Review of FERC's Proposed Standard Market Design and Potential Risks to Electric Service in Virginia

Addendum to 2002 Status Report on Competition

Prepared by the
State Corporation Commission

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January 3, 2003

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

The Honorable Thomas K. Norment, Jr.
Member, Senate of Virginia
Chairman, Legislative Transition Task Force

Members of the Legislative Transition Task Force

As required by the Virginia Electric Utility Restructuring Act (§ 56-579 C of the Code of Virginia), the State Corporation Commission ("Commission") is participating in proceedings of the Federal Energy Regulatory Commission ("FERC") concerning regional transmission entities ("RTEs").

On July 31, 2002, the FERC issued a notice of proposed rule making regarding a standard market design ("SMD") by which RTEs would operate. The potential impact on the Commonwealth is significant. The Commission has analyzed the proposed SMD, and our comments will be submitted to the FERC on January 10, 2003.

We would also note that the Legislative Transition Task Force ("LTTF") has focused much of its 2002 activities on RTEs. Specifically, the LTTF (along with its Consumer Advisory Board) has received presentations from Dominion Virginia Power and American Electric Power concerning their proposed plans to join the PJM RTE. These two presentations resulted in considerable LTTF interest in PJM's locational marginal pricing mechanism (LMP) and its potential impact on the prices Virginians pay for electric service. Subsequently, a PJM representative provided an overview of the PJM model, as well as information about LMP. Additionally, the Commission's Staff, at the request of the LTTF, presented an analysis of how LMP operates within the PJM RTE model at the LTTF's December 12, 2002, meeting. This LTTF scrutiny coincides with an intense national debate over LMP and other key ingredients of FERC's SMD.

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At the heart of this controversy triggered by the SMD is whether its adoption by the FERC as promulgated could result in states' involuntary (or possibly inadvertent) loss of day-to-day authority over the price and reliability of electric service for their citizens.

In light of these critical developments on the national level and the LTTF's timely focus on them, the Commission wishes to supplement its August 30, 2002, status report. The attached paper assesses the potential risks associated with continuing or delaying electric restructuring in Virginia in light of the FERC's proposed standard market design.

As always, the Commission and its Staff are prepared to answer any questions you may have regarding this report.

Respectfully submitted,

Clinton Miller
Chairman

Theodore V. Morrison, Jr.
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cc: Members, Senate of Virginia
Members, Virginia House of Delegates

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Executive Summary

Recent developments impacting electric industry restructuring in Virginia may seriously affect the Commonwealth's ability to protect electricity consumers. The impact is of such significance, state policymakers should decide promptly whether to proceed with or delay implementation of the Virginia Electric Utility Restructuring Act ("Act").

The development of greatest import is the July 31, 2002, issuance of a notice of proposed rule making by the Federal Energy Regulatory Commission ("FERC"). The FERC's proposed Standard Market Design ("SMD NOPR" or "SMD") appears to be a "watershed event" for Virginia's electric industry. It also threatens the state's ability to assure reliable service at stable and reasonable rates.

Other crucial developments include the worsening financial distress being experienced by utilities subject to restructuring, by merchant generators, and by competitive retail suppliers. Also, retail electric choice is stalled or not developing in almost all of the United States, including Virginia.

The State Corporation Commission ("Commission" or "SCC") has aggressively implemented the Virginia Act as adopted by the General Assembly in 1999 and subsequent amendments made in 2000, 2001, and 2002. The FERC SMD, if adopted as proposed, would have a profound impact on restructuring actions the SCC has already taken and may take in the future.

In reviewing FERC's proposal, the SCC is very concerned with the bedrock issues of service adequacy and service prices likely to be available to Virginia. If the FERC implements the proposed SMD or something similar to it, the industry – including that in Virginia – will be radically altered.

The possibility is more acute for the Commonwealth because the Act required the unbundling of electric service into its three primary components –

generation, transmission and delivery. This has been done for Virginia's investor-owned utilities and electric cooperatives.

The Act also requires Virginia's utilities to join regional transmission entities ("RTEs"), and, with prior approval of the SCC, to transfer control of their transmission systems to an RTE.

Currently in Virginia, consumers of electricity have first priority to be served by the generation and transmission facilities that they have bought and continue to pay for through existing rates. FERC believes that this favoring of native load customers is discriminatory and damages wholesale electric markets. The FERC SMD seeks to eliminate the native load preference.

This means, on the hottest and/or coldest days of the year, or whenever some event threatens the integrity of the regional electric transmission system, Virginians could experience service interruptions to make sure the lights stay on somewhere else in the multi-state region which includes Virginia. This could occur even though there is adequate generation and transmission located in Virginia to serve them.

FERC believes that market-based price signals will do a better job of determining where and when generation and transmission facilities need to be built. However, the current generation and transmission regional infrastructure, including facilities built to serve Virginia, was not designed to support a competitive market.

The FERC also believes that, ultimately, competition may regulate the reliability and price of electricity. Federal regulators, however, have concluded that the market cannot now perform this function without substantial mitigation and oversight.

Nonetheless, the proposed FERC SMD includes a regional market pricing mechanism that may allow a generation entity with market power to charge exorbitant rates unless its market power can be identified and corrected in a timely manner. The ability of the FERC to monitor potential market abuses and correct them has been questioned in the past.

Under the FERC's proposed market mechanism, the spot price for electricity at any given point in time will be determined using bids submitted by available generators throughout the region. When transmission is constrained, FERC proposes to implement limits that may be based on the cost of the last generation unit required to serve the load in the constrained area.

Certain areas of Virginia may find themselves in load pockets that cannot be served by the full array of generators in the regional market. Thus, any owner of generation in an isolated pocket could exert market power and demand prices that may prove to be unjust and unreasonable. Without sufficient market monitoring and mitigation, abuses could drive prices up in ways similar to those experienced in California and the mid-west.

Even if the highest bid price submitted to provide power in a load pocket is warranted, it could be higher than the average blended rate Virginians currently enjoy in this relatively low-cost electricity state. An electric cooperative serving Virginia's Eastern Shore has, to a degree, already experienced the financial costs of a similar pricing mechanism that is currently used by an RTE serving Pennsylvania, New Jersey and Maryland.

Under the FERC SMD proposal, Virginia cannot ensure the same price and reliability protection it can at present. Rates could unnecessarily increase and there could be service interruptions that would not occur today.

The proposed SMD impacts all states. It applies to retail choice states with utilities that have transferred control of their transmission systems to a FERC-regulated RTE <u>and</u> to states that have decided not to move to retail choice.

This second group, including North Carolina and most other southern states, will almost certainly mount a judicial challenge to the FERC's authority to impose the SMD on them. In addition, it is highly likely that the 2003 Congress will have before it legislation that will prohibit the FERC from imposing the SMD on states that do not want their utilities to participate in the federal proposal. Also, the FERC itself, in response to mounting criticism, might alter the proposed SMD to allow states to decide whether their utilities will be part of the new SMD.

For the FERC SMD not to apply to Virginia on a mandatory basis, two things must happen. First, as a result of court, congressional, or FERC action, the states must have the opportunity to decide whether their utilities will comply with the requirements of the SMD, including the proposed requirement to have an independent entity operate their utilities' transmission facilities. Second, the Commonwealth must decide that Virginia utilities should not now be part of the proposed federal plan.

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.

If allowed, the Commonwealth could wait until FERC has finalized its rules and regulations. Once the new regime has had an opportunity to prove itself, Virginia could then make an informed choice about transferring jurisdiction from the Commonwealth to the FERC.

Since there are no offers currently being marketed in Virginia, delay should have no significant impact. Merchant plants already planning to construct power plants in Virginia to sell into the wholesale market will continue to have that opportunity.

The steps Virginia has already taken toward retail choice will not be lost. Instead, Virginia will be in a position to implement choice again quickly once it is determined that retail competition does ensure adequate reliability and reasonable prices for all Virginians.

Purpose of this Paper

Over the past few months there have been significant developments that are impacting electric industry restructuring in Virginia. These developments have been predominately national events affecting various components of the electric power industry in historic proportions. The July 31, 2002 issuance of the Notice of Proposed Rulemaking on Standard Market Design[1] by the Federal Energy Regulatory Commission appears to be a "watershed" event for the industry. Other crucial developments have been the continuation and worsening of substantial financial distress among a large number of members in important industry sectors including integrated utilities, merchant generation developers, and competitive suppliers of retail energy services. Also, retail electric service competitive penetration, especially for residential customers, is lessening or not developing in almost all of the U.S., including Virginia.

This paper explores these issues and reviews certain risks associated with continuing restructuring or temporarily suspending the movement to retail choice in the Commonwealth. To place current events in perspective, the paper begins with a brief review of the electric utility industry in Virginia before restructuring, the state's restructuring statutes, and their implementation to date. Next there is a detailed discussion of crucial aspects of the SMD NOPR and issues related to the operation and efficiency of the U. S. bulk transmission system. Next, the paper discusses the current financial distress of the many sectors of the electric power industry. This provides a link to events in Virginia related to industry restructuring and retail choice implementation around the country. Finally, there is a risk assessment of potential future restructuring actions Virginia might take in light of these developments.

The next several years will be critical for Virginia's electric industry. It may be that the FERC SMD is adopted substantially as proposed, and the FERC's actions are upheld by the federal courts. If so, the impact on Virginia will be as discussed in this paper, and Virginia's choices will be severely limited.

On the other hand, the Congress, the federal courts, or the FERC itself in response to rising criticism, could allow states to determine their own path. Virginia might well have the opportunity to decide whether the Commonwealth will be part of the regulatory system envisioned by the FERC's Standard Market Design. This choice will, however, be possible only if Virginia's utilities are not sufficiently tied to the federal regulatory system through, for example, transfer of control of their transmission systems to a FERC regulated entity.

Since Virginia's initial decision to move to retail choice was made in 1999, significant recent events have occurred that may cause decision-makers to decide to suspend implementation of parts of the program. Such a suspension could allow the Commonwealth the opportunity to determine whether Virginia should be a part of the new federal regulatory system and whether retail choice should continue at this time. The purpose of this paper is to provide information to decision makers to aid in the decisions that must be made at this time.

Summary of Restructuring Events

The primary factors and conclusions discussed in this paper are included directly below as a summary:

Events Related to FERC Actions

- Should the SMD NOPR be implemented as proposed by the FERC, the action of federal energy regulators will impact the price and reliability of electricity in Virginia.

- If the FERC's jurisdiction over transmission impacts the price and reliability of electric service in Virginia, the Commonwealth will no longer be able to assure reliable service at stable and reasonable rates as it can at present.

- The FERC recognizes that the market, standing alone, will not adequately regulate reliability or price at this time; hence, the FERC has proposed far-reaching market power mitigation, monitoring, and resource requirements.

- FERC's SMD NOPR is based on large regions and provides that transmission shortfalls may be shared on a *pro rata* basis. As a result, even if Virginia has sufficient generation and transmission to serve her citizens, consumers in the Commonwealth could be curtailed and lose service.

- FERC's pricing proposal is based on market supply and demand concepts, including higher prices when supply is scarce, and thus could increase rates to Virginia citizens.

Events Related to Industry Financial Distress

- Restructuring, and the turmoil surrounding it, have resulted in great financial harm to a number of holding companies and their utility subsidiaries including at least one serving Virginia, Allegheny Energy and its Virginia subsidiary, The Potomac Edison Company.

- Traditional regulated integrated utilities (especially those that refrained from extensive wholesale trading activities) are seen by the rating agencies as the strongest.

- Nearly 180,000 MWs of planned new capacity were canceled or tabled between January 2002 and July 2002. A number of competitive service providers ("CSPs") have also exited the market this year.

The Status of Retail Competition in the U.S.

- Retail competition is not successful in most areas of the nation.

- Nine of 17 states (and the District of Columbia) with residential retail choice have no offers below the incumbents' rates. In several other states, only one utility faces such offers.

- Since 1999 when Virginia adopted restructuring legislation, only the District of Columbia, Michigan and Arkansas have adopted restructuring and Arkansas has since delayed implementation.

- Eight states have delayed, abandoned, or severely limited retail choice since 1999.

- While a failure in Virginia is unlikely to yield California-like results, California demonstrated that if retail competition does not function properly, there can be severe consequences.

