 8/03 upon filing compliance tariffs
Southside	implement 10/1/03
A&N	implement 1/1/04
BARC	implement 1/1/04
Central Virginia	implement 1/1/04
Craig-Botetourt	implement 1/1/04
Mecklenburg	implement 1/1/04
Northern.Neck	implement 1/1/04
Prince George	implement 1/1/04

These Cooperatives will continue to work collectively to address transition issues and take advantage of synergies. The SCC issued its order in Case No. PUE-2002-00086 on June 18, 2002, approving Northern Virginia Electric Cooperative's ("NOVEC") tariffs and terms and conditions amended per Staff's recommendations. NOVEC's initiation of retail choice was conditioned upon the timely receipt of its wire charge allocation agreements with its generation affiliate, Old Dominion Electric Cooperative ("ODEC"), and its revised tariffs. The agreements and tariffs were filed with the Commission on July 12, 2002. REC submitted on August 2, 2002, its plan and associated tariffs to permit implementation January 1, 2003.

Shenandoah Valley Electric Cooperative ("SVEC") filed its application for retail choice on November 1, 2002, to begin on April 1, 2003. The SCC issued its order in Case No. PUE-2002-00575 on April 2, 2003, approving SVEC's tariffs and terms and conditions subject to

[5] No longer applicable because of House Bill 2637 and 2003 amendment to § 56-580 of the Code of Virginia.

modifications recommended by Staff. SVEC was permitted to implement retail choice upon the filing of the required revised tariffs. The Cooperative submitted compliance tariffs on April 21, 2003.

Community Electric Cooperative ("CEC") filed its application on January 28, 2003, to begin retail choice during the summer of 2003. The SCC issued its order in Case No. PUE-2003-00002 on July 30, 2003, approving CEC's tariffs and terms and conditions subject to some modifications recommended by Staff and permitting CEC to implement retail choice upon the filing of the required revised tariffs.

Southside Electric Cooperative ("SSEC") filed its application on May 1, 2003 to offer their customers retail choice beginning on October 1, 2003 and is currently pending before this Commission. Recent applications of A&N, BARC, Central Virginia, Craig-Botetourt, Mecklenburg, Northern Neck and Prince George Electric Cooperatives to offer their customers retail choice beginning on January 1, 2004, are under review by Staff. It is anticipated that Commission approval of these applications will be complete before year-end to comply with the Commission's Order in Case No. PUE-2000-00740 to fulfill the phase-in of electric retail choice in Virginia.

All of the LDCs referenced above continue to participate actively with various work groups assisting Staff to address transition issues and to implement the Restructuring Act.

Suppliers/Aggregators

The Commission is responsible under §§ 56-587 and 56-588 for licensing suppliers and aggregators interested in participating in the retail access programs in Virginia. The Staff has established a streamlined mechanism for processing license applications. To facilitate the prompt processing of license requests, the SCC website provides access to the licensing requirements.[6] Staff has an internal deadline of 45 days from the receipt of a complete application to the issuance of a license. Thus far, that deadline has been met for all applications. Currently, nineteen electric and natural gas CSPs and aggregators are licensed by the Commission to participate in full retail access. A list of suppliers can be found at the end of this section. Since last year, five competitive service providers have voluntarily surrendered their licenses to do business as a CSP or an aggregator in Virginia.

In order to participate in an LDC's retail choice program, a CSP must also complete a registration process with the utility. EDI testing between the CSP and the utility is required as part of the registration process. The testing must be completed before a supplier can begin enrolling customers.

Two CSPs, Dominion Retail and PES, are fully registered with DVP. New Era Energy is the only aggregator fully registered with DVP. Four additional CSPs and aggregators are at various stages in the registration process with DVP:

- Constellation NewEnergy, Inc.
- Old Mill Power
- Washington Gas Energy Services
- EnergyWindow, Inc.

AEP-VA, AP, NOVEC, and REC have each had at least one CSP inquire about their choice programs, but no CSP has yet registered with any of the utilities. WGES is fully registered with Delmarva and Old Mill Power has completed EDI testing but not yet completed its registration with Delmarva.

[6] Guidelines to become licensed as a competitive service provider or aggregator are available on the SCC's website at: http://www.state.va.us/scc/division/eaf/compete.htm.

Applications for Competitive Service Provider/Aggregator Licensure (August 1, 2003)

Company Name	Customer Class(es)	LDC Service Territories in which CSP registered	Services Provided
Pepco Energy Services	R, C, I	DVP, WG, SG, CGV	Natural gas, electric and aggregation (E&G)
Dominion Retail, Inc.	R, C,I	DVP, WG	Natural gas, electric and aggregation (E&G)
Washington Gas Energy Svcs	R, C, I	DPL, DVP(pending), WG, SG, CGV	Electric & natural gas
EnergyWindow, Inc.	R, C, I	DVP (pending)	Aggregation (E&G)
New Era Energy, Inc.	R, C, I	DVP	Aggregation
Amerada Hess Corporation	C, I	WG, SG	Electric, natural gas and aggregation (E&G)
Energy Svcs Mgmt Va LLC, d/b/a Virginia Energy Consortium	C		Aggregation (E)
Bollinger Energy Corporation	C, I	WG, CGV	Natural gas
Tiger Natural Gas, Inc.	R, C, I	WG, SG, CGV	Natural gas
NOVEC Energy Solutions, Inc	R, C, I	WG, SG, CGV	Electric, natural gas and aggregation (E&G)
BGE Commercial Bldg Systems Inc	C, I	WG, SG	Natural gas
Old Mill Power Company	R, C, I	DVP (pending), DPL (pending)	Electric, natural gas and aggregation (E&G)
Metromedia Energy, Inc.	C, I	WG	Natural gas
Stand Energy Corporation	C, I		Natural gas
ACN Energy, Inc.	R	WG	Natural gas
AOBA Alliance, Inc.	C		Aggregation (E&G)
UGI Energy Services, Inc.	C, I		Natural gas
Constellation NewEnergy, Inc.	C,I	DVP (pending)	Electric and aggregation (E&G)
Select Energy, Inc.	C,I		Electric and natural gas

Customer Type: "R" residential; "C" commercial; "I" industrial
LDC Service Territories:

AEP-VA = AEP Virginia
AP = Allegheny Power
DVP = Dominion Virginia Power
DPL = Delmarva Power & Light

CGV = Columbia Gas of VA
WG = Washington Gas
SG = Shenandoah Gas (division of WG)

Marketing

The only marketing activity that has taken place in any retail access program is in DVP's service territory. Pepco Energy Services continues to provide "green power" to residential customers in Northern Virginia. The renewable generation source is biomass, landfill gas from a landfill in central Virginia. The offer consists of 51% renewable energy offered at a premium above DVP's price-to-compare.

Since full retail access began, PES's renewable energy offer is the only offer residential electricity customers have received. To date, about 2,300 residential and 22 commercial customers are enrolled with PES. No industrial customer has yet chosen a competitive electricity service provider.

Customer Participation

Pepco Energy Services began serving retail access customers in January 2002 and is currently the only active CSP.

The following table provides the number of electricity customers in the Virginia LDC territories that are currently eligible to shop for a CSP and how many are enrolled with a CSP as of July 7, 2003.

Company	# of Eligible Residential Customers	# of Eligible Nonresidential Customers	# of Residential Customers Currently Served By a CSP	# of Non-Residential Customers Currently Served By a CSP
DVP	1,836,701	196,499	2,317	22
AEP-VA	421,143	62,084	0	0
AP	72,847	13,019	0	0
DPL	18,757	3,297	0	0
NOVEC	101,901	7,063	0	0
REC	76,752	4,186	0	0
SVEC	29,311	4,907	0	0
CEC	8,086	1,517	0	0

Therefore, out of approximately 2.6 million residential customers in Virginia who currently have the right to choose an alternative supplier of electric energy, less than 2,400 customers are currently doing so, or about 0.1%.

FUNCTIONAL UNBUNDLING AND WIRES CHARGE

This section of the report will detail the steps involved with setting the price for energy while rate caps are in effect. Unbundled generation rates and market prices for generation are essential components to determine wires charges. Additionally, the generation market prices established by the Commission for each incumbent utility help competitive suppliers determine whether they can or will make competitive offers in utilities' service territories.[7]

The first step is the functional unbundling of rates into separate generation, transmission and distribution components as required under § 56-590 of the Restructuring Act. The next step is the calculation of the market price for generation which, when compared to the unbundled generation rate, will determine the amount of an appropriate wires charge, if any. The procedure for calculating market prices and wires charges are detailed in § 56-583 of the Act. A final important component of the pricing of energy is the determination of the price-to-compare for each incumbent electric utility. This benchmark price can then be used by consumers for comparison shopping.

Functional Unbundling

Section 56-590 of the Restructuring Act required Virginia's incumbent electric utilities to file plans detailing the proposed separation of the incumbents' generation, retail transmission and distribution functions. The cases provided the companies an opportunity to file proposed retail access tariffs applicable to customers and third party suppliers. As part of these cases, the Commission also "unbundled" the companies' retail rates for purposes of establishing wires charges.

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[7] It should be noted, however, that if a utility's unbundled generation rate is *less* than the Commission-determined market price for generation, then the price a CSP must "beat" in order to make a competitive offer would be the unbundled generation rate, and not the market price.

Rate unbundling in these cases consisted of separating the utilities' bundled rates,[8] for retail electricity service into separate components to reflect distribution, transmission and generation charges. Transmission charges were also unbundled into base and ancillary services. The companies' retail access tariffs addressed and defined the operational relationship between the utilities and competitive service providers in the provision of competitive generation service within the incumbents' respective service territories. These tariffs, among other things, addressed CSP creditworthiness requirements, noncompliance and default, load forecasting and scheduling procedures, and CSP billing. Each of the functional unbundling cases was discussed in the previous Commission Report and will not be restated here. This section will provide an update to the last report.

AEP-Virginia (PUE-2001-00011): By order dated June 18, 2002, the Commission approved the Company's April 30, 2002, motion requesting that the Commission hold all further proceedings on the corporate separation issues in abeyance until no earlier than July 1, 2003. On July 1, 2003, AEP-Virginia filed a Motion For Leave to Withdraw Request. The Company states that it is no longer actively pursuing legal separation at this time. AEP-Virginia requests leave to withdraw, without prejudice, its request for legal separation and further requests that this proceeding be closed. AEP-Virginia's Open Access Distribution Service Tariff was accepted for filing by the Commission's Division of Energy Regulation on December 23, 2002.

Old Dominion Power Company (Kentucky Utilities) (PUE-2001-00003): House Bill 2637 suspended the application of the Virginia Electric Utility Restructuring Act to any

[8] A bundled rate is a single rate for electricity comprised of all service elements: generation, transmission and distribution.

investor-owned incumbent electric utility supplying electric service to retail customers on January 1, 2003, whose service territory is located entirely within five enumerated counties in Southwest Virginia (Dickenson, Lee, Russell, Scott and Wise). The suspension will continue so long as the utility does not provide retail electric services in any other service territory in any jurisdiction to customers who have the right to receive retail electric service from another supplier. During the suspension period, the utility's rates shall be (i) its capped rates established pursuant to § 56-582 for the duration of the capped rate period, and (ii) determined thereafter by the SCC on the basis of the utility's prudently incurred costs (per § 56-232 et seq.).

Delmarva Power & Light (PUE-2000-00086): On May 15, 2003, the Company filed its Virginia Fuel Index and Proxy Production Function Expense calculations in compliance with the Memorandum of Agreement.

Wires Charge Calculations

The Restructuring Act directs the Commission to establish wires charges for each incumbent electric utility effective upon the commencement of customer choice. In order to establish such wires charges the Commission must determine projected market prices for energy and subtract those projected market prices from each utilities' embedded generation rate. According to the Act, these projected market prices and the resulting wires charges may be adjusted on no more than an annual basis. The embedded generation rate includes fuel costs as determined by the Commission pursuant to § 56-249.6.

Although the Commission's experience in determining market prices began in 2000 with the retail access pilots of AEP-VA, Rappahannock Electric Cooperative, and DVP, market price determination for full retail access began in 2001 with the market price and wires charges determinations for AEP-VA and DVP.[9] This past year the Commission established the market price determination methodology for the electric distribution cooperatives within the Commonwealth and approved projected market prices and any resulting wires charges for calendar year 2003.

The Commission approved the basic methodology for AEP-VA and DVP in its order of November 19, 2001 in Case No. PUE-2001-00306. This order set a general schedule for making annual changes to wires charges at the beginning of each successive calendar year. If either company wishes to revise its wires charges for the following calendar year, it must file market price and fuel factor applications with the Commission by July 1 of the current year. This allows wires charge determinations to be finalized in October or about three months before they will be implemented. This enables the companies to make necessary calculations and carry out compliance filings before the implementation date. Such a timely determination also allows time for CSPs to formulate and implement pricing and marketing strategies for the following year.

In its November 19, 2001 order, the Commission also decided that the projected market prices for generation to be used in wires charge calculations should be based on "forward prices"[10] for electric power traded in the wholesale market. The Commission made this decision with the beliefs that forward prices were a better indicator of projected market prices and that the forward markets were functioning reasonably well.

The forward price method considers prices at two delivery/receipt points (Cinergy and PJM West) for a calendar year of data. Although DVP has incorporated a value for capacity in

[9] Delmarva and Potomac Edison waived their right to wires charges throughout the transition period. AEP-VA waived its right to collect wires charges for calendar years 2002 and 2003, and recently waived its right to wires charges during calendar year 2004.

[10] "Forward prices" generally refer to agreements made today for the future purchase and sale of a specified quantity of electric power at some specified location for a specified time period.

the Company's projected market price formulation, there is no explicit inclusion of a capacity value within the generally approved methodology. Price adjustments for load-shaping are accomplished using methods similar to those employed in the pilot programs. Finally, the Commission specified a method for adjusting market prices in order to consider the cost to transport power to distant markets.

During the early summer of 2002, the Commission Staff convened a work group to investigate potential changes in the methodology of determining market prices. A number of stakeholders in the restructuring process participated in the workgroup; however, only one CSP was represented. The group met on July 24, 2002 to discuss possible revisions to the market price calculation, including, but not limited to, conceptual changes or use of new data sources. The group seemed satisfied, for the most part, with the inputs, data sources, and timing of the current market price methodology. Most of the discussion centered around whether a value for capacity should be included in the market price. A subsequent meeting was held on August 12, 2002. With respect to the inclusion of a value for capacity in the market price projection, the lone CSP representative present indicated that while including a value for capacity would provide some additional headroom, such a capacity adder would be too small to act as an inducement for CSPs to enter the Virginia energy market. In conference calls with three other CSPs, the Staff heard a similar message.

The CSP opinions available to Staff notwithstanding, the workgroup led to a proposal by DVP to incorporate a capacity adder into the projected market price for the company's service territory for 2003. This adder is based on the historical monthly values of capacity as reflected in the PJM Capacity Credit Market. DVP conditioned its offer on certain changes to its CSP Coordination tariff that the company stated were necessary to make DVP whole in the event of a CSP default. In allowing, but not requiring, DVP to implement the capacity adder in the company's market price and wires charge calculation, the Commission declined to allow for the changes in DVP's CSP Coordination tariff. The Commission believed that the proposed changes might have a negative effect on CSP participation in the Virginia retail market; however, the Commission will allow DVP to propose risk mitigation measures in the future if they are shown necessary. The Commission allowed DVP to implement the proposed capacity adder recognizing that it served to lower wires charges slightly and create additional headroom for CSPs and thus, was "a step in the right direction." Subsequent to the Commission's order, DVP incorporated the capacity adder in the company's 2003 market price and wires charge calculation.

Even with the inclusion of the capacity adder, the projected market prices for DVP for 2003 are below the company's capped generation rates. As such, wires charges are applicable to DVP customers that choose to take service from a CSP during 2003. On July 1, 2003, DVP submitted an application to impose a wires charge in 2004. This application is currently under review by Staff and a hearing has been scheduled for September 10, 2003.

With respect to AEP-VA's market price and wires charge calculation, the issue of the company's transmission cost adjustment to market prices has remained outstanding since 2001. Pursuant to §56-583 of the Restructuring Act, the Commission adjusts market prices for the net cost of transmission required to send power that has been displaced by customers who have switched to CSPs to distant power markets. To date, the Commission has not accepted AEP-VA's methodology for calculating this adjustment in that AEP-VA's proposed adjustments have been significantly higher than appears reasonable.

Even with AEP-VA's proposed transmission cost adjustment calculation any calculated wires charges due the company from customers switching to CSPs have been zero or nil, implying that projected market prices calculated under the Commission-approved methodology are in excess of AEP-VA's capped generation rate. Given this circumstance and the lack of a resolution over the company's method of calculating its transmission cost adjustment, AEP-VA has waived its right to collect wires charges in each of the past two years.

The Commission has stated that before it can approve a wires charge for AEP-VA, it "must have net transmission costs that reflect the real cost of delivering power from generating units that would otherwise serve AEP-VA's retail customers adjusted for transmission revenues otherwise recovered in rates subject to state or federal jurisdiction." This issue is moot for 2004 as AEP-VA notified the Commission on July 1, 2003 that the company will not request approval to collect wires charges for 2004. Information provided with this notification implies that market prices for 2004 within the company's service territory will again be above AEP-VA's capped generation rate.

With respect to the electric distribution cooperatives, on May 24, 2002 in Case No. PUE-2001-00306, the Commission adopted a proposal from the Cooperatives and ruled that the basic methodology for calculating generation market prices that it approved for DVP and AEP-VA should be utilized by the Virginia electric distribution cooperatives,[11] subject to the Commission's continued review. There is, however, one basic difference in the methodology as applied to the Cooperatives as opposed to that for DVP and AEP-VA. Whereas, the capped rate for generation for the investor-owned utilities are adjusted annually for the cost of fuel on a prospective basis, the capped rates for the Cooperatives are adjusted monthly on an historical basis. This distinction is to allow the Cooperatives to continue a decades-old practice that allows them to make monthly adjustments for their wholesale cost of power. Without

[11] A&N Electric Cooperative, BARC Electric Cooperative, Central Virginia Electric Cooperative, Community Electric Cooperative, Craig-Botetourt Electric Cooperative, Mecklenburg Electric Cooperative, Northern Neck Electric Cooperative, Inc., Northern Virginia Electric Cooperative, Powell Valley Electric Cooperative, Prince George Electric Cooperative, Rappahannock Electric Cooperative, Shenandoah Valley Electric Cooperative, and Southside Electric Cooperative, Inc.

continuing to allow for these wholesale power adjustments in their retail access tariffs the wires charges for a cooperative would vary on a month-to-month basis. For consistency, the Commission allows the Cooperatives to vary the market price monthly by the same amount as the wholesale cost of power adjustment to maintain a constant wires charge throughout the year.

To date, market prices have been established for four cooperatives. The Commission approved the projected market prices for Northern Virginia Electric Cooperative and Rappahannock Electric Cooperative in June and October, 2002, respectively. To date in 2003, the Commission has approved the projected market prices for Shenandoah Valley Electric Cooperative and Community Electric Cooperative. In all four of these cases, the capped rate has been in excess of the projected market prices within the respective service territories of these cooperatives; therefore, customers switching to CSPs must pay a wires charge to the cooperative serving them.

Additionally, Southside Electric Cooperative, Inc., A&N Electric Cooperative, BARC Electric Cooperative, Central Virginia Electric Cooperative, and Northern Neck Electric Cooperative have filed applications for approval of their retail access tariffs and market prices, however, the approval process has not yet been completed. The remainder of the cooperatives are expected to submit retail access tariff and market price applications by September in order to comply with the Restructuring Act's provision that retail access be available in their service territories by January 1, 2004.

Price-to-Compare

Once rates have been unbundled and the appropriate wires charge has been calculated, a company's price-to-compare can be determined. The price-to-compare is a cents per kilowatt-hour benchmark value that can be used by a customer to evaluate offers from competitive service providers.

The price-to-compare is determined by taking the sum of the unbundled generation rate and the unbundled transmission rate and subtracting the wires charge. If a company does not have a wires charge, because its embedded generation rate is less than the current estimated market price, or if a company has waived its right to a wires charge, the price-to-compare is the sum of the unbundled generation and unbundled transmission rates.

Among investor-owned utilities, only DVP imposed a wires charge component for 2003 to be included within its price-to-compare. Each of the cooperatives implementing retail access in 2003 also included a wires charge component within the respective price-to-compare.

The table below shows the prices-to-compare for the investor-owned utilities in Virginia required to implement retail competition. A similar table for the electric distribution cooperatives that have implemented retail competition is not shown given that, as described above, the cooperatives price-to-compare changes on a monthly basis due to the application of monthly wholesale power adjustments.

The 2003 price-to-compare values are:

Investor-Owned Utilities

Customer Class	Dominion Virginia Power	AEP Virginia	Allegheny Power	Conectiv
Residential	3.983¢/kWh	3.409¢/kWh	3.87¢/kWh	5.47¢/kWh
Small Commercial	4.006¢/kWh	3.230¢/kWh	3.96¢/kWh	5.94¢/kWh
Large Commercial	3.624¢/kWh	3.748¢/kWh	3.90¢/kWh	Not applicable
Small Industrial	3.470¢/kWh	3.125¢/kWh	3.55¢/kWh	5.58¢/kWh
Large Industrial	3.193¢/kWh	2.944¢/kWh	3.34¢/kWh	5.49¢/kWh
Churches	3.834¢/kWh	3.147¢/kWh	Not applicable	Not applicable

As can be seen, the price-to-compare differs among classes of customers. The values above are averages for each customer class. The actual price-to-compare for an individual customer will vary depending upon that customer's usage and rate schedule.

New market price and wires charge calculations are scheduled to be completed in October for use in 2004. Soon after that time, the new price-to-compare values will also be available. Price-to-compare information will appear on the monthly bill of customers who have not yet chosen an alternative supplier.

CONSUMER EDUCATION

Overview

The major objectives of the Virginia Energy Choice ("VEC") consumer education program in the second full year of activities were to continue the steady rise in awareness of energy restructuring and educate Virginians about changes in the energy market. Despite the lack of competitive offers, consumer awareness of Virginia's move to a restructured energy market reached 46 percent by January 2003 compared to less than 29 percent in a benchmark survey conducted in June 2001.

In presenting amendments to the 2002-2004 biennial budget in December 2002, Governor Mark Warner proposed that the State Corporation Commission immediately curtail most of the activities of the consumer education program and defer the startup of any new initiatives for the remainder of the biennium. In the budget approved by the General Assembly, a total of $8.5 million was transferred to the general fund. The budget language called for $2 million transferred in the fiscal year ending June 30, 2003 and $6.5 million in the fiscal year ending June 30, 2004. As such, the education program entered a 16-month "quiet" period.

By March 2003, the SCC stopped all awareness advertising, suspended outreach efforts with community-based organizations, and ceased printing additional VEC publications. The VEC website continues to function. The toll-free VEC information line continues to operate, but with an automated system instead of live customer service representatives. Approved consumer education grants were funded, but no new grants will be awarded during the remainder of the biennium. SCC staff continues to be available for consumer presentations.

All of the communications contractors supporting the SCC in the consumer education program agreed to suspend or greatly reduce activities during the curtailment period. These contractors also agreed to be available to help re-establish the VEC campaign if market development substantiates the need for consumer education and funding is available beginning July 1, 2004.

The SCC continues to share program plans and receive input from the Virginia Energy Choice Education Advisory Committee. The committee members represent investor-owned utilities, electric cooperatives, consumer groups and competitive suppliers.

Consumer Research

VEC conducted consumer surveys in August 2002 and January 2003 to measure awareness and knowledge as well as monitor ongoing consumer attitudes toward energy restructuring. Awareness of Virginia's move to a competitive energy market increased among residents from 43.1 percent to 46.1 percent while business leader awareness decreased slightly from 53 percent to 51.9 percent (overall, significant increases from pre-campaign awareness levels of 28.8 percent and 38.4 percent, respectively.) Although competitive energy service providers are not currently making offers to consumers, the survey in January 2003 revealed that 78.4 percent of consumers say they are interested in energy choice compared to 76.3 percent in August 2002.

In January 2003, consumers were asked to name any concerns that they have regarding energy choice in Virginia. One half of all respondents (50.1 percent) suggested they had no concerns. Another 17 percent were concerned prices would increase, while others were concerned about reliability (6.7 percent), supply problems (5 percent), poorer customer service (3.8 percent), and many marketing calls (3.1 percent). Similar concerns were recorded among business leaders. Strong majorities of both consumers (77.6 percent) and business leaders (72.8 percent) are confident service will continue uninterrupted in a competitive energy market. The SCC has canceled additional VEC consumer surveys in the 2002-2004 biennium.

Advertising

Due to the failure of competition to develop, the VEC paid advertising budget in the second year of the program was reduced by 50 percent. With the input of the Education Advisory Committee, print, broadcast and billboard advertising continued to correspond with the electric choice phase-in schedule, but at a significantly reduced level. A limited Phase I advertising schedule in northern Virginia continued in newspapers and on geo-targeted Internet websites through the fall of 2002. Phase II advertising began prior to electric choice coming to central and western Virginia on September 1, 2002 and concluded at the end of December. Phase III broadcast advertising started in Hampton Roads in October 2002 and concluded at the end of December prior to the introduction of electric choice on January 1, 2003. Some billboards were displayed in the Hampton Roads area in January and February 2003 due to prior agreements. Annual contracts for sports sponsorships (mostly radio commercials) concluded in March 2003.

With limited marketing activity by competitive service providers, the advertising messages of the VEC advertising program were revised in the second year. Initially the advertising focused on consumers having the opportunity to choose their energy suppliers. The advertising was changed to encourage Virginians to contact VEC to learn about changes in the energy industry. The program's toll-free information line and website address were prominently featured in all advertising.

Public Relations

The public relations program broadened the knowledge and awareness levels of Virginians by providing detailed information about energy choice through grassroots education and media relations. Media outlets across the state received a steady flow of updates on the consumer education efforts through December 2002. Although the news media was receptive to VEC information, journalists were quick to learn that energy suppliers were not making competitive offers. The limited level of competitive activity resulted in a corresponding limited level of interest in covering energy restructuring, of which the VEC program was a part. Regardless, in the second year, the program still generated 32 print news articles in daily and weekly newspapers. Additional coverage was generated in television and radio broadcasts.

The grassroots outreach effort provided direct contact with consumer groups and community-based organizations to utilize their networks to distribute education information on energy choice. The program was designed to reach audiences that may have difficulty receiving the information from the mass media or have special information needs. Groups involved include organizations representing senior citizens, minorities, non-English speakers, people with disabilities, residents of rural areas, and small business owners. Since the program began in June 2001, over 600 organizations around the state have agreed to help educate consumers. To date, the groups have distributed more than 1.5 million education materials.

Summary of Grassroots Outreach Activity by Category of Organization as of 5/28/03

	Total number of materials organizations have agreed to distribute (through mailings, emails, presentations and events)					**Website Info**
Populations Represented	**Consumer Guides** Number of Orgs Participating	**Newsletter Articles** Number of Orgs Participating	**Two-Pagers** Number of Orgs Participating	**Spanish Two-Pagers** Number of Orgs Participating	**Flyer** *Number of Orgs Participating*	**Number of orgs agreed to add VEC link/info to website**
Seniors	**23,335** *85 orgs*	**739,240** *46 orgs*	**18,597** *53 orgs*	**4786** *28 orgs*	**6167** *32 orgs*	**28**
African Americans	**16,037** *87 orgs*	**144,150** *29 orgs*	**21,112** *43 orgs*	**2085** *14 orgs*	**6222** *22 orgs*	**21**
Low-Income	**16,921** *69 orgs*	**152,175** *31 orgs*	**15,888** *51 orgs*	**5326** *39 orgs*	**2204** *37 orgs*	**23**
Non-English Speaking	**10,547** *57 orgs*	**111,825** *16 orgs*	**17,982** *38 orgs*	**6505** *40 orgs*	**1587** *29 orgs*	**19**
Disabled	**6746** *60 orgs*	**135,270** *22 orgs*	**14,744** *27 orgs*	**3321** *19 orgs*	**593** *18 orgs*	**21**
Small Business	**9208** *66 orgs*	**239,755** *51 orgs*	**3525** *10 orgs*	**1075** *6 orgs*	**4892** *8 orgs*	**30**

*Note: Some organizations represent multiple populations. The 1.5 million total figure noted in this document has been adjusted downward to eliminate duplication of groups representing multiple audience categories.

Since March 2002, VEC has published and distributed "The Source," an electronic newsletter about developments related to energy choice. Four editions of "The Source" have been published to date. Recipients of the newsletter include organizations that have participated in the grassroots program and individuals who sign up for the mailing list via the VEC website. Quarterly distribution is planned to continue through the "quiet" period in order to keep those who are interested informed about energy choice.

The VEC consumer education program included grant money to help encourage and facilitate the dissemination of information through community-based organizations, member-based groups, associations and organizations that serve a multitude of needs for individuals. These groups are highly credible third-party information sources that have established trust with their members. With a $5,000 limit per grant, an organization could print a special brochure, translate education materials, or conduct workshops. The SCC awarded a total of 13 grants. Several successful grant projects were completed:

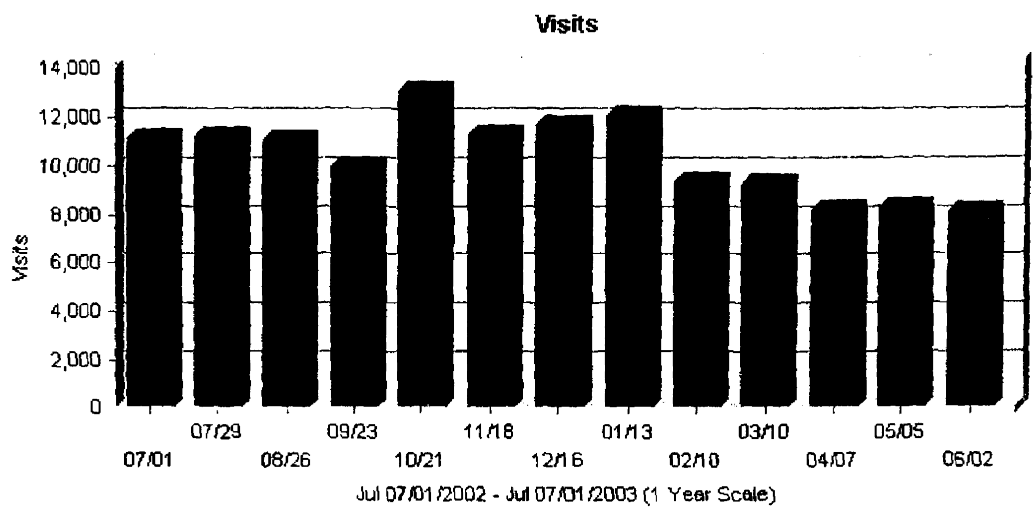
- the Urban League of Greater Richmond conducted a series of workshops for senior citizens on energy choice and produced educational materials ($2,826.84),
- the Henry County Adult Learning Center incorporated energy choice information into an instruction program called "Energy Efficiency and Your Budget" ($2,861.41),
- Campaign Virginia distributed over 16,000 VEC consumer guides as part of its door-to-door canvassing program ($5,000),
- the Virginia Department for the Aging printed a special VEC brochure and produced a Braille version of the education materials ($5,000).

Website

During the "quiet" period for the VEC campaign, the website was updated and a new address was introduced (www.vaenergychoice.org). The old address (www.yesvachoice.com) continues to function, and users who type in or link to the old address are automatically connected to the new location. Existing campaign printed materials that include the old web address are still usable. Any new materials developed in the future will include the new address.

The decision to move to www.vaenergychoice.org was based on two factors. First, consumers are used to website addresses that reflect the name of an organization. This is supported by the fact that the phrase consumers use most often to locate VEC via search engines is "Virginia Energy Choice." Second, the ".org" ending is generally considered to be more neutral than ".com" which fits with the program's goal of having VEC be the objective, informed source of information.

From July 2002 to June 2003, more than 135,000 visits were made to the website. The chart below shows monthly traffic to the site for this period.



Call Center

From July 1, 2001 to February 1, 2003, the VEC program provided customer service representatives to answer consumer questions received on a toll-free information line (1-877-YES-2004). The call center staff was trained to answer frequently asked questions about energy restructuring in Virginia. While the advertising campaign was active, the number of callers ranged between 724 in September 2002 and 962 in January 2003. The center also responded to VEC inquiries by e-mail and fulfilled daily requests for consumer education materials. During the 19 months of one-on-one phone support, the call center served almost

15,000 callers and distributed 208,000 Consumer Guides and other consumer education materials.

Since February 1, 2003, the toll-free information line has been supported by an automated system. Callers have the choice of listening to a brief recording, leaving address information to receive consumer education materials, or requesting a call from SCC staff. The reduced visibility of VEC caused a noticeable drop off of consumer calls and information requests. In the period from February 1 to June 30 of this year, 2,985 automated calls were received and 3,607 consumer education materials were distributed. The average number of calls per month is 597.

Next Steps

Even with the present curtailment of the Virginia Energy Choice consumer education program, the basic structure of the effort is intact and ready to resume activities at the appropriate time. The SCC will continue to receive the input of the Education Advisory Committee to determine the size and scope of the future consumer education activities. Information from research surveys, call center data and web inquiries will also help the SCC in revising the consumer education plan when authorized to begin after July 1, 2004. Based on Education Advisory Committee input and an evaluation of key issues affecting market development, the advertising strategy will be refined and outreach activities will be adjusted accordingly. The renewed program will once again focus on the foundation message of building awareness of energy choice among consumers who have little awareness of Virginia Energy Choice, while beginning to further educate those Virginians who have already become aware of the program. The toll-free information and website will be prominently displayed in all communications.

Regardless of the pace of development for the competitive energy market, consumers will want and need information about energy restructuring. The 16-page VEC consumer guide communicates what changes are underway and includes definitions of key terms. The SCC has an adequate supply of the guides to meet public requests through June 30, 2004. However the guide will need to be updated and revised in the second half of 2004 to incorporate new developments in energy restructuring. Advertising messaging may also be revised based on any new developments and their impact on the overall communications direction.

Consumers have expressed a desire for more specific competitive service provider information than what is currently available from VEC. Supplier telephone numbers, website addresses and registration information are available. Once competitive activity begins, Virginia consumers will renew requests for a chart or web feature that compares rates and services of the marketers.

Local distribution companies continue to be an important link for the VEC campaign. Consumers often call their local utilities first if they have questions about energy services. The VEC program will continue to explore opportunities to partner with utilities to provide consumer information through bill inserts, customer newsletters, web links, and consumer education events.

DEVELOPMENT OF A COMPETITIVE STRUCTURE

This section details activities underway to continue the establishment of the framework within which effective competition may develop. While these activities cannot, in and of themselves, assure that competition will flourish, there is no doubt that a competitive market will require both rules to guide behavior and systems to control business operations. In addition, the continuing development of our energy infrastructure, including power plants, transmission lines and natural gas pipelines, is an essential element of future energy reliability. Finally, properly functioning regional transmission organizations are generally recognized as a necessity for an effective competitive wholesale market, which is a precursor to an effective retail market.

Rules Governing Retail Access

The Restructuring Act directed the SCC to establish a transition schedule for retail access and promulgate regulations to guide the transition.[12] The Commission adopted rules with the following objectives in mind: (1) afford reasonable customer protections, (2) ensure equitable treatment of market participants, and (3) promote the advancement of competition in the Commonwealth.

The Rules Governing Retail Access to Competitive Energy Services ("Retail Access Rules" or "Rules"), adopted by Commission Order in Case No. PUE-2001-00013,[13] currently consist of 12 sections in Chapter 312 (20 VAC 5-312-10 et seq.) of Title 20 of the Virginia Administrative Code and pertain to various relationships among the local distribution companies, competitive service providers and retail customers. Responses to Staff's inquiries

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[12] The rules were to be developed for both a competitive electricity market and a competitive natural gas market. Our focus in this report is the electricity market.
[13] The Rules Governing Retail Access to Competitive Energy Services are available on the Commission's website at: http://www/state/va/us/scc/division/restruct/main/rules/teirrules.htm.

generally indicate that most market participants believe the current Retail Access Rules are: (1) consistent with other state requirements, (2) reasonable to balance the concerns and needs of market participants, and (3) conducive to promoting a competitive energy marketplace.

The Commission's Staff continues to monitor and evaluate the development of the energy marketplace, including our experiences in Virginia, and recommend further adjustments to such Rules, if necessary. Future legislative or Commission decisions may also affect the developing energy marketplace. The Retail Access Rules will be revised and amended as needed to incorporate future rules that may be adopted by the SCC. These Rules were amended to further address a minimum stay period (PUE-2001-00296), supplier consolidated billing (PUE-2001-00297), competitive metering (PUE-2001-00298), and aggregation of competitive energy services (PUE-2002-00174).[14]

Minimum Stay Provisions

The Commission's Final Order in Case No. PUE-2001-00296, which adopted a minimum stay period for large customers, directed the Staff to investigate alternatives to minimum stay periods and submit a report by March 31, 2003. Senate Bill 892 was introduced in the 2003 General Assembly to eliminate the minimum stay requirement for customers willing to take generation service at a form of market rate if they returned to the incumbent utility during the capped rate period following supply service from a CSP. Such proposed legislation was tabled in the Senate Commerce and Labor Committee with the request that the CEUR (formerly LTTF) give the issue further study and consideration.

[14] These Dockets and others regarding restructuring issues may be found on the SCC's website at: http://www.state.va.us/scc/caseinfo.htm .

Subsequently the Staff requested a delay for submitting its report. On March 12, 2003, the Commission granted Staff's request to delay pending the CEUR's further consideration of the tabled legislation.

Competitive Metering Provisions

The Commission entered an Order in Case No. PUE-2001-00298 on August 19, 2002, approving rules regarding competitive electricity metering services for the elements of meter data availability and accessibility effective January 1, 2003. The order directed the work group to continue to meet and address other elements of competitive metering services, including meter ownership for large customers.

The Staff submitted a report on August 30, 2002,[15] recommending that the Staff, with the assistance of the work group, propose rules regarding financial ownership of meters by large industrial and large commercial customers. In addition, the Staff recommended that the work group focus on monitoring market developments in metering as a precursor to the implementation of any additional elements of competitive metering for large customers. Staff also recommended that interested parties be invited to submit comments with respect to competitive metering for residential and small business customers.

In its Order of December 10, 2002, the Commission directed the Staff to proceed with the assistance of the work group to develop rules regarding financial ownership of meters for large industrial and large commercial customers and to file proposed rules on or before March 4, 2003. The Commission also directed the Staff to focus its efforts on monitoring market developments in metering and report to the Commission on such developments approximately

[15] The report may be found at: http://www.state.va.us/scc/caseinfo/pue/case/comp_meter.pdf .

one year after the implementation of rules for meter ownership. The Commission also directed the Staff to continue to study the possibility of the utilities establishing voluntary and/or expanding time-of-use pilot programs for residential and small commercial customers, and to examine the issue of implementing full competitive metering services for residential and small business customers.

The Staff issued its report on February 25, 2003, presenting proposed rules for financial ownership of electricity meters for large industrial and large commercial customers, and recommending the final rules become effective January 1, 2004. On March 3, 2003 the Commission issued an order inviting comments and requests for hearing on the proposed rules. The parties neither requested a hearing nor recommended any revision to the proposed rules. Comments were received regarding the establishment by utilities of voluntary pilot programs for residential and small commercial customers and the implementation of full competitive metering services for residential and small business customers. The Commission's Order of July 11, 2003 adopted rules regarding customer ownership of meters by large industrial and large commercial customers. Each investor-owned distribution electric utility was directed to file revised tariffs by August 30, 2003, reflecting the adopted regulations to be effective on January 1, 2004.

Additionally, this Commission directed Staff, with the assistance of the work group, to continue efforts to study expanded or voluntary Time-Of-Use programs along with new meter technology to ensure currently used technologies do not inhibit the use of price signals or deter the development of a competitive metering market. The Commission expects Staff to submit a report by May 1, 2004 providing the results of its investigation.

Competitive Billing Provisions

On August 31, 2002, the Commission issued an Order in Case No. PUE-2001-00297, adopting rules for CSP consolidated billing.[16] The Commission also found that an EDI workaround approach for implementation of CSP consolidated billing was reasonable on an interim basis, recognizing that such approach will need to be replaced with standardized EDI protocols as the competitive market develops and the volume of competitive billing increases. Subsequently, the Commission granted the requests for the investor-owned utilities for delays in the implementation of CSP consolidated billing by delaying the required implementation date. Such utilities timely submitted revised tariffs to address the necessary changes to implement CSP consolidated billing on July 1, 2003.

Aggregation

The Restructuring Act authorizes the provision of aggregation services for the Commonwealth's retail electricity customers. Section 56-576 of the Act defines aggregator, §56-588 details the licensing of aggregators, and §56-589 authorizes municipal and state aggregation. Aggregation service is the purchasing or arrangement of the purchase of electric energy for sale to two or more retail customers.

As discussed in greater detail in last year's report, the Commission established an investigation of aggregation issues with Case No. PUE-2002-00174.[17] Questions had arisen with respect to which persons or entities needed to be licensed as aggregators.

As required by the Commission's March 18, 2002 Order, Staff prepared and filed a report on August 1, 2002. Staff's report and recommendations were based on both comments

[16] The adopted rules may be found at: http://www.state.va.us/scc/caseinfo/pue/case/e010298b.pdf .
[17] Available at http://www.state.va.us/scc/caseinfo/pue/e020174.htm .

received in writing and from participants in a workgroup meeting. In its August 1, 2002 report, Staff recommended a minor rule change. Staff asserted that an entity that is not involved in the transactional arrangements between a licensed competitive service provider or aggregator and its retail customers should not be required to be licensed. The Staff does not believe that marketing activities, alone, conducted on behalf of, or in conjunction with, licensed CSPs or aggregators warrant licensure of this third party. The Staff concluded that the licensed CSP is responsible for the actions of the marketer. Further, the Staff believes that the recommended marketer disclosure is consistent with the Commission's authority as defined in the Restructuring Act. Staff recommends that one Retail Access Rule be changed to require CSPs to maintain a list of entities with whom they have a marketing relationship. Such information would be helpful to the Staff with respect to investigating any complaints related to marketing practices.

After having considered the Staff's Report and comments filed on the report, by Order dated November 1, 2002, we directed the publication of Staff's proposed rule change in the *Virginia Register of Regulations* and established a procedural schedule to receive comments on Staff's Report. We also directed Staff to file two reports on or before July 1, 2004. One report related to the impact on the development of a competitive market, of incumbent-affiliated competitive service providers and their activities in affiliated LDC's service territories. The second report related to the impact of aggregation contracts, particularly regarding exit fees, on the development of competitive retail markets in the Commonwealth.

