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Administrative Law News

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SCC Approves Settlement in Virginia Electric and Power Company's Rate Case Case No. PUE-2009-00019

By Elaine Sanderlin Ryan

On March 11, 2010, the State Corporation Commission ("Commission") issued a unanimous order approving a Stipulation and Recommendation and Addendum and Modification ("Stipulation and Addendum") agreed to by Commission Staff and all parties to the proceeding as a resolution of issues raised in Virginia Electric and Power Company's ("Company") application for a base rate increase and several parallel proceedings. The parties reached the settlement following a 10 day evidentiary hearing in which the Commission received testimony from approximately 40 witnesses and admitted more than 125 exhibits into the record.

Code § 56-585.1 A directs the Commission to initiate proceedings within the first six months of 2009 to review the rates, terms and conditions for the provision of generation, distribution and transmission services of each investor-owned electric incumbent utility. Under the new provision, the Commission is required to determine fair rates of return on common equity applicable to the utility's generation and distribution services using any methodology it finds consistent with the public interest. The rate of return must meet or exceed a floor determined by calculating the average returns of other investor-owned electric utilities that comprise the utility's statutorily defined "peer group." The combined rate of return may be further increased or decreased by up to 100 basis points for generating plant performance, customer service and operating efficiency, as compared to nationally recognized standards.

The Commission found that the Stipulation and Addendum "are just and reasonable and satisfy the relevant statutory

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ABOUT THE EDITOR Ashley Beuttel Macko is an Assistant Attorney General in the Insurance and Utilities Regulatory Section at the Office of the Attorney General. Before joining the Attorney General's Office in 2005, she worked in private practice for a large law firm. She has experience in administrative and regulatory law matters including electric, natural gas, telecommunications, water and insurance issues. She received her J.D. from the University of Richmond and her undergraduate degree from Wake Forest University.

Message from the Chair . . . Vishwa B. Link

Spring is in full bloom here in Richmond after a long, difficult winter. We know our colleagues up north and to the west had it even worse and we hope you're enjoying the blooms and reawakening of the environment. As images of spring cleaning and new beginnings come to mind, the Board of the Administrative Law Section has been focusing on new initiatives and planning for the future. We are excited to bring you the 28th Annual National Regulatory Conference to be held in our usual home of Williamsburg, Virginia at the Marshall-Wythe School of Law. This year's agenda is focused on the role of technology and how it is shaping and will shape the energy and telecommunications arenas. Please join us on May 20-21, 2010 for "The Future for Utilities: Science or Fiction? Exploring the Promises for the Future of the Energy and Telecommunications Industries Through Technological and Market Innovation." The conference promises to be both informative and entertaining and is submitted for 8.5 hours of CLE, including 2.0 hours of ethics.

In the spirit of spring cleaning and innovation, we are also focusing our efforts to broaden our service to the Administrative Law Section. We recently held a Brown Bag CLE Luncheon here in Richmond entitled, "The Nuts and Bolts of Practicing Before Administrative Law Judges." This diverse and instructive session was offered free to our membership (including lunch and one hour of CLE) where we heard from Robert S. O'Neal, Chief Administrative Law Judge and Director of Hearings for the Department of Alcoholic Beverage Control ("ABC"), Frederick M. Bruner, Deputy Commissioner for the Worker's Compensation Commission and Alexander F. Skirpan, Jr., Senior Hearing Examiner for the Virginia State Corporation Commission. Bringing this group of administrative law judges together allowed our section to gather to discuss important areas of practice of our constituency, those who practice before the ABC Board and the Worker's Compensation Commission, as well as the State Corporation Commission. We heard from the administrative law judges that there is keen interest in expanding the bar of lawyers who practice before those agencies, especially the Worker's Compensation Commission, which struck me as a call to action to broaden our efforts to include these other areas of administrative practice in our Board efforts.

To that end, and in the spirit of spring renewal, I ask that you get involved in the work of the section to help us expand our focus. Whether it is by writing an article about a major decision at an agency you practice before or submitting an idea to the Board for consideration at a future Brown Bag Luncheon, Annual Meeting program or at the National Regulatory Conference, we would like our section efforts to be more representative of our constituents. Naturally, we need your help to do this, so please contact any member of the Board with your thoughts and ideas.

Now back to the yard to finish that spring cleaning.... ❇

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Transmission Planning Revisited: FERC Goes on a Listening Tour

By Kenneth A. Barry

In the closing months of 2009, the Federal Energy Regulatory Commission (FERC) waded into the jungle of emerging transmission issues facing RTOs, ISOs, and "stand-alone" electric systems alike. With the dust barely settled on implementation of Order No. 890 – FERC's 2007 issuance that significantly remapped the rules of the road for transmission planning – this latest foray underscores the high importance FERC attaches to refining transmission expansion policies and practices. But before we look at the latest issues and challenges FERC is spotlighting – as well as the responses of utilities and customer groups – it would be helpful to sketch in some background.

FERC Orders 888, 890, and Transmission Systems Under Stress

Putting transmission planning under the microscope is nothing new for FERC. Grid reinvestment and expansion policies have been a preoccupation of the Commission ever since its 1996 issuance of Order No. 888 – the landmark ruling establishing "open access" transmission as the underpinning of a reconceived wholesale industry structure based on price competition in generation.[1] FERC's restructuring effort centered on a newly designed transmission tariff called the "*pro forma* OATT."[2] All FERC-jurisdictional utilities with significant transmission assets had to adopt the *pro forma* OATT in the form specified by FERC, or request case-specific variances.[3]

With FERC's new market paradigm forcing the "unbundling" of generation from transmission services, electric utilities were expected to become, in effect, common carriers for third-party energy sellers, on top of their traditional duty to maintain adequate facilities to serve native load. This meant both operating and (if necessary) physically expanding the system to enable eligible customers to gain access to competitive generation sources. While developing the "robust" transmission network necessary to accomplish this goal became FERC's watchword, the stubborn fact was that grid investment remained sluggish after both Order No. 888 and its 1999 epilogue, Order No. 2000, which expressly encouraged utilities to form RTOs. Not only were major new transmission facilities costly and difficult to get sited, but creating a competitive energy market gave mixed motives to transmission-owning utilities that retained big stakes in the generation business, when it came to sinking new investment dollars in the "wires side." Although devoting capital to transmission expansion would earn a reliable, albeit regulated, rate of return, it would also expose the utility's regional generation assets to increased competition. Even in those regions served by RTOs or ISOs – which routinely engage in coordinated, multilateral system planning to serve a broad footprint -- the "mixed motive" problem could lurk below the surface as a drag on system expansion.[4] To dissolve this inertia, FERC aggressively sought ways to incentivize transmission development and dismantle institutional barriers.[5] Most observers would credit this stimulation policy with some success.

