

PART II

Status of Retail Access and Competition in the Commonwealth

Executive Summary

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

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

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

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

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

The SCC has issued orders during the past year relating to issues such as competitive metering, supplier billing, market price/wires charge determination, regional transmission organizations, and several access programs within electric cooperative

territories. In addition to the September 1 reports on the status of competition and the December 2002 Addendum, the SCC has issued reports addressing energy infrastructure information and stranded costs. Slow development of competitive activity and statewide budget constraints have caused the SCC to suspend its consumer education efforts for the present.

PART II

STATUS OF RETAIL ACCESS AND COMPETITION IN THE

COMMONWEALTH

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INTRODUCTION

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

During the past year this Commission has continued with the scheduled implementation of the Restructuring Act. At the present time, 2.9 million electricity customers in Virginia have the right to choose an alternative supplier of electricity. By January 1, 2004, an additional 168,500 customers will gain the right to choose a supplier. In compliance with the Act and this Commission's Order in Case PUE-2000-00740, all electricity customers of Virginia's investor-owned utilities and electric cooperatives will be eligible to switch to a competitive supplier except for about 29,400 customers in the southwestern part of the Commonwealth² and approximately 7,000 customers served by Powell Valley Electric Cooperative.

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

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

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

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

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

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

ACTIVITY RELATED TO ACCESS

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

Transition to Full Retail Access (Phase-In)

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

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

³ Doing business in Virginia as the Potomac Edison Company ("PE").

⁴ EDI standards and guidelines are established by the Virginia Electronic Data Transfer Working Group ("VAEDT"). The VAEDT is discussed later in this report.

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

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

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

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

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

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

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

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

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

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

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

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

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

Suppliers/Aggregators

The Commission is responsible under §§ 56-587 and 56-588 for licensing suppliers and aggregators interested in participating in the retail access programs in Virginia. The Staff has established a streamlined mechanism for processing license applications. To facilitate the prompt processing of license requests, the SCC website provides access to the

licensing requirements.⁶ Staff has an internal deadline of 45 days from the receipt of a complete application to the issuance of a license. Thus far, that deadline has been met for all applications. Currently, nineteen electric and natural gas CSPs and aggregators are licensed by the Commission to participate in full retail access. A list of suppliers can be found at the end of this section. Since last year, five competitive service providers have voluntarily surrendered their licenses to do business as a CSP or an aggregator in Virginia.

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

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

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

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

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

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

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

Customer Type: "R" residential; "C" commercial; "I" industrial

LDC Service Territories:

AEP-VA = AEP Virginia

AP = Allegheny Power

DVP = Dominion Virginia Power

DPL = Delmarva Power & Light

CGV = Columbia Gas of VA

WG = Washington Gas

SG = Shenandoah Gas (division of WG)

Marketing

The only marketing activity that has taken place in any retail access program is in DVP's service territory. Pepco Energy Services continues to provide "green power" to residential customers in Northern Virginia. The renewable generation source is biomass,

landfill gas from a landfill in central Virginia. The offer consists of 51% renewable energy offered at a premium above DVP's price-to-compare.

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

Customer Participation

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

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

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

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

FUNCTIONAL UNBUNDLING AND WIRES CHARGE

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

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

Functional Unbundling

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

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

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

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

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

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

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

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

Wires Charge Calculations

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

Although the Commission's experience in determining market prices began in 2000 with the retail access pilots of AEP-VA, Rappahannock Electric Cooperative, and DVP, market price determination for full retail access began in 2001 with the market price and wires charges

determinations for AEP-VA and DVP.⁹ This past year the Commission established the market price determination methodology for the electric distribution cooperatives within the Commonwealth and approved projected market prices and any resulting wires charges for calendar year 2003.