In response to our November 1, 2002 Order, we received comments from one party, Dominion Retail, Inc. ("Retail"). In its comments Retail did not take issue with the adoption of Staff's proposed change to 20 VAC 5-312-20 D. Rather, in its comments, Retail argued that the two July 1, 2004 reports required of Staff were unnecessary.

By Order dated April 9, 2003, the Commission issued an Order in which we adopted Staff's proposed rules change. Additionally, in response to Retail's comments, we reiterated our belief that both July 1, 2004 reports will be beneficial to our assessment of the impact of aggregation on the development of a competitive retail generation market. Lastly, we concluded our investigation by closing the docket.

Distributed Generation

Distributed generation involves moving the generation of electricity away from large central units to smaller units located closer to the point of consumption.[18] In accordance with §56-578 of the Restructuring Act, the Commission instructed the Staff to work with interested parties to develop proposed interconnection standards for distributed generation. The Act specifies that the interconnection standards "shall not be inconsistent with nationally recognized standards acceptable to the Commission."

Following several work group meetings and assistance of interested stakeholders, Staff drafted proposed interconnection standards for Virginia. The National Association of Regulatory Utility Commissioners ("NARUC") has adopted a set of distributed generation rules that States are encouraged to adopt. Staff awaits further direction and decision of NARUC to endorse a model interconnection agreement; of the Institute for Electrical and Electronic Engineers ("IEEE") and its efforts to set national standards for distributed generation interconnections ("IEEE-1547"), and of the Federal Energy Regulatory Commission's ("FERC") activities to develop interconnection procedures.

[18] In May of 2000, the Commission issued rules governing net energy metering promulgated pursuant to § 56-594 of the Restructuring Act. The net metering rules establish interconnection guidelines and tariffs under which an electric customer may interconnect a small wind, hydro or solar generating facility to the grid. The rules may be found at: http://www.state.va.us/scc/caseinfo/pue/case/e990788rul.pdf .

Business Practices

The North American Energy Standards Board ("NAESB") serves to develop and promote standards leading to a seamless marketplace for wholesale, and retail, natural gas and electricity. NAESB is accredited as a standards-setting body from the American National Standards Institute, independent of policy and politics to build public-private partnerships with the FERC, the Department of Energy and the state commissions. NAESB's infrastructure and processes[19] are recognized by the FERC as evidenced by FERC's charge to develop business practices for use by market participants to implement its final rule regarding standard market design or wholesale market platform.[20] Recognizing the ongoing convergence of the natural gas and electricity businesses, NAESB ensures that its implementation standards and business practices will receive and utilize the input of all industry sectors through its open membership and balanced voting processes.

Staff continues to monitor the activities of each quadrant and the various subcommittees to establish standards and business practices. The retail electric ("REQ") and natural gas quadrants ("RGQ") have grown to 46 and 42 members, respectively, and are committed to work jointly as much as possible to ensure consistency among common elements of the respective industries. Efforts of the wholesale gas quadrant ("WGQ"), now comprised of 166 members, will be aided by the Joint Interface Committee ("JIC"), established between NAESB, the North American Electric Reliability Council ("NERC"), and the Independent System Operators/Regional Transmission Organizations ("ISO/RTO") Council, to prevent duplication by organizations in setting electricity standards.

[19] Additional information regarding the NAESB may be found at: http://www.naesb.org .
[20] Additional information regarding FERC's standard market design and structure may be found at: http://www.ferc.gov/Electric/RTO/Mrkt-Strct-comments/smd.htm .

NAESB is the primary industry forum for development and promotion of business practices and electronic communication standards while NERC is the primary industry organization for developing reliability standards for the operation and planning of the bulk electric systems. The ISO/RTO Council is not a standards development organization but may participate with such activities to ensure consistency and prevent duplication.

Staff participates with NAESB's monthly conference calls to update regulators and continues to serve on the Advisory Committee to NAESB.

Virginia Electronic Data Transfer Working Group

The Staff continues to serve as a facilitator for the Virginia Electronic Data Transfer ("VAEDT") Working Group to develop standards and guidelines for electronic data interchange ("EDI"). EDI is a means for a utility and a CSP to communicate electronically and involves the computer-to-computer exchange of business and customer information. All CSPs are required to use EDI to transact business with the utilities. A CSP may negotiate with an LDC to use some alternative to EDI on a temporary, start-up basis to provide additional time to comply with the Retail Access Rules, but should implement EDI within 180 days of an initial service offering.

In December 2002, the VAEDT filed with the Commission for informational purposes its revised Virginia Plan, Implementation Guidelines, and EDI Test Plan.[21] The VAEDT continues to meet periodically to refine standards as the market evolves and experience is gained.

The VAEDT continues to support efforts of the First Regional Electronic Data Interchange ("FREDI")[22] to establish and maintain uniform criteria across the Mid-Atlantic

[21] Additional information available at: http://www.vaedt.org .
[22] Additional information available at: http://www.firstregionalEDI.org .

region[23] and more easily exchange electronic information between electric utilities operating in multiple jurisdictions.

The differences in current EDI guidelines are generally attributable to differences in policies and business rules among the participating jurisdictions. Future revisions to EDI guidelines will be reviewed, accepted and implemented by the respective state EDI work groups within each of the FREDI jurisdictions in a coordinated manner to better realize synergies within the regional energy market. This effort may potentially evolve for the regional jurisdictions to converge to the same EDI standards and perhaps develop consistent business rules to better promote a robust competitive energy market and serve as the basis for NAESB's development of national standards regarding electronic protocols.

Generation and Transmission Additions

Within the last five years, eight generating plants have been built and placed into commercial operation within the Commonwealth, adding 2,781 megawatts ("MW") to existing generation physically located in Virginia.[24] Approval of six additional facilities has been granted by this Commission summing to 3,988 MW, of which two facilities, totaling 1,368 MW, are under construction and should be ready for operation by the summer of 2004. In addition, nine other independent power producers submitted applications for generating capacity of 6,675 MW that are pending before the SCC in various stages of the certification process. Of this amount, six projects totaling 4,810 MW have been suspended by the developers. The Staff is aware of some discussions to develop additional generation facilities but are not yet aware of any commitment. The table at the end of this section provides further detail regarding applications for new facilities.

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[23] Currently comprised of jurisdictions from DC, DE, MD, NJ, PA, OH, and VA.

[24] These new plants are comprised of three Dominion generating stations, one ODEC facility, and four independent power plants, representing 1,500 MW, 465 MW, and 809 MW, respectively.

Changes within the electricity marketplace under a competitive regime, actions by the FERC, and the financial investment and capital markets have caused the electric industry to explore alternatives to traditional integrated resource planning. Evolvement of RTOs to include a broader number of market participants and to cover wider service areas has changed the complexion of the future electric industry. New capacity, generation as well as transmission, will be realized when market participants recognize and react to market signals such as reliability, price, customer service, load growth and economics. Such response will likely include physical construction and enhancement as well as contractual and financial alternatives.

As more independent generators begin commercial operation and suppliers utilize a variety of capacity purchases to serve customer load, the traditional reserve margin loses significance. Difficulties arise in determining which supply sources and which customer loads should be included at any particular time to determine such a calculation.

Expansion of transmission facilities is also needed to accommodate expected customer demand and required energy supply. The SCC granted permission to AEP-VA to construct a 765-kV electric transmission line in southwestern Virginia. That line received final federal approval earlier this year and is not expected to be operational before 2006. Applications for a few smaller transmission lines have been approved or are currently pending before the SCC and are experiencing public opposition. Additionally, several applications to construct natural gas pipelines to supply fuel to some of the proposed generators are also pending before the SCC. Two additional interstate pipelines to transport fuel across the Commonwealth have been approved by Federal agencies but have been slowed because of public opposition.

By order dated August 21, 2002, the Commission adopted filing requirements for applications filed on or after September 1, 2002.[25] In the August 21st Order the Commission also concluded that, due to the passage of SB 554 [26], filing requirements addressing cumulative environmental impacts are not necessary and therefore are excluded from the Commission's filing requirements.

[25] The amended rules may be found at: http://www.state.va.us/scc/caseinfo/pue/case/e010655a.pdf .

[26] The adopted rules may be found at: http://www.state.va.us/scc/caseinfo/pue/e010313.htm. Senate Bill No. 554 was signed by Governor Warner on April 4, 2002, and became effective on July 1, 2002. The bill modified the Commission's role in reviewing the environmental aspect of appliations to construct electric generating facilities in Virginia.

Summary of Construction Activity in Virginia
As of August 1, 2003

Company/Faility	Size	Location	Docket	Fuel	C.O.D.*	Status
Power plantswith SCC certificates that began operation within the last 5 years						
Commonwealh Chesapeake	300 MW	Accomack County	PUE960224	3-OilCT	sum 01	8/5/98 Order
Dominion Virinia Power	600 MW	Fauquier County	PUE980462	4-GasCT	sum 00	5/14/99 Order
Wolf Hills Enrgy, LLC	250 MW	Washington County	PUE990785	5-GasCT	sum 01	5/2/00 Order
Dominion Virinia Power	360 MW	Caroline County	PUE000009	2-GasCT	sum 01	10/10/00 Order
Doswell Limitd Partnership	171 MW	Hanover County	PUE000092	1-GasCT	sum 01	6/15/00 Order
Allegheny Enrgy Supply	88 MW	Buchanan County	PUE010657	2-GasCT	Jun 02	6/25/02 Order
Dominion Virinia Power	540 MW	Prince William County	PUE000343	Gas CC	Jul 03	3/12/01 Order
Louisa Generaion, LLC (ODEC)	472 MW	Louisa County	PUE010303	5-GasCT	Jun 03	7/17/02 Order
	2,781 MW					
Power plantsvith SCC certificates currently under construction.						
Tenaska Virgiia Partners I, LP	900 MW	Fluvanna County	PUE010039	Gas CC	sum 04	4/19/02 Approved
Marsh Run Generation, LLC	468 MW	Fauquier County	PUE-2002-00003	3-GasCT	sum 04	11/6/02 Approved
	1,368 MW					
Power plantsvith SCC certificates, but not yet under construction.						
Competitive Pwer Ventures	520 MW	Fluvanna County	PUE010477	Gas CC	spr 06	10/7/02 Approved
Tenaska Virgiia Partners II, LP	900 MW	Buckingham County	PUE010429	Gas CC	fall 04	1/9/03 Approved
CPV Warren, LC	520 MW	Warren County	PUE-2002-00075	2-GasCC	spr 05	3/13/03 Approved
White Oak Power Co., LLC	680 MW	Pittsylvania County	PUE-2002-00305	4-Gas CT	sum 04	8/1/03 Approvied
	2,620 MW					
Power plants hat have applied for an SCC certificate						
ChickahominyPower, LLC	665 MW	Charles City County	PUE010659	Gas CT	fall 03	HE Report pending
Duke Energy Vythe, LLC	620 MW	Wythe County	PUE010721	Gas CC	sum 04	Remanded 3/11/03
James City Enrgy Park, LLC	580 MW	James City County	PUE-2002-00150	2-GasCC	1/05	HE Report pending
CinCap-Martinsville	330 MW	Henry County	PUE010169	4-GasCT	sum 03	Dismissed 4/29/03
Kinder Morgan VA, LLC	560 MW	Cumberland County	PUE010722	Gas CC	sum 04	Dismissed 1/14/03
Kinder Morgan of Virginia, LLC	550 MW	Brunswick County	PUE010423	Gas CC	win 04	Dismissed 11/1/02
Henry County Power/Cogentrix	1,100 MW	Henry County	PUE010300	Gas CC	sum 04	Dismissed 7/31/03
Loudoun Coury Power/Tractebel	1,400 MW	Loudoun County	PUE010171	Gas CC	sum 05	Dismissed 3/27/02
Mirant Danvill, LLC	870 MW	Pittsylvania County	PUE010430	Gas CC	sum 04	Dismissed 2/6/02

Total 6,675 MW (4,810 MW dismissed leaving **1,865 MW** under consideration)

*Commercial Operation Date

Potential powerplants under consideration, but have not yet filed an application with the SCC**

Competitive Power Ventures	900 MW	Smyth County	Gas CC
US Data Port/Cabine	130 MW	Prince William County	Gas CT
Timber Creek Power Co., LLC	560 MW	Greensville County	Gas CC
Joshua Falls Energy Center	1120 MW	Campbell County	Gas CC
Total	**2,710 MW**		

** compiled from local news stories and DEQ air permit activity list

Transmission lines

AEP-VA	765 kV-90 mi	Wyoming-Jackson's Ferry	PUE970766	2004	5/31/01 Approved
DVP	2@230 kV- 4 mi	Loudoun	PUE010154	2003	6/27/02 Approved

Regional Transmission Organization membership pending before the SCC

DVP	PJM-South	PUE-2000-00551	Company filed application on 6/27/03
AEP-VA	PJM-West	PUE-2000-00550	Order to file supplemental data within 90 days of FERC SMD Order
AP	PJM-West	PUE-2000-00736	Order to file supplemental data within 90 days of FERC SMD Order
Conectiv	PJM-East	PUE-2001-00353	Order to file supplemental data within 90 days of FERC SMD Order
KU	MISO	PUE-2000-00569	Staff report 7/24/02

Natural gas pipelines

DVP	20"-14 mi	Prince William County	PUE000741	2003	11/5/01 Approved
Duke Energy Patriot Extension	95 mi	Wythe to Rockingham Cty	FERC	2004	11/20/02 Approved
Saltville Gas Storage Co., LLC	24"-7 mi	Saltville / Chilhowie	PUE010585	2003	1/22/03 Approved
Dominion Transmission Greenbrier	280 mi	Charleston to Rockingham	FERC	2005	4/9/03 Approved
Dominion Cove Point LNG					

Energy Infrastructure Study

Senate Bill 684, enacted by the 2002 Session of the General Assembly, requires the SCC to convene a work group to "... study the feasibility, effectiveness, and value..." of collecting information relative to the location and operation of specified electric generating facilities, electric transmission facilities, natural gas transmission facilities, and natural gas storage facilities serving the Commonwealth. This information encompasses data relative to the electricity and natural gas loads imposed by Virginia consumers and the dedication of facilities to the service of those loads.

In response to this legislative directive, the Staff solicited written comments from stakeholders and convened several meetings to address issues related to electric and natural gas system reliability, specific proposals for the collection of information necessary to track reliability, transmission planning and how reliability is managed by PJM.

The Commission filed its report on November 20, 2002, and presented the results of its work to the CEUR during its December 12, 2002, meeting. The Commission report concluded that the collection of extensive data related to Virginia's energy infrastructure is, in fact, feasible. With regard to the effectiveness and value of such a data collection effort, the report noted that ". . . the electric utility industry is in a state of extreme uncertainty and will likely remain so for the foreseeable future." The report ultimately recommended three options for the CEUR's consideration. The CEUR concluded that the Commonwealth must continue to maintain oversight over the reliability of the electric infrastructure and adopted a resolution on January 27, 2003 ("Resolution"), requesting, in part, that the Commission collect the data necessary to monitor the dedication of generating facilities to the provision of electric bulk power supply in the Commonwealth. The Resolution also requested the Commission to report the results of its work to the CEUR, on or before July 1, 2003.

The Commission's recently filed report indicated that with the advent of restructuring, electric utilties providing service in the Commonwealth have reduced planned reserve margins and expect to rely largely on the market for the provision of capacity to serve load growth and to provide adequate reserves. The Commission noted that the initial report was fairly general in nature and that the Commission intends to continue to analyze relevant data, seek further clarification of the issues, address longer-range forecasts, and issue a more detailed report in the future.

RTE Development

Section 56-579 of the Restructuring Act requires incumbent electric utilities to establish or join regional transmission entities ("RTEs")[27] as part of the transition to retail competition. This obligation is imposed on each incumbent electric utility owning, operating, controlling, or having an entitlement to transmission capacity. Section 56-579 also requires the State Corporation Commission to determine "whether to authorize transfer of ownership or control from an incumbent electric utility to a regional transmission entity." Behind this requirement was an expectation that RTEs would manage and control the transmission assets of Virginia's utilities with the objective of meeting the transmission needs of electric generation suppliers both within and outside Virginia.[28]

On April 2, 2003, HB 2453 was placed into law. HB 2453 amended §§56-577 and 56-579 of the code of Virginia to require utilities seeking to transfer control of their transmission facilities to an RTE to submit "a study of the comparative costs and benefits thereof, which study shall analyze the economic effects of the transfer on consumers, including the effects of transmission congestion costs." HB 2453 also prohibits the transfer of control prior to July 1,

[27] RTE and RTO (Regional Transmission Organization) are essentially synonymous terms. The former is used in the Act; the latter is the Federal Energy Regulatory Commission ("FERC") preferred acronym.
[28] § 56-579 A 2 d.

2004, and requires the Commission to conduct a public hearing regarding any such request. The Restructuring Act previously required notice and an opportunity for a hearing. HB 2453 also states that "each incumbent electric utility shall file an application for approval pursuant to this section by July 1, 2003, and shall transfer management and control of its transmission assets to a regional transmission entity by January 1, 2005, subject to Commission approval as provided in this section."

Three of Virginia's incumbent electric utilities, Kentucky Utilities, Allegheny Power and Delmarva, have shifted management of their transmission facilities to an RTE. Delmarva and AP are participating in PJM.[29] KU is participating in the MISO.[30]

Virginia Power and AEP, along with a number of other utilities, sought to form the Alliance RTO which was rejected by the FERC on December 20, 2001. On April 25, 2002, FERC issued an order directing the Alliance Companies to make compliance filings detailing which RTO(s) they plan to join, collectively or individually. On May 28, 2002, AEP made a compliance filing noting its intention to join PJM West. Virginia Power also made a filing on that date noting that it was soliciting input from its stakeholders. On July 15, 2002, Virginia Power filed an update to its earlier filing notifying that the Company had entered into a MOU to join PJM as "PJM South."

On July 31, 2002, FERC issued an order conditionally accepting AEP's and Dominion Virginia Power's filings. Both utilities have entered into implementation agreements with PJM. These agreements reflect financial commitments by both companies to fund certain PJM

[29] Delmarva has participated in PJM since PJM's inception decades prior to passage of the Restructuring Act. PJM accepted control of Allegheny's transmission facilities on April 1, 2002. The SCC has not yet granted approval for the ultimate transfer of management and control of Delmarva's or Allegheny's transmission assets to PJM under Sections 56-577 B and 56-579 of Virginia's Restructuring Act.

[30] "MISO" is the Midwest Independent System Operator. MISO began offering transmission service over KU's transmission facilities on February 1, 2002.

expansion related costs and set forth schedules for the proposed expansions. The following discussion will provide additional information regarding the status of individual RTE proceedings currently pending Commission approval.

AEP-VA

AEP-Virginia filed a substitute application for approval to transfer functional control of its transmission facilities to PJM on December 19, 2002. The Commission issued a scheduling order, in Case No. PUE-2000-00550,[31] regarding that application on March 7, 2003. That order required AEP "to develop, as soon as practicable, but no later than 90 days, after a final SMD rule has been adopted, a study of the costs, benefits, and resulting cash flows that would arise from the transfer of AEP-VA's transmission assets to PJM. The Company shall submit a report detailing the methodology, key assumptions, and results of the cost/benefit analysis from the perspective of AEP, AEP-VA, other AEP corporate entities, AEP shareholders, AEP-VA's customers, and Virginia ratepayers as a whole." The order also noted that the Commission expected: "the cost/benefit analysis to include at a minimum an examination of (1) how participation in PJM would impact AEP-VA's fuel factor during the capped rate period; (2) market prices for generation as compared to current cost of service based generation pricing; (3) transmission rates for the recovery of embedded transmission costs; (4) transmission congestion costs incurred under the LMP construct; and (5) the availability and effectiveness of transmission rights for "hedging" against transmission congestion charges. The study also should include a sensitivity analysis to evaluate and identify critical assumptions including, but not limited to, the following: (1) differing load forecasts; (2) differing levels of transmission congestion and associated transmission rights; (3) abnormal vs. normal weather; (4) differing unit outage assumptions; and (5) differing fuel cost projections (higher or lower gas costs vs.

coal costs, for example). Finally, the study should include a discussion of how the completion of the planned Wyoming to Jackson's Ferry 765 kV line might impact study results."

PJM assumed responsibility as the "reliability coordinator" for the AEP region on February 1, 2003. As "reliability coordinator," PJM is responsible for, among other things, the following:

- Transmission system security monitoring and analysis,
- Initiation of measures to avoid transmission congestion,
- Coordination of responses to emergency situations,
- Implementation of reliability measures, and
- Coordination with other NERC approval reliability coordinators, recognizing each region's policies and standards.

PJM states that it has not assumed functional control of AEP's transmission system. The functions have been described by both AEP and PJM as functions for which the reliability council (ECAR) is ultimately responsible.

On March 14, 2003, the public utilities commissions of Ohio, Michigan and Pennsylvania filed a motion requesting that the FERC direct that AEP transfer control of its transmission facilities to PJM, irrespective of pending state regulatory approvals. Exelon Corporation and Commonwealth Edison Company filed in support of the motion on March 17, 2003. This Commission filed a response to those motions on April 1, 2003. The Commission's response sought to preserve state authority and argued against federal preemption. On that same day, the FERC approved AEP's request to join PJM but did not direct that AEP join by a date certain thereby avoiding any ruling regarding state authority relative to RTO participation. Thereafter, the Commission filed a request for rehearing on May 1, 2003, questioning the FERC's decision to grant approval on the basis that the record was devoid of any factual basis for the FERC finding that AEP's transfers of control of its facilities to PJM would be consistent

[31] See http://www.state.va.us/scc/caseinfo/pue/e000550.htm

with the public interest. Significantly, and as emphasized in the Commission's request for rehearing, the application lacked, among other things, information identifying the actual facilities whose control was proposed to be transferred from AEP to PJM. AEP's application was similarly silent concerning the impact of the proposed transfers on customers' rates for power and energy. The Commission's request, as well as various other motions for reconsideration, is currently pending.

On June 26, 2003, the FERC Staff issued data requests to PJM and AEP seeking information regarding the possibility of transferring control of only a portion or portions of AEP's transmission system to PJM. PJM filed responses basically concluding that partial integration of the AEP system was feasible from a technical and operational perspective. By its own admission, PJM did not address any "federal or state legal or regulatory concerns or issues that might arise about dividing AEP-East's facilities ..." AEP filed responses with quite different conclusions. AEP noted that partial integration would result in a long list of quite serious negative consequences, including; (1) increasing the cost to serve AEP customers, (2) violating Commission requirements pertaining to single-tariff service over a single holding company system, (3) potentially creating a seam within AEP-East where none has existed previously, (4) decreasing planning and operational efficiencies, (5) contradicting Commission policies which favor the regionalization of tariff and reliability functions, (6) complicating the pending AEP applications in non-transferring states, and (7) creating intra-company operational barriers for the first time for those individual AEP operating companies that serve customers in more than one state. On July 16, 2003, the Commission filed comments supporting AEP's position and criticizing PJM's response with the FERC.

On July 17, 2003, the Kentucky Public Service Commission denied AEP's application to transfer control of its major transmission lines in Kentucky to PJM. The PSC determined that the proposed transfer would not be in the public interest because it would impose costs on Kentucky Power ratepayers without providing demonstrable benefits. The PSC cited the following factors in denying Kentucky Power's application to join PJM:

- Kentucky Power would pay $3 million annually in membership fees, but could show no quantifiable benefits of membership in PJM.
- Kentucky Power has low costs and reliable transmission, so is unlikely to benefit from membership in PJM.
- PJM could in the future set a single wholesale electricity rate for its entire system, a move that would significantly raise rates for Kentucky Power customers.
- If Kentucky Power joins PJM, the RTO could decide which customers in the overall system get priority in the event of power shortages. That conflicts with Kentucky law that requires utilities in the state to give priority to the "native load" in their service territories. The PSC has no authority to override that law.

AEP filed a petition for rehearing of the Kentucky decision on August 6, 2003.

Allegheny

Allegheny filed an application to transfer control of its transmission facilities to PJM under an arrangement known as PJM West. On August 16, 2001, the Commission issued an Order Prescribing Notice and Inviting Comments and/or Requests for Hearing that established a procedural schedule for this matter, Case No. PUE-2000-00736. On October 26, 2001, Staff filed a report supporting Allegheny's application and its membership in PJM West. However, the Staff noted that it was unknown what would occur as a result of the FERC-ordered mediation involving PJM, Allegheny, the New York Independent System Operator, and ISO New England. The Staff, therefore, recommended that the Commission either delay acting on, or grant only conditional approval of, Allegheny's request to transfer management and control of its transmission facilities in order to permit Staff to review any FERC order in the Northeast RTO proceeding.

On January 30, 2002, FERC issued an Order that, among other things, permitted Allegheny and PJM to form PJM West, effective March 1, 2002. On May 9, 2002, the

Commission issued an order noting that much had occurred regarding the development and implementation of PJM West and that those developments may have affected the accuracy and completeness of the information included in Allegheny's application. Accordingly, the Commission required Allegheny to update its application.

On July 12, 2002, the Staff filed a Supplemental Report recommending that the Commission delay approval of Allegheny's application until more information was known about the ITC proposal for PJM West, Dominion's PJM South proposal, and the outcome of PJM and MISO discussions to form a single energy market across the PJM and Midwest regions.

HB 2453 necessitates the development of a cost/benefit study regarding Allegheny's application and that a public hearing be held. Accordingly on May 30, 2003, the Commission issued an order requiring Allegheny to develop and file a study of the costs, benefits, and resulting cash flows that would rise from the transfer of Allegheny's transmission assets to PJM within 90 days of FERC's adoption of a final rule pertaining to SMD.

Delmarva

On October 16, 2000, Delmarva filed a Motion with the SCC in Docket No. PUE-2000-00086, requesting the Commission to determine that Delmarva's membership in PJM constituted compliance with the requirements of the Restructuring Act and the SCC's Regulations Governing Transfer of Transmission Assets to Regional Transmission Entities, 20 VAC 5-320-10 *et seq.* ("RTE Rules").

On June 1, 2001, the SCC issued a procedural order prescribing notice and inviting comments on Delmarva's request. By Order dated June 22, 2001, the SCC created a separate docket, Case No. PUE-2001-00353, to receive comments and requests for hearing on Delmarva's request. On August 17, 2001, the Staff filed a response to Delmarva's request. In its response, the Staff noted that the FERC had issued an order on July 12, 2001, provisionally granting RTO status to PJM. The Staff commented that the FERC had strongly encouraged the formation of one Northeast RTO encompassing PJM, the New York Independent System Operator, and ISO New England.[32] The SCC Staff observed that the FERC's Order raised the possibility that PJM's configuration could change if a larger Northeastern RTO developed as a result of the involuntary mediation process the Commission had initiated. The Staff, therefore, recommended that the SCC either delay acting on, or grant only interim approval of, Delmarva's request until more was known about the mediation process and about any Northeastern RTO that might be formed.

The Commission entered a second order on May 9, 2002, establishing a procedural schedule and requiring the filing of supplemental documents in this docket. The May 9, 2002 Order observed that a number of developments could have affected the accuracy and completeness of the information accompanying Delmarva's original request. It therefore required Delmarva to file on or before June 18, 2002, complete information about further developments relevant to Delmarva's October 16, 2000 request. Additionally, the Commission directed its Staff to file a supplemental report detailing the further results of Staff's investigation, and invited Delmarva and any interested person to file on or before August 2, 2002, comments responsive to the Staff's supplemental report.

On June 18, 2002, Delmarva filed its response to the SCC's May 9, 2002 Order. In its response, Delmarva reported that there had been no changes in Delmarva's status as a member

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[32] PJM Interconnection, L.L.C., Allegheny Electric Cooperative, Inc., Atlantic City Electric Company, Baltimore Gas & Electric Company, Delmarva Power & Light Company, Jersey Central Power & Light Company, Metropolitan Edison Company, PECO Energy Company, Pennsylvania Electric Company, PPL Electric Utilities Corporation, Potomac Electric Power Company, Public Service Electric & Gas Company, UGI Utilities, Inc., Order Provisionally Granting RTO Status, Docket No. RT01-2-000, 96 F.E.R.C. ¶ 61,061 at 61,231-61,232 (July 12, 2001).

of PJM, and that none of the features of PJM essential to Delmarva's compliance with Virginia's requirements had changed since August 31, 2001, or since Delmarva filed its Request on October 16, 2000.

On July 12, 2002, the Staff filed a supplemental report and recommended that the SCC delay or grant only conditional approval of Delmarva's request until more was known about the proposal for potential expansion of PJM West, Dominion's PJM South proposal, and the outcome of PJM's and MISO's discussions regarding formation of a single energy market across the PJM and Midwest regions.

HB 2453 necessitates the development of a cost/benefit study regarding Delmarva's application and that a public hearing be held. Accordingly on May 30, 2003, the Commission issued an order requiring Delmarva to develop and file a study of the costs, benefits, and resulting cash flows that would rise from the transfer of Delmarva's transmission assets to PJM within 90 days of FERC's adoption of a final rule pertaining to SMD.

Dominion Virginia Power

On June 27, 2003, DVP filed an application seeking to join PJM.

Kentucky Utilities

Kentucky Utilities' application to transfer control of its transmission facilities to the MISO is pending. HB 2637 suspended the applicability of the Restructuring Act to Old Dominion. The implication of this exemption coupled with the fact that the Company has joined MISO must be explored in terms of required Commission approval. More specifically, the issue HB 2637 places before the Commission is whether the Commission has authority to continue its review (post July 1, 2003) of Old Dominion's RTE application.

FERC Fact Finding Investigation

On May 12, 2003, the FERC established a fact finding proceeding (to be facilitated by an Administrative Law Judge) concerning congestion on the Delmarva Peninsula. The purpose of this proceeding is to evaluate the "extent and costs of transmission congestion" and to help identify potential solutions. The FERC fact finding was unusually structured as a "non-adversarial" proceeding with limited discovery and a hearing where only predetermined questions were asked with no opportunity for follow-up. The Virginia, Delaware, and Maryland Commissions were invited to join other interested parties and to send expert staff members and an ALJ to work with FERC's ALJ. The Commission filed a notice of intervention on May 19, 2003. The Commission Staff actively participated in this matter. Additionally, the Commission was represented at the "non-adversarial" hearing held on July 30-31, and on August 1 and 4, 2003.

The Commission filed a report to be appended to the FERC ALJ's report on August 11, 2003. The Commission's report expressed concern that the limited nature of the FERC's "non-adversarial" proceeding did not allow a sufficient exploration of certain issues and recommended that the entire matter should now be referred to the FERC's Office of Market Oversight and Investigations for a full enforcement investigation. The Delaware Public Service Commission also filed a report stating similar concerns and recommending that the FERC conduct a distinct proceeding to solve the Delmarva Peninsula's problems. The ALJ issued her report on August 12, 2003, finding that the record in the proceeding was sufficient to provide the FERC "with relevant and material information necessary to address the facts and determine possible solutions regarding congestion on the Delmarva Peninsula."

FERC SMD NOPR

As noted in Part I of this report, the FERC issued a NOPR regarding standard market design and market oversight for bulk power markets on July 31, 2002. As part of the FERC's proposed standard market design ("SMD"), it proposed to establish a resource adequacy requirement for each load serving entity. The Commission filed comments on the proposed rules on January 31, 2003. Following numerous comments and meetings regarding SMD, on April 28, 2003, the FERC issued its "White Paper" to address the issues and concerns raised by participants and augment and clarify its intentions relative to implementing a standard market platform. One of the basic concerns with the SMD is that Virginia utilities will not be able to operate, as they can today, to give Virginians first call on the transmission systems previously funded through retail rates. Although the "White Paper" indicates that an integrated utility will be permissible, and may have title to its transmission system, the utility will not be permitted to operate the system on an integrated basis to protect native load customers. A more detailed summary of the White Paper is also included in Part I of this report. A deadline for comments on the White Paper has not yet been established.

DOE Cost/Benefit Study of SMD

DOE issued a report regarding the cost/benefits of FERC's SMD initiative on April 30, 2003. The DOE study is based on a number of arguable assumptions and does not address certain risks of the FERC SMD proposal. The Study shows that benefits of the SMD will be small, less than a 1% decrease in average retail electric rates, nationwide. Moreover, the DOE study shows that a majority of the areas of the country will have either no benefit or have retail rates actually increase as a result of SMD.

As is the case with any study of this nature, results are only as good as the underlying assumptions used in the study. The DOE study includes a number of debatable assumptions.

For example, it is generally accepted that a competitive market will require a significant investment in transmission and generation infrastructure to accommodate more trading, to address congestion, and to provide more supply for vigorous competition. The report assesses no cost for such infrastructure improvements. The report also assumes that generators will exercise no market power; that is, an assumption of perfect competition may be largely responsible for any savings that the study produces. Also, the risks of implementing a new, untried system, such as price increases, price volatility, reliability and the like have not been factored in. Natural Gas prices can have a significant impact on the results of the DOE study. The study assumed that gas prices were $3.30 per thousand BTUs (MBTU) in 2005 and escalating to $4.40 per MBTU in 2020. As you may be well aware, we are currently experiencing gas costs above $5.00 per MBTU. The study did not, however, include any sensitivity analysis for changes in gas costs. The report's value is severely limited by such a lack of risk analysis. This fact is acknowledged on page 17 of the report: "All the illustrations presented in this analysis are subject to significant uncertainties, because they are dependent on assumptions about future conditions in the economy and the electricity sector." Moreover, the study assumes transmission capacity to increase by 5 to 10 percent under SMD as a result of generation dispatch over broader geographic areas. It also assumes increased efficiencies of generating units of 2 to 4 percent that may not be valid given the historical excellent performance of generation units serving the Commonwealth.

With regard to the benefits attributable to SMD by the DOE study, they are small. Once the cost of implementing the SMD is considered (about $760 million annually according to DOE), the FERC initiative is expected to generate net nationwide savings of approximately $1 billion per year over the short-term and between $200 million and $700 million over the long-term. While these are large absolute numbers, they represent a very small decline in the transmission and generation components of rates. The best case savings of $1 billion annually yields a decline in the transmission and generation components of a customer's bill of approximately 1 percent. The percentage savings relative to a customer's total bill will be even less when distribution costs are considered. With appropriate sensitivity and risk analysis the savings could easily disappear and become negative; that is, the SMD initiative could result in higher average electricity prices nationwide.

In addition to very small overall benefits nationwide, the study indicates that there are areas of the country that are winners and others that are losers. Of the 16 NERC (National Electric Reliability Council) subregions studied, over the long-term, six areas are expected to experience retail rate decreases; five areas are projected to see increased retail rates; and five regions will experience essentially no rate change.

OTHER ACTIVITIES AND ISSUES

<u>Default Service Investigation</u>

On December 23, 2002, the Commission issued an Order Establishing Investigation in Case No. PUE-2002-00645 relative to the provision of default service pursuant to § 56-585 of the Restructuring Act. In its Order, the Commission directed the Staff to invite interested parties to participate in a work group to assist the Staff in developing recommendations regarding the components of default service and the establishment of one or more programs making such services available to retail customers. Fifteen parties, including six competitive service providers, submitted comments responding to questions posed by the Commission in its Order.

The Staff hosted two work group meetings in March, 2003, with discussions focused primarily on the same questions. As directed by the Commission, the Staff filed a report on May 1, 2003, recommending that the incumbent electric utilities be required to provide default service at capped rates effective January 1, 2004, and until such time that the Commission orders otherwise. Six parties filed comments on the Staff report. The National Energy Marketers Association ("NEM") urged the competitive provision of default service as soon as possible, but also argued that the capped rate and wires charges provisions of the Restructuring Act severely limits the ability of a competitive supplier to provide default service. Other comments supported the Staff's recommendations. No parties requested a hearing.

This Commission issued an Order in this case on July 24, 2003, adopting Staff's recommendations that the components of default service include all elements of electricity supply service and that the incumbent electric utilities provide default service at capped rates until modified by future order of this Commission. Similar to last year, several participants indicate that other obstacles need to be resolved before competitive markets will be able to offer meaningful alternatives to the incumbent utilities. Specifically, the major obstacles to a competitive marketplace, as identified by participants, continue to be capped rates, wires charge structure for the recovery of yet unquantified stranded costs, lack of RTE membership, and the retail electricity supply cost components. Participants claim such items need to be addressed in order for competition to flourish in Virginia.

Additionally, the Commission invited comments regarding an issue raised by participant comments on the Staff Report. Specifically, interested parties were invited to address 1) whether the Commonwealth and its municipalities are "retail customers" as defined by the Act and are entitled to default service pursuant to § 56-585 of the Code of Virginia, and 2) if so, how the Commission should determine such default service rates for such customers.

Stranded Costs

On July 1, 2003, the Commission submitted a Stranded Cost Report prepared by its Staff to the Commission on Electric Utility Restructuring (CEUR), previously the Legislative Transition Task Force. The report was filed in response to requirements set forth in the CEUR's Resolution passed January 27, 2003, specifically to Requested Action No. 2 of the Resolution which requires that the State Corporation Commission:

> *By July 1, 2003, present to the Legislative Transition Task Force the work group's consensus recommendations regarding:*
> *(a) Definitions of "stranded costs" and "just and reasonable net stranded costs."*
> *(b) A methodology to be applied in calculating each incumbent electric utility's just and reasonable net stranded costs, amounts recovered, or to be recovered, to offset such costs, and whether such recovery has resulted in or is likely to result in the overrecovery or underrecovery of just and reasonable net stranded costs.*

The report also addressed Requested Action No. 8, requiring Commission Staff analysis of differing recommendations in the event consensus recommendations were not reached and

Requested Action No. 9, recommendations for legislative or administrative action that the Commission, work group, or both, determine appropriate to address any over- or under-recovery of just and reasonable net stranded costs.

On March 3, 2003, the Commission entered an Order Establishing Proceeding (the "Order"), docketing Case No. PUE-2003-00062.[33] The Order provided guidelines on establishing the work group, a schedule for work group activities, and requested that interested persons respond to a series of questions. The work group held four sessions where definitions and methodologies were discussed in depth. In addition, work group members provided written responses[34] to issues brought up during the work group sessions. Work Group members were unable to reach consensus on the issues before it.

The work group first attempted to reach consensus definitions for the terms "stranded costs" and "just and reasonable net stranded costs." In defining stranded costs the differences came down to (1) terminology, for example should such costs be defined as "lost revenues" or "loss in economic value" and (2) whether the definition should include stranded cost components. There were similar differences of opinion regarding the definition of just and reasonable net stranded costs. Additionally, Dominion Virginia Power stated that further definition of just and reasonable net stranded costs was not necessary because such costs are defined by the methodology for determining wires charges as set forth in § 56-583 of the Restructuring Act.

Staff does not believe that the definitions need to include stranded cost components. Staff disagrees with the position that just and reasonable net stranded costs are defined by the Restructuring Act. To the contrary, Staff believes the Restructuring Act neither defines just

[33] See http://www.state.va.us/scc/caseinfo/pue/e030062.htm
[34] See http://www.state.va.us/scc/division/eaf/comments_strandedcosts.htm

and reasonable net stranded costs nor provides a methodology for calculating them. It defines only the recovery mechanisms, wires charges and capped rates, and a method for calculating wires charges.

Staff recommended the use of the following definitions:

> Stranded Costs *are a utility's net loss in economic value arising from electric generation-related costs that become unrecoverable due to restructuring and retail competition.*
>
> Just and Reasonable Net Stranded Costs *are a utility's net loss in economic value arising from prudently incurred, verifiable and non-mitagable electric generation-related costs that become unrecoverable due to restructuring and retail competition.*

Several methodologies for monitoring and/or measuring the over- or under-recovery of stranded costs were discussed by the work group. Dominion proposed a methodology for monitoring just and reasonable net stranded costs that included reporting to the CEUR (1) the over- or under-recovery of stranded costs collected through the wires charges from switching customers, (2) actual "above-market" or "potential" stranded costs exposure under capped rates, (3) the amounts expended from funds available under capped rates to mitigate potential stranded costs, and (4) additional expenditures that negatively impact (increase) such costs during the transition period.

Staff presented two methodologies. The first calculates just and reasonable net stranded costs based on an asset valuation methodology. The second is an accounting approach that (1) measures recoveries of stranded costs from capped rates and wires charges, (2) measures potential stranded costs on an annual historic basis[35], and (3) after July 1, 2007 could be used to

[35] Potential stranded costs are defined as annual stranded cost exposure during the capped rate period, assuming all customers are paying market rates for generation service. This amount is a recalculation of capped rates based on the current embedded cost of generation by customer class compared to the actual expense rate for the same period. The difference would be multiplied by the total kWh sales to determine the potential stranded costs. In its report, Staff proposed making this calculation annually on a historic basis during the transition period.

calculate actual stranded costs or benefits on an annual historic basis.

The Virginia Committee for Fair Utility Rates and the Old Dominion Committee for Fair Utility Rates (the "Committees") proposed a methodology for calculating just and reasonable net stranded costs based on an asset valuation methodology for measuring stranded costs and incorporating stranded cost recoveries from both wires charges and capped rates.

Generally, utilities and independent power producers supported Dominion's proposal stating that it is easy to administer and consistent with the Restructuring Act. Consumer groups and competitive service providers offered little support for Dominion's proposal because it does not calculate stranded costs nor does it quantify stranded cost recoveries from capped rates.

Regarding Staff's and the Committees' methodologies, the positions of the work group participants are reversed. The utilities state that these methodologies are not consistent with the Restructuring Act and that the asset valuation methodology is too complex, requiring numerous projections. They further state that calculating stranded cost recoveries from capped rates is tantamount to annual rate cases. Conversely, consumer groups and competitive service providers believe the asset valuation methodology is the best method available for calculating stranded costs. These groups agree that this is a complex calculation but can be done with cooperation of all participants. These groups are not in favor of Staff's proposal for calculating potential stranded costs.

Staff believes that to monitor the over- or under-recovery of just and reasonable stranded costs one must calculate two numbers: (1) total just and reasonable net stranded costs; and (2) recoveries of stranded costs from capped rates and wires charges. Staff favors using an asset valuation methodology to determine just and reasonable net stranded costs. Although complex, it is the best tool available. To calculate recoveries of stranded costs from wires charges and capped rates. Staff believes information currently filed annually with the Commission should be used. This information is used to measure a utility's earnings and is much less complex than rate cases.

Attachment 6 to Staff's Stranded Cost Report provides an earnings test analysis of Dominion Virginia Power for the four years that capped rates have been in place, 1999 through 2002. On a cumulative basis, the attachment reflects $886 million of excess earnings which could be applied to stranded cost recoveries[36].

Should the CEUR determine an asset valuation methodology is not appropriate for calculating just and reasonable net stranded costs, Staff suggests that utilities be required to calculate potential stranded costs annually during the transition period and actual stranded costs annually thereafter. This alternative would also include calculating recoveries from wires charges and capped rates as discussed above.

In regard to Dominion's proposal, Staff agrees with the comments of the utilities that Dominion's methodology is easy to administer; however, the fact that it does not calculate just and reasonable net stranded costs and does not quantify stranded cost recoveries from capped rates makes it unacceptable and contrary to § 56-584.