In 2007, FERC stepped up its emphasis on transmission planning, within the framework of a comprehensive rulemaking to update Order 888's original *pro forma* OATT (which was by then 10 years old). The end product, Order No. 890, contained an assortment of tweaks to the *pro forma* OATT crowned by one truly sweeping reform -- a more open transmission planning process. FERC directed all jurisdictional transmission providers to explain how they proposed to adhere to nine newly articulated "planning principles," to be embodied in a new appendix to their individual OATTs. The main thrust of the nine principles can be summed up in a few words: to invigorate transmission planning by giv-

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1 While setting up a platform to accommodate retail as well as wholesale generation competition, FERC has jurisdictional limitations that prevented it from ordering states to impose retail competition; hence today, we have a patchwork quilt of states with retail "customer choice" and those whose *retail* systems are regulated as natural monopolies selling energy and delivery services as a "bundled" product.

2 The acronym stands for "Open Access Transmission Tariff."

3 RTOs/ISOs were given more latitude to seek variations, and the centralized energy-market business models of most RTOs/ISOs have led to significant areas of departure from the *pro forma* OATT. Non-jurisdictional transmission systems (such as those owned by co-ops or Federal or state agencies) also generally adopted the OATT as a "reciprocity tariff," which was a condition for receiving open access service *from* jurisdictional utilities.

4 This would be more the case in regions served by PJM and most of MISO -- and less so in New England and New York, where divestiture of generation assets was the rule.

5 FERC's arsenal includes new Federal Power Act Section 219, part of the Energy Policy Act of 2005, containing authority to reward transmission investment with a variety of financial incentives. This has spurred considerable new investment in transmission construction, including in PJM, over the last 4 years. In addition, FERC has actively encouraged (1) "merchant" transmission investment by non-traditional entities; (2) the complete separation of ownership of generation from transmission assets (*i.e.*, the "transco" model for transmission-owning utilities); (3) institutions for conducting broader transmission planning in regions resistant to creating RTOs/ISOs; and (4) the formation of new types of transmission investment partnerships to step in and build major, high-voltage transmission projects.

ing it a more regional (and even *inter*-regional) focus, with transparent, "user-friendly" procedures designed to facilitate more active stakeholder participation. The intent was to turn what had historically been a cloistered, utility-dominated process into a "big tent" collaboration in which customers, competitors, state regulators, and anyone else with a plausible interest could get into the loop early and inject their own ideas on what system improvements should be prioritized.[6] In addition, FERC insisted on making the consideration of *alternative solutions* to "transmission" issues – e.g., generation, merchant transmission, and demand response resources – an ingrained part of the planning process, rather than externalities.

Throughout 2009, as it reviewed transmission provider filings to implement Order 890, FERC forewarned that it would soon turn to examining how the new guidelines were performing, what refinements might be warranted, and – as its vintage 2007 revision of the OATT receded in the rear-view mirror -- what cutting-edge issues needed tackling. It held three regional technical conferences in September 2009 to probe these points, and, in the following month, put out a "Notice of Request for Comments"[7] listing these leading transmission concerns:

- *Whether existing coordination efforts of "sub-regional" planning groups are too rudimentary to identify or "right-size" alternative regional solutions.*
- *Whether regional planning processes are sufficiently open to stakeholder participation and are consistent in planning assumptions, data, and models.*
- *Whether "interconnection-wide" planning processes stimulated by the American Recovery and Reinvestment Act of 2009 will lead to broader solutions.*
- *Whether system impact studies oriented towards reliability and those designed to evaluate "economic efficiency" opportunities or to meet renewable resource portfolio standards (RPS) should be better aligned.*
- *Whether "merchant" and "independent" transmission projects are appropriately treated under existing planning regimes, or face unwarranted barriers.*
- *Whether the existing, queue-based interconnection process is hindering the transmission system's ability to integrate new generation.*
- *Whether current rules go far enough in standardizing the way that "demand resources" (demand response, efficiency, and distributed storage) are treated.*
- *Whether uncertainty over cost allocations for cross-regional projects is inhibiting their development; if so, what allocation methodologies should be adopted?*[8]

FERC's enquiries generated a myriad of viewpoints submitted in October and November by RTOs/ISOs and other transmission providers, transmission-dependent utilities, generator and consumer associations, and regulatory bodies. Since PJM's opinions on systemic flaws and feasible solutions arguably have the greatest single impact on Virginia utilities and customers, the focus below is on that RTO's advice to FERC, along with the reactions of other entities with a strong local presence.

Stakeholders Concerns and Solutions

Broader and more flexible transmission planning principles, with FERC buy-in. PJM is chafing against the built-in restrictions in the current planning regime, wherein maintaining reliability is still the dominant driver. So-called "economic efficiency" projects are also considered, but PJM finds itself hamstrung by overly "formulaic, bright-line" tests -- superimposed by FERC -- for measuring the sufficiency of customer benefits. Moreover, the current planning process is not well-geared towards enhancing access to renewable resources, which are typically clustered in remote areas with transmission facilities too fragile to carry the new loadings. PJM therefore calls for a new FERC rulemaking to identify broader planning criteria to accommodate the growing list of policy objectives. Its comments also advocate a more proactive level for FERC itself in *evaluating* PJM's "recommendations" for expansion,[9] as well as greater "finality" for approved projects, in the face of requests for subsequent "restudies."[10] Similarly, PJM seeks guidance on how much "deference" it should pay to state or regional priorities such as economic development or promotion of local resources.

Cost allocation guidelines for large regional (or inter-regional) projects. Measuring the potential long-term benefits of large transmission projects that transcend single service territories, and allocating the resulting costs, are inherently difficult and controversial. PJM seeks guidance on how to accomplish such allocations, as well as choosing between large-scale projects boasting economic efficiency payoffs, versus projects focused more on improving the deliverability

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[6] Note, however, that while the reforms gave a seat at the table and enhanced input rights to a wide spectrum of parties in interest, it kept the transmission provider (*i.e.*, the RTO, ISO, or standalone utility) the ultimate decider, subject to existing Federal and state regulatory review.

[7] Oct. 8, 2009, Doc. No. AD09-8.

[8] The Notice of Request for Comments included ten sub-questions on this topic alone.

[9] PJM explained that it currently files *cost allocations* for FERC approval resulting from its annual transmission plan, not the plan itself. Its comments envision putting FERC more in the driver's seat -- along with the PJM Board -- in choosing among *competing* projects that could meet FERC and state policy objectives.

[10] PJM notes that this "finality" is *not* intended to undercut state need and siting reviews.

of local renewable resources. In addition, the ongoing debate between "socializing" system expansion costs uniformly throughout the entire RTO footprint versus "assigning" the costs to internal zones based on their relative benefits surfaced, with Old Dominion Electric Co-op (ODEC) urging the former and Dominion Resources the latter.[11]

More definitive interregional planning processes. While PJM noted that it is already fully immersed in multiple collaborative planning processes with neighboring regions and the Eastern Interconnection as a whole, ODEC identified a need for more sharply defined interregional processes that mimic the stakeholder participatory rights at the core of Order 890. Progress on this front would also entail more "top-down" planning by multi-regional collaboratives, ODEC suggested, as opposed to a mere "roll-up" of projects developed in smaller planning units. Dominion, for its part, endorsed the current status of multilateral planning processes bridging regions, subject to continuing assessment of whether they are meeting Order 890 standards.[12]

More system support for integration of renewable resources. PJM explained that is caught between considerable "public policy" pressures to integrate renewable resources[13] and existing, FERC-approved planning criteria that do not reflect this planning imperative. Moreover, PJM called for a "reconciliation" of the clashing philosophies between cost allocation for generator interconnection-related system upgrades (where all the costs are imposed on the generation developer) and the "public policy" favoring broader system financial support for upgrades necessary to access location-constrained renewable resources like wind farms.[14]

Merchant transmission policies. Both Dominion and ODEC urged FERC not to disturb the current policy under which incumbent transmission owners serve as the primary constructors of new transmission facilities to maintain reliability. Dominion warned of adverse impacts on system coordination and reliability if existing zones began to exhibit a "patchwork" of different transmission owners.