Events Related to Virginia's Competitive Market

- Retail competition is not functioning in Virginia.
    - No offers of any kind are currently being marketed in Virginia.
    - Only three entities can currently make offers in Virginia; two are affiliates of Virginia incumbent utilities.
- A number of merchant plants, totaling thousands of MWs of generation, have been delayed or abandoned in Virginia this year.
- The number of entities that can make competitive offers is diminishing in Virginia and the rest of the nation as such entities face bankruptcy, merge, or simply go out of business.

Virginia's Electric Utility Industry before Restructuring

Prior to restructuring, in order to ensure safe, reliable and adequate service at reasonable costs to consumers, electric utilities and their shareholders were afforded a relatively secure opportunity to earn a reasonable return on their investment. In return, utilities had the obligation to provide safe and reliable electric service to all customers in a designated franchise area at regulated rates. Price ("rate of return" or "cost of service") regulation and entry regulation were the means to that end. This form of industry organization requires a single provider of electricity to serve all customers in a given service territory at regulated rates that equal the full economic cost of providing that service. Utilities planned and provided generation and transmission together to optimize the system with the lowest cost consistent with high reliability.

This structure, basically in place since the early part of the last century, led to well documented industry performance upon which current restructuring efforts seek to improve. Under this system, with rare exceptions, electric utilities across the nation delivered almost 100% reliable electric service at stable rates.

In Virginia specifically, service was not only reliable with stable prices, but rates were below the national average. For example, the average rate per kWh for electric service in Virginia in 1998 (the year before restructuring) was approximately 7.7¢ per kWh for residential consumers and 3.9¢ per kWh for industrial users. This was below the national average rate at that time, 8.8¢ for residential customers and 4.7¢ for industrial users. Moreover, two Virginia utilities (AEP-VA and Old Dominion Power Co.) serving about 450,000 residential customers in western Virginia, had average residential rates of 5.7¢ and 5.0¢ respectively, well below the national average rate of 8.8¢ per kWh, placing them among the least costly electric service providers in the nation. Industrial rates for Virginia's two largest utilities, AEP-VA and Dominion Virginia Power, were 3.6¢ and 4.0¢ respectively, well below the national average of 4.7¢.[2]

Virginia Electric Utility Restructuring Act

The Virginia Electric Utility Restructuring Act seeks to benefit the Commonwealth by changing the way electricity is purchased by Virginia's electricity consumers. Rather than requiring customers to purchase their electricity needs from an integrated utility functioning as a regulated monopoly, the Act allows customers to choose their provider. After the transition, it was envisioned that price, service adequacy, and service quality would be determined by the workings of a free market. In other words, competition would "regulate" the price and reliability of electric service.

To this end the Act, among a host of other requirements, reduced the regulation of electric generation in Virginia after January 1, 2002, required a separation of formerly bundled electric service into their generation, transmission and distribution functional components, and established capped rates and associated wires charges during a transition period that could last until July 1, 2007. Rates were capped at the level in effect when the Act was adopted in 1999.[3] The wires charge allows the incumbent utility to receive from a customer who purchases generation from a third party, an amount equal to the difference between the capped rate for generation and the market price for generation, if such price is below the incumbent's capped rate for generation. Thus, the incumbent utility should receive the same revenue from each kWh sold as long as the rate cap and wires charge continue. The wires charge and rate caps are the means by which Virginia's incumbent utilities can recover just and reasonable net stranded costs.[4] In providing for wires charges as well as the possibility that incumbent electric utilities be permitted to discount capped generation rates,[5] it apparently was envisioned that rate competition could well be in a range below the capped generation rates established pursuant to § 56-583 A.

The Act also provides that incumbent electric utilities should be a part of a regional transmission entity and transfer ownership or control of their transmission system to an RTE after obtaining the approval of the transfer from the Commission.[6] In addition, the General Assembly has recognized that the implementation of the Act would be a "work in progress" and that adjustments might have to be made through time. Indeed, several adjustments have been made to the Act since it was passed by the General Assembly in 1999.

<u>Implementing the Act</u>

Since its passage in 1999, the Commission has been tasked with implementing the Act as amended by the General Assembly. A record of the numerous proceedings, workgroups, studies and reports conducted or produced by the SCC and its Staff are described in great detail in the SCC's reports to the Legislative Transition Task Force ("LTTF").[7]

Pilot choice programs were established[8] and, as provided in the Act, the Commission provided for "choice" to be phased in over two years beginning January 1, 2002.[9] Currently, approximately 2.2 million Virginia customers can choose their electricity provider. By January 1, 2003, all customers in Virginia will be able to choose their electric supplier except for 11 of Virginia's 13 cooperatives and the 30,000 customers of Old Dominion Power Company (which must phase in retail choice by January 1, 2004). Thus, about 3 million of Virginia's 3.1 million electricity consumers will be able to choose their supplier by January of 2003.

Although the Act requires each incumbent utility to join an RTE by January 1, 2001, Virginia's two largest utilities have yet to become functioning members of such an entity. AEP-VA and Dominion Virginia Power initially attempted, along with a number of other utilities, to create a new RTE, the Alliance. This venture failed when it was rejected by the FERC following several years of unsuccessful evolution.[10] Both utilities now seek to become special members of PJM, an RTE serving the mid-Atlantic area.[11] AEP-VA has only recently filed its application with the SCC to transfer control of its transmission system to PJM. Dominion Virginia Power has not yet filed such an application.

The separation of generation, transmission, and distribution was approved by the Commission for all utilities.[12] For the two largest incumbents in Virginia, AEP-VA and Dominion Virginia Power, the separation was accomplished functionally by divisions rather than actually transferring ownership of generation plants to separate corporate entities, either affiliated with the incumbents or not.[13]

The FERC and the SMD NOPR

On July 31, 2002, the FERC issued its SMD NOPR. Based on the NOPR, it is clear that federal regulators have concluded that currently competitive forces, standing alone, will not effectively regulate rates or provide adequate reliability.[14] The FERC has determined that substantial market intervention will be required. As a result, FERC is preparing to impose pervasive new regulations.

In examining FERC's actions and their potential impact on Virginia, it is important to identify the two main problems FERC's actions are designed to remedy and examine the causes of these problems. The first fundamental problem involves certain behaviors by transmission providers; the second fundamental problem is market power.

Protection of Native Load Customers by Transmission Providers

The first 100 or so paragraphs of the SMD NOPR list the circumstances that caused the FERC to promulgate the SMD NOPR. These paragraphs assert that incumbent electric utilities that are also transmission providers may have engaged in inappropriate behaviors. These behaviors have the effect of providing native load customers of integrated utilities with priority transmission services that enhance the reliability of that service while potentially restricting the amount of transmission service available to facilitate wholesale sales of electric power by third parties. In short, electric utilities that operate their systems to give priority to their native load customers by, among other things, reserving a reliability enhancing safety margin for those customers, remove some transmission capacity from the wholesale market. The SMD NOPR seeks to make more transmission capacity available for third parties' wholesale sales by ending the current preference enjoyed by native load customers.

There is a particular set of transmission provider behaviors that illustrate this issue. These behaviors involve certain allegedly inappropriate advantages conveyed by transmission providing integrated utilities to their native load customers. For example, SMD NOPR Paragraphs 69 and 70 state:

> 69. Four prominent examples highlight the alleged advantages that a public utility's bundled retail customers have over wholesale and unbundled retail customers. First, certain reliability practices related to keeping the transmission system balanced may allow a public utility that is responsible for keeping generation and load in balance to obtain lower costs for its own power customers. Second, a transmission-owning public utility may have more de facto flexibility to designate transmission receipt and delivery points than other transmission customers, if that public utility also provides power to customers on its transmission system. Third, the bundled retail customers of a transmission owner may have certain transmission reservation and pricing advantages regarding transmission transfer capability set aside for reliability. Fourth, state transmission curtailment rules that favor a public utility's bundled retail customers

> may conflict with the Commission's [the FERC's] transmission curtailment rules, resulting in a transmission preference to customers in one state over customers served in other states. The first three of these were summarized above, and a detailed discussion with examples is set forth in Appendix C. (footnote omitted)
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> 70. The requirement for all services on the transmission grid to be taken under a common set of rates, terms and conditions will resolve these concerns.

As can be seen, the FERC intends through the SMD NOPR to eliminate the preference for native load customers of integrated electric utilities. The SMD NOPR has not been uniformly received around the country. In states that have restructured, mainly in the mid-west and northeast, the SMD NOPR has been relatively well received as a "tremendous step in the right direction,"[15] although even these states have a number of suggestions and concerns.[16] Other states, particularly in the south and west, have strongly opposed the SMD NOPR;[17] a number of state regulatory commissions believe that preference for native load customers are required by state law and are, in fact, in the public interest. In addition, a number of conservative organizations and individuals, who normally support market solutions, have strongly opposed the SMD NOPR.[18]

The impact of the SMD NOPR on Virginia could be far reaching. For example, 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.

Under the FERC proposal, the goal is to make wholesale markets work more efficiently. To this end, even though Virginians may have paid for --- or are currently paying for --- the generation and transmission that serve their load, Virginians could be impacted significantly in the event that transmission transactions in the region cannot be accommodated by the existing transmission system. First, under the SMD NOPR, available transmission service could cost substantially more because of congestion charges and insufficient allocation of Congestion Revenue Rights ("CRRs"). In addition, if all else fails, transmission curtailments will be on a *pro rata* basis. Under the SMD NOPR, Virginians will not be protected with respect to rates or reliability as they are today.[19]

In simplest terms, this crucial issue can be expressed as follows: FERC believes that practices that favor native load customers are undue discrimination, damage wholesale electric markets, and must be stopped. Others, including many state regulatory commissions in the southern and western U. S., believe such preferences constitute due discrimination, are consistent with state law, and are in the public interest because rate and reliability benefits flow to the customers who have, through time, paid for the transmission system.

Market Power

The second fundamental problem driving FERC's SMD NOPR is market power. While there may be discord surrounding the issue of the appropriateness of transmission preferences for native load customers, there is general agreement that market power needs to be addressed. An entity with market power can charge monopoly or oligopoly prices. Market power can occur even though the market as a whole may be competitive for most areas during the majority of the time. If a particular geographic area does not have sufficient sources of power in the area through generation located there or available to it through enough transmission to support competition, then those who have the available electricity have the market power to charge monopoly rates. These areas are often called load pockets. It is important to note that there may well be, and under regulation almost always has been, sufficient power to serve all loads at all times. There may not, however, be sufficient power to support effective competition.

A simple example demonstrates the problem. If an area has a peak demand of 80 MW on the hottest summer afternoon, and the capacity to serve the area through local generation and transmission from outside is 95 MW, then the area has adequate supply to meet the demand. If, however, one supplier owns or controls at least 25 MWs of generation in the area, that entity would have market power at certain times. If the demand in the area is, say, 50 MW, there may be a sufficient number of sellers for the competitive market to regulate the price. But, once demand reaches the point where the 25 MW unit "must run" to serve a load of 75 MW, the entity that controls the 25 MWs can charge what it wants because without the 25 MWs a blackout may occur. There is no competition at that point.

The demand for electricity is relatively inelastic and it cannot be stored. These facts and the location and size of various generating and transmission facilities create the market power problem. The vast majority of generating plants and all of the current transmission lines were planned and constructed by incumbent utilities when electricity was fully regulated. The goal was to build a combination of plants and transmission lines that would best serve their franchised areas reliably at reasonable rates. The example above does just that. The expected peak is 80 MWs and the area can produce or receive up to 95 MW of power; the expected load could be served with an 18%+ reserve margin. The extra generation or transmission capacity that would be necessary to support competition would be wasteful under regulation because the authorized rates would be designed to provide a reasonable, but limited, return.

Market power problems can occur in markets for energy, capacity, ancillary services, and related or derivative products.[20] The market power problems caused by "load pockets" and "must run" units are complex, dynamic, and pervasive. Relatively isolated areas, such as the Delmarva peninsula, are load pockets, but other larger areas, including a utility's entire service territory, such as Dominion Virginia Power, may also be load pockets at certain times. Ownership concentration can have significant impacts on market power problems associated with load pockets. The number, size, and configuration of load pockets change constantly. The problem affects almost every area and every utility at some point. Obviously, the problem is most severe when demand is at its highest, such as a hot summer or cold winter day.

If a competitive market is to regulate the price and reliability of electricity, there must be capacity through generation and transmission sufficient not only to serve load, but to allow many sellers to provide service to many buyers. The FERC's SMD NOPR makes clear that price and reliability will be considered on a regional, rather than a state basis, and will seek, through price signals, to encourage the construction of the necessary additional generation and transmission facilities to allow competition to work.[21] The current generation and transmission infrastructure throughout the country, including Virginia, was not designed to support a competitive market, but rather to serve the load in a regulated monopoly system.