The final issue addressed in the report is whether legislative or administrative action by the CEUR is necessary. Several work group participants suggested that if a company is found

[36] This number is based on Dominion Virginia Power's annual informational filings from 1999 through 2002, adjusted by Staff to remove certain regulatory assets expensed by the company that Staff considered to be potential stranded costs. This number could be smaller or greater depending on other adjustments that may be proposed by parties. For example, one element that will affect this number will be the return on equity used in the calculation. The CEUR has not selected methodologies either to establish stranded costs or to ascertain whether such costs are likely to be over or under recovered. Further, the CEUR has not requested the Commission to determine the necessary methodologies or to advise the CEUR as to likely over or under collection of stranded costs.

to have over-recovered or it is likely that they will over-recover stranded costs then (1) wires charges should be reduced or eliminated, (2) capped rates should be reduced, or (3) both. Currently, the Restructuring Act does not provide for any of these actions. Legislation would be necessary should the General Assembly desire to take action on the findings made as a result of its stranded costs monitoring. On the other hand, Staff does not believe legislation is necessary to determine any of the stranded cost methodologies identified by the work group.

Staff requested further direction from the CEUR prior to submission of its next stranded cost report currently scheduled to be filed November 1, 2003. Requested Action No. 3 of the Resolution provides that the Commission present to the CEUR the work group's consensus recommendations regarding each utility's just and reasonable net stranded costs and stranded cost recoveries, using the work group's consensus methodology. Because the work group was unable to reach consensus on a methodology it is unable to move forward with the calculations. The Commission requested that the CEUR provide guidance on the appropriate methodology or instruct the Commission to make such determination. The Commission requested that the CEUR instruct the Commission to begin proceedings to implement the chosen methodology. If the CEUR desires the Commission to continue its evaluation, the complexity of such determination makes completion by November 1 unlikely.

Financial Profile of Virginia's Electric Utilities

Since the electric industry is capital intensive, it is very important that electric utilities be able to raise capital on reasonable terms and at favorable rates. A major factor influencing the terms and rates a company is able to obtain when raising debt capital is its credit ratings. The two major rating agencies are Moody's Investors Service ("Moody's") and Standard & Poor's Ratings Services ("S&P"). S&P assigns bond ratings ranging from "AAA" to "D", with a plus (+) or minus (-) added to show relative standing within the major categories. Moody's assigns ratings ranging from "Aaa" to "C", with a modifier of 1, 2 or 3 in each ratings category from "Aa" through "Caa" to show relative standings within the major categories. A bond rated below "BBB-" by S&P or "Baa3" by Moody's is considered non-investment grade or a "junk bond".

Negative rating action continued in 2003 at the unprecedented pace set in 2002 for combined-energy entities with both regulated and non-regulated exposure, as well as for those with an entirely non-regulated focus.[37] Debt financed expansion into non-regulated businesses such as merchant generation and energy marketing and trading continues to damage the consolidated financial profiles of utility holding companies. Managing liquidity has become a major priority for some firms with exposure in the energy merchant sector in light of upcoming maturities over the next three years, including AES Corp., American Electric Power Co. Inc., Dominion Resources Inc.. Duke Energy Corp., Mirant Corp. and others.[38]

Virginia has not been isolated from the turmoil facing energy markets. Two investor-owned utilities operating in Virginia now have Baa3 ratings by Moody's and BBB and B ratings from S&P (see Senior Secured Debt Credit Ratings and Outlooks table below). The lower ratings can be partly attributed to S&P's consolidated ratings methodology that rates corporate parents on par with its legal subsidiaries. The idea is that cash is fungible and therefore can be used anywhere within the corporate family to meet debt service obligations. As a result, a strong utility owned by a weaker parent generally is rated no higher than the parent or the consolidated corporate credit quality.

In response to the balance sheet damage and liquidity crisis over the last several years in the electric industry, a theme of "back-to-basics" is becoming increasingly prevalent. The

[37] Standard and Poor's Industry Report Card: U.S. Electric/Gas/Water; April 28, 2003.
[38] Standard and Poor's Updates Refinancing Needs for the Energy Merchant Sector; Top 10 Rated U.S. Power Companies with the Most Refinancing Needs 2003-2006; April 3, 2003.

industry's repair job involves disposing of non-regulated assets, cutting capital expenditures, de-leveraging balance sheets, negotiating interim re-financings and "state regulatory commissions asserting themselves more vigorously regarding the operations and finances of U.S. electric utilities in the years to come." The fact that, "so few downgrades occurred because of weakened credit profiles of utilities themselves is attributable in no small measure to the support provided by state commissions in recent years."[39]

Financial flexibility has always been important to electric utilities and an industry that is restructuring needs the regulatory and political stability to attract capital from both lenders and investors. Adequate capital structures are becoming not only more costly and difficult to build but more important to maintain. Credit downgrades force companies into making hard decisions about capital structures and operations.[40]

The current ratings for each investor-owned electric utility operating in Virginia and ODEC are listed below. Following the matrix is a brief discussion of the rating agencies' rationale for the rating assigned.

Company	Senior Secured Debt Credit Ratings and Outlooks	
	Moody's Rating/Outlook	Standard & Poor's Rating/Outlook
Appalachian Power	Baa3/Stable	BBB/Stable
Delmarva Power	A2/Stable	A-/Stable
Kentucky Utilities	A1/Stable	A-/Stable
ODEC	A3/Negative	A+/Stable
Potomac Edison	Baa3/Under Review	B/Negative
Virginia Power	A2/Stable	A-/Stable

[39] Standard and Poor's Research: Regulated Operations Back in Fashion for U.S. Electric Utilities; June 19, 2003.
[40] Standard and Poor's Project Finance and Infrastructure Finance; October 2002.

Appalachian Power (AEP-VA) – On March 7th, 2003, S&P downgraded AEP-VA's parent, American Electric Power Company, Inc.'s (AEP) rating to BBB from BBB+, with a stable outlook. S&P cites liquidity and balance sheet improvements such as $2 billion in refinancing and AEP's issuing over $1 billion in equity, although the enhancements were insufficient to support the BBB+ rating. Consistency in AEP's regulated strategy could lead to ratings improvement over time. Moody's downgraded AEP to Baa3 from Baa2 in February 2003. The rating action reflects AEP's weak operating cash flow and continued expectations for poor returns from substantial non-regulated investments. The rating also reflects the negative impact from the Company's large energy trading business.

Delmarva Power - S&P rates Delmarva based on the consolidated credit quality of PEPCO and Conectiv. S&P removed Delmarva from Credit Watch in May 2002 where it was placed on February 13, 2001. S&P rates Delmarva A- with a stable outlook as of July 8, 2002. Delmarva's strengths include its low-risk distribution business, a high percentage of residential customers and a strong service territory economy, according to S&P. The divestiture of generating assets in the PEPCO/Conectiv merger also lowered Delmarva's risk profile. S&P considers transmission and distribution to have lower technical and operational risk than generation, and residential customers to be a very stable revenue source. Moody's confirmed Delmarva's A2 rating in May 2002.

Kentucky Utilities - Kentucky Utilities' (KU) rating is based partly on its direct parent, LG&E Energy Corp., and its ultimate parent E.ON AG, a German utility conglomerate. According to S&P, KU's current A- rating and stable outlook are based on E.ON's commitment to support LG&E Energy and its affiliates. Potential environmental expenditures related to KU's coal-fired facilities and KU's large industrial customer base are future concerns, according to S&P. Moody's confirmed ratings for KU and LG&E in September 2002, but assigned a negative outlook to LG&E.

ODEC - Although ODEC is not subject to SCC rate regulation, its 10 members in Virginia that cover about a third of the state's landmass are subject to capped rates. S&P's A+, stable outlook for ODEC reflects its conservative business strategy that shields them from much of the market risk and uncertainties in the overall U.S. power industry. S&P expects that despite the advent of deregulation, ODEC will not be materially challenged to maintain its customer base. Moody's revised their outlook to negative from stable for bonds issues by ODEC in October 2002.

Potomac Edison - The ratings of Allegheny Energy, Inc. were lowered several times in the past two years, mirroring its debt-financed growth in the merchant and trading business, according to S&P. On May 8, 2003, S&P lowered its rating for Allegheny Energy Inc. and its affiliates to B with a negative outlook, from BB-. The downgrade reflects concerns about the Company's near term liquidity, upcoming debt maturities, deteriorating operating performance in 2002, and their ability to sell assets to meet the terms of recently negotiated bank agreements. In order to meet upcoming maturities the company would need better access to capital markets or to execute significant asset sales. The company would prefer to sell its merchant and trading assets, however their market values are currently depressed. If Allegheny sold native load coal-fired plants, the company would be forced to buy higher cost power on the spot market. In November 2002, Moody's downgraded ratings of Allegheny Energy, Inc. to B1 from Ba1, reflecting its limited financial flexibility and poor near term prospects for merchant power prices.

Dominion Virginia Power - DVP is the only investor-owned electric utility in Virginia whose ratings are not equalized with its corporate parent by S&P. On October 21, 2002, S&P

lowered the corporate credit rating on DVP to A- from A, citing regulatory insulation that is sufficient to merit only a one-notch differential over the consolidated credit rating. DVP's parent Dominion Resources, Inc. is currently rated BBB+ by S&P. DVP is assigned a higher corporate credit rating of A- than its parent Dominion Resources, Inc. DVP's rating "reflects the stability and predictability derived from a fully regulated revenue stream," according to S&P.[41] DVP's higher rating is supported by adequate credit protection measures on a stand-alone basis, according to S&P. "State statute empowers Virginia's regulatory body, the State Corporation Commission, to prevent the utility from paying dividends to the parent if that action would impair the utility or if the parent would profit to the detriment of the utility's bondholders."[42] S&P further states that DVP's rating reflects its "relatively healthy" economic service territory with high per capita income levels and strong population and employment growth.[43]

S&P states that DVP's strengths are partly offset by regulatory uncertainly after July 2007 when the rate cap structure expires and deregulation will be fully implemented. Under the new structure, DVP will be required to sell energy at market-based prices that may be lower than current prices received, and it may no longer pass through stranded costs related to non-utility generation contracts, according to S&P.

Moody's revised its outlook for Dominion Resources, Inc. and Consolidated Natural Gas (CNG) to negative from stable in September 2002. This action reflects Moody's concerns over financial risk from debt-financed growth, "particularly at Dominion Energy and CNG."[44] Moody's outlook remains stable for DVP based on regulatory support afforded the utility in Virginia through 2007.

[41] Standard and Poor's Ratings Direct Research; Summary: Virginia Electric & Power Co.; February 27, 2003.
[42] Standard and Poor's Ratings Direct Research; Summary: Virginia Electric & Power Co.; February 27, 2003.
[43] Standard and Poor's Ratings Direct Research; Summary: Virginia Electric & Power Co.; February 27, 2003.

Proposed Retail Access Pilot Programs

On March 19, 2003, Dominion Virginia Power filed an application requesting approval of three retail access pilot programs to begin in 2004. Combined, the three Pilots make about 500 MW of load available to Competitive Service Providers ("CSPs"), with up to 65,000 customers from all rate classes eligible to participate. To encourage participation by CSPs, the Company proposes to reduce the wires charge for the length of the Pilots by 50% of the amount approved by the Commission for 2003.

The three Pilots consist of: (i) a Municipal Aggregation Pilot, in which one or more localities may aggregate its residential and small commercial customers utilizing an opt-in method[45] and one or more localities may aggregate its residential and small commercial customers utilizing an opt-out[46] method for the purpose of soliciting bids from CSPs for electricity supply service; (ii) a Competitive Bid Supply Service Pilot,[47] in which CSPs will bid to serve blocks of residential and small commercial customers; and (iii) a Commercial and Industrial Pilot, in which CSPs can make offers to large Commercial and Industrial customers with demand equal to or greater than 500 kW.

As amended in the most recent session of the General Assembly, § 56-577 C of the Code of Virginia states:

> The Commission may conduct pilot programs encompassing retail customer choice of electricity energy suppliers for each incumbent electric utility that has not transferred functional control of its transmission facilities to a regional transmission entity prior to January 1, 2003. Upon application of an incumbent electric utility, the Commission may establish opt-in and opt-out municipal aggregation pilots and any other pilot programs the Commission deems in the

[44] Moody's Credit Perspectives: Dominion Resources' Outlook Now Negative; September 23, 2002.
[45] The opt-in method requires that a consumer affirmatively choose to participate.
[46] The opt-out method requires that a consumer affirmatively choose not to participate; absent such a decision the consumer will be included.
[47] Originally named the Default Service Pilot. Following discussion with interested parties, the Company revised the name in an effort to minimize the potential for customer confusion.

> public interest, and the Commission shall report to the Legislative Transition Task Force on the status of such pilots by November of each year through 2006.

The Company asserts that the proposed Pilots are in the public interest and will help stimulate the development of competition within the Commonwealth while simultaneously providing market participants an opportunity to test new market concepts such as opt-in and opt-out municipal aggregation and attributes of default service, including the bidding process.

On April 21, 2003, the Commission issued its Order Prescribing Notice and Inviting Comments and Requests for Hearing establishing this proceeding as Case No. PUE-2003-00118.[48] Subsequently, as a result of discussions with interested parties and in an attempt to address concerns expressed in those discussions, DVP submitted revisions to its application on June 25, 2003. Staff investigated the application and filed its report on July 15, 2003. Several parties submitted comments with no one requesting a hearing.

Generally, some parties believe the proposed pilots are not in the public interest because of confusing complexity and the risk of "slamming" customers through non-consensual switching. Others wish to permit intermediate-sized commercial customers to choose to participate in either the "CBS" Pilot or the Commercial and Industrial Pilot. Another party believes for the proposal to be effective, the size of the programs should be significantly enlarged, the wires charge eliminated, and the start date should not be delayed beyond January 1, 2004 and not end until the end of the capped rate period.

While sharing some of the same expressed concerns, Staff believes that the proposed Pilots are in the public interest and recommends Commission approval of these Pilots with certain modifications. Absent the Pilots, it appears there will be little, if any, shopping for electricity supply in the near future. In addition, the Staff agrees with the Company that the

Commission and other interested parties may learn valuable lessons relative to Municipal Aggregation and the bidding process for competitive electricity supply service.

DVP seriously considered the comments and suggestions of the Staff's report and those of other parties. In its reply comments of August 1, 2003, DVP further revised its proposed Terms and Conditions to incorporate several updates addressing issues such as providing the opportunity for mid-sized commercial customers to participate in either the CBS Pilot or the Commercial and Industrial Pilot, the Company's responsibility to initiate notification to customers randomly selected to participate in the CBS Pilot, and to "hold harmless" the CBS Pilot participants randomly selected to pay no more than they otherwise would have under capped rate service.

Future SCC Activity

We now have the basic rules, systems, and procedures in place to accommodate retail choice. Unless otherwise directed by the General Assembly, the SCC will take the following actions during the next year as part of the effort to facilitate retail access:

- Analyze the technical and operational implications of the RTO filings.
- Continue to explore the potential for designating alternative default service providers.
- Re-evaluate the method for determination of the market price and resulting wires charge for incumbent electric utilities, then re-set those numbers.
- Continue the development of a proper foundation for competition including the on-going work involving competitive metering, consolidated billing, development of business practices, distributed generation interconnection standards, and aggregation.
- Continue the study related to SB 684 regarding the reliability of our energy infrastructure.

[48] See http://docket.scc.state.va.us:8080/vaprod/main.asp , Case No. PUE-2003-00118

- Continue the evaluation of stranded costs and associated over or under recovery.
- Continue to solicit ideas from stakeholders about methods to attract CSPs to the Commonwealth.
- Continue to monitor approaches being used in other states to attempt to stimulate competitive activity.
- Reactivate the education of consumers about choice when it appears appropriate, although at a pace that conserves resources.
- Evaluate the merits of proposed pilot programs to test our infrastructure for a competitive retail marketplace.

APPENDIX I-A

SUMMARY OF NATURAL GAS RETAIL ACCESS PROGRAMS IN VIRGINIA

SUMMARY OF NATURAL GAS RETAIL ACCESS PROGRAMS IN VIRGINIA

This appendix updates last year's report regarding natural gas retail access programs in the Commonwealth of Virginia. Large natural gas customers in the Commonwealth have been allowed to arrange for their own supply and transportation of gas for more than ten years. Natural gas retail access is now available through two programs, one in the service territory of Washington Gas Light ("WGL"), including customers within the service area of Shenandoah Gas, and the other in the territory of Columbia Gas of Virginia ("CGV").

WGL's Retail Access Program

As of July 1, 2003, WGL's program has eleven active CSPs serving slightly more than 7,000 non-residential customers and three active CSPs serving approximately 69,900 residential customers. Cumulatively, these accounts represent approximately 20.3 percent of the 378,642 natural gas customers in WGL's service territory. It is important to note, however, that WGL's unregulated affiliate, WGES, is serving approximately 76 percent of the non-residential shoppers and approximately 73 percent of residential shoppers. The CSP serving the next largest group of customers is also an unregulated affiliate of an incumbent LDC and accounts for almost 13 percent of non-residential customers and about 25 percent of residential customers.

CGV's Retail Access Program

As of July 1, 2003, there are four CSPs providing service to 487 non-residential customers and 6,119 residential customers. Cumulatively, these accounts represent approximately 3.2 percent of the 207,089 natural gas customers in CGV's service territory. It is noteworthy that the same affiliates referenced above serve the greatest number of CGV customers as well, approximately 63 percent and 29 percent, respectively.

CSP Activity

The two natural gas retail access programs have provided useful information to utilities, CSPs, consumers, and the Commission Staff. The level of CSP activity has been considerably better in the natural gas programs than has been experienced in the electric programs, although a high level of affiliate market concentration may have distorted the actual level of competitive activity.

There have been several CSPs to terminate service to customers and return their customers back to the incumbent utilities. This was due in large part to the significantly higher natural gas prices experienced during the past year.

PART III

RECOMMENDATIONS TO FACILITATE EFFECTIVE COMPETITION IN THE COMMONWEALTH

PART III

Recommendations to Facilitate Effective Competition in the Commonwealth

Executive Summary

Part III of the Report consists of two sections. The first section includes a discussion of recommendations advanced by various stakeholders as means of facilitating effective competition in the Commonwealth as soon as practicable. The second section of Part III discusses the SCC's recommendation that a suspension of the Act is in the public interest because delaying implementation of the Act is a prerequisite to the preservation of Virginia's jurisdiction.

To assist development of a comprehensive list of recommendations to foster effective competition, the Staff sent a letter to over 70 interested stakeholders seeking their suggestions. In a letter dated April 16, 2003, Staff posed eight questions designed to stimulate respondents' thoughts on specific restructuring issues. Although the Staff's mailing list targeted stakeholders thought most affected by electric restructuring issues, responses were received from just twelve stakeholders. In a similar survey conducted in 2002, the SCC received sixteen responses. The twelve 2003 responses are included as Appendix III-A to this Report.

Generally, most of the comments received are similar to those expressed in last year's report and reiterated during the past year via various forums such as work group discussions. Respondents' recommendations, while discussed in detail in Part III, do not provide new ideas; the recommendations presented have already been considered by the SCC and the CEUR. Many of the twelve respondents continue to believe that the major obstacles to effective competition in Virginia include:

- The existence of low, capped rates of the incumbent utilities,
- The existence and method of determining wires charges,
- The recovery of yet-to-be-quantified stranded costs,
- The lack of a functional RTO, and
- The lack of effective customer demand response programs.

The second section of Part III contains the recommendation that the General Assembly take action to suspend portions of the Act by re-bundling rates and continuing the moratorium on the transfer of control of Virginia's electric transmission systems to federally-regulated regional transmission entities.

Section 56-596 of the Act requires the SCC to report its recommendations to facilitate effective competition in the Commonwealth as soon as practicable, which shall include any recommendations of actions to be taken by the General Assembly, the SCC, electric utilities, suppliers, generators, distributors, and regional transmission entities it considers to be in the public interest. This year, the SCC has one recommendation, and it is not new.

The status of competition for electric service is not encouraging. There has been little change in market conditions around the country or in Virginia since we submitted the December 2002 Addendum. Though there are isolated instances in other jurisdictions of competitive activity among larger commercial and industrial customers, retail choice is not yet providing meaningful benefits or yielding sustained savings anywhere in the country. Even more distressing than the absence of sought-after competitive activity is the likelihood that the implications of the SMD NOPR will be detrimental to Virginia's electricity consumers.

For these reasons, we renew our recommendation that the General Assembly suspend the Act. Suspension of the Act would require rebundling the components of retail electricity rates and continuing a moratorium on transfers of control over transmission assets to RTOs. However, the General Assembly could allow other aspects of the Act to continue to evolve while these two elements of the Act are temporarily suspended.

Pausing in the implementation of the Act is the best course if we are to preserve Virginia's ability to protect its citizens from the problems that are likely to result from the ceding of regulatory authority to FERC and regional transmission entities. The potential costs of adhering to a perceived schedule for the sake of implementing change outweigh the risks of delay. It is possible that any future benefit of retail access could be affected by a delay of retail access. However, we currently have the basic rules, systems, and procedures in place to harmonize retail access. If Virginia delays full implementation now and retail access proves successful elsewhere, we will be in position to implement retail choice quickly and effectively. This ability to respond quickly should minimize any loss to Virginians with a delay at this time.

CONTENTS

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Section 1 - Stakeholder Recommendations

This final section of the Commission's 2003 report on competition presents a discussion of issues affecting competitive activity within the Commonwealth's electricity market. To assist the Commission in developing this discussion, our Staff sent a letter on April 16, 2003, to over 70 interested stakeholders. In that letter the Staff asked for any thoughts and recommendations related to the specific topics listed in § 56-596 B of the Act. These topics include the supply and demand balance for generation services, new and existing generation capacity, transmission constraints and market power. In addition, Staff posed eight questions designed to elicit respondents' thoughts on specific restructuring related issues.

Staff received comments from twelve respondents. It then held a meeting on June 6, 2003, to discuss the comments and issues raised. Not counting Staff, only twelve people attended the meeting representing eight different organizations.

Provided in Appendix III-A, are the Staff's letter, a list of stakeholders the letter was sent to, and all of the comments that were received.[1] The following stakeholders provided comments and recommendations to the Staff:

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[1] Comments are also posted to http://www.state.va.us/scc/division/eaf/comments_comp.htm .

Utilities:
  Allegheny Power ("AP")
  American Electric Power ("AEP-VA")
  Dominion Virginia Power ("DVP")
  Virginia, Maryland & Delaware Association of Electric Cooperatives ("Cooperatives")

Competitive Service Providers/Aggregators:
  New Era Energy ("NewEra")
  Pepco Energy Services ("PES")
  Strategic Energy, LLC ("SEL")

Consumer Representatives:
  Urchie B. Ellis, Esquire

Others:
  Municipal Electric Power Association of Virginia ("MEPAV")
  National Energy Marketers Association ("NEM")
  Virginia Committee for Fair Utility Rates and Old Dominion Committee for Fair Utility Rates ("VCFUR/ODCFUR")
  Virginia Energy Providers Association and Virginia Independent Power Producers ("VEPA/VIPP")

The remainder of this section discusses the issues identified through the aforementioned forums. These issues are not ranked in any order of preference or importance. Similar to last year's report, the major obstacles to effective competition identified by the respondents include:

- the existence of low, capped rates of the incumbent utilities,
- the existence and method of determining wires charges,
- the recovery of yet-to-be-quantified stranded costs,
- the lack of a functional RTO, and
- the lack of effective customer demand response programs.

Additional comments received by Staff addressed the volatility of natural gas prices, the FERC's SMD NOPR, the robustness of the Retail Access Rules, and consumer education efforts. This section will also update any progress regarding the proposals presented in last year's report. Finally, this section will identify any recommendations to be considered during the next twelve months.

Issue 1: The existence of low capped rates of the incumbent utilities.

Several respondents stated or implied that traditionally, Virginia has enjoyed relatively low electricity prices with the existing monopoly structure. This implies that "*generation, transmission and distribution assets are generally adequate to meet customer demand and that they are generally operated efficiently*" as stated by New Era Energy, Inc. ("New Era") in its letter of May 23, 2003. Currently, these low prices continue providing little margin for which alternative suppliers can compete.

Possibly the most vigorously argued premise advanced by several respondents since the passage of the Restructuring Act is that competition cannot develop until customers are subjected to market-based prices for competitive energy supply. It is also believed by several respondents that price caps prevent appropriate price signals from reaching customers. Allegheny Power points out in its letter of May 23, 2003 that "*Rate caps serve to protect customers during the transition period, but the same rate caps also insulate retail customers from the reality of pricing variability that exists in the wholesale market. This obstacle will be removed when rate caps are removed, at which point the generation component of default service rates will be based on competitive market prices.*" The National Energy Marketers Association ("NEM") submits that "*Price caps do not facilitate energy competition and do not permit consumers to modify their consumption levels in response to price.*" in its comments of May 23, 2003.

As was the comments last year, not all respondents agree that the rate caps should be removed. AEP-VA, DVP, and the Cooperatives state that the rate caps and wires charges are included in the Restructuring Act as a result of negotiations intended to balance developing competition with a smooth transition process. Mr. Ellis states in his letter of May 13, 2003 that "*we now have low rates, good service, and a fine prosperous major power company (Dominion). The only way this can be overcome is to increase the amount that Virginia residential users have to pay for electricity!*"

This issue of removing price caps so that the price for competitive energy supply is market-based has generated a tremendous amount of debate. One side believes that price caps are a fundamental flaw of the Restructuring Act and competition will not develop until they are removed. Once removed, it is argued that the market will develop quickly and serve to regulate prices and protect consumers.

The other argument is that the primary concern during the transition to a competitive market is the protection of the consumer. Such protection requires consumers not be exposed to market-based prices until effective competition has developed and can be depended upon to regulate prices. As a result, there is tension between letting the market set price levels where it will, and ensuring an *effectively* competitive market, a touchstone of the Restructuring Act, where *competition* sets market prices.

Similar to last year, rate caps are believed by many to be an essential consumer protection built into the Act. A concern expressed by several respondents going into restructuring was that Virginia had relatively low-cost energy and that there would be upward pressure on prices in a competitive market. Virginia's electric utilities assert that they agreed to cap their rates through mid-2007 with the expectation that they could continue to earn an adequate return plus recoup any stranded investment during that time frame, thus the rate caps provide a protection for utilities as well as consumers.

The Act changes the processes and obligations though which Virginians will obtain retail electric service. The General Assembly determined that non-fuel rates should be "capped" for incumbent utilities until July 1, 2007. However, this rate cap imposes costs and benefits on incumbents. It also imposes costs and benefits on ratepayers. That is, it is not clear that capping rates confers net benefits on customers. The "cap" has had the effect of a "freeze". In the absence of the cap, it is not known with certainty if non-fuel rates would have been higher or lower than the capped rate level.

Many believe the underlying premise of the Restructuring Act is that a competitive market will result in lower retail electricity prices for Virginia consumers. It appears counterintuitive to believe that these prices must rise to induce competition. A stronger case could be made for market-based pricing during this transition period if Virginia was surrounded by effectively operating competitive electric markets, particularly if the low-cost states in the southeast had deregulated and injected their low-cost generation into the market. Unfortunately, retail competitive activity continues to develop slowly throughout the nation, not just in Virginia or in the Mid-Atlantic region. Consequently, a market has not yet fully developed that can be depended upon to regulate prices.

Issue 2: The existence and determination of wires charges.

Related to the aforementioned issue, respondents continue to claim that the wires charge mechanism may be as strong a detriment to the development of competition as rate caps. For instance, NEM submits, "*the wires charge is a significant barrier to entry in the Virginia market. The manner in which the wires charge is calculated and implemented makes it virtually impossible for competitive suppliers to compete with the utilities.*" They further state that "*Imposing a wires charge on switching customers is unfair and unwise because it penalizes those customers who attempt to lower their energy costs and defeats the entire purpose of permitting price competition in the first instance.*" NEM believes that any costs that are unavoidable to provide default service should be recovered through adjustments to the default service rates and any costs or lost revenues not related to the provision of default service should be added to distribution rates in a neutral fashion.

Similarly, New Era asserts "*the recovery of stranded cost is appropriate but it should only be for facilities investment and long term supply contracts that cannot be mitigated with reasonable efforts. It should not recover lost revenue.*" New Era also states that "*even if the wires charge were to be reduced, its unpredictability creates an unnecessary high risk for competitors. Competitors cannot make price commitments to customers beyond the period of the existing wires charge rate. The inability to realistically predict the wires charge is a serious obstacle.*"

Pepco Energy Services ("PES") contends that the most significant obstacle to an effective competitive retail market in Virginia is the "*artificially low price-to-compare ("PTC") set annually by the Commission on a customer class basis. Projected market* *prices for generation used by the Commission to set wires charges – which, in turn, affect the calculation of the PTC (the wires charge and the PTC have an inverse relationship) — should reflect a retail market price rather than a wholesale market price."* It is worth noting that the PTC for our major low cost utilities is not the market price but rather the embedded cost of generation.

The incumbent utilities share a common view that the relationship between the wires charge and capped rates is a cornerstone of the Restructuring Act that was developed through intense negotiations. The wires charge, they say, is designed to assure utilities of revenue neutrality during the transition period.

It is hard to refute either side of the argument related to this proposal. The wires charge will cause it to be more difficult for competitive suppliers to offer savings to customers. On the other hand, the wires charge is a central component of the Restructuring Act.

The elimination of the wires charge may help, but certainly will not guarantee, competition. Although there is no wires charge within the service areas of Delmarva, AEP, or Allegheny Power, there still is no shopping.

The Commission has already made its interpretation of the Act and how it relates to the issue of a projected market price based on wholesale or retail market prices. It did so in its order in Case No. PUE-2001-00306, where the Commission concluded as follows:

> We do not disagree that allowing for "headroom" by incorporating retail costs in market prices would fairly recognize the costs CSPs will incur to serve customers, and would likely promote competition. However, it would not be revenue neutral to the incumbent utility.
> The Act, in our view, is designed to make the incumbent utility whole, with the wires charge priced to make the utility indifferent as to whether it

recovers stranded costs through capped rates or wires charges. Including retail costs in the calculation of market prices would not likely leave the utility in a revenue neutral position as the Act is designed to do. We cannot, therefore, find that the Act authorizes such action. If the General Assembly determines that this measure is appropriate to advance competition it, of course, may amend the Act to allow it.

Issue 3: The recovery of yet-to-be quantified stranded costs.

Another issue related to those above regard the recovery of stranded costs. Generally, the incumbent utilities believe the Restructuring Act simply requires any stranded costs that exist to be recovered through the utility's capped rates and wires charges without quantifying the amount of such stranded costs. Other respondents contend that one must quantify the total amount of stranded costs to determine an over or under recovery.

In fairness, comments to Staff's April 16, 2003 letter were submitted in May, prior to the release of our Stranded Cost Report on July 1, 2003 to the CEUR. Much discussion was entertained throughout the work group process as described in our Stranded Cost Report to the Commission on Electric Utility Restructuring issued on July 1, 2003. Additionally, we believe the issues raised in the May comments are sufficiently addressed in the Stranded Costs portion of Part II of this Report and need no further discussion at this time. The Commission awaits further direction from the CEUR.

Issue 4: The lack of a fully functional RTO.

Perhaps the most common issue raised among the comments submitted in response to Staff's letter regards the lack of a fully functional RTO as the major obstacle to an inactive competitive market in Virginia. AEP-VA states "*a critical element of successful implementation of the Act, entry in of Virginia's major utilities into an independent regional transmission entity, has been substantially delayed until well into the period ending July 1, 2007.*"

Allegheny Power contends that "*another obstacle to the development of competition is the need for a wholesale power exchange, including real-time energy markets. Real-time energy markets provide an alternative to the purchase of load following products when supplying a retail load-shape.*" NEM "*urges the Commission to require the utilities to transfer control of their transmission systems to an RTO as soon as possible...*"

The Virginia Energy Providers Association ("VEPA") observes that "*the most significant obstacle to the development of robust competition in Virginia is the delay of Virginia's incumbent electric utilities in gaining state approval to join an approved Regional Transmission Organization to serve wholesale markets, ultimately to the benefit of retail customers. Without the participation of Virginia's incumbent utilities in a fully functioning, truly independent, unbiased regional transmission organization, effective wholesale competition can not develop. And without effective wholesale competition, retail competition is impossible.*"

Members of the Municipal Electric Power Association of Virginia ("MEPAV") have "*supported the development of independent RTOs of sufficient size and scope to provide benefits to consumers and have been supportive of the concept of Standard Market Design for wholesale electric markets.*" The MEPAV also supports the 2003 amendments to Sections 56-579 A 2 d and 56-579 F of the Act for the SCC to ensure that consumers' needs for economic and reliable transmission are met and that any transfer of transmission facilities maximize the benefits to all consumers.

DVP states that "*Development of an open-access, non-discriminatory wholesale power market covering a broad region is an essential foundation for successful retail choice. Even most critics of the Standard Market Design initiative launched by the Federal Energy Regulatory Commission concede the benefits of an open interstate wholesale market.*"

Strategic Energy submits that "*because Virginia does not belong to a Regional Transmission Organization, and therefore lacks an active bilateral market and a balancing energy market, there is little or no opportunity to offer value-added services.*" They further state that "*Larger control areas not only create more robust markets, but improve reliability by better coordinating the use of transmission facilities.*"

The Virginia Committee for Fair Utility Rates and the Old Dominion Committee for Fair Utility Rates believes that "*membership in an RTO should enhance reliability by easing access to generation sources across an entire region.*" They also contend that the SCC Order in Case PUE-2000-00550, dated March 7, 2003, "*represents a good start in fulfilling the Commission's revised responsibilities under the new legislation.*"

Many of the respondents also urge the Commission to proactively and cooperatively continue working with the FERC and neighboring states to develop a satisfactory SMD or Wholesale Market Platform. They claim that such resolution will ease the entry of incumbent utilities into RTOs.

The Addendum to 2002 Status Report on Competition that we issued in January discusses our concerns regarding an RTO and FERC's proposed SMD. This supplemental report identifies our concerns regarding FERC's proposed SMD and implications upon an RTO serving the Commonwealth. Since that report, FERC issued its White Paper regarding changes to its originally proposed SMD and the Department of Energy released its cost-benefit analysis of the original SMD proposal.

We further articulated our concerns regarding the proposed SMD and the results of the DOE Study in a letter to U.S. Congressman Bob Goodlatte on June 19, 2003. This letter was also sent to members of the Commission on Electric Utility Restructuring. Summarily, FERC's White Paper amplified our concerns relative to the potential impact of FERC's initiative. The DOE Study reinforces these concerns because, even with optimistic assumptions and virtually no risk analyses, the results do not make a case for going forward. In short, the SMD, overlaid onto Virginia's Restructuring Act, could have significant negative results for Virginia consumers.

As previously discussed in the RTE Development portion of Part II of this Report, the Staff is currently evaluating the transfer of transmission facilities of the incumbent investor-owned utilities to PJM prior to January 1, 2005 and approval of such transfers are pending before this Commission.

Issue 5: The lack of effective customer demand response programs.

Similar to last year, a few respondents submitted comments indicating the need for more effective customer demand response programs. New Era states their belief "that in the long-run, competition will benefit the consumer by creating significant technological advances, new products, alternative rate options, and a far more efficient overall industry" and "that the LTTF, supported by the SCC, needs to create a vision of what new structures and options are desired in the electricity industry and to determine if legislation, regulation or incentives are appropriate to encourage the transition."

New Era also submits that demand response programs already exist but generally are not promoted. Further, they contend that small customers do not understand demand and that there are actions to take to reduce their peak demand, affect their costs, and that there are products available to assist with demand response. Such customers may well respond to price signals if they understood the implications and such signals were made available. Additionally, New Era contends that reliable demand response should be equal in value to supply in meeting reserve requirements.

Allegheny Power submits that an obstacle to a competitive market in Virginia is the absence of demand response to price. AP contends that "*Demand response to price is a key fundamental which is missing in the retail electricity markets. The introduction of demand elasticity based on price, such as real-time pricing, will result in lower market clearing prices, as load will diminish as prices rise.*"

Last year the Consumer Advisory Board recommended to the LTTF that an Energy Management Working Group be established to evaluate demand side management options under the leadership of the SCC. The LTTF elected to table the recommendation because of the heavy work load in 2003.

The SCC has recognized the potential of such developments and has charged the Competitive Metering Work Group to continue to study expanded or voluntary Time-Of-Use programs and expand such study to include new meter technology. Such investigation could include examination of the types of meters used by the utilities and seek to ensure that the current technologies do not inhibit the use of price signals or the development of a competitive metering market. We have directed the Staff to file a report by May 1, 2004, providing the results of its investigation.

Issue 6: The volatility of natural gas prices.

Natural gas prices over the past year or so have experienced high volatile fluctuations compared to prior periods. This uncertainty can have a significant impact on any study or forecast. We have recently experienced natural gas prices above $5.00 per MBTU, compared to around $3.00 last year. Current expectations are for prices to remain higher than traditionally experienced and not return to the low prices we enjoyed earlier.

Environmental concerns have been a primary driver causing natural gas to be the fuel of choice for new generating facilities. As such, one may expect electricity prices to converge with natural gas prices. Allegheny Power summed this issue by stating, "*Traditionally, natural gas-fired peaking facilities set the marginal cost of electricity only during summer peaking conditions. However, with the establishment of NOx regulations, over-firing of coal boilers and the construction of intermediate natural gas generation facilities (combined cycle) have resulted in natural gas setting the marginal cost of electricity more hours of the year, both on-peak and off-peak. Further, with the volatility of summer prices, outages on base-load generation are taken in non-peak periods (spring and fall shoulder peak months), which causes natural gas facilities to supplant this capacity during periods of unseasonal weather in the spring and fall, again increasing the number of hours per year that natural gas sets the marginal cost of electricity.*"

NEM submits that "*Promoting a competitive energy market in Virginia will help to mitigate the potential impact of higher fuel prices by permitting customers to see and select the lowest cost alternative supplies including properly priced demand reduction, load shifting and energy efficiency products and services.*"

Issue 7: The robustness of the Retail Access Rules.

Similar to last year, most respondents generally agreed that the current Retail Access Rules are adequate and consistent with most of the rules in neighboring jurisdictions. The Rules generally strike a balance among all stakeholders by providing consumer protections while ensuring equal treatment of all market participants. Several respondents indicated that although the Rules appear conducive to promoting effective competition in the Commonwealth, the continued lack of competitive activity has not yet fully tested the Retail Access Rules. There is not yet enough information to know from the CSP's perspective how adequate these Rules may be and the burden to explain any reluctance to enter the Virginia marketplace based on the Retail Access Rules falls upon the potential CSPs.

Issue 8: The continuation of consumer education outreach.

Most of the respondents support the current suspension of consumer education regarding energy choice until such time as there are several CSPs actively soliciting customers to enroll. Broad scale efforts should be less visible until the market more fully develops and offers competitive choices. To achieve more effective results, reactivation of the program should be scheduled closer to the expected onset of widespread customer choice.

Issue 9: Update to proposals to consider from the 2002 Report.

Last year's report identified two proposals for consideration by the CEUR that: 1) there should be a staged transition to the competitive markets by rate class, and 2) shopping customers who return to the incumbent utility should have a market-based price as an option of avoiding minimum stay requirements. Having merit, both proposals were drafted and introduced as bills for consideration as amendments to the Act. Both of them were tabled with the request for future consideration of the CEUR.

As a result of continued discussions, the proposed amendments were later withdrawn as DVP announced plans to request approval for three pilot programs to explore the concepts implied by these proposals. The proposed pilot programs are currently pending before the Commission as previously discussed in Part II of this Report.

Other proposals presented last year did not receive any further direction from the CEUR or General Assembly. However, the Commission has addressed several of those proposals in some way with activities previously described in Part II of this Report. Such items regard default service, competitive metering rules, supplier consolidated billing rules, and distributed generation.

Section 1 - Summary

The Commission appreciates the input it received from those respondents that responded by letter and/or participated in the various discussion groups hosted by our Staff. Although we would have preferred a larger number of participants, we did receive the thoughts of a reasonable cross-section of stakeholders: utilities, competitive service providers, aggregators, consumer representatives, and business associations.

In terms of the existence of retail competition, little, if anything, has changed since last year. There still appears to be universal agreement that before a viable competitive retail market develops in the Commonwealth there must be a robust wholesale market and an operational and independent regional transmission organization. While much work has been done or is in the process of being done, it will take more time before that foundation becomes a reality. The stakeholder recommendations included in this section are not new; they are similar to those expressed in last year's report. The SCC does not believe that the adoption of any of these recommendations will facilitate effective competition in the Commonwealth in the present environment.

Section 2 - SCC Recommendation

It has been over four years since the Virginia General Assembly passed the Virginia Electric Utility Restructuring Act; less than four years remain until the mid-2007 end of the transition period set forth in the Act. Section 56-596 of the Act requires the SCC to report to the CEUR and the Governor by September 1 of each year on the status of competition in the Commonwealth, the status of the development of regional competitive markets and the SCC's recommendations to facilitate effective competition in the Commonwealth as soon as practicable. This section of the statute also requires the

SCC to report any recommendations of actions to be taken by the General Assembly, electric utilities, suppliers, generators, distributors, and regional transmission entities that the SCC considers to be in the public interest.

On December 30, 2002, the SCC submitted an Addendum to its status report issued September 1, 2002, that addressed the FERC's NOPR on SMD. That Addendum, entitled "Review of FERC's Proposed Standard Market Design and Potential Risks to Electric Service in Virginia" raised several concerns we had regarding electric industry restructuring and its likely impact on Virginians. In the December 2002 Addendum, the SCC stated:

> Only if the Commonwealth reverses the Act's requirement to unbundle rates and defers the Act's requirement that Virginia's utilities join an RTE can Virginia preserve state jurisdiction. If rates remain unbundled or control of the transmission system is transferred to an RTE, then Virginia's choice will likely have been made. It will be difficult -- if not impossible -- to reverse that choice.

In the months since the SCC issued its December 2002 Addendum to the September 1, 2002, status report, industry events have not lessened our concerns nor cause us to alter our recommendation that the General Assembly take action to preserve Virginia's authority to ensure reliable electric service at just and reasonable rates. Industry, federal regulatory, and legislative uncertainty continue and Virginia's ability to ensure control over its restructured electric utility industry cannot be assured. Consequently, the SCC believes that it is in the public interest to suspend portions of the Act by re-bundling rates and continuing the moratorium on the transfer of control of Virginia's electric transmission systems to federally-regulated regional transmission entities. We note that such a suspension will leave in place rules, procedures and systems that enable retail access. The SCC recommends suspension only as a means to best preserve Virginia's jurisdiction and only as long as necessary to provide Virginia policy makers a reasonably clear view of the likely nature of the transformed industry.