The foregoing is just a sampling of the wealth and diversity of opinions FERC received on how to reshape transmission planning criteria and processes to meet the challenges of the coming decade. While reviewing and synthesizing this input is a considerable undertaking in itself, we can expect FERC to keep it on the front burner. ❇

About the Author: Kenneth A. Barry is a long-time energy attorney who practiced in-house for a Richmond-based industrial consumer, Reynolds Metals, for over twenty years. From 2000, he was Counsel with Hunton & Williams' Washington, D.C. office, working primarily on behalf of independent transmission entities as well as advising in various FERC and state electric and gas regulatory matters. Since 2006, he has assisted a major law firm in advising clients on FERC developments in a consulting capacity. He is a member of the Virginia, D.C., and New York bars, and lives in Northern Virginia.

11 Dominion argues that if the socialization principle is to be used at all, it should be limited strictly to high-voltage (500 kV and above) projects for reliability only. The whole issue is currently under reconsideration at FERC, following a judicial remand of PJM's adoption of cost socialization for *all* projects rated at 500 kV or above.

12 Dominion also suggested that current stakeholder participation rights are sufficient, both in PJM sub-regional planning groups and in multi-regional collaboratives in which PJM participates.

13 Eight states plus the District of Columbia served by PJM currently have RPS requirements in place, the RTO notes.

14 For example, the governors of New Jersey, Maryland, Delaware, and Virginia made a joint filing urging broader *system* ratepayer support for integrating off-shore wind development to meet RPS mandates.

Web Site News

The Section's home page on the Virginia State Bar's web site now provides a helpful bit of history, reflecting past developments in state regulatory law and the Section's efforts to keep its membership apprised of those developments. A comprehensive collection of Administrative Law News dating back to 1988 can now be accessed on-line. In addition, the programs of every National Regulatory Conference can be downloaded.

The Administrative Section home page can be found at http://www.vsb.org/sections/ad/index.htm Or, if it's easier, just go to the State Bar's web site (www.vsb.org), click on "member resources," then "sections," then "administrative law."

Can Cost-effective Energy Conservation and Demand Response Programs Realistically Achieve Energy Reductions? SCC Report Answers Yes.

By Kiva Bland Pierce

At the direction of the 2009 General Assembly, the State Corporation Commission initiated Case No. PUE-2009-00023[1] to determine what achievable, cost-effective energy conservation and demand response targets could realistically be accomplished in Virginia by electric utilities demand-side management portfolios.[2]

The Commission identified nine specific questions to be addressed in the proceeding including what is an achievable, cost-effective energy conservation and demand response target that can be realistically accomplished through generating utility's DSM portfolio and what industry tests should be used to evaluate demand side management ("DSM") programs.[3] Three utilities, Virginia Electric and Power Company ("Dominion"), Appalachian Power Company ("APCo"), and Kentucky Utilities Company were required to file testimony. Other parties included the Southern Environmental Law Center, MeadWestvaco Corporation, Piedmont Environmental Council, Washington Gas Light, the Virginia Committee for Fair Utility Rates and the Old Dominion Committee for Fair Utility Rates, Virginia Energy Purchasing Governmental Association, Ice Energy Corporation, New Era Energy, Inc., EMeter Corporation and Robert Vanderhye. Not all participants filed testimony. A hearing was held in September.

Dominion indicated that a 10% reduction over 15 years, using 2006 base year, was aggressive but realistically accomplishable. It recommended using interim targets to assess achievability and cost-effectiveness. Dominion asserted that the four industry tests (Ratepayer Impact Measure test, Total Resource Cost test, Participant test, and the Utility Cost test) should be used to evaluate the cost-effectiveness of various programs, but stressed that the tests should not be used so that failure of one test would automatically disqualify a program. Rather, Dominion recommended that the tests be applied to an entire demand side management portfolio.

APCO asserted that a realistic approach would be that it could achieve a 2% energy savings from that consumed in 2008 within 5 years of program implementation. APCo advocated that the Commission use the Total Resource Cost ("TRC") test when evaluating DSM programs. APCo also expressed concern over the potential number of its large customers that would be able to automatically opt-out of any DSM programs.

Kentucky Utilities represented that it could achieve a 5% reduction in energy through 2024. While Kentucky Utilities advocated the use of all 4 industry tests, it stressed that the TRC test should receive additional weight since it evaluates whether net benefits will be created for customers and utilities.

The Southern Environmental Law Center ("SELC") asserted that energy efficiency alone could achieve energy savings of 12% of forecast load in 2022 and that 1.3% energy savings each year within 4 years of program implementation. SELC advocated the sole use of the TRC test.

Mr. Vanderhye testified that Virginia could achieve a 20% reduction in electricity consumption in a short period of time by simply instituting an inclining block rate structure for residential customers. He found that energy consumption would be reduced by 3% in the first year, 6% within the next several years, and 20% shortly afterwards by changing electric utilities' rate design.

Ice Energy, Inc. advocated for the use of the TRC test when evaluating DSM programs.

MeadWestvaco advocated for the use of the RIM test and the evaluation of each program by itself, not on a portfolio basis. Washington Gas Light asserted that higher reductions could be achieved if the use of natural gas is considered for residential and commercial heating. The Piedmont Environmental Council urged the Commission to recommend a energy target more than 10%. The Virginia Committee for Fair Utility Rates and the Old Dominion Committee for Fair Utility Rates also advocated the use of the RIM test. The Commission Staff asserted that the RIM test should be given the greatest weight because it is based on objective factors.

The Commission issued its Report to the Governor and General Assembly on November 15, 2009 concluding that a 10% energy reduction by 2022 is achievable.[4] The Commission cautioned that any additional reductions in energy consumption could significantly raise rates. Additionally, the Commission pointed out that many questions remain about achieving the energy target such as how reductions should be tracked and how the costs should be calculated.

As for the cost of DSM programs, based on information provided by the utilities, the Commission estimated the

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increase for a "typical" residential customer using 1000 kWh per month. A Dominion customer would see an increase from $108.89 to $143.89 and a Kentucky Utilities customer would see an increase from $69.91 to $114.91. APCo did not supply the information to make this comparison, but it projected that it would cost $80-100 million for direct program and administrative costs to reach a 2% savings of its 2008 energy consumption and a 5% peak load reduction. These increases would be in addition to any other approved increases. The Commission did not have the information or time to analyze the potential financial benefits that would be associated with decreases in energy consumption and peak load reductions.