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

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

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

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

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

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

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

The CSP opinions available to Staff notwithstanding, the workgroup led to a proposal by DVP to incorporate a capacity adder into the projected market price for the company's service territory for 2003. This adder is based on the historical monthly values of capacity as reflected in the PJM Capacity Credit Market. DVP conditioned its offer on certain changes to its CSP Coordination tariff that the company stated were necessary to make DVP whole in the event of a CSP default. In allowing, but not requiring, DVP to implement the capacity adder in

the company's market price and wires charge calculation, the Commission declined to allow for the changes in DVP's CSP Coordination tariff. The Commission believed that the proposed changes might have a negative effect on CSP participation in the Virginia retail market; however, the Commission will allow DVP to propose risk mitigation measures in the future if they are shown necessary. The Commission allowed DVP to implement the proposed capacity adder recognizing that it served to lower wires charges slightly and create additional headroom for CSPs and thus, was "a step in the right direction." Subsequent to the Commission's order, DVP incorporated the capacity adder in the company's 2003 market price and wires charge calculation.

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

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

Even with AEP-VA's proposed transmission cost adjustment calculation any calculated wires charges due the company from customers switching to CSPs have been zero or nil, implying that projected market prices calculated under the Commission-approved methodology

are in excess of AEP-VA's capped generation rate. Given this circumstance and the lack of a resolution over the company's method of calculating its transmission cost adjustment, AEP-VA has waived its right to collect wires charges in each of the past two years.

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

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

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

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

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

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

Price-to-Compare

Once rates have been unbundled and the appropriate wires charge has been calculated, a company's price-to-compare can be determined. The price-to-compare is a cents per kilowatt-

hour benchmark value that can be used by a customer to evaluate offers from competitive service providers.

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

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

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

The 2003 price-to-compare values are:

Investor-Owned Utilities

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

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

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

CONSUMER EDUCATION

Overview

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

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

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

All of the communications contractors supporting the SCC in the consumer education program agreed to suspend or greatly reduce activities during the curtailment period. These contractors also agreed to be available to help re-establish the VEC campaign if market

development substantiates the need for consumer education and funding is available beginning July 1, 2004.

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

Consumer Research

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

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

Advertising

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

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

Public Relations

The public relations program broadened the knowledge and awareness levels of Virginians by providing detailed information about energy choice through grassroots education and media relations. Media outlets across the state received a steady flow of updates on the consumer education efforts through December 2002. Although the news media was receptive

to VEC information, journalists were quick to learn that energy suppliers were not making competitive offers. The limited level of competitive activity resulted in a corresponding limited level of interest in covering energy restructuring, of which the VEC program was a part. Regardless, in the second year, the program still generated 32 print news articles in daily and weekly newspapers. Additional coverage was generated in television and radio broadcasts.

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

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

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

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

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

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

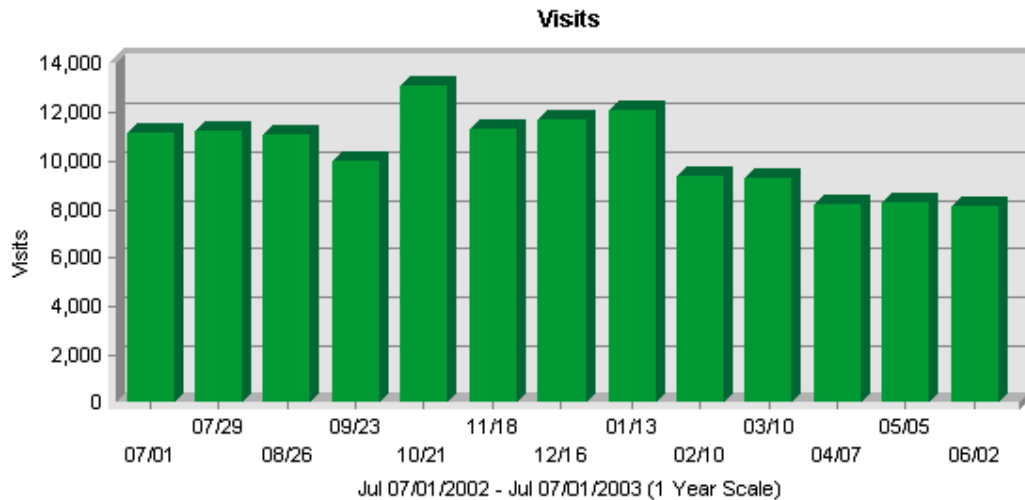
- the Urban League of Greater Richmond conducted a series of workshops for senior citizens on energy choice and produced educational materials (\$2,826.84),
- the Henry County Adult Learning Center incorporated energy choice information into an instruction program called "Energy Efficiency and Your Budget"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