The FERC has recognized in the SMD NOPR that, unless and until new generation and transmission facilities are available to allow competitive forces to regulate the price and reliability of electric power, there must be significant government regulation. As noted above, the FERC has concluded that the market cannot currently discipline power prices or ensure reliability.

At least in the near term --- and quite possibly in the longer term as well --- the performance of a restructured electricity "market" under the SMD will largely depend on how markets are monitored and how initial results are changed by mitigating actions of the market monitor. Given that the FERC has recognized the importance of market monitoring and devoted a substantial portion of the SMD NOPR[22] to its discussion, it is not surprising that market monitoring has been and continues to be among the most crucial and controversial restructuring issues. In fact, one's expectation about the efficacy of future market monitoring efforts may well determine that stakeholder's overall opinion regarding this important public policy issue. The SMD NOPR envisions a market monitoring function that resides at the RTE and is responsible to both the independent governing board of the RTE and the FERC. As of this writing, the SMD NOPR vision for market monitoring is still quite general in nature, and will likely evolve as the NOPR process moves forward. As market monitoring is one of electric restructuring's pivotal issues, that evolution will be critical.

Unfortunately, there are reasons to doubt the ability of future market monitoring efforts to ensure good industry performance. First, the task itself is extremely complex. The number of market participants and the number of geographical and product markets requiring monitoring are astounding. Second, the ability of the FERC to oversee RTE market monitoring efforts is questionable at best, although FERC has recently revamped its organization in an attempt to beef up its market monitoring capabilities.[23] Third, there is substantial debate about how the market monitoring function should be incorporated into an RTE's organizational structure and how the market monitor will relate to the FERC. Finally, even if all of the concerns about organizational structure and scope of task could be resolved, important legitimate differences remain concerning when markets need mitigation and what constitutes appropriate mitigation.[24]

This Commission is very concerned with the bedrock issues of service adequacy and service prices likely to be available to Virginia under the FERC's proposal. As described in this paper, the proposed new FERC structure will hinder Virginia's ability to ensure adequate service at reasonable prices.[25] Note that it does not matter if the FERC is correct in its policy prescription. If the FERC promulgates the SMD, or something similar to it, the industry --- including that in Virginia --- will be radically altered if it is part of an RTE regulated by the FERC or the FERC otherwise has jurisdiction over the transmission component of retail service.

Locational Marginal Price ("LMP")

Another area of substantial concern centers on the SMD NOPR's pricing mechanism for transmission congestion and spot energy markets. In the current system, rates are based on average costs by customer class and do not vary geographically within the boundary of the utility's service territory. This is true even though there may be substantial differences in the costs of serving customers due to customer location. Some customers might be located near, and be served from, low cost resources, some next to high cost resources; some might be in an area with substantial transmission access and some may be in load pockets. Historically, the electric utility sought to deploy resources in a manner that minimized the total cost of serving load. The system was built with the goal of having generating stations of varying fixed and operating costs connected to customers (and each other) by transmission circuits of finite, rather than infinite, capacities. Until generation and transmission facilities are greatly expanded, substantial congestion will result, creating market power in a competitive environment.

The FERC's answer to the problems created by the impact of transmission congestion on the prices ultimately paid by consumers is a system of locational marginal prices that result from spot energy bids made to sell and buy power at each of many definable locations on a transmission system. In theory, the many buyers and sellers come together and determine the hourly value, and thus price, of electricity at each location on the system. The difference in prices between two locations at any given hour is a measure of the value of transmission congestion between those two locations and supposedly provides the appropriate incentive for market participants to deal with that congestion.[26] Since LMP is based on bids, not costs, sellers with market power can raise LMP prices to unjust and unreasonable levels. While LMP applies to the spot market, it will impact bilateral transactions as well. Bilateral buyers and sellers must take into account the possible effects of LMP (in the form of congestion costs) when entering into contracts. LMP could provide upward pressure on prices for bilateral contracts, especially in constrained areas.

LMP pricing can also have even greater negative implications for areas that do have sufficient generation when that generation is more costly than other sources that may be imported via the transmission system. If requests for imports exceed the available transmission capacity, the LMP system would consider the transmission system to be "constrained" and accordingly price all spot transactions as if there were no import capacity. During such constrained periods, a generation owner could effectively establish higher prices by withholding a lower cost unit if that owner holds a significant share of generation behind the constraint. The generation owner may find such action to be beneficial if the withholding of a single unit causes its other generation to be "re-priced" at a higher LMP.

The FERC's solution for these problems is to limit submitted bids where market monitoring indicates a limit is necessary. FERC suggests a series of limits, one of which is based on the cost of the last unit required to serve the load in the area impacted by the congestion. Disregarding whether this solution is reasonable or fair, monitoring and enforcing the limit will require a monumental effort. Almost every generation plant in the nation may be the one to set the price in their location at some time. Identifying the plant and determining the actual cost of producing the power from each of many thousands of plants must be monitored to avoid abuses. It is unclear how, or even whether, such monitoring can be done effectively. If market monitoring is not effective, abuses can drive prices up in ways similar to what occurred in California and the mid-west.

Resource Adequacy

The FERC also believes that in certain circumstances LMP price determination may not yield prices high enough to foster sufficient investment in generation or transmission.[27] This necessitates the resource adequacy requirement included in the SMD NOPR which would require the RTE to perform a demand forecast to seek to ensure adequate generation and apportion resource obligations among those entities serving load on the basis of the ratio of their loads.[28] In other words, adequacy would be established on a regional basis by an entity regulated by the FERC.[29] As a result, if Virginia has adequate generation and transmission for its own needs, it could not effectively use it to protect Virginia customers. Any shortfall might be shared throughout the region.[30] In FERC's view, these actions would eliminate what the FERC considers undue discrimination in favor of native load customers and allow for better performance of wholesale electric markets.

With respect to expansion of the transmission system, the FERC believes that substantial amounts of new transmission facilities are required (in excess of what is needed for reliability) so that the market can become competitive.[31] One of the major issues in the SMD NOPR is how to pay the billions of dollars this will cost. Certain groups suggest that the cost should be socialized by having everyone share the cost. Others argue that only those who "benefit" from the new lines should pay.[32] Either way, consumers will ultimately have to pay for new lines.

Overall Efficacy of the FERC's Initiative

Needless to say, there are tremendous costs to the actions the FERC has taken to date and to what is proposed in the SMD NOPR. These "costs" fall in several categories. First, there are the direct dollar costs of compliance imposed on each entity involved. These include the costs to utilities, government entities, developers, and others involved in the electric industry, including the cost of the new facilities needed to support a competitive market. These costs are in the tens, if not hundreds, of millions of dollars for most utilities and overall are measured in billions of dollars. The second area of costs may be categorized as risks. What is being done and proposed to be done by the FERC is new, untested, and extremely complex. The risks of being wrong may be measured not only in possibly increased prices, but a decrease in reliability that can impact the economy directly. California can attest to the dangers of experimentation. The third area of costs is the social costs including, for example, the perceived environmental cost, and the cost to property values, because of new transmission lines and power plants that would not otherwise be needed.

There are two primary propositions that underlie or drive restructuring, the need for federally regulated RTEs and the elimination of preferences for native load customers. The first is that non-physical impediments (certain behaviors on the part of transmission owning and operating electric utilities) cause the transmission system to be operated in an inefficient and ineffective manner. The result, according to this proposition, is that more expensive generation is operating when cheaper electric generation could be providing service if the transmission system was functioning effectively. The second proposition is that the movement to the competitive provision of generation will cause generators to become more efficient, thus lowering society's electric bill.

The first proposition can be – and has been – tested in several studies.[33] The studies show that the primary benefits of restructuring will be from the assumed savings in generation production costs and not from a re-dispatch of existing units.[34] In other words, for the most part, the least cost units are already being dispatched first without FERC's proposal. A FERC commissioned study supports this conclusion. The study, performed by ICF Consulting,[35] concluded that there could be a 5% "savings" as a result of the formation of large regional transmission markets consistent with the FERC's SMD NOPR proposal. However, a review of the study shows that more than 85% of these savings related to matters other than the re-dispatch of generating units. Thus, the "savings" related to re-dispatching units would be less than 1% according to the study.[36] This means that, for the most part, the nation's electric system is efficiently run given its current stock of generation and transmission assets.

The second proposition driving the FERC's initiatives is more efficient generation and transmission operation, beyond the re-ordering of actual generation dispatch enabled by larger electricity market areas. According to FERC, restructuring will also encourage introduction of new technologies.[37] This proposition cannot be empirically tested. It must, however, be noted that the savings produced by competitive generation must exceed the considerable cost of FERC's initiative for there to be a net benefit. These costs include the cost of establishing and running the organizations that will administer new market structures; the cost of new generation and transmission that are needed to support competition but are not needed for reliability; the loss of efficiencies gained by the current vertically integrated system; the negative impacts of significant price volatility; and the increased risk to reliability.

Certain studies, such as the ICF FERC-commissioned cost benefit analysis noted above, did not address these propositions directly, but rather assumed certain improvements and other positive changes.[38] Surprisingly, however, even with all of the positive assumptions, the net benefits were very small compared to the cost of implementation and operation of the new regime. A slight change to any of numerous assumptions could change the "benefit" to a "detriment."[39] Finally, the study did not include any risk analysis or consider any societal costs associated with additional transmission lines and generating units.

Applicability of the FERC NOPR

Generally, the FERC has jurisdiction over and regulates wholesale sales and transmission service, including rates, terms, and conditions. Transmission service is the transport of electricity at high voltages over substantial distances, for example to move power from remote power plants to metropolitan load centers. Transmission service is often interstate in nature. The states historically have regulated retail sales of electricity, including generation, transmission, and local distribution. Retail customers traditionally have paid bundled rates; that is they pay one rate that includes all elements of electric service: generation, transmission, and distribution.

Jurisdiction can move from the state to the federal level in several ways. For example, if a regulated utility transfers its generating units to a third party and buys power from that, or another, party for resale to its customers, the sales to the regulated utility are wholesale and are regulated by the FERC as to their rates, terms, and conditions. Moreover, generally, the state may not prohibit the regulated utility from passing on to retail customers the wholesale rates established by the FERC.

As noted earlier in this paper, the FERC has determined that there is undue discrimination in providing transmission service to customers of integrated utilities. In an attempt to remedy this perceived undue discrimination, the FERC has issued the SMD NOPR. Under the NOPR, only entities whose sole function is transmission may operate or control transmission facilities.[40] As written, the SMD NOPR applies across the board. In addition to retail choice states with utilities that have transferred control of their transmission systems to a FERC-regulated RTE, the SMD would also apply to states such as North Carolina that have decided not to move to retail choice at this time. Unless there are changes to the Act, Virginia's utilities must join an RTE that would function as required by the SMD NOPR.

It is clear that the FERC has significant authority to remedy discrimination with respect to transmission service. Further, it also appears that if a state has allowed a utility to transfer control of its transmission system to a FERC-regulated RTE, the FERC could impose the SMD on that RTE (and thus the utility) without successful objection by the state. In other words, if the state allowed the transfer of control of the transmission system to the RTE (an entity regulated by FERC), the FERC gains enhanced jurisdiction. Also, there is recent precedent indicating that the FERC has significant authority where rates or costs have been unbundled.[41] Based on this precedent, even if transfer of control of the transmission system to a FERC-regulated RTE has not occurred, if rates are unbundled as Virginia's are, it is highly likely that the SMD NOPR would apply.[42]

What is not as clear is the extent that the FERC may go to remedy the perceived discrimination. It is almost certain that a significant number of states, particularly in the west and south, will challenge in court the FERC's authority to adopt the SMD and to impose its directives on the states that have not transferred control of transmission systems to RTEs regulated by the FERC and do not have unbundled rates. In addition, it is highly likely that the Congress will have before it in the 2003 session legislation that will prohibit the FERC from imposing the SMD NOPR on states that do not want their utilities to participate in the proposal.[43] Further, the FERC itself, in response to mounting criticism, might alter the SMD NOPR to allow states to decide whether their utilities will be part of the new Standard Market Design.[44] It must also be noted, however, that the FERC can and will have a regulatory system, that might well be the SMD, applicable to utilities whose actions have made them part of the federal system. These actions include transfer of control of the utility's transmission system to a federally regulated RTE and having unbundled rates.