Section 56-596 of the Act requires the SCC to report its recommendations to facilitate effective competition in the Commonwealth as soon as practicable, which shall include any recommendations of actions to be taken by the General Assembly, the SCC, electric utilities, suppliers, generators, distributors, and regional transmission entities it considers to be in the public interest. This year, the SCC has one recommendation, and it is not new.

Our concerns with the bedrock issues of electric service adequacy and electric service prices likely to be available to Virginians prompted the SCC to issue its December 2002 Addendum. In the December 2002 Addendum, we described the many serious problems likely to result from implementation of the FERC's proposed rules on Standard Market Design. These problems include the elimination of native load preferences, the questionable ability of FERC to oversee market monitoring efforts, the potential exercise of market power by wholesale suppliers, increased costs resulting from the use of locational market pricing in transmission-constrained areas, and regional resource adequacy requirements.

In response to criticism levied by Virginia and other jurisdictions, on April 28, 2003, the FERC issued a "White Paper" entitled "Wholesale Market Platform." The FERC White Paper has been carefully studied by the SCC. In our opinion, the FERC White Paper neither clarifies nor alleviates our concerns with the SMD NOPR.

Next, on April 30, 2003, the U.S. Department of Energy ("DOE"), at the request of Congress, issued a report "*...to assess various potential impacts of the proposed [SMD] rulemaking by the Federal Energy Regulatory Commission....*" The DOE study of the SMD is based on optimistic assumptions and does not address many significant risks of the FERC SMD proposal. Even this optimistic study, however, shows that benefits of the SMD will be small, less than a 1% decrease in average retail electric rates, nationwide. Moreover, the DOE study shows that a majority of the areas of the country will have either no benefit or have retail rates actually increase as a result of SMD. Virginia customers, as a result of moving to retail competition under Virginia law and the pricing and other requirements of SMD, will likely see significant rate increases when the current rate freeze ends in 2007.

As outlined in this Report, the problems that are impeding the development of retail competition in Virginia and other regional markets continue unabated. Events in 2003 deepen our concern that problems are becoming increasingly complex and their implications irreversible. We face the likelihood that staying on the current path may cause such distress that the development of an effective competitive market at a future date will be foreclosed.

The continued lack of current and expected market activity leads directly to our recommendation that the Act be suspended in order to preserve Virginia's authority. It is in the public interest to avoid ceding jurisdiction over transmission, generation, reliability and, ultimately, the cost of power, to federal regulators and regional entities. The likelihood that increased prices may be required to foster competition and uncertainty regarding Federal direction with regard to RTOs poses additional uncertainty as to what will occur when capped rates end on July 1, 2007.

For these reasons, we renew our recommendation that the General Assembly suspend the Act. Suspension of the Act would require rebundling the components of retail electricity rates and continuing a moratorium on transfers of control over transmission assets to RTOs. However, the General Assembly could allow other aspects of the Act to continue to evolve while these two elements of the Act are temporarily suspended.

Pausing in the implementation of the Act is the best course if we are to preserve Virginia's ability to protect its citizens from the problems that are likely to result from the ceding of regulatory authority to FERC and regional transmission entities. The potential costs of adhering to a perceived schedule for the sake of implementing change outweigh the risks of delay. It is possible that any future benefit of retail access could be affected by a delay of retail access. However, we currently have the basic rules, systems, and procedures in place to harmonize retail access. If Virginia delays full implementation now and retail access proves successful elsewhere, we will be in position to implement retail choice quickly and effectively. This ability to respond quickly should minimize any loss to Virginians with a delay at this time.

In summary, the status of competition is not encouraging. There has been little change in market conditions around the country or in Virginia since we submitted the December 2002 Addendum. Though there are isolated instances in other jurisdictions of competitive activity among larger commercial and industrial customers, retail choice is not yet providing meaningful benefits or yielding sustained savings anywhere in the country. Even more distressing than the absence of sought-after competitive activity is the likelihood that the implications of the SMD NOPR will be detrimental to Virginia's electricity consumers.

Commonwealth of Virginia

State Corporation Commission

Report to the Commission on Electric Utility Restructuring of the Virginia General Assembly

And the Governor of the Commonwealth of Virginia

Appendix III-A

RESPONSES FROM STAKEHOLDERS

August 29, 2003

APPENDIX III-A
RESPONSES FROM STAKEHOLDERS

CONTENTS

COMMONWEALTH OF VIRGINIA

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STATE CORPORATION COMMISSION
DIVISION OF ECONOMICS AND FINANCE

April 16, 2003

Dear Market Participant:

As directed by §56-596 B of the Virginia Electric Utility Restructuring Act, the State Corporation Commission is preparing its third annual report to the Legislative Transition Task Force ("LTTF") and the Governor, to be filed by September 1, 2003. That report will cover three topics: 1) the status of competition in the Commonwealth, 2) the status of the development of regional competitive markets, and 3) recommendations to facilitate effective competition in the Commonwealth.

The Commission Staff is once again soliciting ideas from stakeholders (including electric utilities, competitive service providers, consumer groups, natural gas utilities and business associations) to assist the Commission in developing a comprehensive review of methods that may be considered to facilitate effective competition. The statutory language in §56-596 B related to this part of the Commission report provides as follows:

> This report shall include any recommendations of actions to be taken by the General Assembly, the Commission, electric utilities, suppliers, generators, distributors and regional transmission entities it considers to be in the public interest. Such recommendations shall include actions regarding the supply and demand balance for generation services, new and existing generation capacity, transmission constraints, market power, suppliers licensed and operating in the Commonwealth, and the shared or joint use of generation sites.

We ask that you consider the topics detailed in the statute and provide any recommendations or thoughts you may have regarding them. In addition, we welcome your input to the following:

1. What are the current obstacles to the development of a robust competitive retail electricity market for residential customers? For commercial and industrial customers? How can these obstacles be overcome?

2. With respect to potential obstacles, what is the outlook for future natural gas prices and the impact on wholesale electricity prices and a competitive retail market? Please comment on the postulation by several natural gas industry experts of a growing structural demand/supply imbalance with demand outstripping supply over the next several years. What actions, if any, could be taken to mitigate the potential impact of an over-dependence on a single fuel source?

3. In light of recent legislation, how can the Commonwealth be assured of a continuing reliable electricity system when control of transmission is governed by an RTO? What factors should be considered during the cost/benefit analysis required prior to Commission approval?

4. Later this month, the Federal Energy Regulatory Commission is expected to issue its "white paper" addressing certain issues debated the past several months regarding Wholesale Electric Standard Market Design (SMD). Additionally, the Department of Energy is expected to issue the results of its cost/benefit analyses of the impacts of SMD. Please provide your initial thoughts and reaction to such releases and identify any significant issues of concern.

5. Are the Commission's Rules Governing Retail Access to Competitive Energy Services conducive to promoting effective competition in the Commonwealth? If not, how should they be modified? Is there any way in which these rules can or should be improved, in any event?

6. What should be the level of consumer education when the program is resumed on July 1, 2004? Should it be as visible, more visible or less visible than when the campaign was suspended? Upon resumption of the campaign, what focus, theme or message should be communicated? Since TV advertising is the most expensive component of the program, what level of TV advertising should be included in the resumption of the campaign?

7. Are there any other actions that have been taken or are being considered in other states that may be used to advance competitive activity in Virginia?

8. Do you have any ideas that have not been tried elsewhere that may facilitate competitive activity in Virginia?

Please provide your comments to me by May 23, 2003. Such response may be sent as a hardcopy via mail or preferrably, electronically as an attached WORD Document at deichenlaub@scc.state.va.us. Such comments will be posted to our website at http://www.state.va.us/scc/division/eaf/comments.htm. As an important follow-up to your responses, the Commission Staff will host an informal discussion on the development of effective competition on June 6, 2003 at 9:30 A. M. This meeting will be held in the third floor training room at the Commission. If you plan to attend the meeting, please notify me by e-mail or phone by May 30th. Following that meeting we will provide all parties an opportunity to add to their initial comments and react to others, if they so desire. Both the initial set of comments and any supplemental comments will be attached as an appendix to the Commission's September 1st report.

I thank you in advance for your participation in this important effort.

Sincerely,

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May 23, 2003

Mr. David R. Eichenlaub
Assistant Director, Division of Economics and Finance
Virginia State Corporation Commission
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1300 East Main Street
Richmond, VA 23219

Dear Mr. Eichenlaub:

The Potomac Edison Company dba Allegheny Power ("AP" or "the Company") appreciates the opportunity to respond to your letter of April 16, 2003 concerning the Commission's report to the Legislative Transition Task Force ("LTTF") and the Governor under § 56-596 B of the Virginia Electric Utility Restructuring Act ("the Act").

AP commends the Commission Staff on its willingness to solicit and consider ideas from all stakeholders in this process. This facilitative approach has worked successfully with other matters in the past. AP looks forward to continuing to lend its experience with retail access in the states of Pennsylvania, Maryland, and Ohio to the Commission in a constructive way to facilitate effective competition in Virginia.

AP would like to offer the following comments and recommendations in response to the specific questions posed in your April 16, 2003 letter. Each of these questions is listed below, followed by AP's comments and recommendations.

Question 1: What are the current obstacles to the development of a robust competitive retail electricity market for residential customers? For commercial and industrial customers? How can these obstacles be overcome?

Wholesale and retail price dislocation is a significant obstacle to the development of a competitive market. Rate caps serve to protect customers during the transition period, but the same rate caps also insulate retail consumers from the reality of pricing variability that exists in the wholesale market. This obstacle will be removed when rate caps are removed, at which point the generation component of default service rates will be based on competitive market prices.

Another obstacle to the development of competition is the need for a wholesale power exchange, including real-time energy markets. Real-time energy markets provide an alternative to the purchase of load following products when supplying a retail load-shape.

A third obstacle is the absence of demand response to price. Demand response to price is a key fundamental which is missing in the retail electricity markets. The introduction of demand elasticity based on price, such as real-time pricing, will result in lower market clearing prices, as load will diminish as prices rise.

Lastly, as PE's capped rates in Virginia are, for the most part, below current market rates, the transition period, as currently defined, is not facilitating a transition. While PE fully appreciates the need and desire for consumer protections as the market develops, the SCC should continue to seek a balance between price protection (rate caps) and market development.

Question 2: With respect to potential obstacles, what is the outlook for future natural gas prices and the impact on wholesale electricity prices and a competitive retail market? Please comment on the postulation by several natural gas industry experts of a growing structural demand/supply imbalance with demand outstripping supply over the next several years. What actions, if any, could be taken to mitigate the potential impact of an over-dependence on a single fuel source?

As environmental concerns drive natural gas as the fuel of choice for new generating sources, there will be an increasing convergence of electricity and natural gas prices. Traditionally, natural gas-fired peaking facilities set the marginal cost of electricity only during summer peaking conditions. However, with the establishment of NOx regulations, over-firing of coal boilers and the construction of intermediate natural gas generation facilities (combined cycle) have resulted in natural gas setting the marginal cost of electricity more hours of the year, both on-peak and off-peak. Further, with the volatility of summer prices, outages on base-load generation are taken in non-peak periods (spring and fall shoulder peak months), which causes natural gas facilities to supplant this capacity during periods of unseasonal weather in the spring and fall, again increasing the number of hours per year that natural gas sets the marginal cost of electricity.

To reduce single-fuel dependence and convergence into the future, consideration should be given to a revised national energy strategy that encourages fuel source diversity.

Question 3: In light of recent legislation, how can the Commonwealth be assured of a continuing reliable electricity system when control of transmission is governed by an RTO?

FERC's recent "white paper" set out some important intended changes to its proposed Standard Market Design. FERC clarifies that nothing in its Final Rule will change state authority over resource adequacy and regional transmission planning. Although FERC will require public utilities to join an RTO or ISO, it appears the states will continue to play a significant role in the planning and resource adequacy processes.

What factors should be considered during the cost/benefit analysis required prior to Commission approval?

RTO formation and membership is driven conceptually by the need for open and comparative access to the transmission system for all market participants. It facilitates the efficiency of the wholesale electric marketplace, which in turn supports the possible development of localized retail competitive markets. As such the benefits of RTO membership fall to a broader area, beyond the boundaries of any particular state. Accordingly, any cost/benefit analysis should encompass the regional area. Items that should be included are:

- Regional deliverability of the existing transmission infrastructure and the effect of congestion management mechanisms on the broad wholesale market
- Comparison of regional resource adequacy to more local jurisdictional resource adequacy and estimate of cost to equalize same
- Cost of provision of localized redundancy to assure system security as compared to the current reliance on the regional system to provide that backup
- Cost of RTO operation compared against multiple operational staffs in individual utilities

Question 4: Later this month, the Federal Energy Regulatory Commission is expected to issue its "white paper" addressing certain issues debated the past several months regarding Wholesale Electric Standard Market Design (SMD). Additionally, the Department of Energy is expected to issue the results of its cost/benefit analyses of the impacts of SMD. Please provide your initial thoughts and reaction to such releases and identify any significant issues of concern.

AP is currently reviewing the FERC "white paper" regarding Wholesale Electric Standard Market Design as well as the DOE cost/benefit analysis of the impacts of SMD. AP will provide copies of any comments filed with FERC. Attached at the end of this document is a summary of AP's previous positions on SMD, which were filed prior to the recent "white paper".

Question 5: Are the Commission's Rules Governing Retail Access to Competitive Energy Services conducive to promoting effective competition in the Commonwealth? If no, how should they be modified? Is there any way in which these rules can or should be improved, in any event?

The Commission's Rules Governing Retail Access to Competitive Energy Services ("Rules") are conducive to promoting the advancement of effective competition in Virginia. The Rules strike an appropriate balance of all stakeholder interests by providing consumer protections while ensuring equal treatment of all market participants. Based on AP's experience with similar rules in Maryland, Pennsylvania, and Ohio, the Company believes the Rules will serve as an effective framework for retail access. AP recommends no changes to the Commission's Rules.

Question 6: What should be the level of consumer education when the program is resumed on July 1, 2004? Should it be as visible, more visible or less visible than when the campaign was suspended? Upon resumption of the campaign, what focus, theme or message should

be communicated? Since TV advertising is the most expensive component of the program, what level of TV advertising should be included in the resumption of the campaign?

It is AP's understanding that the primary purpose of the initial advertising campaign was to create interest among consumers and inform them that educational materials are available free of charge. AP feels this is an appropriate focus for the campaign again once it is resumed. Given the limited number of suppliers offering service in Virginia, it may be appropriate at this time to utilize less expensive forms of communication than TV advertising. AP recommends the VEC toll-free information line and the VEC website at www.yesvachoice.com remain available for customers to obtain factual and unbiased information on customer choice.

Question 7: Are there any other actions that have been taken or are being considered in other states that may be used to advance competitive activity in Virginia?

AP encourages the Commission to explore wholesale competitive bidding of default service after the rate cap period ends in Virginia. Currently there is a Maryland proceeding underway to define such a procedure for wholesale bidding of default service at the end of the utilities' rate cap periods in that state. The Maryland Public Service Commission recently approved Phase I of the Settlement Agreement in Case No. 8908, *Standard Offer Service*, which was negotiated between Maryland's utilities, the Maryland PSC Staff, consumer groups and various wholesale and retail suppliers. The Settlement Agreement defines a procedure for the provision of default service to customers through the competitive selection of wholesale supply. The settlement makes such services available at market prices, benefiting all stakeholders. Retail suppliers are allowed to effectively compete for load, thereby stimulating the competitive market with no penalty to customers. Customers are afforded protections beyond the assurances required by Maryland's restructuring statute, while permitting utilities to recover their verifiable, prudently incurred costs to procure the electricity plus a reasonable return.

AP is an active participant in the Commission's work group established in Case No. PUE-2002-00645, *In the Matter Concerning the Provision of Default Service to Retail Customers Under the Provisions of the Virginia Electric Utility Restructuring Act*, and as such the Company has and will continue to share its views on this matter in that forum. In addition, a proposed competitive bidding process is also underway in AP's Ohio jurisdiction. As the Commission develops its recommendations on the important issue of default service, AP looks forward to offering its experiences in both the states of Maryland and Ohio.

AP would also like to point out that while the continuation of the capped rate service may provide short-term protection to consumers, it has also insulated the customer from the pricing variability that exists in the wholesale market. As previously recommended, AP believes that the Electricity Supply service provided by the incumbent utility during the period from January 1, 2004 until July 1, 2007 should be more reflective of the current market prices for wholesale supply. AP has previously proposed alternatives to Staff for consideration and again offers its assistance and support in developing solutions to enhance market development during the remainder of the capped rate period.

Question 8: Do you have any ideas that have not been tried elsewhere that may facilitate competitive activity in Virginia?

AP has no response to this question at this time.

Closing

AP appreciates the opportunity to offer its views and recommendations regarding these issues. Thank you for giving us this opportunity, and please feel free to contact me for further information. AP looks forward to working with Staff to further develop and refine the Commission's recommendations on these very important issues.

Sincerely,

Cynthia A. Menhorn

Cynthia A. Menhorn
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SUMMARY OF ALLEGHENY POSITIONS ON FERC PROPOSED RULEMAKING TO STANDARDIZE MARKET DESIGN ("SMD")

Allegheny Power and Allegheny Energy Supply Company, LLC (Allegheny Companies) support FERC's initiative to standardize transmission access and market design nationally, but suggest that FERC make the following improvements to SMD:

- Protect retail customers against the risk of new transmission congestion costs and service interruptions through allocations of "congestion revenue rights" ("CRRs"). CRRs must "follow the load" (*i.e.*, the right to CRR revenues belong to load and other entities that pay for the fixed costs of the transmission system). CRRs should permit transmission, supply and demand response solutions to compete on an equal footing to resolve congestion.

- FERC must respect the sanctity of contracts, such as pre-Order No. 888 contracts between utilities and their customers. FERC could provide incentives for customers to convert their service entitlements after a four-year transition period (similar to FERC's proposed transition period for placing bundled retail service under the new SMD tariff), as long as FERC provides utilities the opportunity to recover lost revenues.[1]

- FERC generally should not require "participant funding" (*i.e.*, incremental pricing) for new facilities integrated with the AC transmission grid because it is virtually impossible to identify discrete beneficiaries of such projects for the life of the facilities. FERC should permit participant funding for: (1) merchant projects to build DC facilities, and (2) AC projects only when an appropriate load flow study identifies discrete project beneficiaries for the life of the facilities.

- FERC should not mandate immediate implementation of postage stamp rates within the Independent Transmission Provider's ("ITP") system, but instead should encourage a transition from license plate rates over a period of years by permitting transmission owners to recover their lost revenues, or by pricing new construction on a postage stamp basis.

- Concerning resource adequacy, FERC should: (1) require ITPs to adopt reasonable planning horizons of three to five years, (2) permit ITPs to adopt resource adequacy requirements through the stakeholder process, with a minimum default reserve capacity requirement based on application of the North American Electric Reliability Council's

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1 Incentives could include, for example, a stranded cost surcharge for the utility to recover lost revenues similar to the mechanism FERC accepted to allow Allegheny to recover lost through-and-out charges when it joined PJM through PJM West.

one-day in ten year probability of lost load standard, (3) facilitate retail access by permitting ITPs to adopt resource adequacy procurement periods that reflect the rights of retail load periodically to switch suppliers, (4) require ITPs to allocate the resource adequacy reserve requirement to load serving entities ("LSE") based on each LSE's load ratio share of the reserve capacity requirement, (5) require ITPs to develop resource adequacy verification procedures, (6) require ITPs to adopt meaningful deficiency penalties to make it uneconomic for LSEs who fail to meet their reserve capacity obligation, (7) adopt a must-offer requirement for capacity resources to ensure that a contracted resource is actually offered into the market, and (8) require resources (generation or demand response) to demonstrate the ability to perform.

- FERC should promote demand response programs while making clear that: (1) the ITP cannot offer demand response options directly to retail customers because that would make it a market participant, (2) LSEs, not third party aggregators, can sell demand response services so that LSEs will not be saddled with imbalance payment responsibility, and (3) demand response should not be subsidized by above-market payments that are socialized as uplift.

- FERC should delegate only limited ITP functions to independent transmission companies and only on a trial basis because ITCs are, by their nature, market participants whose interests are biased by their profit-making objectives.

- FERC needs to be careful to avoid an improper delegation of exclusive Federal authority over interstate transmission and wholesale power sales to the States through Regional State Advisory Committees

- FERC should not adopt a new definition of "market power" that could undermine confidence in the sanctity of power contracts. FERC should continue to apply the definition of market power that it has used for many years which depends on the ability of a supplier to impose a significant price increase for a significant period of time. FERC should not impose excessive bid caps or market price mitigation because such restrictions distort the market and undermine investment decisions, to the detriment of consumers in the long term. FERC should reexamine annually any mitigation measures it adopts for an ITP to determine whether the mitigation continues to be necessary in light of demand response and resource adequacy developments.

The Allegheny Companies suggested that FERC provide for a comprehensive review of SMD implementation after a reasonable time period.

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May 23, 2003

BY HAND

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Re: SCC Report on the Status of Competition in the Electric Industry

Dear Mr. Eichenlaub:

Thank you for your letter of April 16, 2003 inviting comments for the State Corporation Commission's ("Commission" or "SCC") third annual report to the Legislative Transition Task Force ("LTTF") and the Governor under the Virginia Electric Utility Restructuring Act ("Act"). Section 56-596 B of the Act requires the Commission to report on (1) the status of competition in Virginia; (2) the status of development of regional competitive markets; and (3) recommendations to facilitate effective competition in Virginia as soon as practical. In addition, your letter asks for responses to several questions for purposes of the report. On behalf of Appalachian Power Company, d/b/a American Electric Power ("Company" or "AEP"), this letter will respond to the statutory subjects of the report and the questions in your letter.

STATUS OF COMPETITION IN VIRGINIA

The Company reported last year that: "As of January 1, 2002, all of AEP's Virginia customers have a choice of retail suppliers of electric generation services, and the Company stands ready to respond to customers' choices as alternative supply arrangements may become advantageous to them." However, the Company's most current information is that competitive retail electric generation suppliers have not entered the Virginia retail market, perhaps due in part to structural features of the Act. Due to this absence of generation supplier entry, customers have not had a practical opportunity to exercise their legal option to select alternative generation suppliers.

The implementation of the requirements for retail customer choice are, for the most part, in place and in compliance with the Commission's retail choice rules. Rates are unbundled, and incumbent utilities either operate in a functionally separate manner as required by the Commission or have separated or divested their generation assets and operations to separate legal entities. Other factors are slowing progress to widespread switching of customers among alternative generation suppliers.

The expectations created by the Act from its passage in 1999 have been that retail competition would develop during the period between January 1, 2002 and July 1, 2007, and could possibly develop such that capped rates and wires charges could be ended as early as January 1, 2004. Although much of that period remains, a significant portion of it has passed without progress toward the vigorous competition among generation suppliers envisioned in the Act. In addition, a critical element of successful implementation of the Act, entry of Virginia's major utilities into an independent regional transmission entity ("RTE"), has been substantially delayed until well into the period ending July 1, 2007.

While there appears no need for immediate action in the 2004 Session of the General Assembly, the Company has a growing concern that the development of retail competition in Virginia will require closer monitoring by the LTTF. Unless there is significant progress over the next twelve to fifteen months toward fulfillment of the expectations in the Act, including resolution of the Virginia RTE approvals, the LTTF and the General Assembly may be required to consider appropriate changes in the Act.

STATUS OF REGIONAL COMPETITIVE MARKETS

As the Company noted last year: "Open access transmission services and broad access to energy suppliers remain preconditions necessary to allow robust competition to develop for Virginia electricity customers." However, the development of robust, effective wholesale competition has been affected by a lack of progress in implementing RTEs as anticipated in the Act. AEP and its affiliates have sought to join an appropriate RTE since 1999. After initially approving most aspects of, but then ultimately rejecting, AEP's request to join the Alliance Regional Transmission Organization, the Federal Energy Regulatory Commission ("FERC") has now approved AEP's entry into PJM Interconnection, LLC ("PJM").

The Company has an application pending in Virginia for approval to transfer functional control of its transmission facilities to PJM. RTE participation is a fundamental element of the Act, recognized from the beginning as essential to the development of robust competition, that should now be resolved in Virginia promptly.

RECOMMENDATIONS TO FACILITATE EFFECTIVE COMPETITION

The Company recommends continued efforts to implement the Act, including prompt decisions on RTE participation. In light of the certainty concerning PJM and its market structure and operation, and the fact that the FERC has addressed in the "white paper" many of the Commission's jurisdictional concerns on the original SMD proposal, AEP would encourage the Commission to address, more promptly than was previously planned, AEP's RTE application that is currently pending before the Commission.

In its comments last year, the Company said: "...the Commonwealth continues to have an opportunity to observe changes in economic conditions and developing competition in energy markets before further changes in the balanced approach taken in the Restructuring Act are considered." That opportunity remains today, but it is diminishing. Contrary to the expectations in the Act, substantial progress toward robust competition will not likely occur by January 1, 2004, and perhaps not before July 1, 2007. On the other hand, the Act is complex, and every amendment proposed by one specific interest can lead to countervailing proposals by other interests. Careful study by the LTTF and timely actions by the Commission with respect to RTE approval should be given priority over attempts at immediate, issue-by-issue legislation that could have unintended consequences. If the Commonwealth is to change direction through legislation, that change should be based on a comprehensive reconsideration of the expectations embodied in the Act.

Attached to this letter are responses to the questions contained in your letter of April 16, 2003. On behalf of the Company, thank you for the opportunity to provide these views to you, the Commission, and the recipients of the Commission's report.

Sincerely,

Barry L. Thomas

Barry L. Thomas
Director, Regulatory Services VA/TN

BLT/cde

AEP COMMENTS ON
SCC REPORT ON THE STATUS OF COMPETITION IN THE ELECTRIC INDUSTRY
2003

RESPONSES TO QUESTIONS IN THE STAFF LETTER OF APRIL 16, 2003

1. What are the current obstacles to the development of a robust competitive retail electricity market for residential customers? For commercial and industrial customers? How can these obstacles be overcome?

RESPONSE:

The Company is concerned that competition has failed to develop in Virginia. It has been suggested that current obstacles to development of widespread customer switching of generation suppliers are wires charges and utility rates capped at levels that are, or are becoming, unrealistically low. Another obstacle has been the uncertainty created by controversy surrounding, and the lack of progress toward, RTE development in Virginia. The Company does not believe that legislation is necessary in the 2004 Session of the General Assembly. However, continued lack of progress toward robust retail competition could trigger the need for a broad re-examination of the entire Act. Moreover, narrow legislative proposals to amend individual provisions of the Act, as have been discussed by others in the past, could necessitate a re-examination of many other provisions. Capped rates, wires charges, RTE participation and other critical provisions of the Act should not be excluded from such a broad re-examination, in the Company's view.

2. With respect to potential obstacles, what is the outlook for future natural gas prices and the impact on wholesale electricity prices and a competitive retail market? Please comment on the postulation by several natural gas industry experts of a growing structural demand/supply imbalance with demand outstripping supply over the next several years. What actions, if any, could be taken to mitigate the potential impact of an over-dependence on a single fuel source?

RESPONSE:

The Company does not have sufficient information to attempt to answer this question from the perspective of other competitors or fuel suppliers. In any event, the inquiry should be broader. AEP has a diverse fuel mix, which includes coal, natural gas, nuclear, wind, hydro, and fuel oil, and is not heavily reliant on natural gas-fired capacity to serve its Virginia electricity customers. Volatility in natural gas prices is not the only determinant of the overall variation in fuel prices or wholesale electricity prices. Supply, demand, transmission congestion, generation and transmission outages, and weather are all factors that play a role in determining the price of electricity. AEP has risk management practices in place so as markets develop and change, fuel procurement can be modified accordingly.

3. In light of recent legislation, how can the Commonwealth be assured of a continuing reliable electricity system when control of transmission is governed by an RTO? What factors should be considered during the cost/benefit analysis required prior to Commission approval?

RESPONSE:

AEP believes that its participation in a RTO, specifically PJM, will enhance the reliability of AEP's transmission network. For instance, PJM will be able to plan and schedule generation and transmission line outages for maintenance over a large region in a coordinated manner, which will reduce the potential for congestion and short term reliability problems. Also, with AEP's participation, PJM will be able to use the most cost-effective and reliable combination of generation across a large region to balance the entire regional grid and adjust the dispatch economically to relieve congestion and enhance reliability. PJM will be able to internalize many of the critical loop flows that impact reliability and congestion and use regional dispatch to manage congestion created by loop flows. This will be important for the portion of AEP's system located in Virginia. Since the Allegheny Power and Dominion Virginia Power systems, along with AEP, will be part of PJM, PJM will be better able to manage congestion by internalizing within PJM needed redispatch and transmission operation. The market-based redispatch to alleviate congestion will mitigate the need for the existing NERC TLR process, thus further improving the reliability of transactions. Furthermore, PJM has a long-term regional planning process that is open, transparent, and focused on the public interest and consumer benefits. This process ensures continued reliability and promotes new competitive alternatives to alleviate congestion and therefore enhance reliability.

AEP will provide information regarding costs and benefits of RTE participation as part of its pending RTE case. That information will address factors such as impacts on power supply costs for retail customers and the costs of participating in an RTE, including RTE administrative costs. A complete discussion of these factors will be provided when AEP submits its cost/benefit data.

4. Later this month, the Federal Energy Regulatory Commission is expected to issue its "white paper" addressing certain issues debated the past several months regarding Wholesale Electric Standard Market Design (SMD). Additionally, the Department of Energy is expected to issue the results of its cost/benefit analyses of the impacts of SMD. Please provide your initial thoughts and reaction to such releases and identify any significant issues of concern.

RESPONSE:

AEP is encouraged that FERC made in its "white paper" significant changes to the original SMD NOPR to address concerns raised by AEP, state regulators, and other stakeholders. For instance, FERC has supported regional flexibility on market design elements and addressed jurisdictional issues that the Virginia Commission and others have raised. AEP currently plans to submit comments on the "white paper" and will address at that time both the areas we support and our continuing concerns with the proposal. Also, AEP intends to participate with other parties, including state commissions such as the SCC, in stakeholder discussions at PJM regarding issues concerning implementation of SMD.

DOE's recently issued cost/benefit report indicates that, in general, retail customers across the country will benefit from FERC's SMD proposal, although customers in some areas will experience higher costs in the short run. The DOE's study, like other studies on SMD, is significantly dependent on the assumptions used in the study.

5. Are the Commission's Rules Governing Retail Access to Competitive Energy Services conducive to promoting effective competition in the Commonwealth? If not, how should they be modified? Is there any way in which these rules can or should be improved, in any event?

RESPONSE:

In its comments for the Commission's competition report last year, the Company noted that the degree to which Commission rules might have discouraged competitive entry is unclear. It remains unclear. However, the Company has insufficient information to answer this question from the perspective of a competitive generation supplier. The burden is on potential new entrants to explain any reticence to enter Virginia based on the Commission's rules.

6. What should be the level of consumer education when the program is resumed on July 1, 2004? Should it be as visible, more visible or less visible than when the campaign was suspended? Upon resumption of the campaign, what focus, theme or message should be communicated? Since TV advertising is the most expensive component of the program, what level of TV advertising should be included in the resumption of the campaign?

RESPONSE:

The Company explained last year that: "After a long history of customer reliance on a single provider of electricity supply, there will likely be no successful customer choice program without customer education." While the Company understands the budget and other considerations that have made the program difficult and caused its temporary suspension, customer education remains essential. To achieve effective results, reactivation of the program should be scheduled closer to the expected onset of widespread customer choice, based on the LTTF's assessment of progress toward a competitive retail market.

7. Are there any other actions that have been taken or are being considered in other states that may be used to advance competitive activity in Virginia?

8. Do you have any ideas that have not been tried elsewhere that may facilitate competitive activity in Virginia?

RESPONSE TO QUESTIONS 7 AND 8:

In the Company's view, it is incumbent upon potential competitive generation suppliers to explain their difficulties in entering Virginia. There may be actions taken or considered in other states, or other concepts that have not been tested elsewhere, that competitive suppliers consider promising and encouraging to their entry into the Commonwealth. AEP has insufficient information to suggest changes that might encourage competitive suppliers. However, any proposed changes should provide for customer switching of generation suppliers on a sound economic basis rather than on regulatory calculations intended to create artificial "headroom" between market prices and utility rates.

May 22, 2003

Mr. David R. Eichenlaub, Assistant Director
Division of Economics and Finance
Virginia State Corporation Commission
P.O. Box 1197
Richmond, VA 23218-1197

Dear Mr. Eichenlaub:

Dominion Virginia Power (the Company) is pleased to respond to your April 16 request for comments and recommendations concerning the status of competition in Virginia, the development of regional markets, and steps that can be taken to facilitate effective competition in the Commonwealth. The annual reports required by Virginia Code § 56-596 provide a valuable opportunity for the Commission to keep the legislative and executive branches fully and fairly informed about important issues in Virginia's transition to a fully competitive market. The reports also offer valuable information to other stakeholders in the restructuring process. We appreciate the opportunity to offer input again to this year's report.

We will begin our comments with a brief overview of our thoughts on the status of competition in Virginia. In developing our comments, we have considered topics detailed in the statute, as well as issues raised by the list of questions in your letter requesting comments. In our comments, the Company will focus on some of the successes achieved by restructuring in Virginia, as well as our concerns regarding the development of competitive markets. We also will note areas of progress. Finally, we will offer suggestions for fostering the development of viable competitive electricity markets, both wholesale and retail, that have the potential to benefit Virginia consumers.

2003 Overview: Reasons for Concern and Optimism

The critical date for Virginia's transition to a restructured electric industry is July 1, 2007, with the end of wires charges and capped rates and the beginning of market-based generation pricing for all retail customers. Even though the phase-in of customer choice across the Commonwealth is to be completed by January 1, 2004, the Virginia Electric Utility Restructuring Act (the Restructuring Act) was not designed to ensure or guarantee a fully competitive retail market before the end of capped rates and wires charges in mid-2007. In fact, the design of the Restructuring Act anticipated that time would be needed for market development. Capped rates were purposely established to mitigate consumer exposure to market volatility that could occur during this start-up period and to provide a "safe haven" in the form of stable prices for electricity supply service. With this in mind, we believe that the Restructuring Act is working in large measure as planned and is already producing many benefits for Virginia consumers. For example, a Chmura Economics and Analytics study found that capped rates will save the Company's residential customers up to $871 million from 1998 through 2007, with average per-household savings of up to $480 for the period. The study, commissioned by the Company, was released in November 2002.

We also believe that the Restructuring Act, through its capped rate provisions, provides clear incentives for Virginia's incumbent utilities to reduce costs and become more efficient. For example, during the capped rate period the Company has or will incur hundreds of millions of dollars in significant additional expenses with no ability to request retail base rate increases. In addition, through steps such as efficiency improvements and the elimination of above-market contracts with non-utility generators, the Company can take steps during the capped rate period to bring its generation costs in line with the market. This is important to our future financial health and financial viability. Other incumbents have the same opportunity.

Even with these successes, it must be noted that the development of a competitive electric supply market in Virginia is proceeding at a sluggish pace. The Company believes there are several factors hindering this development, both at the wholesale and retail levels. Regulatory uncertainty, at both the state and federal levels, is contributing to this lack of development. State-federal jurisdictional issues, especially those regarding oversight of the transmission sector, have slowed progress toward the integrated, regional grid needed to support effective wholesale and retail markets.

Renewed discussions over stranded cost recovery – an issue the Company thought settled years ago - have injected additional regulatory uncertainty this spring into Virginia's restructuring picture. The framers of the Restructuring Act wisely avoided a structure that would involve complex and divisive methods such as up-front quantification of stranded costs. During the 1999 General Assembly, the example of New Hampshire was noted numerous times; stranded cost quantification delayed that state's restructuring program for years. We believe a proposal submitted by Dominion Virginia Power with the support of several other parties is consistent with the provisions of the Restructuring Act and offers a straightforward approach to the calculation of stranded cost over or under-recovery. However, several other proposed methods put forward this spring involve elaborate quantification procedures that would almost certainly prove lengthy and controversial. Such procedures run counter to the Restructuring Act's intent to avoid divisive, front-end stranded cost cases. Adoption of these procedures also would require substantial legislative amendment of the Restructuring Act.

Economic and capital market conditions have retarded the development of competition, at the state, regional and national levels. Economic factors have sharply reduced the number and capacity of new generating projects in the Commonwealth. Encouragingly, more than 8,000 megawatts are still planned or under construction. Erratic wholesale prices, coupled with lack of access to generation through regional transmission management, have also hampered retail competitive service providers' ability to secure power and make attractive offers to consumers in Virginia.

But there are also reasons for optimism. Great progress has been made in implementing the rules and procedures needed to conduct customer choice. This was highlighted by the strong rankings recently given Virginia by the Center for the Advancement of Energy Markets (CAEM), a well-known pro-competition group. CAEM gave Virginia 8 out of a possible 10 points in its Uniform Business Practices category, which corresponds to the regulatory rules that provide the framework for retail access. In addition, CAEM has ranked Virginia 13th among jurisdictions worldwide with respect to the general infrastructure and environment for retail competition.

There are other encouraging developments. Competitive service providers and aggregators continue to show interest in Virginia. The 2003 General Assembly amended the Restructuring Act to permit greater experimentation with municipal aggregation, a promising means to bring the benefits of retail access to large numbers of residential and small business customers. The Company in March asked the Commission for permission to conduct three retail access pilot programs that will help stimulate the development of competition and provide valuable information on effective measures to promote customer choice. The application for these programs is now pending before the Commission. A May 8 seminar conducted by the Company on its proposed municipal aggregation pilot program drew participants from 19 counties, cities and towns, as well as representatives of competitive service providers, aggregators and consultants. Finally, support for customer choice remains strong in the Commonwealth. A survey of Dominion Virginia Power's retail customers conducted last fall found that 82 percent supported energy choice.

In the next sections of our response, we will discuss some of this regulatory uncertainty in more detail and present some recommendations on facilitating the development of a viable competitive retail market.

Regulatory Uncertainty: Jurisdiction Questions Hamper Regional Grid Development

Development of an open-access, non-discriminatory wholesale power market covering a broad region is an essential foundation for successful retail choice. Even most critics of the Standard Market Design (SMD) initiative launched by the Federal Energy Regulatory Commission (FERC) concede the benefits of an open interstate wholesale market.

But FERC's move to standardize market rules has prompted concern from the states, including Virginia, over the possible loss of state control over transmission (and to some extent generation) infrastructure and pricing. In Congress, for example, strong efforts have been made in both houses to attach to comprehensive energy bills language drastically curtailing FERC authority. In fact, a provision of comprehensive federal energy legislation sponsored by Senate Energy Committee Chairman Pete Domenici would prohibit FERC from issuing a final SMD order before July 1, 2005, more than two years from now. The legislation is now pending before the U.S. Senate.

In Virginia, the FERC proposal drew a strong negative reaction from the Commission in an addendum issued last December to its 2002 Status Report on Competition. The Commission in a recent order determined that it could not consider or make a final determination on American Electric Power's (AEP) application to join PJM

Interconnection LLC until FERC has issued a final SMD rule and its impact on PJM operations can be evaluated. (See AEP order at pages 6 and 8.) This process could take years. However, in FERC's recent "white paper" on its SMD proposal, FERC stated that it would not use the SMD rulemaking to overturn prior regional transmission organization (RTO) orders where there is overlap. Therefore, the Commission need not wait for a final SMD order before considering and ruling on applications to join an existing RTO such as PJM.

The jurisdictional issues have had the unfortunate effect of provoking calls for radical revision of the Restructuring Act, either through rate rebundling or suspension of customer choice. Both actions, which were endorsed in the Commission's December 2002 Addendum, would amount to a *de facto* repeal of the restructuring law. Both the General Assembly and the Governor rejected that path, but the controversy has confused the restructuring picture in Virginia. It undoubtedly calls into question, in the minds of some stakeholders, the Commonwealth's long-term commitment to competition. Such uncertainty deters potential retail competitive service providers that may be interested in establishing a business presence in Virginia, as well as developers interested in expending capital dollars to build generation resources. Regulatory uncertainty could also act as a deterrent to economic development in the Commonwealth.

The Company continues to believe strongly that Virginia needs to expand market boundaries to give competitive service providers greater access to additional sources of energy. This open, non-discriminatory access over a broad area is necessary for an active retail market. The General Assembly realized this in 1999, when it included mandatory RTO participation requirements in the Restructuring Act. The Assembly reiterated its commitment to regional markets this year; House Bill 2453 amending the Restructuring Act included provisions requiring all transmission-owning utilities in Virginia to join RTOs by January 1, 2005, subject to Commission approval.

To comply with the provisions of the Restructuring Act, Dominion announced last year that it would apply to join the PJM Interconnection as a separate zone, PJM South. We are optimistic that our participation in an RTO will enhance the development of retail competition. Our participation in a regional organization will give customers and suppliers access to a broader selection of generation assets by eliminating deterrents such as "pancaked" transmission rates.

We recognize that states have the duty to protect their citizens' access to economical and reliable supplies of energy. We do not believe, however, that this goal is furthered by the creation of barriers to regional markets; the development of markets over broad regions would, in fact, greatly assist the states in ensuring energy remains reliable and economical. Healthy regional markets would provide customers and suppliers with access to a greater diversity of generating assets over a larger geographical area; this inherently increases the reliability of service to customers. A broad, regionally controlled transmission infrastructure would also enhance reliability by providing unfettered access to additional, redundant pathways for the movement of energy. Regional management would eliminate artificial barriers such as rate pancaking and seams between separately controlled systems.

Nor do we believe that a proper response to those concerns is a retreat from electric industry restructuring. FERC's recent "white paper" on its SMD proposal indicates federal authorities are listening to state concerns and want the states to play an important role in the development of regional transmission management. House Bill 2453 provides a reasonable timetable for incumbent utilities in Virginia to join an RTO, and Dominion is proceeding in accord with that legislation.

Regulatory Uncertainty: Renewed Controversy over Stranded Costs

Renewed controversy regarding stranded cost over or under-recovery is also fostering uncertainty about the course of restructuring in the Commonwealth. Earlier this year, the Legislative Transition Task Force (LTTF), carrying out its duties under the Restructuring Act, requested the Commission to convene a work group of interested stakeholders to develop a consensus methodology for monitoring the over or under-recovery of stranded costs. This methodology, according to the LTTF resolution, was to be "consistent with the provisions of the [Restructuring] Act."

The Company believes the proposal it submitted takes a straightforward approach to calculating stranded cost over or under-recovery that is consistent with the Restructuring Act's intent and language. The proposal has the support of Old Dominion Electric Cooperative (ODEC), AEP, Allegheny and Virginia Independent Power Producers, Inc. Under this proposal, a utility's actual wires charge revenue (based on Commission-established projected market prices) would be compared to the revenue the utility could have realized had the displaced power been sold at the actual market prices occurring that year. Whether the utility ultimately will experience over or under-recovery will only be known at the end of the capped rate period in mid-2007. The utility would also report its total potential stranded cost exposure annually to the LTTF, as well as the amount the utility has spent on mitigating such costs and any additional expenses that increase these costs.