Website

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

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

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



Call Center

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

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

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

Next Steps

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

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

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

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

DEVELOPMENT OF A COMPETITIVE STRUCTURE

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

Rules Governing Retail Access

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

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

¹² The rules were to be developed for both a competitive electricity market and a competitive natural gas market. Our focus in this report is the electricity market.

¹³ The Rules Governing Retail Access to Competitive Energy Services are available on the Commission's website at: <http://www.state.va.us/scc/division/restruct/main/rules/teirrules.htm>.

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

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

Minimum Stay Provisions

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

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

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

Competitive Metering Provisions

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

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

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

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

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

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

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

Competitive Billing Provisions

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

Aggregation

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

As discussed in greater detail in last year's report, the Commission established an investigation of aggregation issues with Case No. PUE-2002-00174.¹⁷ Questions had arisen with respect to which persons or entities needed to be licensed as aggregators.

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

¹⁶ The adopted rules may be found at: <http://www.state.va.us/scc/caseinfo/pue/case/e010298b.pdf> .

¹⁷ Available at <http://www.state.va.us/scc/caseinfo/pue/e020174.htm> .

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

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

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

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

Distributed Generation

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

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

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

Business Practices

The North American Energy Standards Board ("NAESB") serves to develop and promote standards leading to a seamless marketplace for wholesale, and retail, natural gas and electricity. NAESB is accredited as a standards-setting body from the American National Standards Institute, independent of policy and politics to build public-private partnerships with the FERC, the Department of Energy and the state commissions. NAESB's infrastructure and processes¹⁹ are recognized by the FERC as evidenced by FERC's charge to develop business practices for use by market participants to implement its final rule regarding standard market design or wholesale market platform.²⁰ Recognizing the ongoing convergence of the natural gas and electricity businesses, NAESB ensures that its implementation standards and business practices will receive and utilize the input of all industry sectors through its open membership and balanced voting processes.

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

¹⁹ Additional information regarding the NAESB may be found at: <http://www.naesb.org> .

²⁰ Additional information regarding FERC's standard market design and structure may be found at: <http://www.ferc.gov/Electric/RTO/Mrkt-Strct-comments/smd.htm> .

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

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

Virginia Electronic Data Transfer Working Group

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

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

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

²¹ Additional information available at: <http://www.vaedt.org> .

²² Additional information available at: <http://www.firstregionalEDI.org> .

region²³ and more easily exchange electronic information between electric utilities operating in multiple jurisdictions.

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

Generation and Transmission Additions

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

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

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

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

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

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

By order dated August 21, 2002, the Commission adopted filing requirements for applications filed on or after September 1, 2002.²⁵ In the August 21st Order the Commission also concluded that, due to the passage of SB 554²⁶, filing requirements addressing cumulative environmental impacts are not necessary and therefore are excluded from the Commission's filing requirements.