The Commission determined that while all four industry tests would be considered when evaluating DSM programs, the RIM test would receive the greatest weight followed by the TRC test. The Commission found that the RIM test should receive the most weight because it focuses on the impact on customer rates and thus fits with the Commission's existing statutory mandates to ensure just and reasonable rates. The Commission emphasized that the choice of test to use is a policy decision, which is embedded in its governing statutes. Finally, the Commission stated that it will continue to apply traditional ratemaking principles on a case-by-case basis.

To date, the General Assembly has not directed the Commission to conduct a further study or Report on these issues. As noted in another article in the News, the Commission recently ruled on Dominion's request to enter into a DSM portfolio in Case No. PUE-2009-00081.[5] ❇

About the Author: Kiva Bland Pierce is an Associate Attorney General in the Insurance and Utilities Regulatory Section. She joined the Attorney General's Office in 2007 after working in private practice concentrating on regulatory, administrative, and business law in addition to general litigation. She received her law degree from the University of Richmond, T. C. Williams School of Law and her undergraduate degree from Louisiana State University.

1 *Ex Parte: In the matter of determining achievable, cost-effective energy conservation and demand response targets that can realistically be accomplished in the Commonwealth through demand-side management portfolios administered by each generating electric utility identified by Chapters 752 and 855 of the 2009 Acts of the Virginia General Assembly.*

2 Chapter 855 (Senate Bill 1348) and Chapter 752 (House Bill 2531) of the 2009 Acts of Assembly.

3 The 2007 General Assembly found that that the stated goal of the Commonwealth would be to reduce the consumption of electric energy by retail customers by the year 2022 by an amount equal to 10% of the electricity consumed in 2006. Chapter 888 and 933 of the 2007 Acts of Assembly. On November 16, 2007, the Commission Staff issued a report that this goal was attainable. Therefore, the Commission began its analysis with the assumption that a 10% reduction by 2022 is achievable.

4 *Report: Study to Determine Achievable and Cost-effective Demand-side Management Portfolios Administered by Generating Electric Utilities in the Commonwealth,* available at http://www.scc.virginia.gov/comm/reports/dsm_2009.pdf

5 *Petition of Virginia Electric and Power Company For approval to implement new demand-side management programs and for approval of two rate adjustment clauses pursuant to Section 56-585.1 A 5 of the Code of Virginia.*

SCC Approves Demand-Side Management Programs for Virginia Electric and Power Company Case No. PUE-2009-00081

By Elaine Sanderlin Ryan

On March 24, 2010, the State Corporation Commission ("Commission") issued an order approving five demand-side management ("DSM") programs for Virginia Electric and Power Company ("Company") and two related rate adjustment clauses to recover costs associated with the programs. The portfolio of approved programs includes: Residential Lighting Program, Low Income Program, Commercial HVAC Upgrade Program, Commercial Lighting Program, and Air Conditioner Cycling Program.

Virginia Code § 56-585.1 A 5 ("Code") permits cost recovery for projected and actual costs to design and implement peak-shaving and energy efficiency programs, as defined by § 56-576, provided that the Commission finds the programs to be in the public interest. The Commission approved five programs out of the 11 programs proposed, finding that the unapproved programs "have not proven to be in the public interest at this time." Additionally, the Commission noted that while the curtailment and distributed generation programs were not approved in this proceeding, the Company may continue its experimental Commercial Distributed Generation/Load Curtailment Pilot for Large Non-Residential Customers and report on its operation.

The Company's DSM programs are the first to be approved by the Commission since the Virginia General Assembly established a goal for the Commonwealth to

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reduce the electric energy consumption of retail customers by 10 percent by 2022, as compared to consumption levels in 2006.[1] In furtherance of this goal, the General Assembly directed the Commission to conduct a proceeding to consider matters related to cost-effective energy conservation and demand response, including deciding the appropriate cost-effectiveness test to be given the greatest weight in conducting the cost-benefit analysis,[2] and to report its findings to the Governor and the General Assembly.[3] Accordingly, the Commission analyzed the four tests prescribed by the Commission's Cost/Benefit Rules,[4] concluding that the Ratepayer Impact Measure ("RIM") Test should be given the greatest weight, followed closely by the Total Resource Cost ("TRC") Test. The Commission noted that the Participants Test and Utility Cost Test will also be considered in order to fully evaluate each program. The Commission emphasized that programs will be evaluated on a case-by-case basis, using a flexible approach to ensure "impacts on ratepayers are fully considered along with the overall public interest."

Applying these guidelines to the instant case, the Commission found that a portfolio approach, while informative, is neither required by statute nor outcome determinative. Rather, the Commission held that in this instance the analysis should focus on each individual program. The Commission noted that the unapproved programs had low RIM scores and did not have TRC scores high enough to offset the deficiencies. Additionally, the costs of the Curtailment Service and Commercial Distributed Generation programs unreasonably exceeded any benefit, and therefore were not in the public interest as currently proposed.

Despite a low RIM score, the Commission approved the Low Income Program citing the public policy set forth in Chapter 476 and 603 of the 2008 Acts of Assembly, which favors energy assistance programs for low income residential customers. To address concerns over the low RIM score, the Commission directed the Company to file Measurement & Verification ("M&V") reports identifying "the actual value provided to low income customers . . . compared against costs."

The Commission found that the proposed Air Conditioner Cycling Program did qualify as a peak-shaving program under §§ 56-585.1 A 5 and 56-576. Code § 56-576 defines peak-shaving measures as "measures aimed solely at shifting time of use of electricity from peak-use periods to times of lower demand by inducing retail customers to curtail electricity usage during periods of congestion and higher prices in the electrical grid." The Commission held that the definition does not require a finding that the program will shift time of use in all instances.

Although the Company withdrew its request for approval of a Company-wide Voltage Conservation Program, the Company sought recovery for design costs for three Advanced Metering Infrastructure-enabled voltage conservation demonstration projects. The Commission held that § 56-585.1 A 5 c explicitly states that cost recovery is contingent upon a finding by the Commission that the program is in the public interest. Therefore, the Commission could not approve cost recovery for a program not yet found to be in the public interest.

The Commission approved the five DSM programs through March 31, 2013, subject to specific cost limits. Expenditures cannot exceed $27.4 million for the Low Income Program, $15.4 million in total for the Commercial Lighting and Commercial HVAC Upgrade Programs, and $59.5 million in total for the Residential Lighting and Air Conditioner Cycling Programs. In accordance with the Order, the Company must file detailed M&V reports every six months, beginning on October 1, 2010, and "maintain strict and detailed identification and accounting of its common costs for the approved DSM Programs." The Commission emphasized that such costs shall be "scrutinized to ensure that such expenditures are closely and definitely related to the programs approved herein." Lastly, the Commission directed the Company to engage various stakeholders in evaluating the M&V results and in developing future DSM proposals.

The Order Approving Demand-side Management Programs is available on the Commission's docket search website under SCC Case No. PUE-2009-00081. ❇

About the Author: Elaine Sanderlin Ryan is an Associate in the Energy and Environmental Department at McGuireWoods LLP in Richmond, Virginia. Elaine received her J.D. from the University of Richmond, T.C. Williams School of Law and her undergraduate degree from Wake Forest University.

[1] Virginia Acts of the Assembly, 2007 Reconvened Session, Enactment Clause 3 of identical Chapters 888 and 933, (approved April 4, 2007; effective July 1, 2007).