The Company also believes that any attempt to impose a complicated or front-end methodology to determine stranded cost over or under-recovery would create great uncertainty about the future of restructuring in the Commonwealth. Such approaches could not be conducted without significant legislative amendments that would alter central provisions of the Restructuring Act. Unfortunately, uncertainty has already been injected this spring as several parties have offered complicated, divisive and time-consuming proposals for determining over or under-recovery.

These proposals differ in their details, but all include complex and controversial calculations. The calculations include annual determination of "fair" or "appropriate" rates of return for utilities, a step that would represent the *de facto* return of cost of service rate making. The calculations also include estimations of the net present value of cash flows from existing generating assets over their remaining useful life, a period extending for 30 or more years. The dangers in such approaches are clear. Proceedings to establish "fair" rates of return or determine inflation-adjusted cash flows from generating units over a period spanning decades will be lengthy, controversial and divisive, as well as contrary to the Restructuring Act. The Assembly specifically rejected such complicated, front-end proceedings as it developed the Restructuring Act during the 1999 session, with complex and controversial stranded cost mechanisms correctly viewed as significant threats to the viability of restructuring.

As efforts to develop a methodology for calculation of over or under-recovery continue, all parties should bear in mind warnings heard by the legislative committee that examined alternative approaches to stranded costs in the months leading up to the 1999 session. Testimony correctly described complicated and lengthy litigation that developed in states such as New Hampshire that attempted complex, up-front stranded cost determinations. The Commission's Staff at that time also opposed such determinations, finding the results of such analyses were highly uncertain and dependent upon assumptions and projections that had to be made decades into the future.

Pilot Programs: Important Steps to Stimulate Competition

While the Company believes that the easing of some of this regulatory uncertainty will be important in promoting retail competition, it also believes that some active steps can be taken to stimulate the development of healthy competitive markets. In March, the Company asked the Commission to approve three pilot programs to help stimulate the development of a competitive electricity market in Virginia and bring the potential benefits of retail choice to a variety of customers. The pilots are designed to provide competitive service providers, customers and other stakeholders with experience in a variety of competitive situations.

As many as 65,000 retail customers are expected to switch to competitive service providers in the pilots. In all three programs, the Company has proposed a significant reduction in the wires charges customers pay when they switch to competitive service providers. The reduction is designed to help competitive providers make attractive offers to consumers.

Municipal Aggregation Pilot

Two or more municipalities will participate in a program to form two buying groups (aggregations) to secure lower prices on electricity for residential, small business and house of worship customers. The aggregation pilot will include about 100 megawatts of load.

One or more localities with a combined total of up to 30,000 customers will use the "opt in" model. In an "opt in" situation, customers must make an affirmative decision to switch to the competitive service provider secured by the local government.

Also, one or more localities with a combined total of up to 30,000 customers will use the "opt out" approach. Customers in these municipalities will be switched to the competitive provider – with some exceptions - unless they make an affirmative choice not to participate.

Competitive Bid Supply Service Pilot

This program will use competitive bidding to select service providers for some customers. It will test the infrastructure and processes needed to provide default service. Under the Restructuring Act, default service will be offered beginning January 1, 2004.

The competitive bid supply service pilot will include up to 43,000 of the Company's residential and small business customers. Customers will be invited to volunteer to participate, but if the program is under-subscribed, a random selection process may be used to fill the vacancies. The pilot will include about 200 megawatts of load.

The Commission will use its authority under the Restructuring Act to seek competitive bids from service providers that wish to furnish this default service. The pilot will provide valuable real-world information to the Commission's work group currently studying default service.

Commercial and Industrial Pilot

Commercial and industrial customers with demands greater than 500 kilowatts will be eligible for this pilot. Participation would be limited to a total of about 200 megawatts of load. The pilot will be available anywhere in the Company's Virginia service area and is expected to include about 150 customers.

We urge the Commission to approve these pilots so they can be implemented on January 1, 2004. The programs could be incubators of innovation for the development of viable retail competition in Virginia.

We also urge the Commission to redirect at least some of the funds used in the Virginia Energy Choice consumer education program to provide public information about these pilots. Tying the education effort to a real opportunity for consumers would increase awareness of restructuring in general, as well as that of the pilots specifically.

Virginia Electric Industry Restructuring: A Work in Progress

Virginia has made considerable progress in restructuring its electric industry. The Commission is to be congratulated for spearheading the difficult task of developing the policies and procedures needed to implement retail choice. The Commission, through reports such as the one now being prepared, also has kept all branches of government, as well as the public, informed about the course of restructuring. Public support for energy choice remains high, and customers throughout the Commonwealth are already reaping substantial benefits due to capped rates.

We are also encouraged by the fact that many policy makers across the country are now working toward resolving issues retarding the development of viable competitive wholesale and retail markets. Congress is dealing with comprehensive federal energy legislation that contains major electric industry reforms. FERC, in its recent "white paper," has demonstrated its willingness to work with the states to address their concerns regarding the SMD initiative. FERC has also indicated it will factor regional concerns into the final development of the rule. In April, a bipartisan group of 70 state utility commissioners endorsed a Statement of Principles that recognized the "benefits that consumers receive due to the establishment of more dynamic wholesale markets." The Statement of Principles also called on Congress and other policy makers "to support current regulatory efforts to further improve the wholesale power markets of our states and of our nation."

While the move toward competitive energy markets has slowed in some parts of the United States, restructuring has made impressive progress in many states. For example, in Maine the Public Utilities Commission reports that almost one-third of the total state load was served by competitive service providers as of January 1. In Ohio, approximately 730,000 residential customers have participated in one of more than 190 community aggregation groups, according to the Ohio Consumers' Counsel. In Maryland, the Public Service Commission has recently approved rules that could serve as a model for many states, including Virginia, for the process through which distribution companies will procure the electricity supply needed to meet default service obligations. The Maryland Commission's rules call for a competitive wholesale procurement process for default service, called Standard Offer Service in that state. The rules are designed to give retail suppliers the opportunity to compete effectively and, at the same time, ensure stable market-based prices for those customers choosing to receive electricity supply service from their distribution utilities. Such progress provides reasons for optimism.

Additionally, a noted consumer group, Citizens for Pennsylvania's Future, in September 2002 released an updated and comprehensive study addressing the status and development of competition in the United States. This study indicates that restructuring, wholesale and retail, is working well for most consumers. A copy of the study is attached.

The Company remains convinced that Virginia's program is fundamentally sound and has great potential to bring benefits to the Commonwealth's consumers and its economy. Restructuring is very much a work in progress in Virginia; bumps and downturns are not unexpected. They should not hide the progress already made nor the potential restructuring holds for even greater gains for Virginia's citizens. The Restructuring Act must be kept intact to maintain confidence in the minds of stakeholders. This confidence is vital to maintaining and accelerating the momentum carrying the Commonwealth toward the robust competitive markets that have the potential to benefit both business and residential consumers.

Sincerely,

(Original signed by)

E. Paul Hilton
Senior Vice President

Attachment

PennFUTURE

Electricity Competition: The Story Behind the Headlines
A 50-state Report

Citizens for Pennsylvania's Future
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Electricity Competition: The Story Behind the Headlines A 50-state Report

Screaming headlines bring us the Enron scandals, California blackouts, phony electric trades and illegal accounting.

The Bush administration warns that the nation faces rolling blackouts unless it builds a power plant a week, and insists that the nation faces a severe energy crisis.

At first glance, electricity restructuring of wholesale markets in all 50 states that began with the passage of the Energy Policy Act in 1992, and the restructuring of retail markets that began in 1996, appear to be hopeless failures. But a look *behind* the sensational headlines shows a surprisingly different story.

Electricity becomes a bargain as electric industry restructures

In general, as measured by either inflation-adjusted dollars (constant dollars) or non-inflation adjusted dollars (nominal dollars), the price of electricity across the nation is substantially lower than it was in 1996. For most consumers, *there is no electricity crisis*. Instead, electricity is becoming a bargain.

The data demonstrates that the combination of wholesale restructuring in 50 states and retail restructuring in 22 jurisdictions is working well for most, though not all, consumers.

In constant dollars, electric prices went down for every major customer class nationwide from 1996 to 2001. When results in all states plus the District of Columbia are averaged, rates on average fell for residential customers by 13.67%; 13.0% for commercial customers; and by 4.8% for industrial customers.

For residential customers between 1996 and 2001, electricity prices in constant dollars fell in 48 out of 50 states. In states and the District of Columbia where retail generation monopolies were ended, residential rates declined on average 15.9% in constant dollars. Residential rates in states that maintained traditional retail monopolies declined 11.6%. Only the non-retail restructured states of Vermont and Hawaii saw residential electric prices rise in inflation-adjusted dollars during that period.

All 22 states, which includes the District of Columbia, that have restructured their retail electric markets to end generation monopolies had the same or lower residential rates in constant dollars in 2001 than in 1996. Sixteen of the 22 had the same or lower residential rates, even without adjusting for inflation.

And contrary to common expectations, residential rates in both retail and non-retail restructured states fell more than either commercial or industrial rates. So far the big dogs are eating least. In retail-restructured states, commercial rates are down on average 13.7% and industrial rates are down 4.5% in constant dollars. In states maintaining traditional retail regulation, commercial rates are down 12% and industrial rates are down 4.8%.

In constant dollars, five states saw commercial rates increase, while 12 states experienced the same or higher industrial rates.

While electricity is generally becoming a bargain, other vital or popular products have increased sharply in price since 1996, and by doing so underline the superior consumer performance of the electricity industry. From the end of December 1996 to December 2001, cable TV rates rose 31%, prescription drugs hiked 24%, milk jumped 12%, bread spiked 14%, and college tuition escalated 26%. The overall inflation rate for that period was 11.34%.

Policies that introduce more competition into wholesale and retail electricity markets and require some of the competitive savings be passed to consumers as rate cuts are forcing prices down for most electricity customers. In addition to rate cuts made possible by retail restructuring, many consumers benefited from wholesale competition, which produced low prices during most of the period from 1996 to 2001. Another source of savings for some customers in retail-restructured states has been switching to competitive suppliers. Unfortunately, the number of customers switching and their savings could be much greater, but for the addition of so-called *stranded cost charges* to retail market prices.

Ironically, only industrial customers in states like Idaho, Louisiana, Montana, New Mexico, Oklahoma, Texas, and Washington have experienced large rate increases. In fact, industrial rates in Washington, Montana and Louisiana increased a shocking 76.3%, 38.6% and 35.0% respectively.

This is the true but untold story about restructuring.

Restructuring the electric industry

Since the passage of the Energy Policy Act in 1992, it has been national policy to restructure the nation's numerous, balkanized wholesale electricity markets. Less price regulation and more competition have been introduced. In addition, rules require that wholesale competitors have open access to and non-discriminatory pricing of transmission, which is still normally owned and operated by monopoly utilities. Investor-owned utilities, municipal utilities, rural electric cooperatives, and independent generators across the country have responded to these competitive reforms by increasing their focus on efficiency and reducing costs.

Responding to wholesale competition market reform, states began to end retail generation monopolies in 1996. Presently, the National Conference of State Legislatures considers 21 states plus the District of Columbia to have begun restructuring their retail electric markets. In most cases these states have adopted multi-year transition plans to move from monopolized to competitive retail generation markets.

Retail restructuring fosters renewable energy

Retail-restructured states are leading the nation in renewable energy policy by creating funding for the transition to clean energy and by adopting Renewable Energy Portfolio Standards (RPS), which require increasing percentages of electricity supply to come from alternative energy sources like wind and solar power. Seventeen of 22 retail-restructured states have either some form of RPS or clean energy fund that receives revenues by dedicating very small portions of electricity revenues. Unfortunately, just two of the non-retail restructured states — Minnesota and Wisconsin — have a clean energy fund or RPS.

The data on rates and adoption of policies to spur more rapid adoption of clean energy technologies are powerful indicators that retail electricity restructuring is producing important consumer and public interest benefits. Again, electricity restructuring is more success than failure.

Yes, but is it deregulation?

Yet, most importantly, restructuring of neither wholesale nor retail electricity markets is accurately described as *deregulation*. Typically, restructuring is a varied mix of increased use of markets combined with continued regulation and public policy interventions. In this respect, at least when electricity restructuring is done well, it requires a set of policies that pleases neither the ideological left nor the right.

Restructuring also doesn't mean the same thing in the wholesale market in the West as it does in the Mid-Atlantic. It certainly doesn't mean the same thing in the retail markets of Pennsylvania and California.

Electric restructuring done well requires smart rules and an appropriate mix or balance of market forces and government oversight (see page 11 for the 11 Smart Rules for Retail Electric Market Restructuring). Enforcement of rules and government oversight are vital to successful restructuring.

Indeed, the electricity industry can't be *deregulated*. Government has a vital and continuing role to play. Yet wholesale and retail restructuring that mix market competition and public policy can and are benefiting consumers and clean energy technologies which are vital for environmental protection.

Key Findings

Key findings on price

- Contrary to conventional wisdom, retail market restructuring policies benefited residential and smaller customers more than larger customers, although all customer classes have generally received savings.
- Residential rates
  - Rates for residential customers are the same or down in constant dollars in all 22 retail-restructured states including DC, and are the same or down even in nominal dollars in 16 of them.
  - Residential rates are down in constant dollars in 27 and in nominal dollars in 21 of the 29 non-retail restructured market states.
  - Seven retail-restructured states have cut residential rates by 20% or more, while three non-restructured states cut residential rates by that much.
  - In constant dollars, 10 states cut residential retail rates by 20% or more. Of these, seven are retail-restructured: Arizona, Connecticut, Delaware, Illinois, Maryland, New Jersey, and Ohio. By comparison, three non-retail restructured states cut rates by 20% or more: Kansas, Missouri, and Nebraska. The retail-restructured state of Illinois was the only state in the nation to cut residential rates by 30% or more.
  - The five worst performing states for residential customers were Hawaii, Louisiana, Nevada, Vermont, and Wisconsin. In these states residential rates either increased in constant dollars or fell by 5.0% or less. Four of these states — Hawaii, Louisiana, Vermont, and Wisconsin — maintain traditional retail regulation and electric generation monopolies.
- Commercial rates
  - Rates for commercial customers are down in constant dollars in 19 of the 22 retail restructured states including DC, and are down in nominal dollars in 16.
  - Commercial rates are the same or down in constant dollars in 27 and in nominal dollars in 19 of the 29 non-retail restructured retail market states.
  - In constant dollars, 11 states cut commercial rates by 20% or more. Of these, four are non-retail restructured and seven are retail restructured. The four non-retail restructured that cut commercial rates by 20% or more are: Arkansas, Kansas, Minnesota, and Missouri. The seven retail restructured states to cut commercial rates by 20% or more are Arizona, Connecticut, Delaware, Illinois, Maryland, New Jersey, and the District of Columbia.
  - Arkansas and Illinois again stand out as the only states to cut commercial rates by 30% or more.
  - The five worst performing states for commercial customers were California, Hawaii, Louisiana, Maine, and Texas. In these five states, commercial rates rose in constant dollars by 1% to 6%. California, Maine, and Texas are retail restructured.
- Industrial rates
  - Rates for industrial customers are down in constant dollars in 16 of the 22 retail-restructured states including DC, and down in nominal dollars in eight states.
  - Industrial rates are the same or down in constant dollars in 23 and in nominal dollars in 15 of the 29 non-retail restructured retail market states.
  - A total of four states cut industrial rates in constant dollars by 20% or more: Alaska, Delaware, Illinois, and North Dakota. Delaware and Illinois are retail restructured.
  - Delaware is the only state to cut industrial rates by more than 30%, although Illinois by cutting industrial rates by 29.8% came close to reducing rates for each of its customer classes by 30% or more.
  - The single biggest rate increase for any rate class was 76.3% between 1996 and 2001 for industrial customers in non-retail restructured Washington.
- Twenty states plus the District of Columbia earn an *A* for reducing rates (measured in constant dollars) by more than the national average for each of the major customer classes: residential, commercial and industrial. States deserving an *A* are Arizona, Arkansas, Colorado, Connecticut, Delaware, Georgia, Illinois, Indiana, Iowa, Kansas, Kentucky, Maryland, Missouri, Nebraska, New Jersey, North Dakota, Pennsylvania, Utah, Virginia, West Virginia, and the District of Columbia.
- Six states earn a *B* for exceeding the national average rate reduction for two of the three major customer classes: Michigan, Mississippi, North Carolina, New Mexico, South Dakota and Tennessee
- Eleven states earn a *C* for exceeding the national average rate reduction for just one of the three major customer classes: Alabama, Alaska, Florida, Massachusetts, Minnesota, Nevada, New Hampshire, New York, Ohio, South Carolina, and Wyoming.
- Twelve states earn a *D* for failing to reduce rates for any rate class and for raising rates in constant dollars for one or two customer classes: California, Idaho, Louisiana, Maine, Montana, Oklahoma, Oregon, Rhode Island, Texas, Vermont, Washington and Wisconsin.
- One state, Hawaii, earns an *F* for raising rates in constant dollar terms for all customer classes.
- The best performing non-retail restructured state is Missouri with residential rates down in constant dollars by 24.0%, commercial rates down 22.8%, and industrial rates down 17.2%.

- The best performing retail-restructured state is Illinois, with 2001 residential rates down in constant dollars by 32.3%, commercial rates down 30.2%, and industrial rates down 29.8%.
- The worst performing non-retail restructured state east of the Mississippi is Vermont, with residential rates in constant dollars up 1.2%, commercial rates unchanged, and industrial rates down only 1.8%. Hawaii wins this dubious award in the truly far West category.
- The worst performing retail-restructured state is California. Rates are up for commercial and industrial consumers *and* the lights went out too many times to count in 2001.
- Washington State wins the notorious *Rate Gouger* award by raising industrial rates an incredible 76%. Most of us can be thankful that we aren't industrial electricity customers in Washington.

Key findings on renewable energy

- States that have restructured their retail electricity markets are leading the nation toward clean energy technologies by creating large funds to support clean energy projects and by requiring that an increasing percentage of the electricity supplied to consumers comes from renewable resources, such as wind or solar.
- By contrast, very few non-retail restructured states have created funds to support clean energy projects or adopted requirements for increasing the percentage of electricity that must come from renewable resources.
- Specifically, 13 restructured states have created state funds that will provide $3.4 billion through 2011 to support the development of renewable energy and energy conservation: California, Connecticut, Delaware, Illinois, Massachusetts, Montana, New Jersey, New Mexico, New York, Ohio, Oregon, Pennsylvania, and Rhode Island. California leads the nation in funding clean energy technologies.
- Only two non-retail restructured states, Wisconsin and Minnesota, have clean energy funds to support clean energy projects.
- Nine restructured states have adopted full or partial Renewable Energy Portfolio Standards that require increasing percentages of electricity supplied within the state to come from renewable sources: Arizona, California, Connecticut, Maine, Massachusetts, Nevada, New Jersey, Pennsylvania, and Texas. Texas has the nation's most effective RPS, which produced 800 megawatts of wind energy in 2001 alone.
- Only one non-retail restructured state has full or partial Renewable Energy Portfolio Standards — Wisconsin requires that a modest 2.1% of its electric supply come from renewable resources by 2011.
- Four retail-restructured states earn an *A* for adopting key renewable energy policies. California, Connecticut, Massachusetts, and New Jersey all have both large clean energy funds and significant RPS's. No non-retail restructured states earned an *A*.
- Seven retail-restructured states earn a *B* for having a large clean energy fund or a significant RPS: Illinois, Maine, Nevada, New York, Ohio, Pennsylvania and Texas. No non-retail restructured states earned a *B*.
- Eight states earn a *C* for having a modest RPS or small clean energy fund: Arizona, Delaware, Minnesota, New Mexico, Montana, Oregon, Rhode Island, and Wisconsin. Wisconsin and Minnesota are non-retail restructured states, the other six are retail-restructured.
- 31 states earn an *F* for having neither an RPS nor clean energy funds to support financially renewable energy development.
- 27 of 29 non-retail restructured states receive an *F*: Alabama, Arkansas, Alaska, Colorado, Florida, Georgia, Hawaii, Idaho, Indiana, Iowa, Kansas, Kentucky, Louisiana, Mississippi, Missouri, Nebraska, North Carolina, North Dakota, Oklahoma, South Carolina, South Dakota, Tennessee, Utah, Vermont, Washington, West Virginia, and Wyoming.
- Four retail-restructured states earn an *F*: Maryland, Michigan, New Hampshire, and Virginia.

Major Conclusions

- ✓ There is no national electricity crisis or broader energy crisis as demonstrated by substantially declining power prices from 1996 – 2001.
- ✓ Electricity is becoming a bargain, as wholesale electric market restructuring proceeds nationally and retail electric restructuring continues in 20 states plus Washington, DC.
- ✓ Electricity rates for residential customers are down in retail-restructured states by 15.9% versus 11.6% in non-retail restructured states.
- ✓ Electricity rates for industrial customers are down 4.5% in retail-restructured states versus 4.8% in non-retail restructured states.
- ✓ Residential customers are receiving larger rate decreases than industrial customers from the combination of wholesale and retail restructuring.
- ✓ In several states such as Louisiana, Montana and Washington, industrial customers have suffered large rate increases.
- ✓ Retail-restructuring states are leading the nation in adopting key clean electricity policies like RPS's and clean energy funds.
- ✓ Electricity restructuring is producing major benefits for most, if not all, consumers, as well as clean electricity generation.
- ✓ Neither wholesale nor retail restructuring is accurately described as *deregulation*. Restructuring typically means mixing increased competition in the pricing of electricity with public policy protections and continued government oversight of markets.

Methodology

This Report looks at electric rates for residential, commercial, and industrial service charged in each state from 1996 to 2001. Additionally, the Report grades each state on renewable energy policy and the environment.

This Report also compares states that have restructured their retail electric markets, allowing consumers to choose a competitive electric supplier, to those states that have not restructured their markets and continue to have fully regulated retail monopoly electric utilities. When making such comparisons, readers should remember that to varying degrees wholesale markets in all 50 states have been made more competitive as a result of the Energy Policy Act of 1992 and Federal Energy Regulatory Commission orders. With the possible exception of Hawaii, virtually no state has been unaffected by wholesale and/or retail electricity restructuring.

Each state is placed into one of two categories — those that have restructured their retail electric industry to allow some or all of their electric customers to choose a competitive supplier, and those that have not. The Report uses information provided by Matthew Brown of the National Council of State Legislators to classify each state as *restructured* or *non-restructured*, with the exception of California.

The National Council of State Legislators (NCSL) classifies 21 states or jurisdictions as retail restructured: Arizona, Connecticut, Delaware, Illinois, Maine, Maryland, Massachusetts, Michigan, Montana, Nevada, New Hampshire, New Jersey, New Mexico, New York, Ohio, Oregon, Pennsylvania, Rhode Island, Texas, Virginia, plus Washington, D.C. Although California repealed retail choice in 2001, the analysis in this Report also classifies California as a retail-restructured state, since for most of the study period it was. With California placed in the restructured camp, 22 states or jurisdictions are counted as retail-restructured by this Report.

Based on NCSL data and Matthew Brown's update, this Report classifies 29 states as *non-restructured*: Alabama, Alaska, Arkansas, Colorado, Georgia, Florida, Hawaii, Idaho, Indiana, Iowa, Kansas, Kentucky, Louisiana, Minnesota, Missouri, Mississippi, Nebraska, North Carolina, North Dakota, Oklahoma, South Carolina, South Dakota, Tennessee, Utah, Vermont, Washington, West Virginia, Wisconsin, and Wyoming.

The study period begins in 1996 because that year saw the first four states pass retail restructuring legislation and begin the process of opening retail electricity markets to competition, while many other states were also moving in that direction.

The study uses an 11.34% price inflator to convert all prices into constant dollars and allow inflation-adjusted comparisons of 1996 and 2001 rates. The 11.34% inflator was calculated based on December-to-December data for 1997 to 2001 collected by the US Department of Labor, Bureau of Labor Statistics (www.bls.gov).

All electricity prices are from the US Department of Energy (DOE) and the Energy Information Administration. Go to www.eia.doe.gov or call Rodney Dunn at 202-287-1676 for more information. The 2001 prices are preliminary DOE data available from Stephen Scott at 202-287-1737 or www.eia.doe.gov/cneaf/electricity/epm/epmt55p1.html.

The national average results were calculated by taking each state's result and then computing an average for the nation. An alternative method that weights the amount of electricity used in each state produces similar but slightly different results. The alternative methodology concludes that national rates fell for residential customers by 15.4%, commercial customers by 12.8%, and industrial rates by 3.7%.

Each state is assigned a letter grade. An *A* is awarded to states that reduced 2001 rates for each of the three major customer classes at a rate faster than the national average.

A *B* is given to states that reduced 2001 rates faster than the national average for two of the three major rate classes.

A *C* goes to states that reduced rates faster than the national average for just one of the three major rate classes.

A *D* is the grade for states that failed to reduce rates for any customer class faster than the national average and increased rates in constant dollars between 1996 and 2001 for one or two major customer classes.

An *F* is the reward for raising rates in constant dollars for all customer classes.

In terms of renewable energy, the Report focuses on the two key policies states can adopt to promote its development and use — Renewable Portfolio Standards (RPS), which require over time that a growing percentage of electricity comes from renewable resources, and the formation of clean energy funds — because those policies would decrease pollution and its consequences created by the electricity industry.

Presently roughly 70% of all sulfur dioxide pollution, 30% of nitrogen oxide emissions, 30% of carbon dioxide pollution, and 18% of mercury contamination come from the electricity industry. These emissions cause acid rain, smog, global warming, habitat destruction, and human illness and death.

To track state action on RPS and clean energy technology financing, the Report uses research done by Mark Bollinger, et. al., entitled *States Emerge as Clean Energy Investors: A Review of State Support for Renewable Energy*, published in the *Electricity Journal* in 2001, as well as research done by the American Council for an Energy Efficient Economy (www.aceee.org).

The Report assigns an *A* to those states that have adopted a major RPS and created a major clean energy fund; a *B* to those states that have adopted either a major RPS or a large clean energy fund; a *C* to any state that has either a incomplete RPS or a small clean energy fund; and an *F* to any state that has neither. A large clean energy fund is defined as receiving annual revenues of at least $10 million, while a small clean energy fund is defined as annual revenues of less than $10 million.

Examining rates and policies to promote renewable energy in each state produces insights into how the adoption or rejection of retail electricity restructuring is affecting consumers and the environment.

Analysis: Restructuring and Consumers

States have been famously described as the laboratories of democracy, where ideas and policies are tested on a smaller-than-national scale. In electricity policy, the states are playing this laboratory role in retail markets. Since 1996, 22 states including the District of Columbia changed their laws to allow electric consumers the legal right to choose a competitive electricity supplier.

Many states that ended retail generation monopolies did so in response to the federal government's restructuring of the nation's wholesale electricity markets, which began in 1992 with the passage of the Energy Policy Act (EPACT). EPACT restructured the wholesale electricity markets in virtually all utility service territories and in the wholesale electric markets that serve all 50 states.

Since 1992, the specifics of wholesale market restructuring in the 50 states have been left to the Federal Energy Regulatory Commission (FERC). Unfortunately, until Chairperson Pat Wood's arrival in June 2001, FERC failed to standardize vital operational details of wholesale energy markets. It also too often acted as though its mission was to deregulate but to leave electric monopolies intact, instead of overseeing the creation and operation of genuinely competitive wholesale markets. Since 2001, FERC has begun to undo earlier serious policy errors.

No one, however, disputes that in the decade since EPACT's passage, the electric industry underwent revolutionary change, driven mainly by wholesale market reforms and the prospect of allowing retail consumers to choose their electricity suppliers.

The debacle in California followed by the Enron scandal, however, stopped further movement toward allowing retail consumers to choose competitive suppliers and effectively caused California to repeal its consumers' right to choose their electricity providers. At this point, 29 states continue traditional retail regulation of electricity utilities' monopolies. No state regulates wholesale markets.

Ten years after EPACT and five years after retail electricity restructuring began is a good time to see how wholesale restructuring in all 50 states and the decision to restructure or not to restructure retail markets affects consumers and clean energy policies and alternatives.

This Report looks at residential, commercial, and industrial rates in all 50 states. Its basic conclusions that electricity prices are generally going down for all customers, and more so for residential than industrial customers, will surprise some. Plainly, the combination of even imperfect wholesale restructuring in 50 states and retail restructuring in 22 states is producing lower electricity prices for most consumers. Restructuring is much more a success than a failure. Indeed, *electricity is becoming a bargain* and its decreasing cost stands in sharp contrast to water rates, cable TV rates, prescription drugs, college tuition and other items important to consumers.

Electricity prices strongly indicate that there is no current electricity crisis or broader energy crisis.

But while consumers continue to benefit from lower electricity prices, the electric industry causes huge amounts of environmental damage as a result of the pollution it pumps into the air, land, and water when burning fossil fuels to make electricity. This pollution contributes to documented public health and environmental crises like smog, acid rain, toxic pollution, and global warming.

This Report finds that overwhelmingly *it is those states that have restructured their retail markets that also have adopted important public policies to promote the electric industry's transition from traditional reliance on coal and nuclear energy to clean energy alternatives like wind, geothermal, and solar energy.*

By contrast, only two of 29 states that continue traditional regulation of electric generation monopolies have enacted Renewable Energy Portfolio Standards or created clean energy funds to advance the commercialization of renewable energy technologies.

Another major conclusion is that, taken together, *those states that have restructured their retail electricity industry have performed for consumers as well as or better than those states that have continued traditional retail regulation and maintained monopolies.*

Seven retail-restructured states have cut residential rates by 20% or more, while three non-restructured states cut residential rates by that much. The retail restructured state of Illinois was the only state in the nation to cut residential rates by 30% or more.

Perhaps most surprising to some, this Report documents the finding that in retail restructured states, residential consumers have benefited most, more so than commercial and industrial customers. *All 21 restructured states plus the District of Columbia in 2001 had residential rates measured in constant dollars that were below 1996 levels.* Moreover, residential consumers enjoyed rate reductions that were nearly three times larger than those received by industrial consumers.

Best states for electric consumers

By far and away the best state for consumers was Illinois. Residential rates declined by 32.3%, commercial rates by 30.2%, and industrial rates by 29.8%. A truly remarkable performance.

As a group, the retail restructured states of the Mid-Atlantic region also did very well. Rates in Delaware, Maryland, New Jersey, Pennsylvania, and Washington DC are all down sharply. Lower rates in this region reflect the nation's best and most competitive wholesale electricity market known as PJM and state retail restructuring policies.

The PJM spot market since 1999 has cleared at about 3 cents per kilowatt-hour. One-year wholesale forward contracts have fluctuated during that period between roughly 2.8 cents and 5.0 cents per kilowatt-hour within PJM, with recent prices at the low end of the range.

By comparison, in 1996, the unbundled generation portion of the regulated residential rate charged by Pennsylvania utilities ranged from about 3.5 cents to 8.5 cents per kilowatt-hour. In PJM, market prices have usually been well below 1996 regulated generation rates.

But lower prices within PJM have *not* come at the cost of decreased reliability. PJM met record demand for electricity in both 1999 and 2001. The breakdown rate of PJM power plants decreased 50% from 1996 to 2001, as owners faced lost revenue if plants could not operate.

For these impressive reasons, PJM has in many ways become a model for FERC and the nation.

Other states that had strong consumer performance include Kansas and Missouri, both of which provided large rate reductions to all three customer classes. Both are non-retail restructured states.

Worst states for electric consumers

Louisiana and Washington win our award for worst performing non-retail restructured states. Washington raised industrial rates an incredible 76.3%. Louisiana raised industrial and commercial rates and nearly raised residential rates. We'll let Hawaii off the hook because, well, it's Hawaii. But it should do better.

Other poorly performing non-retail restructured states east of the Mississippi for consumers are Wisconsin and Vermont.

Maine was the worst performing retail-restructured state east of the Mississippi. From 1996 to 2001, Maine raised its commercial rates in constant dollars by 3.1% and industrial rates by 20.4%.

The picture, however, was no prettier in retail-restructured California, where industrial rates are up in constant dollars by 6.8% and commercial rates by 0.4%. At least for higher real rates, California could have kept the lights on. It wins the award for the worst performing retail-restructured state for consumers.

The single biggest rate increase for any rate class was 76.3% between 1996 and 2001 for industrial customers in non-retail restructured Washington.

Analysis: Restructuring and Renewable Energy

The decision to restructure or not to restructure should be judged by factors other than rates paid by consumers, since the electric industry so significantly affects human health and the environment.

Nationally, 55% of electricity comes from coal-fired plants and 20% from nuclear plants that are running out of on-site storage space for their highly toxic nuclear waste. Renewable sources of electricity other than large-scale hydroelectric facilities generate roughly 2% of the nation's electricity. Unfortunately, the environmental impact of the electric industry's heavy reliance on burning coal — in often old plants that don't have modern pollution control technologies — has been hugely negative and much bigger than its approximately 2% share of the gross national product would indicate.

Traditional electric regulation and electric monopolies have created today's reality, where the electric industry produces about 70% of all sulfur dioxide pollution, 30% of carbon dioxide, 30% of nitrogen oxide and 18% of mercury emissions. The industry also pumps into the air large amounts of particulate matter — or microscopic dirt — that is a major cause of human illness.

Pollution from the electric industry is a leading cause of smog that sickens and kills humans, acid rain that is damaging forests and streams, toxic pollution that is contaminating the food chain, and global warming.

Cleaning the electric industry is a big task and requires leadership from the industry as well as the federal and state governments. A key to this clean up is to substantially increase the amount of electricity generated by non-polluting, renewable energy power plants. Each state can influence the transition to renewable energy by adopting or failing to implement policies that benefit renewable energy.

While states can do a range of things to promote renewable energy, such as purchasing renewable energy for state facilities or creating green power pricing programs for consumers, the best policies to foster renewable energy are Renewable Energy Portfolio Standards and clean energy funds. An RPS requires that over time an increasing amount of a state's electricity supply comes from renewable resources. Clean energy funds are pools of money, usually raised by a small charge on transmission or distribution, that financially support renewable energy development.

Retail-restructuring states lead on renewable energy policy

Through clean energy funds and RPS requirements, retail-restructured states — far more so than states without retail restructuring — are providing dollars and support for moving the electric industry toward renewable energy. Only two of 29 non-retail restructured states have an RPS or clean energy fund, while 17 of 21 restructured states have implemented either a RPS or a clean energy fund or both. To date, retail restructuring boosts renewable energy, while the decision not to restructure means no RPS or clean energy fund.

Specifically, *13 restructured states have created state clean energy funds that will provide $3.4 billion of funding through 2011* to support the development of renewable energy and energy conservation. They are California, Connecticut, Delaware, Illinois, Massachusetts, Montana, New Jersey, New Mexico, New York, Ohio, Oregon, Pennsylvania, and Rhode Island. California leads the nation on providing financial support for the commercialization of clean energy alternative technologies.

Nine restructured states have adopted full or partial Renewable Energy Portfolio Standards that require increasing percentages of electricity supplied within the state come from renewable energy power plants: Arizona, California, Connecticut, Maine, Massachusetts, Nevada, New Jersey, Texas, and Pennsylvania, although Pennsylvania's RPS is limited to competitive default supply service in four utility service territories.

California, Connecticut, Massachusetts and New Jersey stand out for their leadership by adopting both substantial RPS requirements and clean energy funds.

Unfortunately, just two non-retail restructured states, Wisconsin and Minnesota, have clean energy funds to support renewable energy and only one non-restructured state, Wisconsin, has a modest RPS.

We challenge the non-retail restructured states to adopt clean energy funds and Renewable Portfolio Standards.

Lessons Learned

After a year or more of stories about California and the Enron debacles, the emerging conventional wisdom tells us that wholesale and retail electricity restructuring (usually incorrectly labeled *deregulation*) are hurting consumers and promoting the traditional reliance on coal and nuclear power. Conventional wisdom also maintains that electric restructuring, if it were to benefit any group, would benefit industrial and not residential customers.

But the numbers in this Report tell a different story. In fact, so far, the very imperfect and incomplete wholesale market restructuring in all 50 states and the retail restructuring in 21 states plus the District of Columbia, are benefiting all consumers generally, but residential consumers most of all.

Importantly, this Report also finds that retail-restructuring states are overwhelmingly the ones that have adopted one or both of the two key policies — RPS's and clean energy funds — that best assist renewable energy development. Non-retail restructured states are laggards on implementing these vital renewable energy policies.

Moreover, in the last 10 years, coal and nuclear plants have captured virtually none of the new generation market. Instead, efficient natural gas plants with modern pollution control technology are dominating the new generation market. Also, in 2001 wind energy had its strongest year ever, with more than 1,700 megawatts of new wind power built. About half of this total was built in Texas and resulted from Texas' best-in-the-nation RPS.

Six top questions

- why have most retail-restructured states reduced consumer rates, while a few like California produced rate increases mainly for industrial customers?
- why have nearly all retail-restructured states launched important clean energy policies?
- why have only Minnesota and Wisconsin out of 29 non-retail restructured states authorized RPS's or clean energy funds?
- why have industrial customers in some states seen rates increase sharply?
- why are residential customers benefiting most from the combination of wholesale and retail restructuring?
- what trends are emerging that will affect how consumers in restructured and non-restructured states will fare in 2002 and beyond?

Answers to these questions vary by state and by region. But some broad general trends hold. Traditional regulation of investor-owned electric monopolies is a difficult task, and few states have done it well for long periods of time. In many states, large utilities are highly influential in the selection of regulators and the independence of regulatory bodies is never guaranteed.

Even when done by independent, objective regulators, the regulatory enterprise is complex, requiring massive amounts of information that is not completely available, expertise in many areas like engineering, accounting, finance, and law, as well as the judgment of Solomon. For these reasons, regulation has often resulted in massively bad decisions, like requiring consumers to pay billions of dollars for horribly uneconomic nuclear plants —which would never have been financed without captured customers and regulatory orders requiring large rate hikes.

It's often thought that regulators protect residential customers, since they are the voters. But in fact, under regulation, *industrial* customers have often used the threat of self-generation or leaving a service territory to leverage favorable rates. They benefited from a type of competition before restructuring began. As a result, it's not surprising to us that industrial customers have seen lower rate reductions nearly everywhere and even increased rates in a number of states. Nor is it surprising to see that residential customers in non-retail restructured states have done less well than those in retail-restructured states. Residential customers in non-retail restructured states still have no leverage and must rely on the independence and knowledge of regulatory bodies.

Instead of favoring industrial customers, wholesale and retail restructuring has most benefited residential customers. In retail competition states, the restructuring process has created leverage for residential customers, which has led to rate cuts and caps and other benefits for low-income consumers. For example, 80,000 poor households in the PECO service territory in Pennsylvania have had their total rates cut by up to 50% since 1999 as a result of restructuring.

It's also not surprising to see that states maintaining traditional regulation have almost universally failed to adopt Renewable Portfolio Standards or clean energy funds. Most public utility regulatory bodies have economic and not environmental missions, or they choose to define their work in that way. Consequently, non-restructured states typically lag behind on renewable energy policy.

Restructuring, however, creates a moment where everything is under review and on the table. Environmental advocates in most restructuring states have used the restructuring opportunity to push a fundamental change in mission so that now most restructuring states are promoting renewable energy through public policy.

During the transition to competition, restructuring states also seek to protect the financial stability of their local utilities, benefit consumers, and develop a competitive retail market. There is some tension between these goals, and states have pursued them with three basic policies that vary importantly in the details. These policies mix market forces and public policy in different ways.

Protecting the financial stability of local utilities

To protect the financial stability of utilities, restructuring states have nearly without exception authorized so-called *stranded cost charges* paid to utilities by consumers who both switch to a new company and by those that don't. The stranded cost charge is typically between 0.5 cents and 5.0 cents per kilowatt-hour. It should represent the portion of the regulated rate that is above the competitive price of electricity and reflect the amount of generation investment made under traditional regulation that lower competitive prices would not support.

Revenues raised by the stranded cost charge go to utilities to pay off their uneconomic or non-competitive investments in generation made prior to restructuring. It's important to understand that the stranded cost charge is always a portion of the old regulated rate and that it is added to the competitive price of energy. Its addition to the competitive price of electricity makes it difficult for competitive suppliers to deliver savings to consumers and hinders retail competitive markets. Stranded cost charges conceal from consumers what are in most cases much lower market prices.

Benefiting consumers

To benefit consumers while stranded costs are being paid to utilities, restructuring states have capped rates for the generation portion of the bill and sometimes the transmission and distribution segments of the regulated rate. They have also implemented temporary and sometimes multi-year rate cuts in order to ensure that a portion of the savings from competition reaches consumers.

Developing a competitive retail market

To commence a transition to a competitive retail market, each state has established a target price that competitors must beat that is variously called the *price to compare*, the *default rate*, or *price to beat*. These target prices that competitors must beat have always been much lower than what the monopoly utility charged for generation service during regulation and prior to competition.

In many cases, target prices have been set at levels ridiculously below the historic, regulated utility rate for generation. For example, California set a target price for retail competitors that was basically equal to the wholesale price of electricity (which was very low until the summer of 2000), and about 5 cents below what California's investor-owned utilities were charging residential consumers for generation under traditional regulation.

These low target prices plus the addition of stranded cost charges to the competitive price of electricity means that many states have made it impossible for competitors to offer savings to retail customers, even though the competitive price of electricity is often well below the regulated generation rate.

Finding the right mixture

Successful restructuring states are succeeding because they have found the right mixture of stranded cost charges, rate cuts and caps, and target prices for competitors. Successful restructuring states have also normally had the benefit of a reasonably competitive wholesale market.

The Mid-Atlantic states of New Jersey, Maryland, Pennsylvania, and Delaware, plus the District of Columbia owe a major portion of their restructuring success to the good but not perfect work of the PJM independent system operator, which operates the largest and best wholesale market in America. The competitive wholesale market in PJM has produced spot energy prices that have averaged approximately 3 cents per kilowatt-hour for three years. The spot energy price has been as much as 5 cents less than the up-to-8 cents regulated utilities charged residential consumers just for generation prior to restructuring. Within PJM, market prices have generally been less than the established rate caps.

In sharp contrast to the well-functioning PJM and the New England Power Pool, failed wholesale markets in California and many western states have meant that retail consumers in most retail-restructured and non-retail restructured states of the West have faced sharply higher retail rates. This wholesale market failure led to a breaking of the rate caps by California and much higher rates that devoured most of the earlier rate cuts. In non-retail restructured Idaho and Washington, retail consumers saw rates explode too, by as much as 76% for the industrial consumers of Washington.

The West's wholesale market failure is rooted in California's policy of mandatory divestiture of power plants and the mandatory sale and purchase of all energy from spot markets. Layered on those epic errors were disastrous stranded cost recovery policies and target prices for retail competitors that were designed to keep out competitors and to speed up payment of billions of dollars in stranded costs to California's major utilities. The final blows were failure to create demand-side infrastructure to enable consumers to benefit from high wholesale prices by reducing energy usage, and broad resistance throughout western states to a regional independent system operator to oversee the regional wholesale market.