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

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

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

Company/Facility	Size	Location	Docket	Fuel	C.O.D.*	Status
<u>Power plants with SCC certificates that began operation within the last 5 years</u>						
Commonwealth Chesapeake	300 MW	Accomack County	PUE960224	3-OilCT	sum 01	8/5/98 Order
Dominion Virginia Power	600 MW	Fauquier County	PUE980462	4-GasCT	sum 00	5/14/99 Order
Wolf Hills Energy, LLC	250 MW	Washington County	PUE990785	5-GasCT	sum 01	5/2/00 Order
Dominion Virginia Power	360 MW	Caroline County	PUE000009	2-GasCT	sum 01	10/10/00 Order
Doswell Limited Partnership	171 MW	Hanover County	PUE000092	1-GasCT	sum 01	6/15/00 Order
Allegheny Energy Supply	88 MW	Buchanan County	PUE010657	2-GasCT	Jun 02	6/25/02 Order
Dominion Virginia Power	540 MW	Prince William County	PUE000343	Gas CC	Jul 03	3/12/01 Order
Louisa Generation, LLC (ODEC)	<u>472 MW</u>	Louisa County	PUE010303	5-GasCT	Jun 03	7/17/02 Order
	2,781 MW					
<u>Power plants with SCC certificates currently under construction.</u>						
Tenaska Virginia Partners I, LP	900 MW	Fluvanna County	PUE010039	Gas CC	sum 04	4/19/02 Approved
Marsh Run Generation, LLC	<u>468 MW</u>	Fauquier County	PUE-2002-00003	3-GasCT	sum 04	11/6/02 Approved
	1,368 MW					
<u>Power plants with SCC certificates, but not yet under construction.</u>						
Competitive Power Ventures	520 MW	Fluvanna County	PUE010477	Gas CC	spr 06	10/7/02 Approved
Tenaska Virginia Partners II, LP	900 MW	Buckingham County	PUE010429	Gas CC	fall 04	1/9/03 Approved
CPV Warren, LLC	520 MW	Warren County	PUE-2002-00075	2-GasCC	spr 05	3/13/03 Approved
White Oak Power Co., LLC	<u>680 MW</u>	Pittsylvania County	PUE-2002-00305	4-Gas CT	sum 04	8/1/03 Approved
	2,620 MW					
<u>Power plants that have applied for an SCC certificate</u>						
Chickahominy Power, LLC	665 MW	Charles City County	PUE010659	Gas CT	fall 03	HE Report pending
Duke Energy Wythe, LLC	620 MW	Wythe County	PUE010721	Gas CC	sum 04	Remanded 3/11/03
James City Energy Park, LLC	580 MW	James City County	PUE-2002-00150	2-GasCC	1/05	HE Report pending
CinCap-Martinsville	<u>330 MW</u>	Henry County	PUE010169	4-GasCT	sum 03	Dismissed 4/29/03
Kinder Morgan VA, LLC	<u>560 MW</u>	Cumberland County	PUE010722	Gas CC	sum 04	Dismissed 1/14/03
Kinder Morgan of Virginia, LLC	<u>550 MW</u>	Brunswick County	PUE010423	Gas CC	win 04	Dismissed 11/1/02
Henry County Power/Cogentrix	<u>1,100 MW</u>	Henry County	PUE010300	Gas CC	sum 04	Dismissed 7/31/03
Loudoun County Power/Tractebel	<u>1,400 MW</u>	Loudoun County	PUE010171	Gas CC	sum 05	Dismissed 3/27/02
Mirant Danville, LLC	<u>870 MW</u>	Pittsylvania County	PUE010430	Gas CC	sum 04	Dismissed 2/6/02
Total	6,675 MW	(4,810 MW dismissed leaving 1,865 MW under consideration)				

*Commercial Operation Date

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

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

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

Transmission lines

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

Regional Transmission Organization membership pending before the SCC

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

Natural gas pipelines

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

Energy Infrastructure Study

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

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

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

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

RTE Development

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

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

²⁷ RTE and RTO (Regional Transmission Organization) are essentially synonymous terms. The former is used in the Act; the latter is the Federal Energy Regulatory Commission ("FERC") preferred acronym.

²⁸ § 56-579 A 2 d.