[2] *Id. Commonwealth of Virginia, ex rel. State Corporation Commission, Ex. Parte: In the matter of determining achievable, cost-effective energy conservation and demand response targets that can realistically be accomplished in the Commonwealth through demand-side management portfolios administered by each generating electric utility identified by Chapters 752 and 855 of the 2009 Acts of the Virginia General Assembly*, Case No. PUE-2009-00023.

[3] *Commonwealth of Virginia, State Corporation Commission, Report to the Governor of the Commonwealth of Virginia and the Virginia General Assembly*, "Report: Study to Determine Achievable and Cost-effective Demand-side Management Portfolios Administered by Generating Electric Utilities in the Commonwealth Pursuant to Chapters 752 and 855 of the 2009 Acts of the Virginia General Assembly" (Nov. 15, 2009) ("DSM Report").

[4] Rules Governing Cost/Benefit Measures Required for Demand Side Management Programs, 20 VAC 5-304-10, et seq.

Columbia Gas CARE Plan Approved

By Patrick L. Gregory

On December 4, 2009, the Commission issued a Final Order authorizing Columbia Gas of Virginia, Inc. ("Columbia") to implement its Conservation and Ratemaking Efficiency Plan ("CARE Plan") in Virginia under the Natural Gas Conservation and Ratemaking Efficiency Act ("Act"), §§ 56-600 *et seq*. of the Code of Virginia.[1] The CARE Plan was made effective for three years beginning December 31, 2009 and expires unless Columbia files for an extension.[2] The Act was intended to promote the wise use of natural gas by developing alternative rate designs and other mechanisms "that more closely align the interests of natural gas utilities, their customers, and the Commonwealth" and to "improve the efficiency of ratemaking to more closely reflect the dynamic nature of the natural gas market, the economy, and public policy regarding conservation and energy efficiency."[3] The Act requires a CARE Plan to have several components: (i) one or more cost-effective conservation and energy efficiency programs; (ii) provisions addressing the needs of low-income or low-usage residential customers; (iii) a normalization component removing the effect of weather in determining conservation and energy efficiency results; (iv) a decoupling mechanism and (v) provisions ensuring that rates and service to non-participating customer classes are not adversely impacted.[4] The Commission adopted the Hearing Examiner's finding that the CARE Plan, as modified by the stipulation agreement ("Stipulation") between Columbia and other case participants, met this requirement and represented a "reasonable compromise" of the interests of Columbia and its customers.[5]

Conservation and Energy Efficiency Programs

The Commission approved six conservation and energy efficiency programs for Columbia.[6] The Web-based Home Audit program is intended to provide customized reports recommending home improvements to improve energy efficiency, while the Home Savings Program includes incentives for high efficiency natural gas water heating equipment and home weatherization measures.[7] The Residential Low-Income Program provides funding for training and education for energy auditors supporting low-income weatherization programs.[8] The Business Savings Program provides incentives for small general service ("SGS") customers to invest in high efficiency equipment, while the Business Custom Program is designed "to provide customer-specific conservation and energy efficient solutions for larger SGS customers with customized systems." A community education and outreach program was also included in the CARE Plan.[9]

Performance-Based Incentive Mechanism

The Commission approved a performance-based incentive designed to provide Columbia with an opportunity to earn an incentive of up to 15% of independently verified net economic benefits (measured on a weather-normalized basis) resulting from Columbia's conservation and energy efficiency programs.[10] Virginia Natural Gas, the first company to obtain approval to implement a CARE plan, neither requested nor obtained a performance incentive, making Columbia's the first. The incentive rate will be determined by the annual savings expected to be achieved by such programs as a percentage of specified usage reduction targets that increase each year from 2010-2012. The performance incentive rate will range from 0%, for achieving less than 50% of an annual reduction target, to 15%, for achieving 70% or greater of such target. The rate for subsequent years will equal the rate achieved in the third year of the CARE Plan (2012). This incentive is in addition to other revenue requirements.[11] Of particular significance, calculation of the incentive is based on actual gas prices rather than projected gas costs, "by multiplying cumulative gas usage reductions by the jurisdictional weighted average commodity costs of gas for each year."[12] This approach, the Commission noted, "avoids the vagaries inherent in any long term projection of natural gas prices."[13] The incentive is included in Columbia's Annual Cost Adjustment ("ACA") mechanism, and is recoverable through future ACA filings regardless of whether the CARE Plan is extended, modified, or terminated (subject to measurement and verification).[14]

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1 *Application of Columbia Gas of Virginia, Inc. For approval to implement a natural gas conservation and ratemaking efficiency plan including a decoupling mechanism,* Case No. PUE-2009-00051, Final Order (December 4, 2009) (hereinafter "Final Order").
2 Final Order at 12.
3 Va. Code § 56-601(A).
4 Va. Code § 56-602(A).
5 Final Order at 8-9,11. The other case participants were the Office of the Attorney General Division of Consumer Counsel and the Virginia Industrial Gas Users' Association.
6 Final Order at 2-3.
7 *Application of Columbia Gas of Virginia, Inc. For approval to implement a natural gas conservation and ratemaking efficiency plan including a decoupling mechanism,* Case No. PUE-2009-00051 (June 8, 2009) at 7.
8 Final Order at 2; Stipulation at 2.
9 During 2010 and 2011, the CARE Plan will be supplemented by approximately $382,500 in federal funding from the American Recovery and Reinvestment Act, through a program administered by the Virginia Department of Mines, Minerals and Energy. See Final Order at 6.
10 *See* Stipulation at 5; Va. Code § 56-602 (F).
11 Stipulation at 8.
12 Final Order at 11.
13 *Id.*
14 Stipulation at 8.

PATH Allegheny Transmission Line Delayed

By Ashley B. Macko

On January 27, the Commission in PUE-2009-00043 granted the request of PATH Allegheny Virginia Transmission Corporation (PATH) to withdraw its application and terminate the pending proceeding. The original application was filed in May 2009 and has been a hotly contested proceeding. The proposed line, part of a longer 765kV line to be built from West Virginia to Maryland, would have included two non-contiguous segments 31 miles in length through parts of Loudoun, Frederick and Clarke counties. Applications for approval of portions of the line were filed in West Virginia, Virginia and Maryland.

After the respondents filed testimony, in early November, PATH requested that the procedural schedule be bifurcated with a delay in considering the question of whether the line was needed. Hearings on the routing of the proposed line would continue to go forward under the current procedural schedule. PATH cited the Maryland Public Service Commission's dismissal of its complimentary application in Maryland[1] and its intent to refile. PATH reasoned that it was preferable for all three applications to contain largely the same updated PJM analyses. Since PATH's application would not be considered until mid-2010 in Maryland, it asked for similar treatment of the need issue in Virginia. On November 24, after hearing oral argument, the Hearing Examiner denied the motion for modification.

On December 21, PATH filed a Motion to Withdraw Application and Terminate Proceeding. In its written motion, PATH again cited the disparate schedules in Maryland and West Virginia as opposed to Virginia. At oral argument, counsel for PATH explained that recent PJM studies did not appear to support the need for the proposed line in 2014 as originally projected and accordingly, the applicant could no longer support its application.[2] Commission Staff did not oppose the motion to withdraw, and while many respondents urged dismissal with prejudice, Staff argued that the broader public interest weighed against such a result.