Future judicial, legislative, and FERC actions are impossible to predict accurately. Nonetheless, if Virginia allows the transfer of control of transmission assets to a FERC-regulated RTE or rates remain unbundled, the FERC's resulting jurisdiction can have a significant impact on retail electric rates and reliability. Moreover, it will be extremely difficult, if not impossible for the Commonwealth to retrieve such jurisdiction should it pass to FERC.

Events since 1999 and the reactions of other states

Since the passage of the Virginia Electric Utility Restructuring Act in 1999, a number of events have occurred that have had, and continue to have, a negative impact on restructuring of the electric industry. The changes that have occurred since 1999 involve the market, the electric industry, the reactions of other states, and actions at the federal level as previously discussed.

When the Act was passed, approximately 20 other states had adopted restructuring, relying on the market and competition to regulate the reliability and prices of electricity. The majority of these states had rates above the national average. The remaining states were studying the issue, and several were moving toward restructuring.[45] California was the exemplar for competition; its market appeared to be working, and rates in parts of the state were down significantly.[46] The Independent System Operator was running the transmission system in California without noticeable problems.[47]

In 1999, regional transmission entities were more ideas than a reality; RTEs were to allow the transmission systems to operate more efficiently, helping wholesale and retail markets develop.[48] The RTE idea became more of a reality as incumbent utilities began to come together to form new transmission entities with approval of the FERC.[49] In addition, new companies were forming that would build the power plants of the future, the merchant plants. There was faith in the developing power markets. There was a belief that a restructured electric industry, interacting in a vibrant market, would lead to an electric industry largely regulated by the market, bringing reliable service at lower rates to citizens across the nation, including Virginia.

Since 1999, numerous problems have arisen. The market in California failed, there were blackouts, and rates skyrocketed. At the same time, once mighty utilities filed for bankruptcy and others moved perilously close. The experience also made clear that the electricity market was susceptible to abuse and manipulation. The economy of California was severely damaged, and the state will be paying for its experiment for decades. Ultimately, California abandoned retail choice and has moved back toward more traditional regulation.[50]

While California presents the most extreme example of failure, it is fair to say that there are no sustained success stories, particularly for residential consumers.[51] While there were some initial indications of success in states like Pennsylvania, these were largely the result of regulatory action to lower incumbent utility rates while setting market rates at artificially high levels to encourage competitors. Such action has not been successful in the long run.[52]

Specifically, as Dr. Kenneth Rose reviewed in part of the Commission's report to the LTTF and the Governor earlier this year, there are, nationwide, very few offers to residential customers below the price to compare.[53] According to Dr.

Rose, in the 17 jurisdictions (16 states plus the District of Columbia) where retail choice is available for residential customers, there are 64 incumbent utilities providing service. Of these 64 utilities, only 16 face offers that are below their standard rate; five of these are in Texas. Nine states, including Virginia, have no competitive offers below the standard rate. In other states, offers below the price of the incumbent are rare for residential customers. For example, in Pennsylvania, only one of the eight utilities faces offers below its price to compare. In Maryland, only one of four utilities faces such offers. In short, with few exceptions, competition is not a reality, especially for residential and small commercial customers.

Other events have also impacted the electricity industry. Investigations centered upon the California and mid-west crises and the collapse of Enron have revealed abuses, improper trading, and misleading reporting practices of a number of energy companies.[54] As a result of these revelations, in combination with a downturn in the economy and a reduced demand for electricity, many incumbent utilities are suffering financially.[55] Also, the new energy companies that were going to build many of the merchant plants that would power America are going out of business, merging, and abandoning proposed plants.[56] It was reported recently that nearly 180,000 MWs of planned new capacity have been cancelled or tabled between January and July, 2002.[57] Merchant plant cancellations have continued in the second half of 2002.[58] In addition, the number of competitive service providers who actually make competitive offers to customers has also been greatly reduced.[59]

As a result of the turmoil surrounding restructuring, there has also been a significant weakening in the creditworthiness of the power industry. Standard & Poor's cites as the chief reason for the downturn a loss of investor confidence and heightened business risk as a result of more investment outside the traditional regulated utility business, particularly unregulated generation and energy trading and marketing. The rating agency notes that in the third quarter of 2002 there were 57 downgrades among utility holding companies and operating subsidiaries, compared to just eight upgrades. For the same period in 2001, there were nine downgrades and five upgrades.[60]

A downgrade by a rating agency such as Standard & Poor's almost always results in increased interest rates and other financial costs. In mid-November, Standard & Poor's concluded that the U.S. power and energy sector credit slide would continue.[61] The utilities that are the strongest financially are the traditional utilities; Standard and Poor's stated the following with respect to these companies:

> Indeed, there are still 26 to 27 states that remain untouched by deregulation, or where any such impulses have quickly retreated. Standard & Poor's sees a solid investment-grade picture among the utilities operating in these jurisdictions.[62]

The negative developments have not bypassed Virginia. Allegheny Energy, for years an efficient and financially stable utility, restructured its operations by transferring its generating units to an affiliate as well as purchasing an energy trading operation. Having been wrong about forward markets, Allegheny Energy Supply and parent Allegheny Energy are now in technical default on certain of their credit agreements. This fall, Allegheny Energy's securities were rated as "junk," its dividend was suspended, its share price fell as much as 90%, and it laid-off employees.[63] While the Allegheny subsidiary that provides service in Virginia (The Potomac Edison Company) appears to be sound, its unsecured debt is now rated below investment grade.[64]

Also, Standard and Poor's lowered its rating on AEP-VA's debt from "A-" to "BBB+" based on the ratings review and downgrade of its parent, American Electric Power. The ratings review and downgrade were prompted by AEP's corporate restructuring of its regulated and unregulated lines of business.[65] In addition, AEP has abandoned much of its energy trading and is focusing on more stable and traditional earnings.[66]

Dominion Virginia Power's senior debt rating was also lowered recently to "A-" and certain of its revenue bonds were assigned a rating of "BBB+" even though the company has remained a more traditional utility.[67]

The abandonment of merchant plants across the country has also occurred in Virginia. In the last year, the Commission has had five pending merchant plant applications withdrawn, suspended, or dismissed at the request of the applicant. These plants would have provided almost 4,500 MW of merchant generation had they been completed. A number of other plants representing thousands of MWs that had yet to file with the Commission have also been abandoned or delayed.[68]

Also, the pool of competitive service providers that make competitive offers to Virginia customers is drying up. Just last summer there were twelve electric competitive service providers licensed in Virginia.[69] In the last several months, the number has dropped to nine.[70] Of these nine, only three have fully registered so that they can actually make offers and provide service in the Commonwealth; two of the three are affiliates of Virginia incumbent utilities.[71] No offers are currently being marketed in Virginia.

The reaction of other states to the events of the last few years has been almost uniform. Four states (Arkansas, New Mexico, Oklahoma, and West Virginia) that passed restructuring laws have delayed implementation. California now prohibits new retail access and is moving back toward more traditional regulation. Currently, only 17 jurisdictions allow retail access for residential customers. Nevada, Montana and Oregon allow retail access for large customers only. Eight states continue to study restructuring and 18 states have dropped consideration of restructuring at this time.[72]

<u>Assessment of Risks to Virginia of Future Restructuring Action (or Inaction)</u>

Unfortunately, Virginia has indeed been impacted by the developments described in this paper. Restructuring, and the turmoil surrounding it, has resulted in great financial harm to at least one utility serving Virginia, Allegheny Energy and its

Virginia subsidiary, The Potomac Edison Company. A number of potential merchant power plants have been canceled or delayed by the project developer. Further, there is virtually no activity in Virginia's retail choice market and no competitive service providers are currently marketing service. Only three such providers are currently qualified to offer service and two of those are affiliated with a Virginia electric distribution company.

If Virginia's retail choice program continues with unbundled rates or the transfer of control of transmission facilities to a FERC-regulated RTE, electric service in Virginia will be subject to the final outcome of the FERC's SMD NOPR. It is highly likely that this will be the result even if, through Congress, the courts, or the FERC, the states are given an opportunity to decide whether to transfer jurisdiction to the FERC, because Virginia has implemented retail access and unbundled its rates. If the transfer of jurisdiction has occurred when the final rule is adopted, Virginia's decision will have been made, and it will be difficult, if not impossible, to reverse.

Proceeding with retail choice at this time poses significant risks. As discussed in this paper, as a result of the Standard Market Design proposed by the FERC, rates for Virginia citizens could increase through application of Locational Marginal Pricing, and Virginia will be unable to ensure reliability by, for example, establishing and enforcing reserve margins intended specifically to protect Virginia citizens. Moreover, at present, retail competition is not providing benefits to Virginia customers. While a failure in Virginia is unlikely to yield California-like results, there could be significant price increases and volatility, and reliability would not be within the control of the Commonwealth and could suffer.

For the FERC SMD NOPR not to apply to Virginia on a mandatory basis, two things must happen. First, as a result of court, congressional, or FERC action, the states must have the opportunity to decide whether their utilities will comply with the requirements of the SMD NOPR, including the NOPR's requirement to have an independent entity operate their utilities' transmission facilities. Second, the

Commonwealth must decide that Virginia utilities should not now be part of the proposed federal plan. This decision could be made by amending the Act to rebundle rates and service and defer, or eliminate for now, the requirements that Virginia's electric utilities join an RTE and seek to transfer control of their transmission systems to such RTE.

If the Commonwealth rebundles retail rates and service and defers the RTE requirements, and is given the option of preserving state jurisdiction, Virginia could wait until the FERC has finalized its rules and regulations and they have had an opportunity to be tested in practice. The Commonwealth could wait and see if competition develops and if the monitoring envisioned in the SMD NOPR is effective and prevents abuses. After the new regime has had an opportunity to prove itself, Virginia could then make an informed choice about transferring jurisdiction from the Commonwealth to the FERC.

While continuing the implementation of certain sections of the Act may be risky, other sections' implementation could move forward. For example, the implementation of §§ 56-578 B, 56-578 D, and 56-580 D could continue with the goal of harnessing beneficial competitive forces and applying those forces to the provision of electric service in Virginia. Respectively, these statutes provide for the orderly interconnection of distributed generation, expedited permitting for small generation projects and merchant plant construction without a demonstration of need. Also, the Commission could continue to require utilities to obtain competitive bids for any new needed generation rather than simply constructing units. Furthermore, new merchant generation facilities that are constructed will not lose the ability to compete for sales in the wholesale market.

As for the risk of delay, there are no offers of any kind being marketed in Virginia. With rare exceptions, retail competition is not providing meaningful benefits anywhere in the nation. It has been tried now for several years and has yet to yield sustained savings. Other states have recognized this fact and delayed, abandoned, or severely curtailed retail choice.

If retail choice is delayed, however, it is possible that the benefits of retail choice, such as those that appear to be currently realized in Texas, could be delayed in Virginia. However, we now have the basic rules, systems, and procedures in place to accommodate retail choice. If Virginia delays implementation now and retail competition is shown to work well elsewhere in the future, we will be in a position to implement retail choice again quickly. Because choice could be implemented quickly, Virginians should have little to lose with a delay at this time.

ENDNOTES

[1] 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).

[2] Edison Electric Institute Typical Bills and Rate Report, Winter and Summer, 1998. Note that the data available to the General Assembly in early 1999 may have been applicable to 1997. Those numbers were virtually unchanged between 1997 and 1999.

[3] *See* Va. Code §§ 56-577 A (3), 56-590 B, 56-582, and 56-583. Note that incumbents' fuel cost recovery was not capped. Also, the provisions of Virginia Code §§ 56-582 B and 56-582 C allow for adjustments to or termination of rate caps under certain circumstances. The Commission may adjust capped rates pursuant to a utility's recovery of fuel costs pursuant to Virginia Code § 56-249.6, changes in taxation by the Commonwealth of incumbent electric utility revenues, financial distress of the utility beyond its control, and certain other circumstances related to electric cooperatives.

Further, a utility may petition the Commission to terminate the capped rates to all customers any time after January 1, 2004, and such capped rates may be terminated upon the Commission finding of an effectively competitive market for generation services within the service territory of that utility. If the capped rates are continued after January 1, 2004, an incumbent electric utility which is not, as of the effective date of the Act, bound by a rate case settlement adopted by the Commission that extends in its application beyond January 1, 2002, may petition the Commission for approval of a one-time change in the non-generation components of such rates. This, in effect, allows all Virginia utilities except Dominion Virginia Power the opportunity to seek Commission approval to increase non-generation rates after January 1, 2004.