The huge damage done by these policy errors was magnified by drought conditions that reduced hydroelectric production, market manipulation by unscrupulous traders, and craven regulatory reaction by the Federal Energy Regulatory Commission prior to June of 2001, when it was liberated by new leadership.

In 2002, trends are beginning to emerge that suggest that consumers in retail-restructuring states may further benefit. For example, large stranded cost charges are beginning to expire. In the Duquesne Electric service territory, serving the Pittsburgh area in Pennsylvania, the removal of stranded cost charges led to a total residential rate cut of 16% and returned electric rates to the early days of the Reagan presidency, when a stamp cost 20 cents and the minimum wage was $3.35. Wholesale electric prices have sharply declined and restructured states are often in a good position to quickly pass these price declines through to retail customers, as demonstrated by the recent 15% rate cuts announced by two major Massachusetts utilities.

How Does Pennsylvania Rank?

- Earns an *A* for reducing rates for each customer class by more than the national average rate. Residential rates are down in constant dollars by 20%; commercial rates are down by 16%; and industrial rates by 17%.
- Reduced 2001 rates below 1996 levels for all customer classes in both constant and non-inflation adjusted dollars.
- The average Pennsylvania residential rate in 2001 was 8.7 cents per kilowatt-hour and would have been 10.8 cents had 1996 rates increased at the rate of inflation.
- The average Pennsylvania commercial rate in 2001 was 7.8 cents per kilowatt-hour and would have been 9.3 cents had 1996 rates increased at the rate of inflation.
- The average Pennsylvania industrial rate in 2001 was 5.5 cents per kilowatt-hour and would have been 6.6 cents had 1996 rates increased at the rate of inflation.
- Pennsylvania's average industrial rate was 1.33 cents above the national average in 1996. In 2001, Pennsylvania average industrial rate was just 0.56 cents above the national average. The average rate for each customer class in 2001 has declined and moved much closer to national averages. Pennsylvania's electricity rates are becoming more competitive with other states.
- Pennsylvania earns a *B* on renewable energy policy for creating clean energy funds during restructuring. These funds should be increased.
- Pennsylvania has a very limited Renewable Portfolio requirement that should be expanded. Only the competitive default supply program includes an RPS, and that program is only operating partially within the PECO service territory, although it is authorized for the PPL, Allegheny, and First Energy/GPU service territories.

In the End

Electricity restructuring will be an ever-evolving process in the US. But evidence and not hype shows that it should and can continue, and that making electricity cleaner, more efficient, and more affordable is not only plainly possible, but in every consumer's best interest.

11 Smart Rules for Retail Electric Market Restructuring

1. A wholesale electricity market serving a state must be of sufficient size and operate in accordance with standard market design to create conditions for genuine wholesale competition, prior to retail restructuring.
2. A wholesale electricity market must be operated by a genuinely independent organization that is charged with maintaining reliability and ensuring workably competitive markets.
3. There must be robust market monitoring of electricity markets to identify and prevent market manipulation, conducted by the independent organization operating regional wholesale markets as well as state and federal regulatory agencies. Penalties for market manipulation should be large and serve as real deterrents.
4. States making the transition to competitive retail electricity markets should not rush into it. An effective transition period takes about 10 years.
5. During the transition period, all retail consumers should have meters upgraded and appliance control devices installed that allow them to voluntarily change their demand for electricity in response to different prices of electricity based on time of day and season. States should have *demand-response* programs that have 5% to 10% of consumers responding to price in real time.
6. Stranded cost recovery may be necessary to protect the financial stability of utilities but it should be recovered in a manner that minimizes negative impact on retail market development. Consistent with the financial stability of the utility, the transition default rate or price to compare should be set as close as possible to the utility's historic or embedded regulated generation rate.
7. Budgets for programs that ensure low-income households access to electricity and deliver energy conservation should be maintained or increased during the transition. Benefits of energy conservation programs include protection of reliability, reduction of peak demand and prices, and lower over-all prices.
8. Each state should create alternative energy funds to increase the supply of renewable energy generated from the wind, biomass, geothermal, low-impact hydro, and solar.
9. Each state should adopt a Renewable Energy Portfolio Standard designed to require that 10% of a state's electricity supply comes from clean, renewable energy sources within 10 years.
10. Each state should ensure that interconnection and net metering policies promote clean distributed power sources or personal power units, like fuel cells or solar, that can be installed at a customer's premises.
11. States must carefully consider policies requiring divestiture of generation and must ensure that electricity supply can be contracted for short and long periods.

State Grades on Consumer Rates for Electricity

State	*Grade*	*Restructured?*	*State*	*Grade*	*Restructured?*
Alabama	C	N	Montana	D	Y
Alaska	C	N	Nebraska	A	N
Arizona	A	Y	Nevada	C	Y
Arkansas	A	N	New Hampshire	C	Y
California	D	Y	New Jersey	A	Y
Colorado	A	N	New Mexico	B	Y
Connecticut	A	Y	New York	C	Y
Delaware	A	Y	North Carolina	B	N
District of Columbia	A	Y	North Dakota	A	N
Florida	C	N	Ohio	C	Y
Georgia	A	N	Oklahoma	D	N
Hawaii	F	N	Oregon	D	Y
Idaho	D	N	Pennsylvania	A	Y
Illinois	A	Y	Rhode Island	D	Y
Indiana	A	N	South Carolina	C	N
Iowa	A	N	South Dakota	B	N
Kansas	A	N	Tennessee	B	N
Kentucky	A	N	Texas	D	Y
Louisiana	D	N	Utah	A	N
Maine	D	Y	Vermont	D	N
Maryland	A	Y	Virginia	A	Y
Massachusetts	C	Y	Washington	D	N
Michigan	B	Y	West Virginia	A	N
Minnesota	C	N	Wisconsin	D	N
Mississippi	B	N	Wyoming	C	N
Missouri	A	N			

State Grades on Environmental Policies on Electricity

State	*Grade*	*Restructured?*	*State*	*Grade*	*Restructured?*
Alabama	F	N	**Montana**	C	Y
Alaska	F	N	**Nebraska**	F	N
Arizona	C	Y	**Nevada**	B	Y
Arkansas	F	N	**New Hampshire**	F	Y
California	A	Y	**New Jersey**	A	Y
Colorado	F	N	**New Mexico**	C	Y
Connecticut	A	Y	**New York**	B	Y
Delaware	C	Y	**North Carolina**	F	N
Florida	F	N	**North Dakota**	F	N
Georgia	F	N	**Ohio**	B	Y
Hawaii	F	N	**Oklahoma**	F	N
Idaho	F	N	**Oregon**	C	Y
Illinois	B	Y	**Pennsylvania**	B	Y
Indiana	F	N	**Rhode Island**	C	Y
Iowa	F	N	**South Carolina**	F	N
Kansas	F	N	**South Dakota**	F	N
Kentucky	F	N	**Tennessee**	F	N
Louisiana	F	N	**Texas**	B	Y
Maine	B	Y	**Utah**	F	N
Maryland	F	Y	**Vermont**	F	N
Massachusetts	A	Y	**Virginia**	F	Y
Michigan	F	Y	**Washington**	F	N
Minnesota	C	N	**West Virginia**	F	N
Mississippi	F	N	**Wisconsin**	C	N
Missouri	F	N	**Wyoming**	F	N

Estimated U.S. Electric Average Rates per Kilowatt-hour to Ultimate Consumers * *in cents*

Rate Chart 1

1996 Inflation Adjusted

	RESIDENTIAL				COMMERCIAL				INDUSTRIAL		
	1996	2001	%		1996	2001	%		1996	2001	%
New England:											
Connecticut	13.4	10.5	**-21.8**		11.5	9.0	**-21.5**		8.8	7.6	**-13.3**
Maine	14.0	12.8	**-8.7**		11.5	11.9	**3.1**		7.0	7.0	**0.0**
Massachusetts	12.5	11.8	**-5.9**		11.1	9.7	**-12.5**		9.4	8.7	**-7.4**
New Hampshire	15.0	13.3	**-11.2**		12.6	11.0	**-12.8**		10.2	9.3	**-8.9**
Rhode Island	13.2	12.0	**-8.9**		11.3	10.2	**-9.8**		9.5	9.2	**-3.0**
Vermont	12.3	12.4	**1.2**		11.3	11.3	**0.0**		8.5	8.3	**-1.8**
Mid-Atlantic:											
Delaware	10.0	7.7	**-23.0**		7.8	6.1	**-21.8**		5.2	3.0	**-42.5**
District of Colu mbia	8.7	7.2	**-16.9**		8.2	6.5	**-21.2**		4.9	4.3	**-11.5**
Maryland	9.2	6.8	**-26.2**		7.6	5.6	**-26.5**		4.6	4.2	**-9.2**
New Jersey	13.4	9.6	**-28.2**		11.5	8.8	**-23.5**		9.1	8.1	**-10.8**
New York	15.7	13.8	**-11.8**		13.5	12.0	**-10.9**		6.3	5.1	**-18.6**
Pennsylvania	10.8	8.7	**-19.8**		9.3	7.8	**-16.1**		6.6	5.5	**-16.8**
South Atlantic:											
Florida	8.9	8.2	**-7.9**		7.4	6.9	**-6.6**		5.7	5.2	**-8.7**
Georgia	8.5	7.1	**-16.9**		8.0	6.4	**-19.9**		4.8	4.2	**-12.2**
North Carolina	9.0	7.7	**-14.2**		7.1	6.3	**-11.6**		5.3	4.6	**-13.9**
South Carolina	8.4	7.5	**-10.3**		7.1	6.6	**-7.2**		4.3	4.0	**-7.8**
Virginia	8.5	6.9	**-18.6**		6.6	5.6	**-15.0**		4.4	4.1	**-7.8**
West Virginia	7.1	5.9	**-17.0**		6.4	5.3	**-16.7**		4.4	3.5	**-19.7**
East North Central:											
Illinois	11.5	7.8	**-32.3**		8.9	6.2	**-30.2**		5.8	4.1	**-29.8**
Indiana	7.5	6.3	**-16.5**		6.6	5.6	**-15.4**		4.4	3.8	**-13.3**
Michigan	9.4	8.2	**-13.2**		8.9	7.6	**-14.1**		5.7	5.2	**-8.2**
Ohio	9.6	7.6	**-20.7**		8.6	7.5	**-12.7**		4.7	4.6	**-2.0**
Wisconsin	7.7	7.6	**-0.9**		6.3	6.1	**-3.7**		4.1	4.2	**2.9**
West North Central:											
Iowa	9.1	7.7	**-15.4**		7.3	6.3	**-13.5**		4.4	3.8	**-12.8**
Kansas	8.8	7.0	**-20.1**		7.4	5.9	**-20.7**		5.2	4.6	**-12.2**
Minnesota	7.9	7.1	**-10.7**		6.8	5.2	**-24.0**		4.7	4.7	**0.0**
Missouri	7.9	6.0	**-24.0**		6.7	5.2	**-22.8**		4.9	4.1	**-17.2**
Nebraska	7.0	5.5	**-21.6**		6.1	5.0	**-18.3**		4.1	3.6	**-12.2**
North Dakota	6.9	5.8	**-15.9**		6.8	5.5	**-18.7**		4.9	3.8	**-23.2**
South Dakota	7.8	6.8	**-12.9**		7.3	6.1	**-16.7**		5.0	4.3	**-13.3**

Estimated U.S. Electric Average Rates per Kilowatt-hour to Ultimate consumers * *in cents*

Rate Chart 1

1996 Inflation Adjusted

	RESIDENTIAL				COMMERCIAL				INDUSTRIAL		
	1996	**2001**	%		**1996**	**2001**	%		**1996**	**2001**	%
East South Central:											
Alabama	7.4	6.5	**-12.1**		7.2	6.4	**-11.5**		4.3	3.8	**-12.6**
Kentucky	6.2	5.2	**-16.0**		5.8	5.0	**-13.6**		3.3	3.0	**-7.8**
Mississippi	7.8	6.6	**-15.9**		7.9	6.8	**-14.0**		4.9	4.4	**-10.5**
Tennessee	6.6	6.2	**-5.4**		7.4	6.2	**-16.2**		5.0	4.4	**-12.7**
West South Central:											
Arkansas	8.7	7.0	**-19.2**		7.5	5.0	**-33.5**		5.0	4.3	**-13.7**
Louisiana	8.4	8.2	**-2.6**		7.9	8.4	**5.8**		4.8	6.5	**35.0**
Oklahoma	7.5	6.6	**-11.8**		6.5	6.2	**-4.1**		4.2	4.8	**13.9**
Texas	8.7	7.8	**-10.0**		7.5	7.7	**2.9**		4.5	5.1	**13.5**
Mountain:											
Arizona	10.0	7.1	**-28.8**		8.9	6.8	**-23.5**		5.8	4.9	**-15.3**
Colorado	8.3	7.0	**-16.2**		6.6	5.4	**-18.3**		4.8	4.2	**-13.4**
Idaho	5.9	5.4	**-8.3**		4.7	4.5	**-5.2**		3.0	3.4	**13.8**
Montana	6.9	6.4	**-7.7**		6.1	5.7	**-7.2**		3.7	5.1	**38.6**
Nevada	7.7	7.7	**0.0**		7.4	7.3	**-0.9**		5.5	4.9	**-10.3**
New Mexico	10.0	8.2	**-17.6**		8.8	7.2	**-18.6**		4.8	6.0	**23.7**
Utah	7.8	6.6	**-14.9**		6.6	5.3	**-19.4**		4.1	3.5	**-15.1**
Wyoming	6.8	6.0	**-12.2**		5.7	5.1	**-9.9**		3.8	3.4	**-11.6**
Pacific Contiguous:											
California	12.6	11.2	**-11.3**		11.0	11.0	**0.4**		7.8	8.3	**6.8**
Oregon	6.3	5.9	**-7.0**		5.7	5.2	**-9.4**		3.8	4.3	**13.1**
Washington	5.6	5.4	**-3.7**		5.4	5.4	**0.0**		3.2	5.6	**76.3**
Pacific Noncontiguous:											
Alaska	12.7	11.3	**-10.8**		10.7	9.7	**-9.2**		9.4	7.2	**-23.7**
Hawaii	15.9	16.6	**4.4**		14.5	15.1	**4.3**		11.2	11.7	**4.6**

Data retrieved from the Energy Information Administration/Electric Sales and Revenue Publications for 1996, 1998, 2000 & 2001.

Data available at www.eia.doe.gov or by calling Rodney Dunn, Survey Manager at (202) 287-1676.

Table prepared by **Citizens for Pennsylvania's Future**, 610 N. Third St., Harrisburg, PA 17101 ph. (717) 214-7920.

Estimated U.S. Electric Average Rates per Kilowatt-hour to Ultimate Consumers * *in cents*

Rate Chart 2

Not Adjusted for Inflation

	RESIDENTIAL				COMMERCIAL				INDUSTRIAL		
	1996	2001	%		1996	2001	%		1996	2001	%
New England:											
Connecticut	12.0	10.5	**-12.5**		10.3	9.0	**-12.6**		7.9	7.6	**-3.8**
Maine	12.6	12.8	**1.6**		10.4	11.9	**14.4**		6.3	8.4	**33.3**
Massachusetts	11.3	11.8	**4.4**		9.9	9.7	**-2.0**		8.4	8.7	**3.6**
New Hampshire	13.4	13.3	**-0.7**		11.3	11.0	**-2.7**		9.2	9.3	**1.1**
Rhode Island	11.8	12.0	**1.7**		10.1	10.2	**1.0**		8.5	9.2	**8.2**
Vermont	11.0	12.4	**12.7**		10.1	11.3	**11.9**		7.6	8.3	**9.2**
Mid-Atlantic:											
Delaware	9.0	7.7	**-14.4**		7.0	6.1	**-12.9**		4.7	3.0	**-36.2**
District of Columbia	7.8	7.2	**-7.7**		7.4	6.5	**-12.2**		4.4	4.3	**-2.3**
Maryland	8.3	6.8	**-18.1**		6.8	5.6	**-17.6**		4.2	4.2	**0.0**
New Jersey	12.0	9.6	**-20.0**		10.3	8.8	**-14.6**		8.2	8.1	**-1.2**
New York	14.0	13.8	**-1.4**		12.1	12.0	**-0.8**		5.6	5.1	**-8.9**
Pennsylvania	9.7	8.7	**-10.3**		8.3	7.8	**-6.0**		5.9	5.5	**-6.8**
South Atlantic:											
Florida	8.0	8.2	**2.5**		6.6	6.9	**4.5**		5.1	5.2	**2.0**
Georgia	7.7	7.1	**-7.8**		7.2	6.4	**-11.1**		4.3	4.2	**-2.3**
North Carolina	8.0	7.7	**-3.8**		6.4	6.3	**-1.6**		4.8	4.6	**-4.2**
South Carolina	7.5	7.5	**0.0**		6.4	6.6	**3.1**		3.9	4.0	**2.6**
Virginia	7.6	6.9	**-9.2**		5.9	5.6	**-5.1**		4.0	4.1	**2.5**
West Virginia	6.4	5.9	**-7.8**		5.7	5.3	**-7.0**		3.9	3.5	**-10.3**
East North Central:											
Illinois	10.3	7.8	**-24.3**		8.0	6.2	**-22.5**		5.2	4.1	**-21.2**
Indiana	6.8	6.3	**-7.4**		5.9	5.6	**-5.1**		3.9	3.8	**-2.6**
Michigan	8.5	8.2	**-3.5**		7.9	7.6	**-3.8**		5.1	5.2	**2.0**
Ohio	8.6	7.6	**-11.6**		7.7	7.5	**-2.6**		4.2	4.6	**9.5**
Wisconsin	6.9	7.6	**10.1**		5.7	6.1	**7.0**		3.7	4.2	**13.5**
West North Central:											
Iowa	8.2	7.7	**-6.1**		6.5	6.3	**-3.1**		3.9	3.8	**-2.6**
Kansas	7.9	7.0	**-11.4**		6.7	5.9	**-11.9**		4.7	4.6	**-2.1**
Minnesota	7.1	7.1	**0.0**		6.1	5.2	**-14.8**		4.3	4.7	**9.3**
Missouri	7.1	6.0	**-15.5**		6.0	5.2	**-13.3**		4.4	4.1	**-6.8**
Nebraska	6.3	5.5	**-12.7**		5.5	5.0	**-9.1**		3.7	3.6	**-2.7**
North Dakota	6.2	5.8	**-6.5**		6.1	5.5	**-9.8**		4.4	3.8	**-13.6**
South Dakota	7.0	6.8	**-2.9**		6.6	6.1	**-7.6**		4.5	4.3	**-4.4**

Estimated U.S. Electric Average Rates per Kilowatt-hour to Ultimate Consumers * *in cents*

Rate Chart 2

Not Adjusted for Inflation

	RESIDENTIAL				COMMERCIAL				INDUSTRIAL		
	1996	2001	%		1996	2001	%		1996	2001	%
East South Central:											
Alabama	6.6	6.4	**-3.0**		6.5	6.5	**0.0**		3.9	4.0	**2.6**
Kentucky	5.6	5.1	**-8.9**		5.2	4.7	**-9.4**		2.9	3.0	**2.7**
Mississippi	7.0	6.5	**-7.1**		7.1	6.9	**-2.7**		4.4	4.5	**2.0**
Tennessee	5.9	6.1	**3.4**		6.6	6.2	**-6.6**		4.5	4.6	**1.8**
West South Central:											
Arkansas	7.8	7.0	**-10.3**		6.7	5.9	**-12.5**		4.5	4.2	**-6.0**
Louisiana	7.6	8.2	**7.9**		7.1	8.4	**18.0**		4.3	6.5	**50.5**
Oklahoma	6.7	6.6	**-1.5**		5.8	6.2	**6.9**		3.8	4.8	**27.0**
Texas	7.8	7.8	**0.0**		6.7	7.7	**14.8**		4.0	5.1	**26.6**
Mountain:											
Arizona	9.0	7.1	**-21.1**		8.0	6.8	**-14.7**		5.2	4.9	**-5.6**
Colorado	7.5	7.0	**-6.7**		5.9	5.4	**-8.9**		4.4	4.2	**-3.4**
Idaho	5.3	5.4	**1.9**		4.3	4.5	**5.6**		2.7	3.4	**26.9**
Montana	6.2	6.4	**3.2**		5.5	5.7	**-3.4**		3.3	5.0	**51.5**
Nevada	6.9	7.7	**11.6**		6.6	7.3	**10.4**		4.9	4.9	**0.0**
New Mexico	8.9	8.2	**-7.9**		7.9	7.2	**-9.2**		4.4	6.0	**37.9**
Utah	7.0	6.6	**-5.7**		5.9	5.3	**-10.2**		3.7	3.5	**-5.4**
Wyoming	6.1	6.0	**-1.6**		5.1	5.1	**0.0**		3.5	3.4	**-1.4**
Pacific Contiguous:											
California	11.3	11.2	**-0.9**		9.8	11.0	**11.9**		7.0	8.3	**19.1**
Oregon	5.7	5.9	**3.5**		5.2	5.2	**0.0**		3.4	4.3	**26.1**
Washington	5.0	5.4	**8.0**		4.9	5.4	**10.7**		2.9	5.6	**96.5**
Pacific Noncontiguous:											
Alaska	11.4	11.3	**-0.9**		9.6	9.7	**1.3**		8.5	7.2	**-15.0**
Hawaii	14.3	16.6	**16.1**		13.0	15.1	**16.2**		10.0	11.7	**16.7**

Data retrieved from the Energy Information Administration/Electric Sales and Revenue Publications for 1996, 1998, 2000 & 2001.

Data available at www.eia.doe.gov or by calling Rodney Dunn, Survey Manager at (202) 287-1676.

Table prepared by **Citizens for Pennsylvania's Future**, 610 N. Third St., Harrisburg, PA 17101 ph. (717) 214-7920.

Estimated U.S. Electric Average Rates per Kilowatt-hour to Ultimate Consumers * *in cents*

Rate Chart 3

(YTD December 2001 and 2000 Table)

1996 Inflation Adjusted

	RESIDENTIAL				COMMERCIAL				INDUSTRIAL		
	1996	2001	%		1996	2001	%		1996	2001	%
New England:											
Connecticut	13.4	10.9	**-18.9**		11.5	9.3	**-18.9**		8.8	7.7	**-12.1**
Maine	14.0	11.0	**-21.6**		11.5	11.3	**-2.1**		7.0	7.0	**0.0**
Massachusetts	12.5	12.3	**-1.9**		11.1	10.7	**-3.4**		9.4	9.7	**3.2**
New Hampshire	15.0	12.5	**-16.6**		12.6	10.5	**-16.8**		10.2	9.2	**-9.9**
Rhode Island	13.2	12.1	**-8.1**		11.3	10.4	**-8.0**		9.5	9.8	**3.3**
Vermont	12.3	12.5	**2.0**		11.3	11.1	**-1.8**		8.5	7.9	**-6.5**
Mid-Atlantic:											
Delaware	10.0	8.6	**-14.0**		7.8	7.1	**-9.0**		5.2	5.1	**-2.2**
District of Columbia	8.7	7.7	**-11.1**		8.2	7.7	**-6.7**		4.9	4.8	**-1.2**
Maryland	9.2	7.7	**-16.4**		7.6	6.4	**-15.9**		4.6	4.4	**-4.9**
New Jersey	13.4	10.3	**-22.9**		11.5	9.2	**-20.0**		9.1	8.4	**-7.5**
New York	15.7	14.1	**-9.9**		13.5	13.0	**-3.5**		6.3	5.2	**-17.0**
Pennsylvania	10.8	9.7	**-10.6**		9.3	8.0	**-14.0**		6.6	5.8	**-12.3**
South Atlantic:											
Florida	8.9	8.5	**-4.6**		7.4	7.0	**-5.3**		5.7	5.4	**-5.2**
Georgia	8.5	7.9	**-7.5**		8.0	6.7	**-16.2**		4.8	4.3	**-10.1**
North Carolina	9.0	8.2	**-8.6**		7.1	6.5	**-8.8**		5.3	4.8	**-10.1**
South Carolina	8.4	7.6	**-9.1**		7.1	6.3	**-11.4**		4.3	3.8	**-12.4**
Virginia	8.5	7.7	**-9.1**		6.6	5.8	**-12.0**		4.4	4.2	**-5.6**
West Virginia	7.1	6.3	**-11.4**		6.4	5.4	**-15.2**		4.4	3.7	**-15.1**
East North Central:											
Illinois	11.5	8.7	**-24.5**		8.9	7.2	**-19.0**		5.8	4.8	**-17.8**
Indiana	7.5	6.9	**-8.6**		6.6	5.8	**-12.4**		4.4	4.0	**-8.7**
Michigan	9.4	8.4	**-11.0**		8.9	7.7	**-13.0**		5.7	5.2	**-8.2**
Ohio	9.6	8.3	**-13.4**		8.6	7.7	**-10.4**		4.7	4.8	**2.3**
Wisconsin	7.7	7.9	**3.0**		6.3	6.4	**1.1**		4.1	4.3	**5.4**
West North Central:											
Iowa	9.1	8.4	**-7.7**		7.3	6.7	**-8.0**		4.4	4.2	**-3.6**
Kansas	8.8	7.7	**-12.1**		7.4	6.2	**-16.6**		5.2	4.6	**-12.2**
Minnesota	7.9	7.5	**-5.6**		6.8	5.9	**-13.8**		4.7	4.6	**-3.1**
Missouri	7.9	7.0	**-11.3**		6.7	5.9	**-12.4**		4.9	4.5	**-9.1**
Nebraska	7.0	6.6	**-5.9**		6.1	5.6	**-8.5**		4.1	3.8	**-7.4**
North Dakota	6.9	6.7	**-2.9**		6.8	5.9	**-12.8**		4.9	4.1	**-17.2**
South Dakota	7.8	7.7	**-1.3**		7.3	6.6	**-9.9**		5.0	4.6	**-7.3**

Estimated U.S. Electric Average Rates per Kilowatt-hour to Ultimate Consumers * *in cents*

Rate Chart 3
(YTD December 2001 and 2000 Table)
1996 Inflation Adjusted

	RESIDENTIAL				COMMERCIAL				INDUSTRIAL		
	1996	2001	%		1996	2001	%		1996	2001	%
East South Central:											
Alabama	7.4	7.0	**-5.3**		7.2	6.6	**-8.8**		4.3	3.8	**-12.6**
Kentucky	6.2	5.5	**-11.1**		5.8	5.1	**-11.9**		3.3	3.0	**-7.8**
Mississippi	7.8	7.4	**-5.7**		7.9	7.0	**-11.4**		4.9	4.5	**-8.5**
Tennessee	6.6	6.4	**-2.4**		7.4	6.3	**-14.9**		5.0	4.4	**-12.7**
West South Central:											
Arkansas	8.7	7.7	**-11.1**		7.5	6.2	**-17.5**		5.0	4.5	**-9.7**
Louisiana	8.4	8.0	**-5.0**		7.9	7.6	**-4.3**		4.8	5.5	**14.2**
Oklahoma	7.5	7.2	**-3.7**		6.5	6.1	**-5.7**		4.2	4.2	**0.0**
Texas	8.7	8.7	**0.0**		7.5	7.6	**1.6**		4.5	5.2	**15.7**
Mountain:											
Arizona	10.0	8.3	**-16.8**		8.9	7.4	**-16.7**		5.8	5.2	**-10.1**
Colorado	8.3	7.4	**-11.4**		6.6	5.7	**-13.8**		4.8	4.5	**-7.2**
Idaho	5.9	6.0	**1.9**		4.7	5.2	**9.5**		3.0	3.6	**20.5**
Montana	6.9	7.0	**1.0**		6.1	6.4	**4.2**		3.7	5.8	**57.7**
Nevada	7.7	9.0	**17.0**		7.4	8.5	**15.4**		5.5	6.4	**17.2**
New Mexico	10.0	8.8	**-11.6**		8.8	7.5	**-15.2**		4.8	5.4	**11.4**
Utah	7.8	6.7	**-13.6**		6.6	5.5	**-16.4**		4.1	3.6	**-12.7**
Wyoming	6.8	6.7	**-2.0**		5.7	5.5	**-2.9**		3.8	3.5	**-9.0**
Pacific Contiguous:											
California	12.6	10.9	**-13.7**		11.0	11.2	**2.2**		7.8	9.1	**17.1**
Oregon	6.3	6.3	**-0.7**		5.7	5.5	**-4.2**		3.8	4.1	**7.9**
Washington	5.6	5.7	**1.7**		5.5	5.4	**-1.8**		3.2	4.4	**38.5**
Pacific Noncontiguous:											
Alaska	12.7	12.2	**-3.7**		10.7	10.1	**-5.4**		9.4	7.9	**-16.3**
Hawaii	15.9	16.0	**0.6**		14.5	14.5	**0.0**		11.2	11.3	**1.1**
U.S. Average	**9.3**	**8.48**	**-9.0**		**8.5**	**7.76**	**-8.9**		**5.1**	**5.02**	**-2.1**

Data retrieved from the Energy Information Administration/Electric Sales and Revenue Publications for 1996, 1998, 2000 & 2001.
Data available at www.eia.doe.gov or by calling Rodney Dunn, Survey Manager at (202) 287-1676.
Table prepared by **Citizens for Pennsylvania's Future**, 610 N. Third St., Harrisburg, PA 17101 ph. (717) 214-7920.

May 23, 2003

David R. Eichenlaub
Assistant Director, Division of Economics and Finance
State Corporation Commission
P.O. Box 1197
Richmond, VA 23218-1197

Dear Dave:

In response to your letter dated April 16, 2003, soliciting informal written comments regarding Staff's review of methods to facilitate effective competition in Virginia, please accept this letter as the preliminary comments of A&N Electric Cooperative, BARC Electric Cooperative, Central Virginia Electric Cooperative, Community Electric Cooperative, Craig-Botetourt Electric Cooperative, Mecklenburg Electric Cooperative, Northern Neck Electric Cooperative, Northern Virginia Electric Cooperative, Prince George Electric Cooperative, Rappahannock Electric Cooperative, Shenandoah Valley Electric Cooperative, Southside Electric Cooperative, Old Dominion Electric Cooperative and the Virginia, Maryland & Delaware Association of Electric Cooperatives (collectively, the "Cooperatives"). The Cooperatives appreciate the opportunity to provide input at this stage of the proceeding, and look forward to participating actively in any further discussions with Commission staff and with the Legislative Transition Task Force.

In addition to providing answers to the specific questions posed by the Staff, the Cooperatives would like to again state that at this time there is no benefit to consumers in further amendments to the Virginia Electric Utility Restructuring Act ("Restructuring Act") and to the Rules Governing Retail Access to Competitive Energy Services ("Retail Access Rules"). Participating in the various proceedings conducted to enact or promulgate the legal framework that will guide the transition to retail access has already caused the Cooperatives to expend tremendous resources, both in staff time and the expenditure of dollars, all of which ultimately come from the cooperative member-consumers. The Cooperatives have relied on the Restructuring Act and the Retail Access Rules while conducting the expensive and time-consuming task of preparing for retail access. At this time, departure from this framework is unnecessary and will only make the transition process even more expensive. Since the members they serve own the Cooperatives, increased expenses will mean increased costs – either directly or through reduced margins - for our consumers.

1. **What are the current obstacles to the development of a robust competitive retail electricity market for residential customers? For commercial and industrial customers? How can these obstacles be overcome?**

Competitive markets cannot be mandated; they emerge with the right combination of market rules and competitive pressures. In Virginia, with the combination of relatively low energy prices and capped rates, consumers are reaping the benefits of a competitive wholesale market, without the competition. If consumers were allowed and capable of responding to changing market prices and those prices were established by the existence of many market sellers and buyers, competitive pressures would exist that could lead to efficient outcomes that benefit all market players. Competitive markets also require informed market players. Information on the prices offered by competitive suppliers is currently of no value because no prices are being offered less than the current capped rates.

As for transmission adequacy, recent experience in PJM both on the Delmarva Peninsula and more recently in the newly added Allegheny Power area demonstrates certain areas of the system are not sufficiently robust to expose consumers to a LMP-based market. This is evidenced by increases in local congestion. More transmission, as facilitated by a collaborative stakeholder process with the stated goal of minimizing congestion costs to the consumer, is required.

2. **With respect to potential obstacles, what is the outlook for future natural gas prices and the impact on wholesale electricity prices and a competitive retail market? Please comment on the postulation by several natural gas industry experts of a growing structural demand/supply imbalance with demand outstripping supply over the next several years. What actions, if any, could be taken to mitigate the potential impact of an over-dependence on a single fuel source?**

The long-term outlook for natural gas prices is one of moderate growth given the increasing demand for the product. Demand will continue to grow because of the product's relative abundance and environmentally friendly qualities. The short-term outlook is one of price volatility. Increased demand for natural gas due to the building of natural gas-fired generation results in supply shortages, which in the short term leads to higher prices. Those higher prices should lead to more exploration and an eventual increase in the supply of natural gas, putting downward pressure on the price increase. As the price of natural gas rises (and the resulting electricity price from natural gas generation), other fuel sources and actions such as demand reduction through conservation or load management become economical.

3. **In light of recent legislation, how can the Commonwealth be assured of a continuing reliable electricity system when control of transmission is governed by an RTO? What factors should be considered during the cost/benefit analysis required prior to Commission approval?**

Reliability should not be a problem exclusively because a utility turns over the operation of the transmission system to an RTO. If an agreement is reached between the RTO and the transmission utility that restricts system outages to only those control areas that caused the reliability problems, no reliability problem exists other than those that were already present. In other words, as long as the transmission system in a control area cannot be expected to assist a reliability problem in another control area, there is no compromise of reliable service. However, this agreement undercuts one of the advantages of having an integrated bulk transmission system from the operator's point of view. In addition, agreement as to what operation reliability standards (i.e. ECAR or MAC) will prevail must be reached before a utility with a transmission system that crosses different reliability zones is permitted to join an RTO.

The Commission's best opportunity to assure reliability after the RTO is in place is to take a proactive role in the planning and stakeholder process envisioned by the Federal Energy Regulatory Commission. The Virginia Commission must use its considerable influence and expertise to assure that the common RTO protocol is reliable.

The Virginia Commission needs to be fully aware of the current costs and benefits of a utility joining an RTO and a reasonable assumption as to the expected costs and benefits over the mid-term (5 to 10 years) future period. Such assumptions should include an analysis of any potential costs and benefits in a competitive retail market scenario. The Commission also needs to consider carefully any utility's present or future plans for transmission expansion. Meaningful analysis will require the Commission to quantify and fully understand the current condition of each participating utility's transmission system and whether such transmission systems are capable of contributing to a viable competitive wholesale market. The Commission must have access to enough information so that any areas of tight transmission capacity (relative to load) can be analyzed to determine the cost impact of such congestion on consumers and the potential cost of "fixing" the situation. The Commission must also determine if transmission-planning processes adequately address economic development and growth. If the transmission system's operation now and in the future does not lead to the realization of economic benefits for all market players, including and even primarily consumers, then the idea of joining an RTO is a bad one.

4. **Later this month, the Federal Energy Regulatory Commission is expected to issue its "white paper" addressing certain issues debated the past several months regarding Wholesale Electric Standard Market Design (SMD). Additionally, the Department of Energy is expected to issue the results of its cost/benefit analyses of the impacts of SMD. Please provide your initial thoughts and reaction to such releases and identify any significant issues of concern.**

The Wholesale Power Market Platform White Paper issued by FERC represents a major retreat from the principles set forth in Order 2000 and with the objectives issued with the original SMD NOPR. The White Paper suggests a departure from the goal of developing consistent market rules across all RTOs and therefore may lend itself to criticism of discrimination by transmission owners. The White Paper properly emphasizes the importance of preserving and clarifying states' jurisdiction, but fails to specify how the states will participate in an RTOs' operation or planning process. The Cooperatives believe that the Virginia State Corporation Commission can play a valuable role in ensuring that the operation of any RTO system is crafted in a manner beneficial to consumers.

The White Paper also suggests that an LMP-type congestion management system is no longer mandatory. While the FERC still clearly favors an LMP-type congestion management system, there are congestion management systems other than LMP and the Commission should fully explore which system provides the greatest benefit to consumers. The White Paper also leaves open the market mitigation tools and the method of market monitoring to be deployed by the RTO. A strong market monitor and effective mitigation procedures are necessary items in order for the RTO to create an effective and transparent market. It should be noted that the White

Paper also removes the notion of auctioning FTRs if an LMP based congestion management system is implemented. Removing the auction requirement is a positive step in providing protection for loads that are native to the transmission system.

Finally, trying to develop a standard market design applicable to all RTOs (markets) no longer seems to be an objective of FERC. Regionalization will create different sets of market rules and prevent "seamless" transactions across different parts of the network. The Cooperatives are concerned that exempting existing RTOs from any review only serves to exacerbate this very problem.

The Cooperatives have conducted a cursory review of the Department of Energy's cost/benefit analysis. It appears to demonstrate modest benefits. The Cooperatives do wish to clarify that, contrary to the report, Old Dominion Electric Cooperative's congestion situation has not been "alleviated" despite such an assertion on page 60 of the report.

5. **Are the Commission's Rules Governing Retail Access to Competitive Energy Services conducive to promoting effective competition in the Commonwealth? If not, how should they be modified? Is there any way in which these rules can or should be improved, in any event?**

The Commission's Rules Governing Retail Access to Competitive Energy Services are conducive to promoting effective competition in Virginia. Competition (in the form of many buyers and sellers) has failed to emerge not because the market rules as established by the Commission are less than adequate, but because no supplier can produce and deliver electric energy at a cheaper rate than the incumbent utility. If there were suppliers capable of producing electricity and delivering such power with an acceptable margin attached at a price that was less than the energy currently available, competition in Virginia would be viable, rather than theoretical as is the case today and for the foreseeable future.

6. **What should be the level of consumer education when the program is resumed on July 1, 2004? Should it be as visible, more visible or less visible than when the campaign was suspended? Upon resumption of the campaign, what focus, theme or message should be communicated? Since TV advertising is the most expensive component of the program, what level of TV advertising should be included in the resumption of the campaign?**

The Cooperatives actively participated in the Commission's Education Task Force. The Cooperatives believe that continuing to conduct the current Virginia Energy Choice program when there is essentially no competitive market is ineffective and wasteful. The program should be placed on hold until such time as there is an effective competitive market. The Cooperatives also suggest that continuing to run such advertising despite the lack of participating CSPs may unnecessarily raise consumers' expectations.

As noted previously, the Cooperatives will continue to educate their members on retail access through the use of our Association magazine, *Cooperative Living*. Additionally, member systems have produced and distributed handouts and placed educational information on their internet websites.

7. **Are there any other actions that have been taken or are being considered in other states that may be used to advance competitive activity in Virginia?**
8. **Do you have any ideas that have not been tried elsewhere that may facilitate competitive activity in Virginia?**

At the present time, the Cooperatives believe that Virginia should take no further actions, either those tried elsewhere or those yet to be implemented anywhere, in order to advance competitive activity in Virginia. If it is to happen at all, or certainly at any time in the next decade or so, competitive activity in Virginia will occur on its own accord without additional action by the state. Competition will occur when and if it is capable of producing economic benefits for market participants, including both buyers and sellers. Until such economic benefits evolve, any market activity that may develop would be based on weak and unsupportable models and would therefore neither be robust nor long-lived. What Virginia has done is the most appropriate course at this time: having the mechanisms and guidelines in place if competition develops while maintaining safeguards against unregulated monopolies if competition does not develop.

New Era Energy, Inc.

May 23, 2003
Mr. David Eichenlaub
State Corporation Commission
P.O. Box 1197
Richmond, Virginia 23218-1197

Dear Mr. Eichenlaub:

This letter is in response to your 16 April 2003 solicitation for ideas from stakeholders in conjunction with the State Corporation Commission (SCC) Report to the Legislative Transition Task Force (LTTF). Our comments will follow the format of the questions specified by the SCC solicitation.

1. What are the obstacles to the development of a robust competitive retail electricity market for residential customers? For commercial and industrial customers? How can these obstacles be overcome?

We believe that the most important factor is that Virginia enjoys relatively low prices for electricity in the existing monopoly market structure. This means that generation, transmission and distribution assets are generally adequate to meet customer demand and that they are generally operated efficiently. Just allowing these large companies to sell into each other's territories, without other changes from the existing pricing and distribution processes, leaves very little margin to compete on.

Compounding this situation is the authorization for incumbent utilities to recover a wires change. We believe that the recovery of stranded cost is appropriate but it should be for facilities investment and long term supply contracts that cannot be mitigated with reasonable efforts. It should not be a recovery of lost revenue. Considering the projection for shortages of supply over the next several years, we believe that any excess supply capacity could probably be sold on the wholesale market. If that is the case, what is actually stranded?

Even if the wires charge were to be reduced, its unpredictability creates an unnecessary high risk for competitors. Competitors cannot make price commitments to customers beyond the period of the existing wires charge rate. Customers are less likely to shift suppliers when the offer has a short horizon. Competitive markets, under the best of conditions, carry significant risks to the suppliers. Cost uncertainty is one of the biggest issues. The inability to realistically predict the wires charge is a serious obstacle.

Another major obstacle is the reluctance of customers to change. Regardless of the default service provisions, customers have a perception that there is some risk to the

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level of service, billing or customer service. In testimony to the Consumer Advisory Board, the Apartment and Building Owners Association explained the process they went through during the original pilot programs in evaluating potential vendors. The conclusion was that all venders except Dominion Retail had too high a perceived risk. This issue is reinforced when we look at the difficulty the long distance and local service telephone companies have had in prying customers away from AT&T and the Bell operating companies. We think the willingness to accept risk to service will be even harder to overcome in electricity than it is in telephone service. The subsequent success in long distance competition was enhanced because suppliers could get dramatically lower prices. This was not the result of competition per se but because of the huge over-expansion of broadband capacity that was installed to support corporate data transmissions and the Internet. This excess capacity drove prices down. We believe it is highly unlikely that a comparable over-capacity of electricity generation and transmission will facilitate similar price reductions for competitive suppliers of electricity.

We believe that, in the long run, competition will benefit the consumer by creating significant technological advances, new products, alternative rate options and a far more efficient overall industry. This will not suddenly spring up because competition is authorized. Just as the Federal Energy Regulatory Commission (FERC) Standard Market Design (SMD) is intended to correct transmission structural issues that have evolved under the existing industry structure, legislative and regulatory action may be needed to facilitate changes in the retail system. In an atmosphere of "deregulation", it is tempting to step back and assume that the free market will bring all these changes if we are simply patient. It appears to be contradictory to impose new regulations to replace old ones. But "if we don't know where we are going, any road will get us there." We believe that the LTTF, supported by the SCC, needs to create a vision of what new structures and options are desired in the electricity industry and to determine if legislation, regulation or incentives are appropriate to encourage the transition.