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

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

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

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

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

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

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

AEP-VA

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

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

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

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

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

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

³¹ See <http://www.state.va.us/scc/caseinfo/pue/e000550.htm>

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

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

On July 17, 2003, the Kentucky Public Service Commission denied AEP's application to transfer control of its major transmission lines in Kentucky to PJM. The PSC determined

that the proposed transfer would not be in the public interest because it would impose costs on Kentucky Power ratepayers without providing demonstrable benefits. The PSC cited the following factors in denying Kentucky Power's application to join PJM:

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

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

Allegheny

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

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

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

On July 12, 2002, the Staff filed a Supplemental Report recommending that the Commission delay approval of Allegheny's application until more information was known about the ITC proposal for PJM West, Dominion's PJM South proposal, and the outcome of PJM and MIS0 discussions to form a single energy market across the PJM and Midwest regions.

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

Delmarva

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

On June 1, 2001, the SCC issued a procedural order prescribing notice and inviting comments on Delmarva's request. By Order dated June 22, 2001, the SCC created a separate docket, Case No. PUE-2001-00353, to receive comments and requests for hearing on Delmarva's request. On August 17, 2001, the Staff filed a response to Delmarva's request. In

its response, the Staff noted that the FERC had issued an order on July 12, 2001, provisionally granting RTO status to PJM. The Staff commented that the FERC had strongly encouraged the formation of one Northeast RTO encompassing PJM, the New York Independent System Operator, and ISO New England.³² The SCC Staff observed that the FERC's Order raised the possibility that PJM's configuration could change if a larger Northeastern RTO developed as a result of the involuntary mediation process the Commission had initiated. The Staff, therefore, recommended that the SCC either delay acting on, or grant only interim approval of, Delmarva's request until more was known about the mediation process and about any Northeastern RTO that might be formed.

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

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

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

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

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

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

Dominion Virginia Power

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

Kentucky Utilities

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

FERC Fact Finding Investigation

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

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

FERC SMD NOPR

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

DOE Cost/Benefit Study of SMD

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

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

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

With regard to the benefits attributable to SMD by the DOE study, they are small. Once the cost of implementing the SMD is considered (about \$760 million annually according to DOE), the FERC initiative is expected to generate net nationwide savings of approximately \$1 billion per year over the short-term and between \$200 million and \$700 million over the long-term. While these are large absolute numbers, they represent a very small decline in the

transmission and generation components of rates. The best case savings of \$1 billion annually yields a decline in the transmission and generation components of a customer's bill of approximately 1 percent. The percentage savings relative to a customer's total bill will be even less when distribution costs are considered. With appropriate sensitivity and risk analysis the savings could easily disappear and become negative; that is, the SMD initiative could result in higher average electricity prices nationwide.

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

OTHER ACTIVITIES AND ISSUES

Default Service Investigation

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

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

This Commission issued an Order in this case on July 24, 2003, adopting Staff's recommendations that the components of default service include all elements of electricity supply service and that the incumbent electric utilities provide default service at capped rates until modified by future order of this Commission. Similar to last year, several participants

indicate that other obstacles need to be resolved before competitive markets will be able to offer meaningful alternatives to the incumbent utilities. Specifically, the major obstacles to a competitive marketplace, as identified by participants, continue to be capped rates, wires charge structure for the recovery of yet unquantified stranded costs, lack of RTE membership, and the retail electricity supply cost components. Participants claim such items need to be addressed in order for competition to flourish in Virginia.

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

Stranded Costs

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

By July 1, 2003, present to the Legislative Transition Task Force the work group's consensus recommendations regarding:

(a) Definitions of "stranded costs" and "just and reasonable net stranded costs."

(b) A methodology to be applied in calculating each incumbent electric utility's just and reasonable net stranded costs, amounts recovered, or to be recovered, to offset such costs, and whether such recovery has resulted in or is likely to result in the overrecovery or underrecovery of just and reasonable net stranded costs.