In his ruling recommending allowing withdrawal, the Hearing Examiner considered three issues: whether to allow withdrawal or dismiss on the merits based on the need issue; whether there should be any conditions on that withdrawal or dismissal and; whether to impose sanctions or costs on PATH, as requested by numerous respondents.

On the issue of whether to allow withdrawal or dismiss, the Hearing Examiner reasoned that the distinction was largely insignificant. One area of possible concern would be potential Federal Energy Regulatory Commission jurisdiction under amendments to the Federal Power Act made by the Energy Policy Act of 2005. Under § 216(b)(1)(C)(i) of the FPA, FERC would have siting authority over the line if the SCC:

> Withheld approval for more than 1 year after the filing of an application seeking approval pursuant to applicable law or 1 year after the designation of the relevant national interest electric transmission corridor, whichever is later; . .

While FERC had originally interpreted this language to include an outright dismissal of a proceeding, in *Piedmont v. FERC*,[3] the Fourth Circuit held that the language of this section does not apply when a State commission affirmatively denies an application. Thus, under current law, a dismissal would not give rise to FERC jurisdiction. Likewise, allowing withdrawal would not confer jurisdiction. Notwithstanding this Fourth Circuit decision, the Hearing Examiner reasoned that there might be a future possibility of reversal and this made allowing withdrawal slightly safer in terms of preserving SCC jurisdiction.

In terms of conditions to the withdrawal or dismissal, the Hearing Examiner was mindful of the efforts put forward on the application by numerous respondents and modified the protective ruling in the case to allow current respondents to continue to maintain confidential information for one year as opposed to having to return or destroy it upon the pending dismissal or withdrawal. They would also be able to use the information in the next case upon leave of the Commission.

With respect to sanctions, many respondents had requested sanctions and/or attorneys fees associated with the costs of participating in the pending proceeding. The hearing examiner agreed with PATH, however, that the Commission lacked authority to impose sanctions under the circumstances.

In its Order Granting Withdrawal, the Commission focused on the fact that PATH could not longer support its own application and PATH's position that the FERC would not have jurisdiction to permit the PATH line under 216(b)(1)(C)(i) of the FPA, as well its commitment not to seek invocation of FERC jurisdiction. The Commission directed additional items to be included in any future PATH application and agreed with the Hearing Examiner's recommendations with respect to modifying the protective ruling. With respect to sanctions, the Commission found "neither

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Commission Approves Dominion's Modified Financing Request

By Ashley B. Macko

On September 8, 2009, Virginia Electric and Power company and its parent Dominion Resources, Inc. requested authority for Virginia Power to issue and sell up to $3.0 billion of authorized but unissued shares of common stock. The applicants represented that the proceeds from the sale may be used to refund outstanding securities, for capital requirements and other general corporate purposes. The applicants requested expedited consideration.

Responding to comments of the Virginia Committee for Fair Utility Rates which opposed expedited consideration and requested an evidentiary hearing, the Commission scheduled a hearing and provided for the pre-filing of testimony. The Committee's testimony recommended the Commission authorize issuance of a smaller amount of common equity and initiate a capital structure planning proceeding to outline reasonable ranges of capital structure targets. Commission Staff's testimony recommended the Commission authorize issuance of $1 billion during 2009 and an additional $500 million during 2010, but require additional approval for any subsequent issuances. Commission Staff further recommended a "soft cap" of 50% on the Company's equity ratio. If the Company files for approval of a nuclear facility, Staff recommended that the Company be required to file a plan for financing the facility, including an analysis of any need to increase its equity ratio.

At the commencement of the evidentiary hearing, the applicants made a modified request to the Commission. They requested that Virginia Power be permitted to issue and sell up to $1.5 billion of common stock through December 31, 2010, with no more than $1.0 billion issued in 2009.

In its decision, the Commission first reviewed the statutory standards under Chapter 3 and 4 of the Title 56 of the Code. Based on these standards, the Commission found that the Applicants' modified request should be approved. The Commission stressed, however, that "we reject the Company's suggestion that potential rate impact of the proposed transaction is irrelevant to the approval requested herein." "We similarly reject the Company's insinuation that Virginia's ratemaking statutes are irrelevant to this proceeding; in order to evaluate the impact on rates, we necessarily must consider the Virginia statutes that govern those rates."

The Commission directed its Staff to continue to monitor the elements which comprise the Company's capital structure to determine periodically whether this goal is being met in light of the changes in capital markets, including debt ratings, as well as the Company's construction activities and other relevant factors. The Commission declined to place a cap on the Company's equity ratio or initiate a separate capital structure planning proceeding as requested by the Committee. Finally, the Commission noted that its approval did not represent a finding that any specific equity ratio is reasonable for subsequent ratemaking purposes.

See Application of Virginia Electric and Power Co. and Dominion Resources, Inc. for expedited approval of authority to issue up to $3 billion in common stock to parent under Chapters 3 and 4 of the Code of Virginia of 1950, as amended, Case No. PUE-2009-00100, Order Granting Authority (Oct. 30, 2009). ❇

PATH Allegheny Transmission Line Delayed *(continued)*

a factual or legal basis has been established requiring the Commission to grant outstanding requests or motions for sanctions, attorneys fees, or other costs associated with participating in this proceeding."

Application of Path Allegheny Virginia Transmission Corporation for certificates of public convenience and necessity to construct facilities: 765kV Transmission Line through Loudoun, Frederick, and Clarke Counties, Case No. PUE-2009-00043, Order Granting Withdrawal (Jan. 27, 2010). ❇

[1] PATH represented that the Maryland PSC had dismissed the application as being brought by an entity which was not an "electric company" as required by Maryland law.
[2] The reduced demand on the system is largely due to the economic downturn and increased demand response programs. See Peter Behr, *Energy Conservation Helps Stymie a Major Transmission Line*, NY TIMES, Jan. 6, 2010.
[3] 558 F.3d 304 (2009).

Virginia Corporation Commission Staff files Comments in FCC Truth-in-Billing Proceeding

By Ashley B. Macko

In response to a Notice of Inquiry issued by the Federal Communications Commission, the Virginia State Corporation Commission Staff filed comments on October 13, 2009. The Notice of Inquiry was focused on the question of whether there are opportunities to protect American consumers by ensuring sufficient access to relevant information about communications services. The Notice had stressed that "[p]rotecting and empowering American consumers is a core responsibility of the Commission" and that it had been a decade since the adoption of the Truth-in-Billing rules.

SCC Staff supported the FCC's efforts to ensure that consumers have the necessary information to make good purchasing decisions. SCC Staff reported that it receives many complaints and inquiries regarding communications services from consumers in Virginia. Specifically, Staff had handled an average of 6,100 complaints over the last three years which have resulted in $1.1 million in customer refunds and adjustments. SCC Staff explained that problems arise in its handling of complaints when the particular communications service is outside the state corporation commission's jurisdiction. It suggested that one approach might be to create a "direct liaison mechanism" between state commission and the FCC.