The Consumer Advisory Board recommended to the LTTF that an Energy Management Working Group be established to work on one aspect of this effort, demand side management. This is still needed and it is recommended that the SCC take a leadership role in pursuing that effort. Retail distributed generation, retail green power and retail clean power are examples of issues that should be addressed to identify a intermediate term vision of objectives for customer options and government action, if any, needed to facilitate that vision. We believe that these all will become key aspects for product differentiation in an emerging competitive market, especially demand response. These Virginia efforts should not be undertaken in isolation from similar activities underway elsewhere, such as the California demand response case and the PJM Working Groups.

2. With respect to potential obstacles, what is the outlook for future natural gas prices and the impact on wholesale electricity prices and a competitive retail market? Please comment on the postulation by several natural gas industry experts of a growing structural demand/supply imbalance with demand outstripping supply over the next several years. What actions, if any, could be taken to mitigate the potential impact of an over-dependence on a single fuel source?

We are aware of the projections for increases in natural gas prices. Most new generation that has been added recently has been fueled by natural gas. More importantly, the downgrading of utility debt and the economic downturn has combined to cause a drastic reduction in new generation construction. When the economy turns around, which we are confident will happen, it is highly likely that demand/supply imbalances can be expected. Demand can be expected to grow substantially faster than supply. If this combines with extremes in weather, serious shortage may occur. If this happens while we are still in the capped rate period, we could have a similar problem to the one that created massive financial losses for California utilities. The degree of risk of this event needs to be monitored closely be the SCC on an on-going basis.

Conceptually, assuming that Virginia utilities will ultimately become aligned with PJM, it is the responsibility of that organization to assure there are adequate generation and transmission resources. It could be years before the combination of federal legislation and wholesale industry restructuring makes this effective. In the meantime, the state needs to require default utilities to maintain adequate capacity and reserves, either by generation and transmission capacity or by demand response.

Demand response programs exist that are not promoted. Many small and medium-sized businesses are already billed on a demand basis in many jurisdictions but these customers generally do not understand demand. They do not understand that there are actions they can take to reduce their peaks demand. They do not understand how that impacts on their cost. They do not understand that there are products on the market that would assist them in demand response. They do not understand that there are rate options, in some cases, that the utility does not advise them of. In some cases, this extends to residential customers.

If the existing demand response programs for these customers are not effective in the view of the SCC or the incumbent utilities, a serious and high priority effort should be undertaken to change it. If that requires approval by the SCC of new demand response systems, with appropriate rate options specifically for that system, that should be permitted without creating a change to the capped rate structure for all other customers. We understand the reluctance to open a rate case that modifies the agreements to hold existing rates until 2007. At the same time, the urgency to create more effective demand response in the short-term requires some common-sense flexibility.

The utilities have directed most of their demand response efforts toward larger commercial and industrial customers. These customers can potentially drop substantial load and they generally have more technically competent managers. But these customers also have a more level load and there are adverse financial and operational consequences of dropping that load. Reliable participation by these users has been disappointing in most states. More importantly, these are generally not the customers that are creating the problem in the first place. The variation in demand from day to day and hour and hour is primarily the result of residential and small business users. There is extensive experience that these smaller customers will respond to price signals and that many of them desire options to help themselves save on energy costs. Existing programs require demand control action for over 2,000 hours a year, making it more difficult to minimize discomfort and inconvenience. Using 1999 wholesale prices as a measure of supply problems, prices per mWh exceeded $40 for less than 800 hours and exceeded $100 for only about 100 hours. During those 100 hours, prices reached almost $1,000 per mWh. A real-time communication system allowing TOU or critical peak pricing only when actually needed is feasible with today's technology and could help dramatically expand customer acceptance of demand response. Pricing options need to be coordinated to include both supply and distribution rates. The industry has failed to develop options for these customers that reconcile their own interests, their customer's interest and the interests of third party companies that facilitate customer demand response. Strong leadership from federal and state regulatory authority, seeking legislative action when necessary, is needed to change this. For example, Virginia Power is implementing a major Automated Meter Reading (AMR) Program. We believe that the SCC should evaluate the degree to which the selected approach and equipment might create a barrier to entry for new demand response initiatives. The feasibility and upgrade cost to accommodate likely real-time demand response programs should be a consideration in approval of such a program.

Notwithstanding the good intentions of establishing capped rates as a customer protection measure, this is essentially a price controls action. Historically, price controls have not worked in our economy. They impede investment in the quality and quantity of supply. We believe that having these price controls for such an extended period of time is a significant factor in restraining capacity growth.

3. In light of recent legislation, how can the Commonwealth be assured of a continuing reliable electricity system when control of transmission is governed by an RTO? What factors should be considered during the cost/benefit analysis required prior to the Commission approval?

We believe that local control acts to restrain investment by those that create the capacity that is needed to assure adequate supply. The best way to assure a reliable supply in the long run is to encourage a fully robust competitive national market, with adequate reserves of generation and transmission and with adequate reserves required by all participants. The default providers in the state must demonstrate that they have sufficient supply commitments to meet reasonable expectations of demand to an acceptable degree of reliability established by the SCC. There must be a serious financial penalty to any Competitive Service Provider (CSP) that fails to meet the demands of its customers. This penalty should provide part of the resources to reimburse default providers for their potentially excess commitments.

Reliable demand response should be equal in value to supply in meeting these reserve requirements.

Under the FERC proposal, the state is represented in many of the processes that impact this issue. How the state is represented, by whom and with what authority will be vital.

Ultimately, in a completely restructured wholesale and retail market, individual states will have less control over this than has been the case in the monopoly structure of the past. A decision to proceed with restructuring assumes acceptance of this fact.

4. Later this month, the Federal Energy Regulatory Commission (FERC) is expected to issue its "white paper" addressing certain issues debated the past several months regarding Wholesale Electric Standard Market Design (SMD). Additionally, the Department of Energy is expected to issue the results of its cost/benefit analysis of the impacts of SMD. Please provide your initial thoughts and reaction to such releases and identify any significant issues of concern.

We believe that the responsibility for having adequate supply available migrates to the RTO and its member companies. FERC proposes location marginal prices, or something that serves the same purpose, to drive financial consequences down to those causing the imbalance/congestion. The White Paper states, "Efficient market behavior depends heavily on assigning cost responsibility to those who cause the costs and the benefits to those who reduce costs." In the long term, this is an important and valid requirement to support a competitive market but it will not necessarily avoid short-term problems with serious consequences. We believe this can only be mitigated by requiring that sufficient supply and/or demand response be committed to by suppliers such that it motivates construction of the appropriate capacity or the developing and deploying of demand response systems. Financial penalties need to make failure to do this an unacceptable risk.

While FERC and PJM both appear to be strongly encouraging a demand response solution to help solve this problem and to make the industry more efficient, we do not see significant efforts by the individual utilities to respond.

The FERC SMD and federal legislation under consideration in the Congress are key steps in developing an effective competitive wholesale market. It is likely that approval and implementation of this design will take a number of years. In the meantime, the wholesale price risks to retail suppliers also is an obstacle to competitive retail markets.

5. Are the Commission's Rules Governing Retail Access to Competitive Energy Services conducive to promoting effective competition in the Commonwealth? If not, how should they be modified? Is there any way in which these rules can or should be improved, in any event?

We believe that the Rules do not promote or not promote competition. They are permissive in that they provide a structure for how the process works for a competitor to enter the market. The issues that impede development of the competitive market are not a result of these rules.

6. What should be the level of consumer education when the program is resumed on July 1, 2004? Should it be as visible, more visible or less visible than when the campaign was *suspended? Upon resumption of the campaign, what focus, theme or message should be communicated? Since TV advertising is the most expensive component of the program, what level of TV advertising should be included in the resumption of the campaign?*

The Consumer Education Program has been focused on simply advising customers that they have a choice. These customers then went through the very frustrating process of contacting a long list of licensed providers to learn that there are no offers. Even today, when customers inquire of Virginia Power about this programs, they are referred to the SCC website. After they call everyone on the list on that site, they learn that there are no offers. Almost every customer that contacts our company expresses anger and frustration that they have been sent by Virginia Power to a website list as if someone on that list would make them an offer. Local Distribution Companies (LDC) require CSPs to become licensed or registered by them. They can require that these companies advise if they are making offers and they can provide to customers making inquires a list of suppliers only if the are making offers. The SCC site should, likewise, be modified to show licensed companies and whether they are making offers. This requirement can be relaxed after there are numerous companies making offers.

The Customer Education Program should expand its charter to preparing customers for a competitive marketplace. The program should include education about default service, to overcome the concern about risk to service. The program should provide education about the need for and potential benefits of demand response. The purpose is to create a fertile potential customer base for such programs in the future, as well as for those that may exist today from their LDC. This type of education should be on going, regardless of the temporary lack of offers. In geographic areas where existing rates promote demand response, education for customers should include actions they can take to reduce their cost by taking demand reductions actions. We believe that the prospective reduction in the customer's cost for electricity that are likely due to the introduction of competition within the next five years is much smaller than the potential reduction in cost from simply better managing their demand, under either new or existing rates. This education would not only help prepare customers for the demand response programs expected to emerge, it would help to reduce the impact of demand/supply imbalances and to reduce the customer's cost of electricity in the short-term.

TV ads similar to the existing program for announcing choice should not be used until there are at least three suppliers already offering realistic competitive rate choices. Other education programs proposed above should be accomplished with significantly less expensive programs, such as by free brochures, speakers bureau, direct mail targeted to customers most likely to benefit, such as low load-factor businesses and large residential customers, bill stuffers and supplying information for media feature articles.

7. Are there any other actions that have been taken or are being considered in other states that may be used to advance competitive activity in Virginia?

Other states are pursuing the same type of demand response programs proposed herein. California has a Rule Making Case entitled Advanced Metering, Demand Response and

Dynamic Pricing. The situation in California is substantially different than Virginia but we believe that we share the goals of this case, to find cost-effective real-time demand response solutions for all customer classes.

In a May 2003 Draft Report by the Oregon Public Utility Commission entitled "Demand Response Programs for Oregon Utilities", the recommendations were:

"1. The utilities' Integrated Resources Plans (IRPs) should evaluate demand response programs on par with other options for meeting energy and capacity needs.

2. The utilities should bring forward by Sept. 30, 2003, for PUC's consideration at least one voluntary real-time hourly or critical-peak pricing tariff for nonresidential customers with demand of 200 kW or greater.

3. The utilities should bring forward by Sept. 30, 2003, for PUC's approval a program to expand their direct load control efforts for Oregon's small customers beginning January 2004. Programs should target time-of-use customers but allows others to participate. The utilities should also consider testing critical-peak pricing for time-of-use customers that choose utility load control.

4. The PUC should determine whether time-of-use energy rates should be adjusted and whether meter charges should be reduced.

5. The PUC should open an investigation to identify policies that facilitate the adoption of more advanced meters, communication technology and automated meter reading.

We believe that these recommendations should apply to Virginia was well.

Pennsylvania is planning random assignment of large blocks of customers to competitive suppliers as a means to jump-start the transition of residential customers. This approach was used in England.

Ohio and some other areas have encouraged municipal aggregation as a means of bringing large blocks of customers to competitive suppliers, significantly reducing the marketing cost that would otherwise be required to attract that many customers. Monitoring results in these programs over time and testing the concept here with Virginia Power's proposed pilot are appropriate. The fact that this is a pilot of limited duration may act as a restraint on attracting participants. It is also not yet clear whether the proposed reduction in the wires charge will be sufficient to attract multiple suppliers to bid for this business.

We understand that either the Ohio or Pennsylvania approach, or something like them, is be an effective way to migrate large numbers of customers that would otherwise ignore competitive offers. But the "opt-out" version essential represents a slamming program by the local government. It puts the government in the position of selecting a "one size fits all" offer. This contradicts our view of the true value of competition, as we have seen it in every other market. That is that competition creates a proliferation of options benefiting the widely different interests and goals of individual customers. The "opt-out" approach would represent an overwhelming barrier to entry for smaller competitors that want to market a unique feature or capability. The monopoly nature of the local government's role in these programs also creates a fertile ground for passing through local tax increases or other local government overhead expenses. Regardless of whether "opt-in" or "opt-out" is used, we believe that as the competitive market matures, these government aggregation approaches would no longer be needed and should be phased out. We believe that considerably more progress is needed in developing Virginia's wholesale competitive markets before these approaches should be seriously considered beyond pilot programs.

8. Do you have any ideas that have not been tried elsewhere that may facilitate competitive activity in Virginia?

There is nothing that hasn't been addressed in answers to previous questions.

We appreciate the opportunity to contribute our opinions to this very important process.

Jack Greenhalgh
President

PEPCO ENERGY SERVICES, INC.

RESPONSE TO QUESTIONS FROM THE STATE CORPORATION COMMISSION STAFF ON COMPETITIVE ELECTRICITY MARKETS IN VIRGINIA

Pepco Energy Services, Inc. ("PES") submits the following comments to questions posed by the Virginia State Corporation Commission Staff ("Staff") in its letter of April 16, 2003 seeking comments to assist the Virginia State Corporation Commission ("Commission") in its third annual review of means to facilitate effective competition in Virginia electricity markets.

PES is a licensed supplier of electricity in the Commonwealth and other states in the Mid-Atlantic region. In Virginia, PES is the only licensed competitive service provider ("CSP") currently serving residential customers. PES has experience with competitive retail markets in various jurisdictions and respectfully submits the following comments for the Commission's consideration.

Question 1:

What are the current obstacles to the development of a robust competitive retail electricity market for residential customers? For commercial and industrial customers? How can these obstacles be overcome?

The most significant obstacle to the development of a competitive retail market in Virginia for all customer classes is the artificially low price to compare ("PTC") set annually by the Commission on a customer class basis. As many parties to this discussion noted last year, use of wholesale market prices for calculation of the PTC establishes a benchmark that makes it all but impossible for competitive suppliers to enter and compete in Virginia markets and fails to further the intent of the Virginia Electric

Utility Restructuring Act ("the Restructuring Act") to foster retail competition. Projected market prices for generation used by the Commission to set wires charges—which, in turn, affect the calculation of the PTC (the wires charge and the PTC have an inverse relationship)--should reflect a retail market price rather than a wholesale market price.

For purposes of this discussion, PES defines "wholesale market price" as one that includes only costs associated with purchasing electricity to serve retail customers from the wholesale market. A retail market price would include a number of other costs that determine the end-use price of electricity, including the wholesale market price; billing, customer service, and general and administrative costs; and costs associated with credit worthiness, including bonding requirements established by both the Commission and incumbent utilities. Additionally, the retail price of electricity offered by a CSP includes customer acquisition costs and the retailer's margin. In sum, a retail market price concept includes all of the costs that a supplier must incur to serve customers. Use of wholesale market prices for setting the PTC makes it impossible, by definition, for CSPs to offer a retail price at or below the PTC.

The Restructuring Act supports use of this retail market price concept. Section 56-583(A) of the Restructuring Act states as follows:

> To provide the opportunity for competition and consistent with § 56-584, the Commission shall calculate wires charges for each incumbent electric utility, effective upon the commencement of customer choice, which shall be the excess, if any, of the incumbent electric utility's capped unbundled rates for generation over the projected market prices for generation, as determined by the Commission.... (§56-577 et seq. of the Code of Virginia, emphasis added.)

Given the range of costs that any supplier must incur, as discussed above, and the fact that the Restructuring Act is silent on whether wholesale or retail market prices are to be used when calculating projected market values for generation, PES believes that the only reasonable interpretation of the Restructuring Act is that retail market prices for generation should be used in the calculation of wires charges and, correspondingly, setting the PTC.

Several recent developments support the position that an unrealistic PTC is the single greatest barrier to competition in Virginia. In its recent filing for approval of retail access pilots, Dominion Virginia Power ("DVP") tacitly admits that CSPs cannot compete against current PTCs and that some action, namely a reduction or, in this case, a partial waiver, of the wires charge is necessary to promote competition:

> Importantly, with each of the Pilots, the Company is proposing to waive a portion of the wires charge for all participating customers in order to create additional "headroom" for CSPs to cover their costs of doing business and to offer savings to customers. (Section III, "Common Pilot Elements," page 9, line 8)

In seeking to create "headroom" for suppliers, DVP acknowledges the same point that PES made earlier—that a realistic PTC should include all supply costs, including the "costs of doing business," an item excluded from a PTC calculated from wholesale market prices.

PES intends to participate in the pilot programs and has been an active participant in preliminary meetings to discuss their development. We are hopeful but cautious, given that at the expiration of prior pilot programs competitive suppliers returned their customers to the incumbent utility due to the transition to an unrealistic standard for the calculation of the PTC. PES also notes that the PTC of the first pilot programs was three to four mills higher than the current pilot programs' projected PTC (after adjustments for the proposed 50% reduction in wires charges).

Recently, the Commission itself has begun to examine factors that influence calculation of the PTC. The Commission has initiated investigations into both standard offer service (also known as "default" service) and stranded costs. In the latter proceeding, the Commission is exploring methodologies for identifying stranded costs and actual calculation of a stranded cost amount. PES believes that a determination by the Commission of the total amount of stranded costs to be recovered by each utility and the specification of a transition period over which each incumbent will be permitted to recover its stranded costs will greatly enhance the current process for establishing PTCs.

With respect to remedies that will foster the development of competition in the commercial and industrial ("C&I") segments, PES supports proposals similar to those introduced earlier this year by Senator Watkins. While the Legislative Transition Task Force tabled discussion of the Watkins' proposals until a later date, PES encourages the Commission's consideration of similar measures. Specifically, the first proposal would have waived wires charges for C&I customers that switch to a competitive supplier, provided that the incumbent utility could charge market-based rates to any previously switched customers that return to default service. The second proposal eliminated minimum stay requirements for customers returning to default service, again with the provision that incumbent utilities could charge market-based rates to these customers. These proposals would encourage C&I customers to participate in the competitive market and allow incumbent utilities to be fully compensated, through market-based rates, for all costs incurred to serve those customers returning to the incumbent's service.

In summary, the use of wholesale market generation prices in the Commission's process for establishing the wires charge understates the PTC and results in three adverse consequences that unreasonably impede the development of competition in Virginia:

- CSPs are forced to compete in a retail environment against wholesale PTCs, establishing a *de facto* entry barrier for suppliers;

- Consumers are denied the economic and environmental benefits of a competitive market--electricity bill savings and innovation in energy services, respectively; and

- Overstated wires charges misallocate ratepayer resources, potentially rewarding incumbent utilities for costs that are not stranded.

Question 5:

Are the Commission's Rules Governing Retail Access to Competitive Energy Services conducive to promoting effective competition in the Commonwealth? If not, how should they be modified? Is there any way in which these rules can or should be improved, in any event?

As mentioned last year, PES has found the Commission's Rules Governing Retail Access to Competitive Energy to be a reasonable attempt to create a level playing field on which suppliers can compete. Certain steps should be taken, however, to improve the Rules in ways that will foster the growth of competition.

In 20 VAC 5-312-70(B), the Commission requires that suppliers

> [P]rovide to a prospective residential customer, by mail or by electronic means, prior to, or contemporaneously with, the written contract, an estimated electricity supply service or natural gas supply service annual bill assuming average monthly usage of 1,000 kWh of electricity or 7.5 Mcf or 75 therms of natural gas, including all fees and minimum or fixed charges, exclusive of any non-recurring financial incentives, and the total average price per kWh, Mcf, or therm based on the annual bill.

Based on PES' experience in serving residential electricity and natural gas customers in Virginia, customers sometimes find this information confusing for several reasons.

First, many residential customers are not accustomed to thinking about their energy bills on an annual basis and therefore do not have a reference for comparison when provided the information required by the regulations. Second, most customers' usage is not "average." Customers with significantly higher usage may find that the estimated cost of service looks like a bargain while the low usage customers may think they are not getting a very good deal.

Even if a customer uses the annual average amount of electricity, that consumption is not evenly distributed throughout the year. If pricing is seasonally differentiated, then a customer with heavy summer usage and gas heat will have an annual cost that is quite different from a customer with electric heat and lower summer usage. As a consequence, the average cost per kWh calculation requirement may not be reflective of the customer's usage pattern.

Finally, average cost is not directly comparable to the average PTC that the incumbent utility provides and which is based on actual usage. In short, the use of a generic average cost, either on an annual basis or on a $/kWh basis, is often confusing and in many cases misleading.

SEL

April 22, 2003

David R. Eichenlaub
State Corporation Commission
1300 E. Main Street
Richmond, VA 23218

Mr. Eichenlaub,

On April 16, 2003 you issued a solicitation of "ideas from stakeholders" in preparation for the State Corporation Commission's annual report on the status of competition. Strategic Energy is a competitive service provider active in seven states, currently serving over 3,000 MW of retail load. Strategic Energy appreciates the opportunity to provide comments for the Commission's report, and will participate in the informal discussions on June 6, 2003. Below are the initial responses of Strategic Energy.

1. What are the current obstacles to the development of a robust competitive retail electricity market for residential customers? For commercial and industrial customers? How can these obstacles be overcome?

   Strategic Energy's target market is Commercial and Industrial (C&I) customers, therefore, we will limit our comments to those customer classes. The current obstacles to serving C&I customers in Virginia are largely due to the stranded cost recovery mechanism in place. As the stranded cost methodology allows most Virginia utilities to charge any retail access customer for its total lost revenue, there is little or no opportunity to offer customers a discount on the utilities rate. The wires charge roughly equals the difference between the revenues that the utility expects to receive from the customers, minus the spot market price in PJM west. This will ensure that the wires charge overstates the stranded cost of the utility because it assumes the minimum value for energy in the wholesale market (spot prices reflect short-run marginal cost, and not the long-run value of energy delivery service) and no cost avoidance from losing a customer. For some customers with flexible production processes or demand response capabilities it might still be possible to provide added value (and thereby get a customer to switch) even with the wires charge penalty. However, because Virginia does not belong to a Regional Transmission Organization, and therefore lacks an active bilateral market and a balancing energy market, there is little or no opportunity to offer value-added services.

Given the provisions of the Restructuring Act there may be little that the Commission can do on the retail rate structure. The Commission can review the calculation of the wires charge to determine whether utilities are over-collecting stranded costs, and lower the wires charge if appropriate. The Commission should also develop a methodology for fixing the wires charge so that consumers can better evaluate the potential costs and benefits of switching to a competitive supplier. The Commission should also actively promote a process either having Virginia utilities join an active RTO (such as PJM) or create a Virginia RTO.

2. With respect to potential obstacles, what is the outlook for future natural gas prices and the impact on wholesale electricity prices and a competitive retail market? Please comment on the postulation by several natural gas industry experts of a growing structural demand/supply imbalance with demand outstripping supply over the next several years. What actions, if any, could be taken to mitigate the potential impact of an over-dependence on a single fuel source?

   Future natural gas prices are unpredictable, as the price swing in the past four years are shown. However, there are valid reasons for assuming that natural gas supplies will not keep pace with demand in the long-run as domestic resource continue to be depleted. Strategic Energy firmly believes that the market is best able to determine the appropriate fuel mix, as fuel cost and reliability are key components to planning and new generation. However, market forces can sometimes be distorted by regulatory overlays, and the Commission should take care that regulation does not overly promote one technology or one fuel source to the detriment of reliability. One example of a distorting regulatory overlay is the resource adequacy mechanism used by PJM. The Installed Capacity or "ICAP" requirement in this control areas is designed to subsidize all generation, irrespective of fuel type. The nature of this subsidy provides an incentive for building the least-capital intensive resources (i.e. low capital costs with high energy costs). While firmly believing that Virginia should join the PJM RTO, and adopt the PJM energy market rules, Strategic Energy strongly recommends that the Commission consider adopting an alternate resource adequacy mechanism. The alternate is to adopt the ECAR/MidWest ISO reserves-based reliability mechanism. In addition the Commission should with a resource adequacy mechanism that can directly invest in new resources in the event of a market failure. By direct investment in new resources the Commission can place requirements on the new resource, including fuel-source, to ensure that an appropriate level of fuel diversity can be maintained.

3. In light of recent legislation, how can the Commonwealth be assured of a continuing reliable electricity system when control of transmission is governed by an RTO? What factors should be considered during the cost/benefit analysis required prior to Commission approval?

   A robust energy market for Virginia's consumers is highly dependent upon transmission assets being placed under the control of an Independent System Operator, or a Regional Transmission Organization ("RTO"). The purpose of an RTO is to maximize consumer welfare by eliminating the discriminatory behavior that is endemic of transmission systems where the system operator has business interests in the wholesale and retail markets. Furthermore, by joining a larger RTO, Virginia will become more firmly a part of a larger planning process to ensure reliability. Larger control areas not only create more robust markets, but improve reliability by better the coordinating the use of transmission facilities. It is worth noting that the creation of larger, multi-state control areas such as PJM was prompted by the need to reduce the threat to reliability inherent when interconnected transmission operators do not adequately coordinate dispatch. The economic benefits of centralized dispatch and open access to the transmission system came later.

4. Later this month, the Federal Energy Regulatory Commission is expected to issue its "white paper" addressing certain issues debated the past several months regarding Wholesale Electric Standard Market Design (SMD). Additionally, the Department of Energy is expected to issue the results of its cost/benefit analyses of the impacts of SMD. Please provide your initial thoughts and reaction to such releases and identify any significant issues of concern.

   The FERC's white paper on SMD is aimed at eliminating, as much as possible, lingering discrimination in access to the nation's transmission system, and at providing some market standardization to reduce the transaction costs and increase the liquidity of the wholesale energy market. All consumers will benefit from a reduction in discrimination and transaction costs. Strategic Energy will wait until it has seen the white paper before identifying specific "significant issues of concern."

5. Are the Commission's Rules Governing Retail Access to Competitive Energy Services conducive to promoting effective competition in the Commonwealth? If not, how should they be modified? Is there any way in which these rules can or should be improved, in any event?

   The Rules Governing Retail Access are generally similar to rules that are in jurisdictions where retail markets are active and do not impose a substantial barrier to competition. The extent to which the rules will need to be modified will largely be determined after retail competition becomes active in Virginia.

6. What should be the level of consumer education when the program is resumed on July 1, 2004? Should it be as visible, more visible or less visible than when the campaign was suspended? Upon resumption of the campaign, what focus, theme or message should be communicated? Since TV advertising is the most expensive component of the program, what level of TV advertising should be included in the resumption of the campaign?

   Resuming a consumer education program while competitive suppliers are kept out of the market by the wires charge will only create unrealistic consumer expectations.

7. Are there any other actions that have been taken or are being considered in other states that may be used to advance competitive activity in Virginia?

Strategic Energy recommends that the Commission research the rules and regulations governing retail competition in Texas. Texas retail competition began on January 1, 2002, and already approximately 30% of all customer load is served by alternative suppliers. Strategic Energy believes much of the success in Texas is because the default rates in Texas are market-based. The Price to Beat (default rate available to customers with a peak demand less than 1 MW) in Texas can be adjusted up to twice a year to reflect an increase or decrease in natural gas or electricity prices. This adjustment mechanism provides alternative suppliers a greater opportunity to compete by preventing the default rate from becoming a below cost rate. The Texas structure also promotes competition by requiring all customers over 1 MW to negotiate contracts for competitively priced electricity. Finally, Texas created a solid foundation for competition by requiring vertically integrated investor-owned utilities to structurally unbundled generation, retail services, and transmission and distribution functions into separate corporations. The transmission and distribution utility in Texas is truly a "wires" only company specifically prohibited from providing generation service with a strong code of conduct that governs the relationship between the utility and its affiliates.

Strategic Energy also recommends that the Commission consider the rules and regulations for Default Service in New Jersey (Basic Generation Service) and Maryland (Standard Offer Service.) These states are also providing a variable rate Default Service for the largest customers, and a more stable, market-rate service for smaller commercial residential customers. These states are not requiring the level of utility restructuring as in Texas, but are adopting measures that will also promote robust competition.

8. Do you have any ideas that have not been tried elsewhere that may facilitate competitive activity in Virginia?

Not at this time.

Respectfully Submitted,

-/s/-

Michael Swider
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Vienna, VA 22180

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7900 Marlea Road
Richmond, Virginia 23225
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May 13, 2003

Mr. Howard M. Spinner (attn. Mr. Dave Eichenlaub)
Division of Economics and Finance, SCC

Dear Mr. Spinner:

Your letter of April 16 asks for comments in connection with upcoming 3d Annual Report to the Legislative Transition Task Force (LTTF), pursuant to Sect. 56-596 B. The report is expected to cover three topics. As one of the very limited voices on behalf of the general public, I submit my comments and recommendations, as follows:

(A) In spite of my extensive involvement in this subject for over 2 years in the General Assembly, and in the hearings before the SCC in the Dominion Virginia Power case, I am not able to provide in depth comment on the several issues raised in your letter, but will do my best..

It should be recognized that the general public cannot deal with the simple aspects of electric deregulation and Choice, much less with the technical issues such as wires charges, stranded costs, etc. which are far more complex.

Most of the impetus, and emphasis, and the Stakeholders, in deregulation arise from the desire of the utilities to sell their power generated in Virginia to consumers in other areas who are now paying higher rates than we do in Virginia, and to avoid their obligation to their present customers, and from the desires of larger industrial interests to benefit from possible lower rates.. The proposed protections of the public are inadequate !!! (See my response to Mr. Williams, of last June 15, 2002, copy attached, which remains appropriate)

We need to stop deregulation, and rebundle and roll-back to the fully regulated status. The details and views set forth in the large 2 Vol. Annual Report of the SCC last Aug. 30, and in the Blue Cover report as per SB 684 dated Nov. 30, 2002, and in the Addendum (yellow cover) report filed Jan 3, 2003, are strong supporting reasons, and have been further reinforced by subsequent events and information.

(B) Reponding specifically to the questions raised in your letter of April 16, as follows:

(1) The current obstacles to development of a robust (or any) competitive retail electricity market for Virginia residential customers are that we now have low rates, good service, and a fine prosperous major power company (Dominion). The only way this can be overcome is to increase the amount that Virginia residential users have to pay for electricity !!

(2) Natural gas prices are probably going to stay relatively high, and that fuel is of greater importance for home heating and other uses. Large use for electric generation, and other heavy industrial purposes should be discouraged. We should promote increased use of neuclear, coal, and water power, and perhaps oil, for electric generation.

(3) The only way we can be assured of reliable generating capacity for Virginia residents is for the SCC to have full regulatory control, as it had for about 100 years.

(4) FERC has apparently issued its paper, and I am not able to find any assurance of protection of the Virginia general public. What I have read increased my concern !!!

(5) The Commission's rules governing retail access are not doing any good. They are too complicated for the public to handle. The way to improve the rules is to eliminate the need for them, by stopping deregulation.

(6) The consumer education program has been almost a total waste, and the public has paid no attention to the material which they have been receiving for about 2 years. The program should be stopped, or largely curtailed, until there is some real lower cost "Choice" available to the general public.

(7) I have not heard of any other successful deregulation programs in any state. I have read that legislators in California are proposing to stop deregulation and go back to the old system.

(8) I have no suggestions to facilitate competitive activity in Virginia.

I will try to attend the meeting at 9:30 on June 6.

Respectfully yours,

Urchie B. Ellis,
Va. State Bar No. 5422

Urchie B. Ellis
ATTORNEY AT LAW
7900 Marilea Road
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Phone 804-272-5923

June 15, 2002

Mr. Richard J. Williams, Director
Division of Economics and Finance, SCC

Thank you for your letter of June 12, attaching copy of your letter of April 24 which went to many parties interested in electric deregulation, but somehow seems to have missed the public and consumer interests (somehow I was left out even thought I played a major part in the recent Dominion Virginia Power case, and in hearings at the General Assembly the past 2 years). I am glad your procedure will admit further comments, and hope you have notified other possible public consumer interests.

I have reviewed the April 24 letter, and seen several of the extensive replies by major business representatives---e.g. Delmarva, Pepco, Virginia Power, and the Coops.

My comments are as follows:

(1) Most of the questions, and the responses, are concerned with details to benefit the utilities and independent generators, and there is little to reflect concern for the public interest. Even though I have had heavy involvement in the subject, most of the questions and responses are too complicated for me to understand or to deal with. I urge that another list of questions be sent out which ask for comments and suggestions to adequately protect the public in Virginia to ensure that we have adequate, easily available electric power at low rates and with great reliability, and with a minimum of confusion or literature to read and understand. The list should go to many public entities, and a good sample of residential and small business consumers for a broad response.

The language from Sect. 56-596B quoted in the April 24 letter directs that the SCC report have recommendations "in the public interest". Developments in the past year around the U.S. in connection with electric deregulation demonstate that the "public interest" needs greater SCC regulation and supervision, not less. The underlying concept of the Task Force, and the deregulation law to date has been to benefit the utilities, and to allow them to sell their Virginia generated power to consumers in other areas of the U.S. who would pay more for it----and the proposed arrangements thus far have imposed nearly all of the serious risk on the residential consumer and small business in Virginia. The SCC recommendation "in the public interest" should be for a 5 year moratorium, and any needed reregulation, to preserve the status quo to allow us to see what happens elsewhere.

SOME OF THE SPECIFIC QUESTIONS PERMIT RESPONSE, AS FOLLOWS

1. The major obstacle to development of a robust competitive retail electricity market retail residential customers in Virginia is the fact that we now have low rates and good service. No residential customer wants any change. We want the SCC to continue to have full authority to supervise electricity and regulate rates and service. Deregulation only serves the purposes of the

utilities, who have developed trading floors and want to sell their generated power elsewhere for higher revenues, and be relieved of most of their obligations to the Virginia public!!!

2. and 3. deal with RTOs and transmission service, and are too complicated for me to try to comment, and are of little importance to the residents of Virginia. for the reasons stated in No.1

4. The SCC rules are too complicated, and the public cannot understand or deal with them. I suspect that few, if any , of the Task Force Committee, or the General Assembly, can understand the several pamplets and various notices on CHOICE, etc. and admit that I cannot, and I am sure that few residential consumers have even read them. We need the SCC-

5. In the light of the many complications that have arisen around the U.S. and with several of the power trading companies, it is clear that Virginia "public interest" requires a 5 year moratorium.

6, 7, 8, 9, are too complicated, but in general we need steps to protect the public, not the utilities, because the whole program and the details are not working, and are too complicated for the public to understand and deal with.

10---14 are too complicated for me to try to deal with, except to urge that rate caps need to be kept low and not exceed current rates in Virginia, and we should stick with SCC regulation.

15, 16 Some other states are not progressing deregulation, and that is the pattern Virginia should follow. Nothing will facilitate competitive activity in Virginia because we now have low rates and good service.

I hope these comments will be useful, and I will supplement them by reference to my letters of Nov. 27, 2001, and Dec. 24, 2001, to the Task Force, where I urged a moratorium!!!

Respectfully yours,

Urchie B. Ellis
Virginia State Bar No. 5422

May 20, 2003

By E-mail and U.S. Mail

David R. Eichenlaub
Assistant Director, Economics
Division of Economics and Finance
State Corporation Commission
1300 East Main Street
Richmond, VA 23218

Re: Comments on Topics to be Addressed in Third Annual Report to LTTF

Dear Mr. Eichenlaub:

These comments are submitted by the Municipal Electric Power Association of Virginia ("MEPAV") in response to your letter of April 16, 2003 to Market Participants soliciting ideas to assist the Commission in developing a comprehensive review of methods that may be considered to facilitate effective competition.

MEPAV is an organization formed to meet the needs of its members by providing information, support and group advocacy on legislative and regulatory issues for the 16 localities that operate electric distribution utilities in the Commonwealth:

City of Bedford
Town of Blackstone
City of Bristol
Town of Culpeper
City of Danville
Town of Elkton
City of Franklin
Town of Front Royal
Harrisonburg Electric Commission
City of Manassas
City of Martinsville
City of Radford
Town of Richlands
City of Salem
Virginia Polytechnic Institute & State University
Town of Wakefield

MEPAV has been active in the electric restructuring legislative process in Virginia. In addition, MEPAV's members have participated in a coalition representing transmission dependent utilities that has participated in working group committees and stakeholder meetings in connection with RTOs and other forms of RTEs which have included the investor-owned utilities that provide transmission service in Virginia and has also participated in related proceedings at the Federal Energy Regulation Commission ("FERC"). In addition, all but one are members of the Transmission Access Policy Study Group ("TAPS"), an organization of transmission dependent utilities in 33 states across the U.S. that has participated actively in FERC rulemaking proceedings regarding transmission issues. Although some of the 16 MEPAV localities own and operate generation, none has sufficient generation to meet its total loads. Thus, all must purchase their energy needs from the wholesale market and are dependent on the transmission systems of others to get the energy from the suppliers' resources to their systems.

Because MEPAV's members are wholesale electric customers of their suppliers, the rates they pay for purchases of power supply are either regulated by FERC (or are not regulated) and the rates and service conditions for transmission and related services they receive are subject to FERC regulation, these comments will focus on the third and fourth items for which you have sought input.

MEPAV's members have supported the development of independent RTOs of sufficient size and scope to provide benefits to consumers and have been supportive of the concept of Standard Market Design for wholesale electric markets. MEPAV's members have actively participated before FERC as members of a coalition of transmission dependent utilities (currently called the "Coalition of Municipal and Cooperative Users of New PJM Companies' Transmission") and through TAPS in proceedings raising substantial issues with respect to specific RTE proposals and particular elements of SMD. With respect to FERC's orders dealing with RTEs, MEPAV has been pleased with much of what FERC has done, but has been disappointed in other respects. Our principal disappointment has been with FERC's past attitude of giving great deference to each utility's decision on which RTE to join and FERC's unwillingness previously to consider whether a particular RTE selection was the optimal selection. MEPAV supported the 2003 amendments to Sections 56-577 and 56-579 of the Virginia Electric Restructuring Act as related to regional transmission entities. Particularly important to MEPAV are the provisions of Sections 579.A.2.d and 579.F. The first requires that the Commission, in developing rules and regulations for the transfer of control, ownership or responsibility to an RTE that generally promote the public interest, ensure that consumers' needs for economic and reliable transmission are met. The second is the requirement that the Commission find that any request for approval of transfer of ownership or control of or responsibility for transmission facilities shall include a study of the comparative costs and benefits thereof, which study shall analyze the economic effects of the transfer on consumers, including the effects of transmission congestion costs.

MEPAV is cautiously optimistic as a result of FERC's April 28, 2003 White Paper on Wholesale Power Market Platform that FERC will be receptive to considering costs and benefits in evaluating regional transmission entity issues and that it will consider the interests of all market participants in market design.

MEPAV believes that the transmission owners' selection regarding participation in an RTE should have the principal objective of maximizing the benefits to all consumers, including providing the lowest cost of energy delivered to its customers on a reliable basis. In general, MEPAV believes that consumer benefits will be maximized by the RTE selection that is most conducive to creating a robustly competitive market for energy in which all load-serving entities may participate. However, the ultimate criterion must be the delivered cost of reliable power supplies to all retail customers, including the customers served by transmission dependent utilities such as MEPAV's members.

Among the questions that should be addressed by an incumbent electric utility in a request for approval of transfer of ownership or control of or responsibility for transmission facilities are the following:

- What is the "natural market" of which the utility considers itself a part? What is the basis for that view?
- What are the predominant patterns of historical energy trade in which the utility has participated?
- What are the utility's strongest interconnections with adjacent systems?
- Does the utility agree that benefit to customers should be the principal criterion for evaluating its RTE-participation alternatives? If not, what other standard(s) does the utility believe are more important than benefit to customers?
- What measures does the utility believe it should put in place to ensure that customers are protected from any adverse economic impact of RTE participation?
- What analyses has the utility performed to evaluate and compare the economic impacts on retail and wholesale customers of its participation in various RTEs? What did those analyses show?
- What analysis has the utility made comparing the costs of entry it would incur to join each of the RTEs in which participation was considered? If so, what does that analysis show?
- Has the utility analyzed the costs that would ultimately be borne by ratepayers under each of the alternative RTE-participation options that were considered? What does that analysis show?

- Has the utility conducted any analysis of its system to determine whether its system is well-suited to the application of market rules of the RTE it proposes to join? What does the analysis show?
- Has the utility compared the impact that participation in various RTEs would have on the transmission congestion costs incurred by the utility and transmission dependent utilities located within their transmission systems? Has the utility analyzed whether participation in one RTE or another would be more likely to lead to an increase in transmission congestion costs? If so, what do these analyses show?
- Has the utility analyzed the additional transmission expansion or other alternatives required to fully integrate the utility into the RTE it proposes to join without incurring significant congestion costs.
- If PJM is the RTE the utility proposes to join, does the utility agree that the PJM pricing model should be modified to resolve the problem of high prices in load pockets? What modifications does the utility believe should be adopted to hold its transmission dependent utility customers as "cost neutral" as possible?
- If the utility were to join PJM, would it be willing to cooperate with stakeholders to seek resolution of the problems that have arisen under PJM's pricing approach within transmission-constrained areas?
- Is the utility willing to commit to absorbing any congestion-related costs of serving transmission dependent utilities if those costs are incurred as a result of joining PJM?
- What does the utility consider to be the most significant "seams" issues between RTEs?
- Among the RTE-participation options open to the utility, which option does the utility believe is most conducive to minimizing seams issues? What is the basis for that belief?

As the Commission is aware, the cost of congestion that Old Dominion Electric Cooperative ("ODEC") and other transmission dependent utilities experienced in the Delmarva Peninsula under PJM's system of locational marginal pricing and fixed transmission rights was a major factor driving the 2003 legislation. As reflected in many of the above questions, MEPAV is concerned that the experience in assigning congestion costs in the Delmarva Peninsula not be repeated in other areas. Part of the potential problem arises from the fact that the existing transmission systems of utilities were not planned or constructed under an LMP/FTR regime, but one in which costs were socialized over a broad area. It is important that any shift to a new cost allocation and pricing regime be attentive to this problem and adapt to it, such as by providing a sufficiently long transition period, to avoid hardship on particular customers and a pricing scheme that does not penalize or unduly burden customers located in load pockets. MEPAV also believes that an equitable allocation of FTRs, rather than an auction, is necessary and most equitable for those utilities who have had and will continue to have an obligation to serve the loads they now serve.

We note that FERC on May 12 established a fact-finding proceeding to be facilitated by an administrative law judge concerning transmission congestion in the Delmarva Peninsula (Docket No. PA03-12-000). MEPAV regards this as a favorable indication that FERC recognizes the problem that has been faced by ODEC and other customers on the Delmarva Peninsula and may be willing to deal with those problems more proactively than it has in the past. The information to be developed by the Commission in its cost/benefit analysis may interface well with the FERC fact finding proceeding.

MEPAV appreciates the opportunity to present its views on matters on which you have sought input.

Sincerely yours,

Allen Todd
President

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May 23, 2003

Dave Eichenlaub
Assistant Director, Economics
Virginia State Corporation Commission
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Dear Mr. Eichenlaub:

The National Energy Marketers Association (NEM) hereby submits comments pursuant to the April 16, 2003, letter that posed questions related to: 1) the status of competition in Virginia; 2) the status of the development of regional competitive markets; and 3) recommendations to facilitate effective competition in the Commonwealth.