[4] Va. Code §§ 56-583 and 584.

[5] *See* Va. Code § 56-595 C (ii). This provision of the Act requires the Legislative Transition Task Force to determine "whether, and on what basis, incumbent electric utilities should be permitted to discount capped generation rates established pursuant to § 56-582."

[6] Va. Code §§ 56-577 and 56-579.

[7] *See* Report to the Legislative Transition Task Force 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, ,Volume I, Part I (August 30, 2002) and Status Report: The Development of a Competitive Retail Market for Electric Generation within the Commonwealth of Virginia, Part II (August 31, 2001).

[8] *See* Application of Rappahannock Electric Cooperative, For Approval of an Electricity Retail Access Pilot Program, Case No. PUE-2000-00088, 2000 S.C.C. Ann. Rep. 504; Commonwealth of Virginia, At the relation of the State Corporation Commission, Ex Parte: In the matter of considering an electricity retail access pilot program -Virginia Electric and Power Company, Case No. PUE-1998-00813, 2000 S.C.C. Ann. Rep. 398; Commonwealth of Virginia, At the relation of the State Corporation Commission, Ex Parte: in the matter of considering an electricity retail access program – American Electric Power – Virginia, Case No. PUE-1998-00814, 2000 S.C.C. Ann. Rep. 413.

Virginia conducted three electric retail access pilots. Appalachian Power Company ("AEP-Virginia"), Rappahannock Electric Cooperative ("REC") and Virginia Electric and Power Company d/b/a Dominion Virginia Power ("DVP" or "Dominion Virginia Power") each hosted an electric retail access pilot. No customers switched to competitive service providers in either the AEP-Virginia or REC pilot. In DVP's pilot about 30,000 residential customers switched to "competition." The majority of participating customers were served by a DVP subsidiary. Those customers not served by a DVP affiliate were served by an affiliate of another incumbent utility (either gas or electric) in Virginia. Although the customers participating in the DVP pilot were allowed to continue to receive service from their competitive supplier as choice was phased in, the number of customers being served by a competitive supplier has dropped from about 30,000 to about 2,300. These remaining customers are currently paying a price for generation service above that otherwise charged by the incumbent DVP.

[9] In Commonwealth of Virginia, ex rel. State Corporation Commission, Ex Parte: In the matter concerning a draft plan for phase-in of retail electric competition, Case No. PUE-2000-00740, 2001 S.C.C. Ann. Rep. 491, the Commission established the schedule for the phase-in of choice, pursuant to Va. Code § 56-577 of the Act. The Commission's March 30, 2001, Order in this proceeding adopted a schedule providing for the implementation of retail access for all retail customers within the Virginia service territories of AEP-Virginia, Delmarva Power & Light Company, and The Potomac Edison Company on January 1, 2002. The schedule also provided for a one-year phase-in of retail access within the service territory of Dominion Virginia Power: residential customers in the northern, central, and eastern portions of the Company's Virginia service territory on January 1, 2002, September 1, 2002, and January 1, 2003, respectively. Retail Access for Dominion Virginia Power's non-residential load was scheduled in thirds on these same dates on a first-come basis. Finally, the Commission determined that the electric cooperatives, operating largely in rural territories, and Old Dominion Power, operating in the far western counties of the Commonwealth, should have the entire two-year period permitted by the Act to ready themselves for retail choice. It should be noted, however, that the Commission has approved the retail access applications of Northern Virginia Electric Cooperative ("NOVEC") and Rappahannock Electric Cooperative . NOVEC implemented retail choice within its service territory on July 1, 2002, and REC will implement retail choice on January 1, 2003. Additionally, Shenandoah Valley Electric Cooperative has filed an application with the Commission proposing to implement retail access on April 1, 2003.

[10] The Alliance Companies were: American Electric Power Company ("AEP") on behalf of the public utility operating company subsidiaries of the AEP system, Consumers Energy Company, Detroit Edison Company, FirstEnergy Corp. on behalf of the transmission-owning FirstEnergy Operating Companies (The Cleveland Electric Illuminating Company, Ohio Edison Company, Pennsylvania Power Company, and The Toledo Edison Company), and Virginia Electric and Power Company. The Alliance Companies originally sought FERC approval of the necessary transactions to form the Alliance on June 3, 1999 and continued development efforts until the Alliance was ultimately rejected by the FERC.

On December 20, 2001, the FERC issued its Order on Requests for Rehearing that found, among other things, that the Alliance RTO, "lacks sufficient scope to exist as a stand-alone RTO…." Alliance Companies, et al., 97 F.E.R.C. ¶61,327 at 62, 525 (2001).

[11] PJM currently manages the transmission system and generating markets that serve Delaware, Maryland, New Jersey, most of Pennsylvania, and portions of Virginia and West Virginia. PJM West is a newer division of PJM that has a slightly different set of rules. The most significant difference between PJM and PJM West is associated with how load serving entities are required to meet their capacity obligations. AEP (including AEP-VA) seeks to join PJM West. Dominion Virginia Power seeks to form a third division of PJM- PJM South. Details regarding how PJM policies and practices may change as a result of further expansion of PJM West and the development of PJM South have not been determined at this time.

[12] *See* Application of Virginia Electric and Power Company, For approval of a Functional Separation Plan under the Virginia Electric Utility Restructuring Act, Case No. PUE-2000-00584, 2001 S.C.C. Ann. Rep. 467;
Application of Appalachian Power Company d/b/a American Electric Power-Virginia, For approval of Functional Separation Plan under the Virginia Electric Utility Restructuring Act, Case No. PUE-2001-00011, 2001 S.C.C. Ann. Rep. 533;
Application of The Potomac Edison Company d/b/a Allegheny Power, For approval of Functional Separation Plan (Phase II), Case No. PUE-2000-00280, 2001 S.C.C. Ann. Rep. 413;

Application of Delmarva Power & Light Company, For approval of a plan for functional separation of generation pursuant to Virginia Electric Utility Restructuring Act and Application of Delmarva Power & Light Company, Conectiv Delmarva Generation, Inc., and Conectiv Energy Supply, Inc., For approval of transactions under Chapter 4 and 5 of Title 56 of the Code of Virginia, Case No. PUE-2000-00086, 2000 S.C.C. Ann. Rep. 499;
Application of Southside Electric Cooperative, Inc., For approval of a functional separation plan, Case No. PUE-2000-00749, 2001 S.C.C. Ann. Rep. 510;
Application of Community Electric Cooperative, For approval of a functional separation plan pursuant to Virginia Code § 56-590, Case No. PUE-2000-00746, 2001 S.C.C. Ann. Rep. 505;
Application of Craig-Botetourt Electric Cooperative, For approval of a functional separation plan, Case No. PUE-2001-00009, 2001 S.C. C. Ann. Rep. 531;
Application of A&N Electric Cooperative, For approval of a functional separation plan pursuant to the Virginia Electric Restructuring Act, Case No. PUE-2001-00008, 2001 S.C.C. Ann. Rep. 529;
Application of Rappahannock Electric Cooperative, For approval of a functional separation plan, Case No. PUE-2001-00007, 2001 S.C.C. Ann. Rep. 526;
Application of Northern Neck Electric Cooperative, For approval of a functional separation plan, Case No. PUE-2001-00006, 2001 S.C.C. Ann. Rep. 524;
Application of Northern Virginia Electric Cooperative, For approval of a functional separation plan, Case No. PUE-2001-00005, 2001 S.C.C. Ann. Rep. 522;
Application of Mecklenburg Electric Cooperative, For approval of a functional separation plan, Case No. PUE-2001-00004, 2001 S.C.C. Ann. Rep. 519;
Application of Kentucky Utilities Company, For approval of a functional separation plan, Case No. PUE-2001-00003, 2001 S.C.C. Ann. Rep. 518;
Application of BARC Electric Cooperative, For approval of a functional separation plan, Case No. PUE-2001-00002, 2001 S.C.C. Ann. Rep. 515;
Application of Prince George Electric Cooperative, For approval of a functional separation plan pursuant to Virginia Code § 56-590, Case No. PUE-2001-00001, 2001 S.C.C. Ann. Rep. 514;

[13] *See* Application of Virginia Electric and Power Company, For approval of a Functional Separation Plan under the Virginia Electric Utility Restructuring Act, Case No. PUE-2000-00584, 2001 S.C.C. Ann. Rep. 467, 474-475 and Application of Appalachian Power Company d/b/a American Electric Power-Virginia, For approval of Functional Separation Plan under the Virginia Electric Utility Restructuring Act, Case No. PUE-2001-00011, 2001 S.C.C. Ann. Rep. 533. For AEP-Virginia, the Commission accepted a stipulation that, among other things, required continued separation of AEP-Virginia's distribution, transmission and generation functions by division and allowed for a further inquiry into the terms and conditions for the proposed transfer of generation assets to an affiliate, to be conducted during calendar year 2002. AEP-VA later requested that this further inquiry be deferred until a later date.

[14] *See*, 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). As to the markets' failure to provide adequate reliability, Id. at 55455, para. 4.; 55511, para. 461; 55511 n.117.

[15] According to the comments of an Illinois state commissioner at a Senate hearing on the SMD NOPR held on September 17, 2002.

[16] *See, e.g*., Lori A Burkhart, *A Fight Over Standard Market Design*, Public Utilities Fortnightly, November 15, 2002, at 18-31. See the comments of Michigan Public Service Commission Chair, Laura Chapplle, Id. at 27, and those of New York Public Service Commission Chair, Maureen O. Helmer, Id. at 28.

[17] Id. The article quotes Alabama Public Service Commission President, Jim Sullivan, as follows: "I believe SMD, in its current form, is the most detrimental regulatory proposal I have ever seen ... an artificial national market." Id. at 21. Also, California Public Utilities Commission President, Loretta Lynch,

said: "We will fight it [SMD] with our last dying breath. FERC's one-size-fits-all policy just will not work for the West and will not work for California." Id. at 25.

[18] *See* letter from *Conservatives for Balanced Electricity Reforms,* dated September 23, 2002, to U.S. Senator Trent Lott, available at <http://www.protectpowerconsumers.org/index_files/CEBR%20Letter.pdf>.

[19] *See* Remedying Undue Discrimination through Open Access Transmission Service and Standard Electricity Market Design, Notice of Proposed Rulemaking, 67 Fed. Reg. 55452, 55475 at paras. 158-159 (2002) (to be codified at 18 C.F.R. pt. 35) (proposed July 31, 2002). Under this new regime, any required TLRs (i.e., transmission curtailments) to relieve overloads will be borne on a "*pro rata*" basis by all transmission customers holding Congestion Revenue Rights ("CRRs") after those without CRRs have been curtailed. This means that, as proposed by the SMD NOPR, Virginia will not be able to ensure that generation will be delivered to retail customers under operating conditions that require a load curtailment. Even if Virginia's retail customers have reserved or paid for both generation and transmission capacity and have obtained CRRs consistent with their use of the transmission system, they will be placed in the same position as wholesale transmission customers that hold CRRs if a curtailment is required. Further, such CRRs must be in the right place, in the right direction, and at the right time. If the correct CRRs have not been obtained for Virginia's retail customers, they will have less priority than wholesale transmission customers with CRRs. Moreover, CRRs have obligations and can be a liability. Thus, Virginia policymakers may be unable to ensure adequate reliability at reasonable prices.

[20] There are several markets related to the competitive provision of electric service. Note that basic energy and capacity markets have both regional and temporal dimensions. For example, markets may be defined as the New England capacity market or the southeast energy market. In addition, market arrangements that set terms and conditions for future delivery and payment (forward markets) define large numbers of additional transactions. Other related markets include ancillary services such as spinning reserves and regulation service. Finally, traded Congestion Revenue Rights that confer upon the holder obligations and benefits related to simultaneous differences in the price of power at distinct locations on the electric power grid define yet another series of particularly complicated transactions. If such CRRs are auctioned or traded in resale markets, then they too will be a product in a separate market.

[21] *See, e. g.,* Remedying Undue Discrimination through Open Access Transmission Service and Standard Electricity Market Design, Notice of Proposed Rulemaking, 67 Fed. Reg. 55452, 55456 at para. 12 (2002) (to be codified at 18 C.F.R. pt. 35) (proposed July 31, 2002).