SCC Staff identified a type of bundled communications service that was not addressed in the FCC's notice – that involving bulk billing arrangements that combine cable, telephone and internet services as part of homeowner association fees or dues. These types of arrangements create a lot of problems for consumers.

With respect to cramming, the SCC Staff indicated that it continued to received cramming complaints, although not large in number, they are increasing in frequency. SCC Staff asserted that the only way to stop this unscrupulous practice is to require local telephone companies to cease billing for others. At a minimum, upon challenge by a customer, the local telephone company should remove the charge immediately and charge it back to the company initiating the charge.

See In the Matter of Truth-in-Billing and Billing Format, FCC CC Docket No. 98-170 ❇

Appeals Corner: Supreme Court of Virginia Upholds State Corporation Commission's Approval of Wise County Power Plant

By Ashley B. Macko

On April 27, 2009, the Supreme Court of Virginia issued an opinion in an appeal of the Commission's approval of a power plant to be built by Dominion Virginia Power in Wise County. Specifically, the SCC approved Dominion's proposal to build a carbon capture compatible, clean-coal powered electric generation facility to be located in the coalfield region of the Commonwealth. Appellants included Appalachian Voices, Chesapeake Climate Action Network, Sierra Club and Southern Appalachian Mountain Stewards (collectively "Appalachian Voices"). Appalachian Voices' primary argument on appeal was that § 56-585.1(A)(6) violated the Commerce Clause of the United States Constitution by requiring the proposed plant to "utilize() Virginia coal" and thus discriminating in favor of Virginia coal at the expense of out-of-state coal.

As an initial matter, the Supreme Court rejected Dominion's challenge to Appalachian Voice's standing to maintain an appeal. Specifically, the Court found that Dominion had failed to raise the standing challenge before the Commission and the Supreme Court would not consider a standing challenge for the first time on appeal.

On the constitutional claim, Appalachian Voices argued that the statute was discriminatory on its face. The Supreme Court agreed with the SCC and rejected this argument finding that "the statute in question does not require – and the Commission did not order – that any amount of Virginia coal be used in the proposed coal-fired plant." The meaningful distinction found by the Court was that the statute only required the plant be able to burn Virginia coal. The Supreme Court also cited that fuel factor statute, § 56-249.6 which imposed on utilities the duty to use the most economical mix of generating resources available. Thus, the Court reasoned, the use of Virginia coal is not favored under Virginia law. "Not only is there no economic incentive to use Virginia coal under the Virginia statutory scheme, there

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Practice Corner: Discovery - Hearing Examiner Overrules Objections to Commission Staff's Instructions and Definitions Contained in Interrogatories

By Ashley B. Macko

In the PATH transmission line case (PUE-2009-00043), the Hearing Examiner overruled certain objections of PATH to Commission Staff's Instructions and Definitions contained in its interrogatories.

Specifically, PATH objected to an instruction which stated that "[t]hese requests should be regarded by you as continuing. Please provide updated or corrected responses as any additional information becomes available." PATH asserted that this instruction sought to impose duties and obligation greater than those imposed by the Commission's Rules of Practice and Procedure. PATH argued that the Commission's Rules only required information known by the party at the time of the response. The Hearing Examiner ruled that designating a request as continuing is within the discovery rule which requires "information as is known." (5 VAC 5-20-260).

PATH objected to another instruction which sought "information available from all corporate and individual files of the Company and any affiliate as well as from all past and present board members, officers, and management level employees of the Company and any affiliate" on the grounds it exceeded the "information as known" standard. Specifically, PATH complained that the instruction required a search of all past and present agents and affiliates of PATH, making compliance virtually impossible. The Hearing Examiner disagreed:

In this case, the decisions, underlying studies, and analyses regarding the proposed project likely occurred over time. Depending upon the interrogatory, relevant responsive information may be known to reside in the files of former officers or agents, or may be known to reside in the files of a subsidiary that is otherwise unrelated to the project. The instruction appears to be designed to avoid the limitations PATH attempts to impose.

The Hearing Examiner further stressed that "[b]y itself, the instruction seeks no information. Furthermore, the reasonableness of the scope of the required search for information depends on the interrogatory and the specific facts and circumstances related to the requested information."

PATH also objected to instructions which requested underlying calculations and the company's best estimate in the event a precise number was unknown. PATH asserted these instructions went beyond the "information as known" standard. The Hearing Examiner once again rejected this argument, finding that PATH's objection was limited to situations where the instruction would impose duties and obligations greater than those in the Commission's rules. He found that such an instruction standing alone is not objectionable, but may be, depending on the particular details of an interrogatory.

PATH also objected to certain definitions contained in Staff's interrogatories to the words "describe" and "document." The Hearing Examiner overruled PATH's objections, reasoning that "whether a definition is overly broad can be determined only by considering its application to a specific interrogatory."

In total, the Hearing Examiner rejected each of PATH's objections and upheld Commission Staff's Instructions and Definitions contained in its interrogatories. He left open the possibility that the instruction and definitions, as applied to a particular interrogatory, might be objectionable as exceeding the "information and known" standard.

See *Application of PATH Allegheny Virginia Transmission Corp. for certificates of public convenience and necessity to construct facilities: 765 kV Transmission Line through Loudoun, Frederick, and Clark Counties,* Case No. PUE-2009-00043, Hearing Examiner's Ruling (Aug. 27, 2009). ❇

Appeals Corner *(continued)*

is a statutory disincentive to utilization of Virginia coal if use of the out-of-state coal is more economical."

The Supreme Court further held that severance of the allegedly impermissible language would otherwise save the statute from invalidation. Citing § 1-243 of the Code of Virginia, the Supreme Court found "[c]learly, other provisions of Code § 56-585.1 (A)(6) can be given effect without the phrase "utilizes Virginia coal," the statute itself does not specifically provide that its provisions are not severable, and no other provision of Code § 56-585.1(A)(6) operates "in accord" with the phrase at issue.

On the remaining assignments of error, the Court held that they were dependant on a successful constitutional challenge and because it failed, the remaining assignments also failed.

See *Appalachian Voices v. State Corporation Commission*, 277 Va. 509, 675 S.E.2d 458 (2009). ❇

SCC Approves Settlement *(continued)*

requirements," but cautioned that "such finding does not establish precedent for any specific matter addressed in the Stipulation and Addendum." In support of this finding, the Commission emphasized the benefits afforded to residential and business consumers during the current economic climate and the promotion of economic development in the Commonwealth. The Commission noted that the Stipulation and Addendum will deliver $726 million in value to customers and will prohibit the Company from requesting an increase in base rates prior to December 1, 2013. According to the terms of the Stipulation and Addendum, the Company will provide a $529 million base rate credit to customers from its 2008 revenues through 2012 to offset previously approved incremental rider rates for Riders R,[1] S [2] and T,[3] and will waive recovery of $197 million in previously incurred and federally-approved costs related to providing transmission service. The Company will also reduce base rates of service to their pre-September 1, 2009 level, when Commission-approved interim rates went into effect, and will refund to customers the increased revenues collected under the interim base rates.