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

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

On March 3, 2003, the Commission entered an Order Establishing Proceeding (the "Order"), docketing Case No. PUE-2003-00062.³³ The Order provided guidelines on establishing the work group, a schedule for work group activities, and requested that interested persons respond to a series of questions. The work group held four sessions where definitions and methodologies were discussed in depth. In addition, work group members provided written responses³⁴ to issues brought up during the work group sessions. Work Group members were unable to reach consensus on the issues before it.

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

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

³³ See <http://www.state.va.us/scc/caseinfo/pue/e030062.htm>

³⁴ See http://www.state.va.us/scc/division/eaf/comments_strandedcosts.htm

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

Staff recommended the use of the following definitions:

Stranded Costs are a utility's net loss in economic value arising from electric generation-related costs that become unrecoverable due to restructuring and retail competition.

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

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

Staff presented two methodologies. The first calculates just and reasonable net stranded costs based on an asset valuation methodology. The second is an accounting approach that (1) measures recoveries of stranded costs from capped rates and wires charges, (2) measures potential stranded costs on an annual historic basis³⁵, and (3) after July 1, 2007 could be used to

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

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

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

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

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

Staff believes that to monitor the over- or under-recovery of just and reasonable stranded costs one must calculate two numbers: (1) total just and reasonable net stranded costs; and (2) recoveries of stranded costs from capped rates and wires charges. Staff favors using an asset valuation methodology to determine just and reasonable net stranded costs. Although complex, it is the best tool available. To calculate recoveries of stranded costs from wires

charges and capped rates, Staff believes information currently filed annually with the Commission should be used. This information is used to measure a utility's earnings and is much less complex than rate cases.

Attachment 6 to Staff's Stranded Cost Report provides an earnings test analysis of Dominion Virginia Power for the four years that capped rates have been in place, 1999 through 2002. On a cumulative basis, the attachment reflects \$886 million of excess earnings which could be applied to stranded cost recoveries³⁶.

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

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

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

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

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

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

Financial Profile of Virginia's Electric Utilities

Since the electric industry is capital intensive, it is very important that electric utilities be able to raise capital on reasonable terms and at favorable rates. A major factor influencing the terms and rates a company is able to obtain when raising debt capital is its credit ratings. The two major rating agencies are Moody's Investors Service ("Moody's") and Standard & Poor's Ratings Services ("S&P"). S&P assigns bond ratings ranging from "AAA" to "D", with a plus (+) or minus (-) added to show relative standing within the major categories. Moody's

assigns ratings ranging from "Aaa" to "C", with a modifier of 1, 2 or 3 in each ratings category from "Aa" through "Caa" to show relative standings within the major categories. A bond rated below "BBB-" by S&P or "Baa3" by Moody's is considered non-investment grade or a "junk bond".

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

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

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

³⁷ Standard and Poor's Industry Report Card: U.S. Electric/Gas/Water; April 28, 2003.

³⁸ Standard and Poor's Updates Refinancing Needs for the Energy Merchant Sector; Top 10 Rated U.S. Power Companies with the Most Refinancing Needs 2003-2006; April 3, 2003.

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

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

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

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

³⁹ Standard and Poor's Research: Regulated Operations Back in Fashion for U.S. Electric Utilities; June 19, 2003.

⁴⁰ Standard and Poor's Project Finance and Infrastructure Finance; October 2002.

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

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

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

concerns, according to S&P. Moody's confirmed ratings for KU and LG&E in September 2002, but assigned a negative outlook to LG&E.

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

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

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

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

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

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

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

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

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

Proposed Retail Access Pilot Programs

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

The three Pilots consist of: (i) a Municipal Aggregation Pilot, in which one or more localities may aggregate its residential and small commercial customers utilizing an opt-in method⁴⁵ and one or more localities may aggregate its residential and small commercial customers utilizing an opt-out⁴⁶ method for the purpose of soliciting bids from CSPs for electricity supply service; (ii) a Competitive Bid Supply Service Pilot,⁴⁷ in which CSPs will bid to serve blocks of residential and small commercial customers; and (iii) a Commercial and Industrial Pilot, in which CSPs can make offers to large Commercial and Industrial customers with demand equal to or greater than 500 kW.