[22] The FERC's Market Power Mitigation proposals are set forth in SMD NOPR paragraphs 390 through 456. Remedying Undue Discrimination through Open Access Transmission Service and Standard Electricity Market Design, Notice of Proposed Rulemaking, 67 Fed. Reg. 55452, 55503-55511 (2002) (to be codified at 18 C.F.R. pt. 35) (proposed July 31, 2002). The proposal sets forth three mandatory measures and one voluntary measure. The first mandatory measure is a cost-based bid cap applicable to hours when a particular unit must run to serve load. The second mandatory measure is an overall $1000 per MWH "safety-net" bid cap. The third mandatory measure involves the development of a resource adequacy requirement which would discipline market prices by increasing supply, other things being equal. The voluntary measure would be applied if the market monitor detected economic withholding. In that circumstance bids into energy markets could be limited to certain predetermined levels.

[23] *See, e.g.,* United States General Accounting Office, Report to Congressional Requesters, "ENERGY MARKETS - Concerted Actions Needed by FERC to Confront Challenges That Impede Effective Oversight", June 2002. In a section labeled "Results in Brief"on page 4, this report states:

> FERC has not yet adequately revised its regulatory and oversight approach to respond to the transition to competitive energy markets. The agency recognizes that the change from highly regulated monopolies to competitive markets requires it to fundamentally change

how it does business. However, it has struggled through various strategic planning and other efforts to define the specific strategies, processes, and activities that it will use to regulate and oversee these markets.

[24] *See, e.g.*, "Market Power Mitigation: Principles and Practice", Larry E. Ruff, Charles River Associates, November 14, 2002. Available at http://www.ksg.harvard.edu/hepg/Papers/Ruff_Mkt.power.mitigation_as-Filed_11-14-02.pdf; *contrast with*, "Affidavit of Frank A. Wolak on Behalf of the Electricity Consumer Resource Council, the Transmission Dependent Utility Systems, Buckeye Power, Inc., Great River Energy, Wolverine Power Supply Cooperative, Inc., and East Texas Electric Cooperative, Inc.," filed November 15, 2002, in FERC Docket No. RM01-12-000.

[25] SMD NOPR paragraph 11, Remedying Undue Discrimination through Open Access Transmission Service and Standard Electricity Market Design, Notice of Proposed Rulemaking, 67 Fed. Reg. 55452, 55456 (2002) (to be codified at 18 C.F.R. pt. 35) (proposed July 31, 2002) states:

> Several changes required by Standard Market Design promote greater customer access to low-cost power. We note that this may raise concerns that cheap power may leave one region for sale in another, higher-priced region. This can only happen with generation that is not already under contract for purchase. Thus, customers in low-cost regions can ensure that low-cost power "stays home" by contracting for that power. This way, only excess power will leave the region to serve another market.
>
> Id. at 55456.

If this paragraph means what it says, it simply cannot work. If electricity in a jurisdiction is inexpensive to generate and is currently priced based on cost, and customers in another jurisdiction pay more for power, the fear is that the utility will sell the "low cost" power in the second jurisdiction to make additional profit. The FERC's solution is for customers in the first jurisdiction to "contract" for the low cost power. The utility, however, will not voluntarily "contract" with these customers at the low "cost." Rather, the utility will charge the higher "market" rate that it can get by exporting the power. If a Virginia utility can receive 8¢ per kWh (net of transmission costs) by selling electricity to the north of the Commonwealth, it understandably will not voluntarily contract to sell that power to a Virginia customer for 5¢.

On the other hand, if the FERC means that regulators in low-cost states could reserve low-cost power by requiring self-scheduling of generation, the low cost power still may not be available for Virginia customers. Under the SMD NOPR, curtailment of transmission could prevent the "low cost" power from reaching Virginia customers as it would have before the NOPR. Specifically, the Virginia utility could not simply curtail non-Virginia load on the transmission system to support Virginia customers. Rather, the RTE would be the entity responsible for implementing curtailments. The Virginia utility would therefore first have to have sufficient transmission rights of the right kind in the right place. There is no certainty, however, that such "rights" will be available in every case and, in certain cases, these rights must be purchased thus possibly increasing costs to customers. Even if the utility has sufficient CRRs, if transmission is constrained, curtailment will be on a *pro rata* basis with other CRR holders. Thus, self-scheduling under the SMD NOPR does not provide the same reliability Virginia customers currently enjoy.

[26] The concept of LMP is developed in Paragraphs 203 through 253 in the SMD NOPR under the sub-heading "The New Congestion Management System". Remedying Undue Discrimination through Open Access Transmission Service and Standard Electricity Market Design, Notice of Proposed Rulemaking, 67 Fed. Reg. 55452, 55479 - 55487 (2002) (to be codified at 18 C.F.R. pt. 35) (proposed July 31, 2002). FERC explains in Paragraph 205:

> LMP is a market-based method for congestion management. Congestion is managed through energy prices and transmission usage charges (congestion and loss charges) determined in a bid-based market. When there is no congestion anywhere on the system (when there is enough

transmission capacity to get power from the cheapest available generators to all potential buyers) there will be only one energy price in the transmission system, the price bid by the last, or marginal, generator that provides energy or load that offers to reduce its demand. When there is congestion, the cheapest generators may be unable to reach all their potential buyers. Consequently, when there is congestion there may be many different energy prices across the transmission system.

Under LMP, the Independent Transmission Provider will establish separate energy prices at each node on the transmission grid and separate prices to transmit energy between any two nodes (receipt and delivery points) on the grid. These prices reflect the cost of congestion. LMP relies on economic redispatch in managing congestion. Redispatching means decreasing the energy the Independent Transmission Provider obtains in front of the constraint (where the power is flowing from) and increasing the energy the Independent Transmission Provider obtains behind the constraint (where the power is flowing to). The cost of redispatch is the basis for the congestion charges under LMP. If a customer is willing to pay the marginal cost of redispatch, which it signals through its bids, the Independent Transmission Provider will schedule the transmission service.

Id. at 55480.

[27] In SMD NOPR paragraph 12, FERC states "… there are cases where LMP price signals alone will not encourage all beneficial transmission investments". Id. at 55456. *See also* SMD NOPR Paragraph 461. Id. at 55511.

[28] In paragraphs 485 and 486, the SMD NOPR provides only the following about the demand forecast that is crucial to its resource adequacy requirement:

> 485. An Independent Transmission Provider would be required to do an annual demand forecast for its area. The forecast would look ahead for the time period needed to add new supply and demand response resources. We will refer to this time period as the planning horizon, a topic discussed further below.
>
> 486. Demand forecasts have long been used in the utility industry to determine the need for future resources and to plan new infrastructure investments. The Independent Transmission Provider may undertake a "bottom up" method of demand forecasting by adding up the demand forecasts of its component areas where they can be relied on.221 This may be accomplished through a collaborative process with all stakeholders.
>
> Note 221. A load-serving entity has an incentive to underestimate its future load if doing so would reduce its share of the resource adequacy requirement. For an analysis of bias in demand forecasts, see Mark Bock, "Analysts hunt for bias in NERC forecasts," Electric Light & Power, July 2002.
>
> Id. at 55513.

While the demand forecast is central to a resource adequacy requirement, the SMD NOPR says little about the difficulty of developing such a forecast in a competitive regime. An accurate aggregate industry forecast will be very hard to produce in retail markets consisting of many sellers with changing market shares. Accurate forecasting was a difficult enough task in the monopoly world of integrated utilities when the seller had a long-term relationship with the buyer pool. Under a competitive regime, the forecasting task is complicated by the potentially short relationships and information exchange between buyers and sellers. This is made even more difficult if load-serving entities have an incentive to underestimate actual future requirements as a way of reducing its share of the resource adequacy requirement.

[29] *See* SMD NOPR Paragraphs 158 and 159 and SMD NOPR footnote 98. Id. 55475.

[30] For example, if a Virginia utility that is a member of an RTE was required by state regulation to carry a reserve margin of 20%, while the RTE required a regional reserve margin of 15%, the extra 5% would not provide the same degree of reliability protection that it would at present. First, the SMD NOPR does not make clear that the extra 5% would do more than simply increase the overall RTE reserve margin above 15%. Second, even if Virginia could schedule the Virginia dedicated units, the reliability would not be the same. To get the "Virginia" power to customers when transmission capacity is tight, Virginia could not simply curtail others using the transmission system to protect native load customers. Rather, the RTE would be responsible for implementing curtailments, and the Virginia utility would first have to have sufficient transmission rights (CRRs) of the right kind, in the right place. There is no certainty, however, that such "rights" will be available in every case and, in certain cases, these rights must be purchased thus possibly increasing costs to customers. Finally, if there must be curtailment of those who hold CRRs, the curtailment would be *pro rata* including non-native load customers. As such, Virginia's ability to set its own reserve margins for its own electric customers will not provide the protection it can today.

[31] *See, e.g.,* SMD NOPR Paragraphs 12, 97,98,99 and 191. Remedying Undue Discrimination through Open Access Transmission Service and Standard Electricity Market Design, Notice of Proposed Rulemaking, 67 Fed. Reg. 55452, 55456, 55467, 55478 (2002) (to be codified at 18 C.F.R. pt. 35) (proposed July 31, 2002). Paragraph 12, for example, opens with the following: "The Commission proposes a pricing policy and process for recovering the costs of new transmission investment so as to develop the infrastructure needed to support competitive markets." Id. at 55456.

Also, in recent testimony before the Committee on Governmental Affairs of the United States Senate on November 12, 2002, Pat Wood, Chairman of the FERC stated: "The Commission is pursuing a number of regulatory initiatives to establish the market rules and regulatory framework necessary to ensure adequate incentives for much-needed infrastructure, to support the most efficient wholesale competitive marketplace, and to provide adequate market monitoring and market power mitigation to protect customers."

[32] It is clear that the manner in which transmission expansions are to be funded will have a tremendous impact on whether such investments will be made. While most industry participants would agree in principle with the statement "those who benefit should pay" for transmission investments, in practice it is very difficult to allocate such benefits among retail customers, wholesale customers, generators, transmission providers, or other interested parties.

"Socialized rates" refers to a regime where the costs for transmission upgrades are spread broadly over a region and collected from all ultimate consumers of electric service through regulated rates. Advocates of socialized rates --- and opponents too --- believe that such a funding mechanism will increase the nation's transmission infrastructure. Advocates hold that such an increase is needed to support well functioning competitive power markets that will eventually provide universal benefits. Thus, advocates argue, socialized rates are justified --- everybody benefits so everybody pays. Advocates are generally competition boosters, transmission dependent utilities, and merchant generators.

On the other side of the debate are those who argue that only those who "benefit" from the new lines should pay. This is generally known as participant funding. This group includes many transmission providing integrated electric utilities and state regulators in regions that have not embraced restructuring. This position believes that if a project enhances reliability or helps a region meet its supply requirement then costs should be socialized. All other transmission investments are held to benefit specific market participants and should be funded by those participants. As noted above, it is extremely difficult in practice to make many of these determinations.

The debate surrounding participant funding in some way is like what comes first "the chicken or the egg." Competition advocates claim that socialized funding is necessary to ensure that adequate generation and transmission are developed to support the competitive provision of electric service by providing excess supply needed to discipline prices. Participant funding advocates believe that many of these investments are wasteful because they support infrastructure that is unnecessary for the provision of safe and reliable electric service.

[33] These studies are summarized in Appendix A to a study prepared by Charles River Associates for the Southeastern Association of Regulatory Utility Commissioners entitled The Benefits and Costs of Regional Transmission Organizations and Standard Market Design in the Southeast (November 6, 2002) ("SEARUC Study"). The studies were:

1) A study conducted for PJM to estimate the benefits of combining PJM, NYISO and ISO-NE into a single RTO.
2) A study conducted by ISO-NE and NYISO to assess combining ISO-NE and NYISO and then combining that entity with PJM.
3) Tabors Caramanis & Associates conducted a cost/benefit analysis for the member utilities of RTO West. The primary aim of the study was to assess the benefits in the RTO West and WSCC regions from establishing RTO West.
4) FERC commissioned ICF Consulting to study the long-term costs and benefits of nation-wide RTO formation. The ICF Study is more formally: Economic Assessment of RTO Policy, prepared for: Federal Energy Regulatory Commission, prepared by: ICF Consulting, February 26, 2002.