The National Energy Marketers Association (NEM) is a national, non-profit trade association representing wholesale and retail marketers of energy, telecom and financial-related products, services, information and related technologies throughout the United States, Canada and the U.K. NEM's Membership includes wholesale and retail suppliers of electricity and natural gas, independent power producers, suppliers of distributed generation, energy brokers, power traders, and electronic trading exchanges, advanced metering and load management firms, billing and information technology providers, credit, risk management and financial services firms, software developers, clean coal technology firms as well as energy-related telecom, broadband and internet companies.

This regionally diverse, broad-based coalition of energy, financial services and technology firms has come together under NEM's auspices to forge consensus and to help resolve as many issues as possible that would delay competition. NEM members urge lawmakers and regulators to implement:

- Laws and regulations that open markets for natural gas and electricity in a competitively neutral fashion that bring suppliers and consumers together at the lowest possible cost;
- Standards rates, tariffs, taxes and operating procedures that unbundle competitive services from monopoly services and encourage true competition on the basis of price, quality of service and provision of value-added services;
- Accounting and disclosure standards to promote the proper valuation of energy assets, equity securities and forward energy contracts, including derivatives; and
- Policies that encourage investments in new technologies, including the integration of energy, telecom, digital communications and Internet services to lower the cost of energy and related services.

1. What are the current obstacles to the development of a robust competitive retail electricity market for residential customers? For commercial and industrial customers? How can these obstacles be overcome?

The most significant obstacles to the development of a robust competitive retail electric market in Virginia are the current artificial price caps and the existing wires charge. Lifting price caps and allowing consumers to see and respond to changing prices for energy and related energy services, information and technology is critical. Finally, the removal, or at a minimum, a revision in the methodology for the calculation and assessment of the wires charge is also necessary for the development of the Virginia retail market. Stranded costs should be collected in a competitively neutral manner to foster competition.

A. Price Caps Impede the Development of a Robust Competitive Retail Electricity Market

Price caps do not facilitate energy competition and do not permit consumers to modify their consumption levels in response to price. Utility pricing mechanisms must reflect changes in wholesale prices and the true costs of serving retail load. NEM is cognizant of the concern that consumers should be protected from erratic price swings and the ability to mange price risks and offer fixed or variable priced contracts should be a competitively offered retail product. If utility consumers are permitted to respond to accurate pricing signals they could adjust their consumption thereby lessening the impact of price spikes or choose competitive offerings from alternative suppliers.

NEM submits that capped utility rates do not reflect the fully embedded costs of serving retail load and undermine the ability of competitive suppliers to invest in serving Virginia consumers. Staff, in its May 2003 Report in Case No. 2002-00645, stated that there is substantial uncertainty as to the feasibility of an entity other than the incumbent utility providing default service until the end of the capped rate period. The Report indicated that a factor contributing to its view was the current capped rate and wires charge structure that severely undermines competitive pricing. NEM urges the Commission to open the market for default service because requiring the utilities to provide default service at capped or artificially subsidized rates sends distorted and normally cross-subsidized price signals to consumers. NEM submits that it is the structure of Virginia's energy market and not current marketer competence that is restricting marketers from supplying these services. Marketers have the ability and experience to supply default services to customers. Marketers have long been involved in developing and aggregating generation and providing utilities with energy related services and technologies. In many cases, marketers have supplied utilities with energy and related services on an outsourced basis for years.. Consequently, marketers have the ability to provide default service and should be allowed the opportunity to do so in the Commonwealth.

If the Commission decides that the utilities should continue to provide default service, the requirements of section 56-585(C)(1) that, "the rates for default service provided by a distributor shall equal the capped rates" until the expiration or termination of capped rates, presents a significant obstacle for the market. As has been evidenced by lackluster customer participation in choice programs in the state, the capped rates instituted for the utilities have stifled competition. Capped rates are set artificially low and competitive suppliers cannot offer competitive prices when utility offered competitive services are cross-subsidized. Additionally, since capped rates do not change to reflect changes in the wholesale market or the added costs of serving last minute, no notice default services, there is little opportunity for retail suppliers to compete on the basis of price or quality of service provided. Default service pricing mechanisms that allow prices to change over time in response to wholesale market conditions as well as the true costs of delivering "last resort," no notice default retail services better reflect real competitive markets, provide more accurate price signals, and help level the competitive retail playing field.

The provision of default service based on capped or subsidized rates will not foster the development of the competitive market. If the Commission mandates the selection of the incumbent utility for all customers who fail to make timely supplier elections and sets a non-competitive price for no notice default service, it will create a significant barrier to new suppliers while perpetuating the same non-competitive energy services that restructuring is designed to replace.

B. Wires Charge Must be Competitively Neutral

NEM submits that the wires charge is a significant barrier to entry in the Virginia market. The manner in which the wires charge is calculated and implemented makes it virtually impossible for competitive suppliers to compete with the utilities. NEM recognizes that the recovery of prudently incurred and aggressively mitigated stranded costs is a valid concern for the utilities. However, NEM urges that a competitively neutral means of collecting stranded costs should be instituted. NEM recommends that any costs that are unavoidable because utilities must incur such costs to perform Provider of Last Resort (POLR)-related services should be recovered through adjustments to the rates charged for POLR related services. Any costs and/or lost revenues not connected with the utilities' provision of POLR-related services and fully bundled sales service should be added to distribution rates in a competitively neutral fashion.

NEM is encouraged by the current proposal to allow large commercial and industrial (C&I) customers who are willing to commit to market-based pricing, should they ever return to the incumbent utility, to switch to a competitive supplier without having to pay a wires charge. NEM encourages Virginia legislators to propose the required amendment to the Restructuring Act to allow large customers the ability to avoid a wires charge and receive the benefits of competition.

True price competition benefits all customers; not just those who shop for lower prices. The first and foremost benefit provided is the economic stimulus provided by economically efficient competitively priced energy as well as the ability to exercise choice beyond the regulated service they have traditionally received. Imposing a wires charge on switching customers is unfair and unwise because it penalizes those customers who attempt to lower their energy costs and defeats the entire purpose of permitting price competition in the first instance. If a charge applicable only to retail access customers is set too high, no one will be able to participate in the market. Assessment of stranded cost charges only against retail access customers will not only punish migrating customers, thereby slowing migration and the development of functional retail markets, but it will also encourage utilities to continue to invest in competitive services thereby further increasing future potentially "stranded" costs. In the end, society will pay a far higher transition cost the longer utilities provide competitive services.[1]

2. **With respect to potential obstacles, what is the outlook for future natural gas prices and the impact on wholesale electricity prices and a competitive retail market? Please comment on the postulation by several natural gas industry experts of a growing structural demand/supply imbalance with demand outstripping supply over the next several years. What actions, if any, could be taken to mitigate the potential impact of an over-dependence on a single fuel source?**

NEM is aware of the current projections for higher natural gas prices and their potential impact on gas fired generation. However, government intervention or mandates as to fuel sources have normally had unintended significant adverse impacts. Promoting a competitive energy market in Virginia will help to mitigate the potential impact of higher fuel prices by permitting customers to see and select the lowest cost alternative supplies including properly priced demand reduction, load shifting and energy efficiency products and services. . Additionally, in markets that are open to competition, "green suppliers" have entered the market to provide renewable energy to customers who desire this niche product. Customer demand should determine the types and varieties of competitively provided products, services, information, and technology offered in the Virginia marketplace. NEM recognizes that some consumers will be interested in reducing demand or purchasing power from green sources, and the market should give them both the opportunity and accurate price signals to do so. NEM urges the SCC to avoid costly mandates on competitive suppliers (such as mandatory renewable portfolio standards) that could impede the growth of competition and consumer choice.

Additionally, retail competition will allow customers to shift the risk of higher gas prices on to competitive service providers who are in a position to better manage the risk. Without retail access, bundled utility customers are bearing the risk and cost of higher gas prices through fuel adjustment clauses or other mechanisms imposed to take the risk off of the utility.

3. **In light of recent legislation, how can the Commonwealth be assured of a continuing reliable electricity system when control of transmission is governed by an RTO? What factors should be considered during the cost/benefit analysis required prior to Commission approval?**

RTO membership effectively addresses reliability concerns. When the transmission network is operated regionally under independent management, without financial conflicts of interest among the owners of affected transmission, distribution, and generation assets, operational decisions can be made solely upon operational considerations. NEM urges the Commission to require the utilities to transfer control of their transmission systems to an RTO as soon as possible in light of FERC's White Paper on a Wholesale Power Market Platform, which proposes mandatory RTO membership.

[1] See Also, NEM's Initial Comments In the Matter of Developing Consensus Recommendations on Stranded Costs, PUE-2003-00062, www.energymarketers.com/documents/NEM_stranded_cost_cmts_final.pdf

An accurate cost/benefit analysis of RTO membership should recognize that a key element in linking geographically separate electricity markets is the integrity of the transmission network. A RTO operated transmission network facilitates the movement of bulk power transactions to ensure reliability, economic efficiency and market liquidity. Given the current commercial bottlenecks in transmission service, transmission owners should be monitored to avoid the use of these constraints unfairly as market power to their own financial advantage. The Commission can also consider incentive based rates to accelerate recovery of investments made to eliminate congestion.

4. **Later this month, the Federal Energy Regulatory Commission is expected to issue its "white paper" addressing certain issues debated the past several months regarding Wholesale Electric Standard Market Design (SMD). Additionally, the Department of Energy is expected to issue the results of its cost/benefit analyses of the impacts of SMD. Please provide your initial thoughts and reaction to such releases and identify any significant issues of concern.**

NEM is concerned that without nationwide standards for data exchange, ATC determinations, delivery terms, operating procedures and practices, interconnection standards, etc., the full value to consumers of true price competition will be harder to achieve. NEM believes that the following steps should be part of any plan to restructure the U.S. energy markets:

- **Uniform, national technology standards** can and should be implemented as soon as possible.
- **Transparent, auditable, transactional price data must be available on an equal, non-discriminatory basis to all market participants.**
- **All electricity should be treated as native load.**
- **Regions and utilities must eliminate seams** that are created by differences in information and operating standards and protocols.
- **Wholesale generators, marketers and traders must know precisely what practices are proscribed before, not after, transactions are completed.**
- **Local distribution rates must be unbundled to permit consumers to see the actual, fully allocated, embedded costs they are paying for each element of bundled utility service or default services.**
- **Consumers must be empowered to use these embedded costs as credits against their utility bills to shop for competitive supplies and services.**
- **Utilities must be incented to outsource competitive services and to reinvest in upgrading infrastructure, delivery services and reduced congestion.**
- **Lastly, energy efficiency and demand side resources must be priced competitively.**

5. **Are the Commission's Rules Governing Retail Access to Competitive Energy Services conducive to promoting effective competition in the Commonwealth? If not, how should they be modified? Is there any way in which these rules can or should be improved, in any event?**

The Commission's rules governing the various aspects of retail access to competitive energy service should be adjusted as described below to more effectively promote competition in Virginia.

A. Default Service Should Be Priced To Reflect The Fully Embedded Costs of Serving No-Notice Retail Load

Default energy suppliers must stand ready to serve any customer, new or old, at any time, twenty-four hours a day, seven days a week, 365 days a year without any advanced notice. This is an important obligation and it requires a number of important assets and supplier skill sets. However, such no no-notice service is far more expensive than other types of service and it is critical that consumers understand and see the real costs of relying on no-notice default service.

The pricing of default service is also critically important to the development of a competitive market because the default price serves as the "price to compare" - the target against which all competitive offers are judged by consumers. Therefore, default service should be priced to reflect the fully allocated embedded costs associated with no notice retail related services for each customer class. If a subsidized or artificially low rate is set, true competition will not develop. NEM submits that default pricing for electricity should at a minimum include transmission charges, scheduling and control area services, and distribution system line losses, a share of pool operating expenses, risk management premiums, load shape costs, commodity acquisition and portfolio management, working capital, taxes, administrative and general expenses, the costs of metering, billing, collections, bad debt, information exchange, compliance with consumer protection regulations, and customer care.

NEM submits that if a bid process is properly structured it could encourage a competitive market. NEM believes that bids should not be based solely on the wholesale price of the energy commodity. NEM submits that bids should include all of the energy supply and related costs plus all the commercial costs of rendering this type of service. NEM urges the SCC to design a bid process that selects suppliers to directly serve retail customers because implementation of a bid system for wholesale contracts will not contribute to the ultimate development of a competitive retail market. Under a wholesale only bid process consumers will be unaware of the competitive suppliers serving their supply needs and prevent direct supplier-customer relationships which are vital to building brand awareness.

Additionally, the Commission should allow alternative suppliers to provide default service as soon as reasonably practicable and convert the utilities' obligation to serve into an obligation to deliver.[2]

B. Competitive Advanced Metering Should Be Instituted for All Customers As Soon As Practicable

[2] See NEM's Answer to Question 1, Paragraph A, and NEM's National Guidelines for Designing and Pricing Default Energy and Related Services, http://www.energymarketers.com/Documents/FinalDefaultPaper.pdf

The Commission issued an order in Case No. PUE 010298 on Aug 19, 2002, approving rules regarding competitive electricity metering services for the elements of meter data availability and accessibility effective January 1, 2003. The Commission is currently considering proposed rules regarding financial ownership of meters by large C&I customers. The Commission stated in its December 10, 2002 Order on Electricity Metering, that it is premature to develop rules for additional elements of competitive metering, beyond meter ownership for large customers, at this time. NEM agrees that the opening of customer choice in metering services depends on the operational readiness of the associated support systems. However, NEM submits that affordable advanced metering and related information technologies are currently available to bring consumers and small businesses the benefits of advanced real-time data collection and energy supply and cost management.

The competitive unbundling of advanced metering and related technologies will enable efficient management of both energy supply and demand through timely, accurate dissemination of critical real-time energy usage information. Additionally, advanced meters will permit suppliers to more accurately match supplies to meet demand and avoid imbalance penalties ultimately reducing costs and bringing customers savings on their energy bills. Therefore, NEM urges the SCC to implement a timeline, which provides utilities with targeted, time-sensitive, performance-based incentives to implement the operational systems necessary to support competitive metering so the benefits of these upgrades can be realized at the earliest possible date.

C. Competitive Billing Should Be Implemented As Soon As Practicable

Competitive Service Provider (CSP) consolidated billing, was scheduled by the Act to become effective January 1, 2003. The Commission's August 21, 2002, Order adopted final rules to govern the implementation and provision of CSP consolidated billing. With respect to implementation, the Commission has accepted an interim system workaround approach that will be replaced with standardized business practices and EDI protocols as the competitive market develops and the volume of competitive billing increases.

NEM submits that CSP consolidated billing should be implemented as soon as reasonably practicable. Encouraging the development of a competitive market for billing services will allow competitive marketers to provide consumers with enhanced, value-added services. Suppliers should be able to present bills in order for consumers to have better access to innovative product offerings. It normally is not possible for CSPs to provide many of these choices to consumers when the LDC presents the bill. Without the option for suppliers to present bills to consumers, consumers are prevented from enjoying these innovative possibilities in product choice.

Billing is an important point of contact for a CSP because it enables the supplier to promote and market its energy services. Inasmuch as consumers cannot choose their distribution company, billing simply does not serve the same function for the regulated utilities. Therefore, NEM urges the SCC to fully implement the provisions of CSP consolidated billing at the earliest possible date.

D. Minimum Stay Requirement Should Be Eliminated

Under the Commission's current regulations, customers with a demand of 500 kW or higher are subject to a twelve-month minimum stay period upon returning to their incumbent utilities for capped rate service after receiving service from an alternative supplier. NEM asserts that minimum stay requirements unnecessarily restrict customers from exercising the option to choose another supplier. NEM urges the Commission to eliminate the minimum stay requirement for all customer classes. NEM is encouraged by the current proposal to eliminate the minimum stay requirement for returning customers that agree to purchase electric energy at market based rates from the incumbent electric utility.

6. **What should be the level of consumer education when the program is resumed on July 1, 2004? Should it be as visible, more visible or less visible than when the campaign was suspended? Upon resumption of the campaign, what focus, theme or message should be communicated? Since TV advertising is the most expensive component of the program, what level of TV advertising should be included in the resumption of the campaign?**

Consumer education about customer choice is an invaluable component of implementing successful choice programs. NEM submits that upon implementation of the recommendations set forth in NEM's responses to foster market development, customer education initiatives must be redoubled to overcome customer inertia that may have developed due to lack of initial competitive offerings because of current market structure and conditions.

NEM submits that an appropriate message to promote the competitive energy market is that in every market that has opened for competition and provided customers with choice, consumers have received the benefits of lower prices and access to innovative new offerings of products, services, information and technology.[3] NEM urges the Commission to work with NEM and the marketer community to fashion an effective, accurate and competitively neutral public educational message.

7. **Are there any other actions that have been taken or are being considered in other states that may be used to advance competitive activity in Virginia?**

NEM urges the SCC to implement innovative programs similar to the ones Orange and Rockland Utility (O&R) is using to stimulate competition in New York. O&R customers have switched at nearly four times the statewide average switch rate for residential gas customers. A significant reason for this level of activity is their Switch and Save Program. Under this program the utility actively solicits customers to volunteer for the program and guarantees them a certain percentage of savings over the utility commodity price for two months. O&R assigns the customers to an Energy Supply Company (ESCO) on the basis of the ESCO's program participation level. The customers in the program can switch to another ESCO or back to utility commodity service after the two months if they so choose. ESCOs have been able to continue delivering savings to

[3] See Text for NEM's Ad, "ABCs of Energy Competition, Attached as Exhibit A.

customers after the initial two-month period. The Switch and Save program has proven to be highly effective for customers and participating ESCOs.

Another innovative program O&R uses is its guaranteed payment for ESCO services. Except for O&R, other New York utilities have opted to allocate customer payments to their receivables before the ESCOs. The result has been the streaming of nearly all bad debt related to serving energy choice customers to the ESCOs. Bad debt rates among ESCOs in excess of 10% have been common and have made the business environment in New York State very expensive while the ESCO's ability to provide savings to customers has been severely damaged. However, ESCOs participating in the O&R program have a bad debt rate of 0%. Since O&R's delivery service rates include an allowance for bad debt on commodity service, the utility is at no more risk for non payment from ESCO commodity service customers than for customers receiving utility commodity service. In effect, O&R is not harmed from a bad debt perspective by migration of customers to energy choice. On the other hand, most other utilities are benefiting to some degree by collecting an allowance for ESCO commodity bad debt while they have no exposure.

NEM encourages the SCC to incorporate innovative programs, similar to the ones O&R uses, to facilitate competition in the Commonwealth.

Conclusion

NEM appreciates this opportunity to comment on the facilitation of effective retail electric competition in Virginia and reiterates our commitment to working with the Commission and the other stakeholders to devise fair and effective ways to implement competitive restructuring in the state.

Sincerely,

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Dated: May 23, 2003.

EXHIBIT A

Choice - In every market that has opened for competition and provided consumers with a choice, consumers have received the benefits of lower prices and access to innovative new offerings of products, services, information and technology.

Offerings - There are a host of energy information and technology providers that have developed products such as real-time meters, home control systems and distributed generation that allow consumers to control the amount of energy they use so they can control how much they pay.

Monopoly - Monopoly pricing is never lower than competitive pricing. It's just that simple.

Price Reduction - It is estimated that wholesale power markets are already saving customers $13 billion per year. As a result of federal legislation and regulation opening wholesale gas markets, the price of natural gas to LDCs and large industrial consumers declined on average by as much as 50%. In Texas, it is estimated that retail customers have saved, at a minimum, over $1.5 billion in electricity costs during the first year of competition as compared to the regulated rates in effect during 2001. In Pennsylvania, it is estimated that consumers have saved $3.8 billion from rate reductions since the beginning of the electric choice program in 1997 through 2001. In Massachusetts, since the passage of the electric restructuring law in 1996, the retail price of electricity for commercial customers has dropped 12%.

Energy - Energy is the lifeblood of the economy. All consumers benefit when competitive forces are brought to bear on energy prices.

Technology - When competitive forces enter energy markets, it results in an array of technological advances.

Innovation - Real-time meters are the "cash registers" of the new energy economy. Distributed generation is the portable, cost-effective "cell phone" of the emerging energy industry.

Time-of-Use - New time-of-use offerings give customers control over their bill by allowing them to vary their usage based on rate differentials throughout the day.

Information - New energy services provide consumers with the information they need to take control of their energy bill.

Options - As more alternative energy suppliers enter the market, competition will be enhanced to provide consumers with better price and service options.

New Jobs - Lower energy prices offered by competitive suppliers permit states to attract new businesses, increasing job opportunities and state tax revenues.

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May 28, 2003

David M. Eichenlaub
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1300 East Main Street
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Re: Comments Concerning the Status of Competition – Compliance by the State Corporation Commission with § 56-596.B of the Code of Virginia

Dear Mr. Eichenlaub:

Thank you for your letter of April 16, 2003, requesting comments on various topics pursuant to Virginia Code § 56-596.B relating to the status of competition in Virginia.[1] We respond on behalf of the Virginia Committee for Fair Utility Rates and the Old Dominion Committee for Fair Utility Rates (collectively, "the Committees"), which consist of large industrial customers of Virginia Power and AEP-Virginia, respectively. The Committees have a vital interest in the development of competition in Virginia and in the region.

I. INTRODUCTION

In Virginia at present, retail competition for generation services essentially does not exist. With the exception of a miniscule number of customers that purchase power at above-market rates from a competitive service provider ("CSP") that has stopped offering the service to new customers, there is no retail competition at all. Thus, in terms of the existence of retail competition, little, if anything, has changed since last year, when, in response to the Commission's inquiry into the status of competition, the Committees submitted comments, dated May 28, 2002 ("Committees' 2002 Comments"), that offered a number of suggested remedies for the dearth of retail competition in Virginia. The chart below summarizes key suggestions in those comments and their subsequent disposition.

[1] Section 56-596.B of Virginia's Electric Utility Restructuring Act ("Restructuring Act"), Va. Code § 56-596.B, requires the Commission to recommend actions to be taken by the General Assembly, the Commission, electric utilities, suppliers, generators, distributors and regional transmission entities that the Commission considers to be in the public interest, including actions regarding the supply and demand balance for generation services, new and existing generation capacity, transmission constraints, market power, suppliers licensed and operating in the Commonwealth, and the shared or joint use of generation sites.

COMMITTEES' PROPOSALS	DISPOSITION
***Wires Charges.* Remedy the lack of headroom for customers of Virginia Power by reconsidering the legal conclusions on which the present methodology for the calculation of wires charges is based.** **Adopt a new methodology using projected retail market prices for generation.**	The SCC reiterated its prior legal conclusion in its report to the General Assembly, dated August 30, 2002 ("2002 Report"), and, in its Final Order in the wires charges case, dated October 11, 2002.[2] In the latter order, the SCC declined to adopt a new methodology that uses projected retail market prices for generation.
***Wires Charges.* If, upon reconsideration, the SCC reached the same legal conclusions, it should recommend to the General Assembly amendment of the Restructuring Act to clarify that its discretion in determining the projected market price of generation is not constrained by the goal of achieving "revenue neutrality."**	The SCC declined to make such a recommendation in its 2002 Report. The SCC recommended in the 2002 Report that the General Assembly consider amending the Act to allow a large commercial or industrial customer that is willing to commit to market-based pricing should it ever return to its incumbent utility, the ability to switch to a CSP without paying a wires charge.[3] (Legislation, SB 891, subsequently was introduced in the General Assembly but did not pass.)
***Wires Charges.* Deny requests by utilities to subtract from the Commission's projected market prices for generation the cost of transmission that could have been avoided if they had joined or established a regional transmission organization ("RTO" or "RTE).**	The SCC denied AEP-Virginia's request on other grounds but granted Virginia Power's request for a transmission cost adjustment. Neither utility has joined or established an RTO.[4] (The General Assembly later amended the

[2] *Commonwealth of Virginia at the Relation of the State Corporation Commission Ex Parte: In the matter of considering requirements relating to wires charges pursuant to the Virginia Electric Utility Restructuring Act*, SCC Case No. PUE-2001-00306 ("Wires Charges Case"), Final Order, dated October 11, 2002, at 5, 6; 2002 Report at 20-23.

[3] 2002 Report at 65.

[4] Wires Charges Case, Final Order, dated October 11, 2002, at 22.

	Restructuring Act to prohibit utilities from transferring control of transmission assets to an RTO prior to July 1, 2004.)
***Alleged Stranded Costs*. Analyze whether the existence and amount of "just and reasonable net stranded costs" warrant the recovery of such costs through wires charges.**	The LTTF adopted a resolution requesting the Commission to establish and convene a work group to develop "consensus" recommendations among interested persons regarding a definition of just and reasonable net stranded costs and methodologies for their calculation and recovery; however, utility members of the work group have urged, in essence, that neither just and reasonable net stranded costs nor their recovery under capped rates and wires charges be estimated.
***RTOs*. Consider instituting show-cause hearings to require compliance by Virginia Power and Appalachian Power Company with their obligations, as incumbent electric utilities under the Restructuring Act, to join or establish a regional transmission "entity" on or before January 1, 2001.**	The SCC recommended, in a supplement to the 2002 Report, that the General Assembly decide promptly whether to proceed with or delay implementation of the Act (including retail customer choice), citing the FERC's proposed standard market design ("SMD") rulemaking, worsening financial distress among utilities subject to restructuring, merchant generators, and competitive retail suppliers, as well as the lack of development of retail electric choice in the U.S., including Virginia. The General Assembly enacted HB 2453, which, *inter alia*, eliminated the January 1, 2001, deadline and prohibited utilities from transferring control of transmission to an RTO prior to July 1, 2004.
***Fuel*. To ensure that CSPs have sufficient advance knowledge of the "price to beat," establish fuel factors and wires charges well in advance of September 1 of each year.**	The 2002 Report does not propose to change the schedule for establishing fuel factors and wires charges, and the SCC has not adopted any changes in the schedule previously adopted in its wires charges and fuel factor orders.[5]

[5] Id., Final Order, dated November 19, 2001, at 27; Final Order, dated October 11, 2002, at 13; 2002 Report at 24 (explaining that the annual July 1 filing date for fuel factor applications and applications for wires charges for utilities wishing to impose them is to allow wires charges determinations to be "finalized" in October).

***Fuel.* Discontinue annual re-calculation of fuel factors and wires charges; consider fixing them for two or three years.**	While acknowledging that the proposal "may have merit," the 2002 Report stated that "it is unclear" that the proposal would "accomplish the goal of advancing competition" and further stated that legislation "appeared" to be required to allow a fuel factor to be set for more than one year.[6] The SCC in its order authorizing Virginia Power's 2003 fuel factor later rejected a proposal to "freeze" Virginia Power's fuel factor stating that the proceeding "did not encompass the notice required by § 56-249.6 prior to dispensing with the adjustable fuel factor"; however, the SCC noted that "such a fixed fuel factor may have certain merits, including increased judicial economies, changed incentives on the part of DVP, and increased electricity cost certainty for customers during the freeze period. As such we remain open to proposals of this nature."[7]
***Fuel.* Consider time-of-use fuel factors – *e.g.*, fuel factors that would vary by season – as an alternative to the use of single fuel factor as a means of "matching" more closely wholesale and retail prices, allowing CSPs more opportunities because their headroom during each season would be more closely tied to the wholesale market.**	The 2002 stated that the SCC "stands ready to investigate reasonable proposals that may provide improved regulated price signals," and it noted that, in a recent order, it encouraged a work group assisting Staff to study the possibility of utilities establishing (and/or expanding) voluntary time-of-use rate programs.[8]

[6] 2002 Report at 25. The report quotes from the provisions of Va. Code § 56-249.6, which requires each utility that purchases fuel for generation of electricity to submit to the Commission its estimate of fuel costs for the twelve-month period beginning on the date prescribed by the Commission and requires the Commission, upon investigation, to direct each company to put in place tariff provisions designed to recover the fuel costs determined by the Commission to be "reasonable for that period …" *But see* Va. Code § 56-582.B, which authorizes the Commission, "[n]otwithstanding § 56-249.6," to "authorize tariffs that include incentives designed to encourage an incumbent electric utility to reduce its fuel costs by permitting retention of a portion of cost savings resulting from fuel cost reductions or *by other methods determined by the Commission to be fair and reasonable to the utility and its customers*." (Emphasis added.)

[7] *Application of Virginia Electric and Power Company to revise its fuel factor pursuant to Va. Code § 56-249.6*, SCC Case No. PUE-2002-00377, Order Establishing 2003 Fuel Factor, dated October 16, 2002, at 5.

[8] 2002 Report at 42. The SCC also noted that it would be hesitant to reallocate fuel cost responsibility among rate classes in light of the Restructuring Act's capped rate provisions.

Transmission. **Obtain data on transmission constraints and load pockets for Virginia's utilities.**	The 2002 Report stated that, in accordance with § 56-578 G of the Restructuring Act, the SCC "would be responsible for monitoring market power over the sale of electric generating capacity or energy to retail customers." It noted, however, that, "to the extent that market power is exercised by a generating facility dispatching into a wholesale market, the mitigation of that market power will likely be the responsibility of the" FERC.[9] The Report stated that the SCC "will perform its statutory obligations under § 56-578 G with respect to market power exercised in Virginia's retail markets. In doing so, it might retain the use of a consultant." The 2002 Report also described the Energy Infrastructure Study underway pursuant to Senate Bill 684, which was enacted in the 2002 Session of the General Assembly and which required the SCC to convene a work group to "...study the feasibility, effectiveness, and value ..." of collecting information relative to energy infrastructure facilities, including electric transmission facilities.[10] The SCC's report of November 20, 2002, to the LTTF, submitted pursuant to SB 684, stated that "given the ongoing evolution of the electric utility industry and potential for significant jurisdictional shifts relative to the oversight of Virginia's generation/transmission reliability, it is "difficult to make absolute statements as to the *value/effectiveness* of collecting this information."[11] The report further stated that "basic information" relative to *generation* adequacy could be collected;

[9] 2002 Report at 64.
[10] Id., at 56.
[11] *Report to the Legislation Transition Task Force of the Virginia General Assembly: The Feasibility, Effectiveness, and Value of Collecting Data Pertaining to Virginia's Energy Infrastructure Pursuant to Senate Bill 6684 Enacted by the 2002 Session of the General Assembly of Virginia, dated November 20, 2002*, at 17.

	[d]ata relative to transmission facilities could also be provided if the need for more detailed information arises." The report stated that this "flexible approach may be more practical in the current environment and would certainly be less burdensome to those entities providing the information."
***Minimum Stay*. Permit customers that shop and return to the incumbent to pay the incumbent a market-based price, instead of capped rates, upon return in order to avoid the 12-month minimum stay requirement.**	The 2002 Report agreed that the proposal has merit, concluded that legislation may be required to implement it, and recommended that the General Assembly consider whether an amendment is needed to permit it.[12] (Legislation, SB 892, subsequently was introduced in the General Assembly but did not pass.)
***Demand side options*. Permit customers to receive, on a voluntary basis, more accurate price signals so that they may adjust their demand accordingly and receive market-based compensation for doing so.**	The 2002 Report does not adopt the recommendation.
***Generation*. Grant expeditious and favorable treatment to applications for the construction of new generation that will assist in the development of competition.**	The 2002 Report reviews the signing of the memorandum of agreement between the SCC and the Department of Environmental Quality regarding coordination of reviews of the environmental impact of electric generating plants and associated facilities. Since the report, the SCC has issued a number of orders approving the construction of additional generation in Virginia.[13]

[12] Report at 26, 65.

[13] See, for example, *Application CPV Cunningham Creek, LLC, For a certificate of convenience and necessity pursuant to Va. Code § 56-265.2 for an exemption from Chapter 10 of Title 56, and for interim authority to make financial expenditures*, SCC Case No. PUE-2001-00477, Final Order, dated October 7, 2002; *Application of Tenaska Virginia II Partners. L.P., For a certificate of convenience and necessity pursuant to Va. Code § 56-265.2, an exemption from Chapter 10 of Title 56, and interim approval to make financial commitments and undertake preliminary construction work*, SCC Case No. PUE-2001-00429, Final Order, dated January 9, 2003; *Application of CPV Warren, LLC, for a certificate of convenience and necessity for electric generation in Warren County, Virginia*, SCC Case No. PUE-2002- 00075, Final Order, dated March 13, 2003.

II. COMMENTS AND RESPONSES TO QUESTIONS

We address below the questions posed in your letter that appear to be of particular importance to the Committees.

1. ***What are the current obstacles to the development of a robust competitive retail electricity market for residential customers? For commercial and industrial customers? How can these obstacles be overcome?***

As indicated, the Committees' 2002 Comments identified and discussed key obstacles to the development of a robust competitive retail electricity market in Virginia. Obstacles included the lack of "headroom" for CSPs, transmission constraints, the adequacy of generation not owned by incumbents, and the lack of a regional transmission entity ("RTE" or "RTO"). Such obstacles remain. As indicated above, the Committees' 2002 Comments suggested a number of remedies for alleviating or removing them. With the possible exceptions of the working group on stranded costs, commenced pursuant to the LTTF's resolution of January 27, 2003, which has begun investigating that subject, and the recent orders granting approval to the construction of generation, none of the suggested remedies has been implemented.

Importantly, the Committees' 2002 Comments contended that the current methodology for the calculation of wires charges represents a significant obstacle for Virginia Power's customers and that that methodology is flawed because it requires would-be competitors to provide generation at retail prices significantly below prevailing wholesale prices. The comments urged the Commission to reconsider the legal conclusions on which the present methodology is based and adopt a new approach that would permit competition to develop.

In the Commission's 2002 Report, and in its Final Order, dated October 11, 2002, in the Wires Charges Case, the Commission reiterated its prior position that "revenue neutrality" is intended by the Act. Accordingly, it has left the current methodology essentially undisturbed.

The Committees recommended in their 2002 comments that if upon reconsideration the Commission reached the same legal conclusion, it should recommend amending the Restructuring Act to clarify that its discretion in determining the projected price of generation is not constrained by the goal of achieving "revenue neutrality." The Commission's 2002 Report, however, did not include such a recommendation. The Report instead suggested that wires charges be eliminated for large customers willing to forego their current right to return to the incumbent's capped rates upon terminating service with a competitive supplier. While the Commission's recommendation, if adopted, probably would have improved the outlook for competitive entry, no such legislation was enacted.

In a supplement to its 2002 Report, the Commission recommended that a decision by policymakers be made on whether customer choice should be suspended, along with Virginia utilities' then-existing obligations to join regional transmission entities. While the General

Assembly did not suspend customers' right to choose under the Restructuring Act, it did enact House Bill 2453, which amended the Act, among other things, by (i) eliminating the January 1, 2001, deadline by which incumbent electric utilities with transmission capacity were to join or establish an RTO; (ii) prohibiting such utilities from transferring ownership or control of, or operational responsibility over, any transmission system to any person prior to July 1, 2004; and (iii) modifying the standards to be applied by the Commission in approving such transfers.

Enactment of HB 2453 may delay RTO membership for Virginia utilities that have not already joined an RTO; it is unlikely to hasten the development of competition. Recommendations for suspension of customer choice will not do so. In sum, with the major obstacles identified by the Committees still in place, with few efforts underway to alleviate or remove them, and with enactment of HB 2453 and proposals for suspending the right to choose, the present absence of retail competition is likely to continue.

2. ***With respect to potential obstacles, what is the outlook for future natural gas prices and the impact on wholesale electricity prices and a competitive retail market? Please comment on the postulation by several natural gas industry experts of a growing structural demand/supply imbalance with demand outstripping supply over the next several years. What actions, if any, could be taken to mitigate the potential impact of an over-dependence on a single fuel source?***

The Committees have not prepared a projection of future natural gas prices; however, they are acutely aware of the recent increases and the views of some observers that a structural change in the natural gas market has occurred such that higher-than-historic prices can be expected in the future. Virginia's Restructuring Act does not provide for a remedy, other than market forces, for over-dependence upon a single fuel source.

3. ***In light of recent legislation, how can the Commonwealth be assured of a continuing reliable electricity system when control of transmission is governed by an RTO? What factors should be considered during the cost/benefit analysis required prior to Commission approval?***

The new Virginia legislation, House Bill 2453, requires the Commission to develop rules under which incumbent electric utilities owning, operating, controlling, or having an entitlement to transmission capacity in Virginia, may transfer control or ownership to an RTO upon such terms and conditions that the Commission determines are consistent with, among other things, "ensuring that consumers' needs for economic and reliable transmission are met."[14] The Commission's procedural order in response to AEP-Virginia's application to join the PJM

[14] Va. Code § 56-579.A.2.d.(i)

includes a number of requirements that address reliability issues.[15] The order also contains specific requirements for a cost/benefit analysis. The order represents a good start in fulfilling the Commission's revised responsibilities under the new legislation.

As a general matter, membership in an RTO should enhance reliability by easing access to generation sources across an entire region. For that reason, among others, utilities' membership in RTOs has been an important element in Virginia's Restructuring Act.[16]

4. ***Later this month, the Federal Energy Regulatory Commission is expected to issue its "white paper" addressing certain issues debated the past several months regarding Wholesale Electric Standard Market Design (SMD). Additionally, the Department of Energy is expected to issue the results of its cost/benefit analyses of the impacts of SMD. Please provide your initial thoughts and reaction to such releases and identify any significant issues of concern.***

The Committees have not taken a position on the recent "white paper" or reviewed the Department of Energy analysis.

5. ***Are the Commission's Rules Governing Retail Access to Competitive Energy Services conducive to promoting effective competition in the Commonwealth? If not, how should they be modified? Is there any way in which these rules can or should be improved, in any event?***

The Committees have no suggestions at this time for changes in the Commission's Rules Governing Retail Access to Competitive Energy Services.

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[15] *Commonwealth of Virginia At the Relation of the State Corporation Commission Ex Parte: In the matter concerning the application of Appalachian Power Company (d/b/a American Electric Power – Virginia) for approval of a plan to transfer functional and operational control of certain transmission facilities to a regional transmission entity*, SCC Case No. PUE-2000-00550, Order for Notice, dated March 7, 2003, at 11; *see also*, 20VAC5-320-40.

[16] We note that the Federal Energy Regulatory Commission's ("FERC's") recently issued "white paper" in its standard market design rulemaking proceeding addressed resource adequacy and transmission planning. It states that "nothing in the Final Rule will change state authority over these matters [referring to resource adequacy requirement and the regional transmission planning requirement in the proposed standard market design]." *Remedying Undue Discrimination through Open Access Transmission Service and Standard Electricity Market Design*, FERC Docket No. RM01-12-000, White Paper, Wholesale Power Market Platform, issued April 28, 2003, at http://www.ferc.gov. According to the white paper, the RTO or ISO may implement a resource adequacy program "only where a state (or states) asks it to do so, or where a state does not act." (Id.) The white paper states that RTOs and ISOs will be directed to develop a periodic regional transmission plan *for submission to relevant state and local siting authorities* and *to assist* states in whatever manner they desire, including evaluating the impact of new generation, transmission, energy efficiency and demand response on regional reliability and resources adequacy. (Id.) (Emphasis added.)

6. ***What should be the level of consumer education when the program is resumed on July 1, 2004? Should it be as visible, more visible or less visible than when the campaign was suspended? Upon resumption of the campaign, what focus, theme or message should be communicated? Since TV advertising is the most expensive component of the program, what level of TV advertising should be included in the resumption of the campaign?***

The Committees recommend that the consumer education program be less visible until competitive entry of retail suppliers has real prospects to develop in Virginia. No such prospects exist today.

7. ***Are there any other actions that have been taken or are being considered in other states that may be used to advance competitive activity in Virginia?***

See the Committees' response to question 1.

8. ***Do you have any ideas that have not been tried elsewhere that may facilitate competitive activity in Virginia?***

See the Committees' response to question 1.

III. CONCLUSION

The Committees appreciate the opportunity to comment, and they look forward to continuing to assist the Commission in its response to the mandate contained in Va. Code § 56-596.B.

Sincerely,

Louis R. Monacell

Edward L. Petrini

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May 23, 2003

Mr. David R. Eichenlaub
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State Corporation Commission
Division of Economics and Finance
1300 E. Main Street
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VIA EMAIL

Dear Mr. Eichenlaub:

The comments of Virginia Energy Providers Association (VEPA) in response to your letter of April 16, 2003 follow.

In addition, we do plan to attend the June 6th informal discussion on the development of competition.

Very truly yours,

/s/

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vep0523a

Comments of Virginia Energy Providers Association (VEPA)

May 23, 2003

VEPA continues to observe that the most significant obstacle to the development of robust competition in Virginia is the delay of Virginia's incumbent electric utilities in gaining state approval to join an approved Regional Transmission Organization (RTO) to serve wholesale markets, ultimately to the benefit of retail customers. Without the participation of Virginia's incumbent utilities in a fully functioning, truly independent, unbiased regional transmission organization, effective wholesale competition can not develop. And without effective wholesale competition, retail competition is impossible.

Since the Commission's last annual report on competition, a vigorous national debate has occurred involving the Federal Energy Regulatory Commission's (FERC) proposed Standardized Market Design (SMD). FERC's vision of SMD is to encourage electric utilities to combine their high-voltage transmission systems into regional and super-regional power grids operating with standardized rules and procedures. FERC's proposed rules, however, generated considerable opposition from some Western and Southern states, leading FERC to announce recently that it will wait until after the federal Congress adopts pending energy legislation before finalizing its SMD approach.

VEPA's primary suggestion, therefore, is for the SCC to work cooperatively with neighboring states in the region and with FERC to resolve all issues in dispute, so that a satisfactory market design can be agreed to, leading to the entry of our incumbent utilities into regional transmission organizations as quickly as possible. This approach, reflected in FERC's recent "White Paper," can be used to address state and regional issues and to provide additional local implementation flexibility, where necessary.

Particularly important is the need for FERC and the states to work cooperatively to establish clear and definite agreements on jurisdictional responsibilities, so that wholesale restructuring under federal supervision and retail policies of the states are coordinated to yield clear benefits to wholesale and retail customers. RTOs with responsibility for administering both transmission service and standard market rules within regions are necessary to support the investment in and provision of efficient and advanced electric infrastructure and services, efficient development and use of energy resources, and lowest cost of supply to consumers in the long run.

VEPA urges the Commission and the Commonwealth to support development of a standard market design in Virginia and this region that includes the following elements, at a minimum:

- A congestion management system using both day-ahead and real-time Locational Marginal Prices (LMPs) and financial congestion charges.

- Flexible financial tools which allow hedging of day-ahead congestion charges, and a mechanism for getting those tools into the hands of market participants in order to promote an open, transparent and liquid market.
- Stable capacity requirements to assure the existence of reliable levels of capacity over the long run.
- Economically efficient demand response programs in all appropriate markets.

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