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

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

⁴⁴ Moody's Credit Perspectives; Dominion Resources' Outlook Now Negative; September 23, 2002.

⁴⁵ The opt-in method requires that a consumer affirmatively choose to participate.

⁴⁶ The opt-out method requires that a consumer affirmatively choose not to participate; absent such a decision the consumer will be included.

⁴⁷ Originally named the Default Service Pilot. Following discussion with interested parties, the Company revised the name in an effort to minimize the potential for customer confusion.

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

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

On April 21, 2003, the Commission issued its Order Prescribing Notice and Inviting Comments and Requests for Hearing establishing this proceeding as Case No. PUE-2003-00118.⁴⁸ Subsequently, as a result of discussions with interested parties and in an attempt to address concerns expressed in those discussions, DVP submitted revisions to its application on June 25, 2003. Staff investigated the application and filed its report on July 15, 2003. Several parties submitted comments with no one requesting a hearing.

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

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

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

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

Future SCC Activity

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

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

⁴⁸ See <http://docket.scc.state.va.us:8080/vaproduct/main.asp> , Case No. PUE-2003-00118

- Continue the evaluation of stranded costs and associated over or under recovery.
- Continue to solicit ideas from stakeholders about methods to attract CSPs to the Commonwealth.
- Continue to monitor approaches being used in other states to attempt to stimulate competitive activity.
- Reactivate the education of consumers about choice when it appears appropriate, although at a pace that conserves resources.
- Evaluate the merits of proposed pilot programs to test our infrastructure for a competitive retail marketplace.

APPENDIX I-A

**SUMMARY OF NATURAL GAS RETAIL
ACCESS PROGRAMS IN VIRGINIA**

SUMMARY OF NATURAL GAS RETAIL ACCESS PROGRAMS IN VIRGINIA

This appendix updates last year's report regarding natural gas retail access programs in the Commonwealth of Virginia. Large natural gas customers in the Commonwealth have been allowed to arrange for their own supply and transportation of gas for more than ten years. Natural gas retail access is now available through two programs, one in the service territory of Washington Gas Light ("WGL"), including customers within the service area of Shenandoah Gas, and the other in the territory of Columbia Gas of Virginia ("CGV").

WGL's Retail Access Program

As of July 1, 2003, WGL's program has eleven active CSPs serving slightly more than 7,000 non-residential customers and three active CSPs serving approximately 69,900 residential customers. Cumulatively, these accounts represent approximately 20.3 percent of the 378,642 natural gas customers in WGL's service territory. It is important to note, however, that WGL's unregulated affiliate, WGES, is serving approximately 76 percent of the non-residential shoppers and approximately 73 percent of residential shoppers. The CSP serving the next largest group of customers is also an unregulated affiliate of an incumbent LDC and accounts for almost 13 percent of non-residential customers and about 25 percent of residential customers.

CGV's Retail Access Program

As of July 1, 2003, there are four CSPs providing service to 487 non-residential customers and 6,119 residential customers. Cumulatively, these accounts represent approximately 3.2 percent of the 207,089 natural gas customers in CGV's service territory. It is noteworthy that the same affiliates referenced above serve the greatest number of CGV customers as well, approximately 63 percent and 29 percent, respectively.

CSP Activity

The two natural gas retail access programs have provided useful information to utilities, CSPs, consumers, and the Commission Staff. The level of CSP activity has been considerably better in the natural gas programs than has been experienced in the electric programs, although a high level of affiliate market concentration may have distorted the actual level of competitive activity.

There have been several CSPs to terminate service to customers and return their customers back to the incumbent utilities. This was due in large part to the significantly higher natural gas prices experienced during the past year.