[34] The studies that demonstrate this are summarized in the SEARUC Study as follows:

> Six (6) benefit-cost studies of RTOs conducted by others are reviewed in Appendix A [of the SEARUC Study]. These studies have estimated benefits in a manner generally consistent with the approach used in this study. The primary measure of benefits in these studies to date has been the savings in generation production costs. These savings have ranged from around 0.5 percent (ICF study) of total production costs to as much as 2.0 percent (PJM study). (See Appendix A [of the SEARUC Study] for additional details.) Similarly, this study finds that production cost savings are between 0.5 and 1.0 percent of production costs.
>
> SEARUC Study, page 14.

[35] Economic Assessment of RTO Policy, prepared for: Federal Energy Regulatory Commission, prepared by ICF Consulting, February 26, 2002 ("ICF Study").

[36] *See* SEARUC Study, Table A-4 in Appendix A (page 106). Charles River Associates The Benefits and Costs of Regional Transmission Organizations and Standard Market Design in the Southeast (November 6, 2002).

[37] It may be argued that the "market" will bring improvements and innovations to generating equipment and, as occurred in the telecommunications industry, to end users of electricity. Note that there has historically been significant upstream and downstream competition for components of both the bulk power system as well as end-use equipment in the absence of restructuring. This is particularly true given that most states, such as Virginia, no longer allow a utility simply to build a generating plant; rather, the need must be put out to bid. If another entity can supply the power less expensively, the utility must purchase the power rather than build the plant.

The situation in the electricity industry is also far different today than circumstances in the telecommunications industry at the time its restructuring was contemplated. Regardless of whether today's telecommunications innovations were imagined in the early 1980's, it is important to note that the managers of the Bell System historically sought to suppress certain kinds of innovations provided by non-Bell providers. These innovations applied to both system components and customer end-use equipment. Systematically, a single large national entity successfully thwarted at least a portion of potentially useful innovations for a long period of time. Given this, one would expect significant pent up demand for and supply of telecommunications innovations. This certainly does not apply to the attachment of devices to an electric utility's system.

[38] For example, in the ICF Study, the bulk of the benefits of the RTO Policy Case, in excess of those produced by the Base Case, are directly caused by a number of questionable assumptions. These critical assumptions include allowing 100 percent of electricity transfer capability (versus 75 percent for the Base Case), hurdle rates that fall to zero (within the four posited RTOs) by 2004, a 5 percent increase in effective transfer capability among sub-regions of an RTO at no incremental cost by 2004, a 2 percentage point decrease in system average reserve margin requirements (from 15 percent to 13 percent by 2020), generation unit heat rate improvements of 6 percent by 2010, and generation unit availability increases of 2.5 percent. The ICF Study contained no basis or support for these assumptions. They appear to be borrowed from other studies or based on intuition or hunches rather than fact. The quantification of such assumptions to specific percentage changes in the above listed performance levels was troubling. This is especially so given that the logic supporting the assumed direction of the change in these performance measures, to say nothing of their respective magnitudes, did not appear in the ICF Study. It may well be that expected performance measure improvements instead turn out to be degradations turning expected RTO Policy Case benefits into detriments.

[39] See note 38, *supra*. Notwithstanding the questionable assumptions, one may view the ICF Study results *assuming* that these assumptions are valid. Doing this produces the further perspective that, even if one assumes away all of the study's serious flaws, the reported dollar benefits of the RTO Policy Case versus the Base Case are small relative to the magnitude of transmission and distribution cash flows through time. This should serve as a cautionary note when contemplating the implementation of an industry structure consistent with the RTO Policy Case. If the assumptions do not turn out to be as positive as expected, small expected net benefits could quickly turn out to be net detriments.

To see this more clearly, note that Table 3.17 on page 77 of the ICF Study shows a net present value (NPV) benefit of $40.9 billion (which, although appearing considerable, is a reduction of only 3.8%) for the RTO Policy Case versus the Base Case. Since the table's title is "System Level Production Costs Across Cases," it appears that near-term RTO establishment costs are excluded from the $40.9 billion result. Including those costs would produce a more accurate representation of the NPV benefit of implementing the RTO Policy Case versus the Base Case.

Two additional points should be noted. First, it appears that the quantification of RTO start-up costs is based in part on ISOs that were formed from existing power pools. Creating RTOs from "scratch" in areas without pre-existing power pools is likely to be a more expensive proposition. Second, note that the NPV benefits appearing in the table are derived using a 6.97% discount rate. While the use of the appropriate discount for this type of analysis is often controversial, the use of a higher discount rate produces lower NPV benefits. Since the implementation of the RTO Policy Case may risk further shock to an already roiled U.S. electric energy market, the use of a higher discount rate should, out of caution, also be analyzed.

[40] *See* SMD NOPR Subpart G, § 35.35 (c) (2). It states:

> To implement the requirements of Non-Discriminatory Open Access Transmission Services and Standard Market Design, every public utility that owns, controls or operates facilities used for the transmission of electric energy in interstate commerce must (a) meet the definition of Independent Transmission Provider, (b) turn over the operation of its transmission facilities to a regional transmission organization, as defined in section 35.34(b)(1) of this title, that meets the definition of Independent Transmission Provider, or (c) contract with an entity that meets the definition of Independent Transmission Provider to operate its transmission facilities.

Remedying Undue Discrimination through Open Access Transmission Service and Standard Electricity Market Design, Notice of Proposed Rulemaking, 67 Fed. Reg. 55452, 55529 (2002) (to be codified at 18 C.F.R. pt. 35) (proposed July 31, 2002).

According to SMD NOPR paragraph 8, an "Independent Transmission Provider" has no financial interest, either directly or through an affiliate, as defined in section 2(a)(11) of the Public Utility Holding Company Act (15 U.S.C. § 79b(a)(11), in any market participant in the region in which it provides transmission services or in neighboring regions. A "market participant", is defined by the FERC [SMD NOPR footnote 6] as (i) Any entity that, either directly or through an affiliate, sells or brokers electric energy, or provides ancillary services to the [RTO], unless the Commission finds that the entity does not have economic or commercial interests that would be significantly affected by the [RTO's] actions or decisions; and (ii) Any entity that the Commission finds has economic or commercial interests that would be significantly affected by the [RTO's] actions or decisions. Id. at 55455.

[41] *See* New York et al. *v*. Federal Energy Regulatory Commission, 122 S.Ct. 1012 (2002).

[42] The Supreme Court held that FERC has clear authority over the transmission component of unbundled retail rates. Further, the Court found that FERC's decision not to regulate bundled retail transmission was a statutorily permissible policy choice. This may imply that had FERC chosen to regulate such service that also would have been a statutorily permissible policy choice. Cutting the other way, the majority also agreed with FERC's conclusion that regulating the transmission component of bundled retail service raises difficult jurisdictional issues. Id. at 1027-1028. Clearly there is an argument, implicit in the SMD NOPR, that the FERC has jurisdiction to impose the SMD NOPR on all states regardless of whether their utilities have transferred control of their transmission systems to an RTE or unbundled rates.

[43] *See, e.g., Congressional Effort to Restrict SMD Expected to Resume Next Year*, Inside FERC, December 9, 2002, at 1.

[44] The FERC has already signaled its willingness in a number of RTE-related cases to depart from the provisions of the SMD NOPR to accommodate "regional differences." *See* the FERC's orders in *Cleco Power LLC, et al.* (Setrans), Docket No. EL02-101-000 (October 10, 2002); Avista Corporation, et al., (RTO West Stage II), 100 FERC ¶ 61, 274 (September 18, 2002).

[45] *See* the Energy Information Agency ("EIA") retail access timeline at <http://www.eia.doe.gov/cneaf/electricity/chg_str/retail_access_timeline.html> and the EIA's restructuring status map at <http://www.eia.doe.gov/cneaf/electricity/chg_str/regmap.html>.
See also Edison Electric Institute Typical Bills and Rate Report, Winter and Summer, 1998.

[46] *See* EIA at <http://www.eia.doe.gov/cneaf/electricity/page/fact_sheets/california.html>:
Trends in California's Electricity Retail Prices -- Fact Sheet:

> California was one of the first States to restructure its retail electric power markets. Under their restructuring plan, which started March 31, 1998, customers of California's three investor-owned utilities (IOUs) were allowed to shop for alternative sources of power. The plan also froze electricity prices for the same customers at June 1996 levels, and additionally, residential and small commercial customers received a 10-percent rate reduction in their electricity bills. These changes have resulted in significant decreases in California's average retail price since 1996. (emphasis added)

[47] A tremendous amount of material has been written about the California energy situation. For example, in a paper by Dr. C. Mensah-Bonsu and Dr. S. Oren, *California Electricity Market Crisis: Causes, Remedies and Prevention*, available at< http://www.caiso.com/docs/09003a6080/14/c5/09003a608014c508.pdf>, the authors stated:

The competitive electric power market of the State of California began operation on March 31, 1998 with the California Independent System Operator (California ISO) and the now bankrupt Power Exchange (PX) as the main operationally independent market facilitators. The market took off smoothly and the prices were seemingly just and reasonable until May 2000 when the first signs of market crisis emerged". (emphasis added)

[48] Although the idea of a regional, independent operator of a transmission system to enable electricity trading has developed to seek to enable electric power competition, regional coordination of transmission and generation assets is not a new concept. The New York and New England Power Pools and the Pennsylvania-New Jersey-Maryland Interconnection (now PJM) successfully operated for many years as "tight" power pools. This means that the generation and bulk transmission assets of member utilities were operated as a single operating entity in order to minimize cost and maximize reliability for the members, each of which was a franchised regulated monopoly provider of electric service. The RTEs and RTOs now envisioned by the FERC to facilitate electric power competition are much different in purpose and operation. The fact that tight pools were successful may have led to early optimism about an RTO's or RTE's ability to guarantee good results under competition.

[49] In addition to the Alliance, a number of other RTEs got started, but have not been completed. For example, work on DesertSTAR, a not-for-profit RTO, was abandoned in late 2001 in favor of a for-profit RTO. Also, in June of 2002, GridSouth sponsors Duke Energy, CP&L Energy and South Carolina Electric & Gas (SCANA) announced that they will delay filing applications with their state commission and will suspend the GridSouth Implementation project. Other RTEs appear to be more successful and continue to develop. Among these are SeTrans and MISO.

[50] A good discussion of the electric market's failure in California is found on the EIA's website at <http://www.eia.doe.gov/cneaf/electricity/california/subsequentevents.html>. The discussion on the EIA website outlines three major aspects of the crises; high wholesale prices, intermittent power shortages, and the severe financial distress encountered by Pacific Gas and Electric (PG&E), Southern California Edison (SCE) and San Diego Gas & Electric (SDG&E).

The basic problem for PG&E and SCE was their inability to pass on astronomical wholesale power costs to retail customers. PG&E reported unrecovered power costs of $9 billion and filed for Chapter 11 protection under the U.S. Bankruptcy Code on April 6, 2001. SCE reported unrecovered power costs of $2.6 billion.

SDG&E reported unrecovered power costs of $447 million and, as permitted by California's restructuring legislation, attempted to recover those costs from retail customers. That attempted recovery increased typical residential bills by over 70% as compared to bills rendered during the summer of 1999. The California Public Utilities Commission issued a rate stabilization plan for SDG&E on August 3, 2000 preventing that company from collecting its shortfall. (See decision in case U 903-E at <http://www.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/1354.htm>.

As a result of the events in the California energy market, several sellers of electric power have been accused of various types of inappropriate behavior and have been or currently are under investigation. For example, Enron is the subject of an extensive federal and state inquiry, as has been Southern Company, Reliant, Mirant, Dynegy, El Paso Energy, Duke, Williams, Portland General Electric and others. The allegations generally accuse these sellers of various forms of market manipulation which served to increase wholesale electric power prices in California beginning in May, 2000. For example, the California PUC recently (September, 2002) released a "Report on Wholesale Electric Generation" (available at http://www.cpuc.ca.gov/static/industry/electric/wholesale+generator+report.pdf) which concludes that five companies (Dynegy, Duke, Reliant, Mirant and Williams/AES) failed to make available to the market all available power during periods of statewide blackouts or service interruptions. The Report establishes that Californians need not have experienced the large majority of blackouts and service interruptions in 2000-2001. The FERC also conducted a more general investigation into the potential manipulation of electric and natural gas prices in the Western United States. 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). The FERC Staff's initial report on this investigation is available at
<http://www.ferc.gov/electric/bulkpower/pa02-2/Initial-Report-PA02-2-000.pdf>.

California's three major investor owned utilities have experienced substantial financial distress as a result of business activities related to restructuring. As noted earlier, PG&E filed for bankruptcy protection in April of 2001. In addition there is a long list of integrated electric utilities that have experienced substantial financial trauma.

As a direct result of high wholesale prices and the inability of California's major investor owned utilities to collect those costs from retail customers, the utilities' resulting financial distress translated into credit induced service interruptions which prompted the State of California to purchase power on behalf the financially stressed utilities. These efforts resulted in California's commitment to purchase large amounts of power at very high prices for long periods of time. A portion of these contract costs have been financed through bond sales. In order to recover the costs associated with these bonds, the California PUC recently instituted a charge of between one-half cent and one cent per kWh on retails customers. This comes in addition to an approximate 3 cent per kWh average rate hike approved March 27, 2001 to support financially strapped PG&E and SCE.

While we know of no specific study that shows the precise impact of the California energy crises' blackouts and rate hikes on the California economy, it is clear that the crises has certainly not helped the California or U. S. economy at a time when other factors where causing substantial economic dislocations.

Finally, in Re San Diego Gas and Electric Company, Decision 01-09-060 (September 20, 2001), the California Public Utilities Commission suspended Direct Access (retail choice) for those customers who were not direct access customers as of the date of that order.

[51] In addition to the problems in California, the mid-western United Stated experienced substantial price spikes during the summers of 1998 and 1999. Those prices may have led to the addition of generating capacity, which in the presence of an economic recession and lower natural gas costs, have led to relatively low wholesale prices in that region of late. Despite these low wholesale prices, the only substantial residential choice penetration in the mid-west appears to be in the service territories of the FirstEnergy companies in the state of Ohio. This pattern is also true for industrial customers, although the penetration rates are surprisingly less for industrials than for residential customers.
See also Report to the Legislative Transition Task Force 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, Volume I, Part II (August 30, 2002).

[52] Pennsylvania's experience is demonstrative of this point. After the California disaster, Pennsylvania was held out as a restructuring success story measured in terms of switching customers, load, and the amount of money saved by retail customers. However, since mid-2000 there has been a marked decline in the amount of load provided by alternative suppliers. Also, by mid-2002, the number of competitive offers to customers that are below the price to compare (so that customers may save money versus staying with the incumbent) had fallen to just three --- all in the service territory of Philadelphia Electric Company. Most importantly, it is often reported that Pennsylvania electricity consumers have collectively saved a large amount of money due to restructuring. However, what is seldom mentioned is that much of those savings arose from Pennsylvania Public Utility Commission action that came at the expense of shareholders and applied to all customers --- even those that continued to receive service from their incumbent utility. *See e.g., Philadelphia Electric Company* - Form 8-K, filed with the U. S. Securities and Exchange Commission, January 26, 1998 and April 30, 1998.

[53] *See* Report to the Legislative Transition Task Force 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, Volume I, Part II (August 30, 2002).

[54] A large number of firms have been accused of or admitted to improper behavior. These behaviors fall into two major categories; market manipulation and securities fraud. Market manipulations involve various schemes to drive up or mis-report prices to increase the firm's profits. AEP fired five traders as a result of

the discovery of this practice at the company's energy trading unit. Williams and AES have recently been accused by the FERC of conspiring to drive up energy prices. *See* <http://www.ferc.fed.us/foia/williams-11-15-02.pdf>.

There has also been substantial evidence of behaviors that have as their goal increased stock prices. Here, traders are alleged to have engaged in "round-trip" trades that seek to misreport a trading entity's trading volumes. A trader buys and immediately sells power --- with the same counterparty --- solely to inflate its reported trading volumes and, thus, its stock price.

[55] In addition to California's major investor owned incumbent electric utilities, several other utilities have experienced substantial financial distress as a result of business activities related to restructuring. As noted in a prior endnote, PG&E filed for bankruptcy protection in April of 2001. In addition there is a long list of integrated electric utilities that have experienced substantial financial trauma. That list includes Allegheny Energy, General Public Utilities (since acquired by FirstEnergy), TXU Corporation, Excel Energy, Duke Power and others.

[56] There has been a near total washout in the merchant power business. Certain spun-off or unaffiliated merchant power producers are in the worst shape. Mirant, Calpine, Dynegy, Enron, Williams and AES fall into this category. Dynegy is on the verge of bankruptcy and may soon be de-listed by the New York Stock Exchange. Enron declared bankruptcy in late 2001. Mirant is losing money and has delayed filing its third quarter financial statement with the U.S. Securities and Exchange Commission as it addresses certain accounting issues. Calpine, like all or most merchant generating companies, has seen its stock price and credit ratings plummet and has scaled back plant development plans.

A recent article in Platts *ElectricUtility Week* reported that PG&E Corporation's merchant subsidiary, National Energy Group, may have to join its parent company in bankruptcy. The article notes that National Energy Group, which sold 280 million MWH in 2001 and has 27 generating units with a net capacity of 7,469 MW, would likely be defaulting on $1.4 billion worth of loans. *See Worst is to Come for Electric Sector, S&P Says as Financials Slide*, Platts Electric Utility Week, November 18, 2002, at 1.

The problem for the merchant generation industry has been caused by over aggressive plant construction. The expansion was financed primarily with debt. Venders must now try to sell power into a market with currently depressed prices due to over-capacity and recession induced poor demand. The resulting cash flows simply cannot cover financial obligations.

[57] Presentation of Kenneth Rose, Ph.D., to the Legislative Transition Task Force of the Virginia General Assembly, November 26, 2002, available at < http://www.state.va.us/scc/caseinfo/reports/rose_lttf_pres.pdf>.

[58] For example, in Virginia Kinder Morgan withdrew two pending merchant plant applications in November, 2002. These plants represented 1,110 MW of potential generation.

[59] As part of the continuing industry shakeout, a number of entities that once offered retail service are no longer doing so. For example, NewPower has declared bankruptcy and ceased operations. Integrated utility holding companies like Allegheny Power have terminated operations at business units that once sold competitive retail electric service. There has also been some degree of industry consolidation in this sector. AES NewEnergy, for example, was recently acquired by Constellation, the parent of Baltimore Gas & Electric.

[60] *Downward Credit Pressure Continues on U.S. Power Industry,* Standard &Poor's Utilities & Perspectives, October 14, 2002, at 2.

[61] *U.S. Power and Energy Sector Credit Slide to Continue*, Standard & Poor's Utilities**,** November 20, 2002.

[62] *Id*.

[63] On October 1, 2002, Moody's downgraded Allegheny Energy and Allegheny Energy Supply from "Baa2" to "Ba1" or to junk. Moody's stated that the downgrade was a result of declining cash flow and earnings

and increased reliance upon sales in the merchant power market, which Moody's expects to be depressed at least until 2004. Moody's also stated that Allegheny Energy's deteriorating financial performance is largely due to weak wholesale power markets and problems with its energy trading activities.

As a result of the downgrade, Allegheny Energy and Allegheny Supply were required to post additional collateral under the terms of their principal credit agreements with a number of its trading counterparties. Since Allegheny Energy declined to do so, these trading counterparties declared Allegheny Supply in default under these agreements on October 8, 2002. This default triggered the cross-default provisions under its principal bank credit agreements and other trading agreements.

Following the announcement of the technical default by Allegheny Energy and Allegheny Energy Supply, Standard and Poor's downgraded Allegheny Energy and all of its subsidiaries, including the corporate credit rating of The Potomac Edison Company, from "BBB" to "BB" on October 9, 2002. On November 6, 2002, Moody's further downgraded Allegheny Energy from "Ba1" to "B1".

On December 5, 2002, Allegheny announced that it will suspend its dividend payment to shareholders. It has laid-off 10% of its workforce or approximately 650 positions. Its 52-week high was $43.29 on April 19, 2002. Since Allegheny Energy's price hit its 52-week high it closed as low as $3.80 on October 8, 2002, which is down 91.22% from the high of $43.29.

[64] On October 9, 2002, Standard & Poor's downgraded The Potomac Edison Company's senior unsecured debt rating to "B+" or to junk bond status. Standard & Poor's attributed the downgrade of The Potomac Edison Company to the financial difficulties of its parent, Allegheny Energy. On November 6, 2002, Moody's lowered The Potomac Edison Company's senior unsecured debt rating from "Baa1"to "Ba1" which is in the junk bond category. Moody's stated that the downgrade reflects potential for increased pressure to support the cash needs of the parent and diminished financial flexibility of the family of companies. Moody's also noted that the renegotiated provider of last resort contract between Allegheny Energy Supply and The Potomac Edison Company has resulted in an increase in costs to The Potomac Edison Company.

[65] On May 23, 2002, Standard & Poor's downgraded American Electric Power Co. Inc. and its subsidiaries including Appalachian Power Company from "A-" to "BBB+". Standard & Poor's attributed the downgrade to the expected restructuring of AEP, whereby it will be organized along two business lines -- a regulated business line and an unregulated business line.

[66] See, for example, a recent article by Peter Behr, *A Shock to the System - Electricity Firms Return to Their Roots*, Washington Post , November 15, 2002. The article states "AEP – like the rest of the nation's battered power industry – has been forced back to its boring past, to a time when it delivered both electricity and slow, steady growth and predictable returns to its risk-averse investors." AEP's CEO E. Linn Draper Jr. was quoted in the article as stating: "I hope we have demonstrated that we have stable and traditional earnings and can support the dividend."

[67] *Virginia Electric and Power Co.'s revenue bonds rated BBB+*, Standard & Poor's Ratingsdirect Link, October 25, 2002. While Virginia Power's revenue bonds were assigned a rating of BBB+, it is assigned a higher corporate credit rating than its parent, Dominion Resources. In discussing this, the analyst stated the following:

> VEPCO is assigned a higher corporate credit rating . . . than parent Dominion Resources whose rating reflects a relatively high-risk growth strategy. VEPCO's higher rating is supported by adequate credit protection measures on a stand-alone basis, combined with statutory insulation, which restrains VEPCO from subsidizing holding company expansion into non-regulated activities . . .. VEPCO's ratings reflect the stability and predictability derived from a fully regulated revenue stream.

The strengths of VEPCO were, according to the analysts, partially off set by regulatory uncertainty after July 2007 when the rate caps expire. Standard & Poor's expects that VEPCO may be required to sell energy at market based prices that Standard & Poor's expects will be lower than the prices currently received and that the company may no longer be able to pass through stranded costs related to non-utility generation contracts. Standard & Poor's, however, "does not expect deregulation to have a significant effect on VEPCO's financials in the near term."

[68] Based on information gleaned from newspaper articles, meetings with power plant developers, merchant plant filings with discussion with other agencies, approximately 17,600 MW of new generating capacity to be sited in Virginia has been proposed or announced since January 1, 2001. Approximately 8,700 MW, or almost 50%, of this planned capacity has now been delayed or abandoned.

[69] As of last summer, the following twelve companies had electric CSP licenses issued by the Virginia State Corporation Commission: Pepco Energy Services, Dominion Retail, Washington Gas Energy Services, Allegheny Energy Supply, The New Power Company, Amerada Hess, AEP Retail Energy, NOVEC Energy Solutions, Old Mill Power, Cook Inlet Power, AES New Energy and Select Energy.

[70] On September 27, 2002, an order was issued revoking the license of Allegheny Energy Supply at the company's request. Cook Inlet Power's license has also been revoked (10/31/02) as was the license of The New Power Company (11/13/02). These revocations have not been for any violation or inappropriate behavior; rather these firms are exiting the business.

[71] Of the remaining nine licensed CSPs, only three have completed EDI testing with a utility and fully registered with that utility allowing them to make an offer to customers whenever they wish. Both Pepco Energy Services and Dominion Retail have done so with Virginia Power. Washington Gas Energy Services has done so with Conectiv. The only offer available in Virginia is the green power offer of Pepco Energy Services, and it is not marketing that offer.

It is important to note that all three of these entities are affiliated with a regulated energy utility. Pepco Energy Services is affiliated with the Potomac Electric Power Company serving the District of Columbia and parts of Maryland. Dominion Retail is affiliated with Dominion Virginia Power and Washington Gas Energy Services is affiliated with Washington Gas Light Company.

[72] *See* Report to the Legislative Transition Task Force 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, Volume I, Part II (Executive Summary to Part II, page ii) (August 30, 2002). *See also* California's order suspending retail choice Re San Diego Gas and Electric Company, Decision 01-09-060 (September 20, 2001) available at: <http://www.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/9812.htm>.