The Stipulation and Addendum also address several key issues under Code § 56-585.1 A related to the biennial review process and future rate adjustment clause ("RAC") applications. In accordance with the Stipulation and Addendum, the Commission authorized a return on equity ("ROE") of 11.9%, inclusive of a 60 basis point performance incentive, to be applicable to the Company's base rates until reset in the first biennial review proceeding. The "Initial Return" as defined in § 56-585.1 A 2 d, will be 11.3% reflecting the base ROE exclusive of any performance incentive adder. Additionally, the Stipulation and Addendum provide guidelines for Earnings Test Adjustments in the first and second biennial reviews. With respect to rider treatment, the parties to the Stipulation and Addendum agree to support a base authorized ROE of 11.3% for any RAC applications or petitions for initial or updated approval filed on or before June 30, 2010.

While the Commission expressly refrained from establishing a precedent for any specific matter contained in the Stipulation and Addendum, the Commission ruled on two significant questions of law during the course of the proceeding which help clarify the interplay of Chapter 10 of Title 56 and § 56-585.1 A. First, the Commission was requested to determine the proper rate year applicable to the proceeding in order to establish the scope of ratemaking adjustments. In making this determination, the Commission considered whether § 56-585.1 A modified the rate year provisions of Chapter 10 of Title 56, thus replacing the traditional 12-month rate year and permitting cost of service recovery for the entire period that the new rates would be in effect. Based on the Company's initial application, this time frame would equal 27 months, reflecting a rate effective date of September 1, 2009 through December 1, 2011, when rates are anticipated to be adjusted as a result of the first biennial review.

Code § 56-235.2 permits "annualized adjustments for future costs as the Commission finds reasonably can be predicted to occur during the rate year." Code § 56-585.1 A, in turn, provides that "the Commission . . . shall be authorized to order increases to the utility's rates necessary to provide the opportunity to fully recover the costs of providing the utility's services

. . . ." and that proceedings initiated under this provision "shall be governed by the provisions of Chapter 10 (§ 56-232 et seq.) of this title, except as modified herein." Subsection C further directs that

> Except as otherwise provided in this section, the Commission shall exercise authority over the rates, terms and conditions of investor-owned incumbent electric utilities for the provision of generation, transmission and distribution services to retail customers in the Commonwealth pursuant to the provisions of Chapter 10 (§ 56-232 et seq.) of this title, including specifically § 56-235.2.

The Commission found that § 56-585.1 A did not expressly modify the rate year provisions of Chapter 10. The Commission emphasized that the plain language of the statutes indicates the General Assembly's intention for proceedings brought under § 56-585.1 to be governed by Chapter 10, including § 56-235.2, unless a specific provision of § 56-585.1 modified Chapter 10. As noted by the Commission, the General Assembly has previously modified the rate year concept by expressly allowing for ratemaking adjustments for a rate period from 2001 to 2007 under the 1999 Electric Utility Restructuring Act. Further, as applied to the current proceeding, the Commission emphasized that the General Assembly has expressly modified Chapter 10 under § 56-585.1 A with respect to determining fair rates of return on common equity.

The Commission likewise rejected the argument that § 56-585.1 A implicitly modifies the traditional rate year concept under Chapter 10. While § 56-235.2 A requires the Commission to establish rates sufficient to "provide the opportunity to fully recover the costs of providing the utility's services," this provision does not entitle the utility to recover costs for the entire time period that the rates would remain in effect. The Commission noted that § 56-585.1 B specifically authorizes investor-owned incumbent electric utilities to apply for a rate increase under § 56-245 or the Commission's rules governing rate increase applications, 20 VAC 5-200-30. Accordingly, the Commission held that the provisions

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1. *Application of Virginia Electric and Power Company, For approval of a Rate Adjustment Clause for Recovery of the Costs of the Bear Garden Generating Station and Bear Garden-Bremo 230 kV Transmission Interconnection Line,* Case No. PUE-2009-00017, Order Approving Rate Adjustment Clause (Dec. 16, 2009).

2. *Application of Virginia Electric and Power Company, For approval of the Annual Filing as required by Final Order of the State Corporation Commission in Case No. PUE-2007-00066 granting approval of a rate adjustment clause, Rider S, with respect to the Virginia City Hybrid Energy Center generation and transmission facilities located in Wise County, Virginia,* Case No. PUE-2009-00011, Order Approving Rate Adjustment Clause (Dec. 16, 2009).

3. *Application of Virginia Electric and Power Company, For approval of rate adjustment clause pursuant to § 56-585.1 A 4 of the Code of Virginia,* Case No. PUE-2009-00018, Final Order (June 29, 2009).

SCC Approves Settlement *(continued)*

taken together provide the utility an opportunity to fully recover the cost of providing its services without modifying the traditional rate year concept.

The Commission was also asked to determine the proper capital structure to be used in developing the revenue requirement. In considering the issue, the Commission examined whether the requirement under § 56-585.1 A 10 to use an actual end-of-test period capital structure applies only to the biennial review process and not a "going-in" rate review. The Commission held that while the last phrase of § 56-585.1 A states that "the Commission . . . shall conduct biennial reviews of rates, terms and conditions for the provision of generation, distribution and transmission services by each investor-owned incumbent electric utility, *subject to the following provisions*" (emphasis added), this phrase does not limit application of the subsequent provisions to the biennial review process. To the contrary, the Commission noted that the subsequent provisions include rate adjustment clauses and rate of return requirements which apply equally to a going-in rate review.

The Commission acknowledged that the statute grants discretion to authorize use of something other than an actual end-of-test period structure should the Commission find the debt to equity ratio of such capital structure unreasonable, but noted that this discretion is limited to biennial review proceedings. Moreover, the Commission held that requiring an actual end-of-test period capital structure does not preclude a utility from fully recovering its costs and earning a fair return. In support of this conclusion, the Commission again pointed to the language of § 56-585.1 B which permits the utility to apply for an increase in rates under § 56-245 or the Commission's rules governing rate increase applications.

The Order Approving Stipulation and Addendum is available on the Commission's docket search website under SCC Case No. PUE-2009-00019. ❇

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Columbia Gas CARE Plan Approved *(continued)*

Decoupling Mechanism

Columbia asserted that its current rate design created a disincentive for it to promote conservation, as it recovered the majority of its revenues based on the amount of natural gas sold or transported, thus its profits were tied to the amount of gas sold.[15] As provided for under the CARE Act, the Commission approved, as a part of the CARE plan, a decoupling mechanism separating volumes of gas sold from distribution revenues in the form of a "Revenue Normalization Adjustment" ("RNA"), a sales adjustment clause that "adjusts non-gas distribution revenue to allowed distribution revenue." The "allowed distribution revenue" is determined based on the rates in effect under Columbia's performance-based regulation plan previously approved by the Commission.

The Commission noted that the decoupling mechanism might produce lower benefits for non-participating customers engaging voluntarily in conservation or energy efficiency measures outside of the CARE Plan.[16] It stated that without the RNA, customers who lower their thermostats to reduce gas usage could benefit from reducing their contributions to Columbia's distribution costs. In contrast, the RNA "will prevent customers from lowering their contributions to [Columbia's] distribution costs by curtailing gas usage." Nonetheless, the Commission approved the RNA as the Act mandated that the Commission approve such a mechanism if it met the statutory standards.

Impact on Non-Participating Customer Classes

The Act required Columbia to address concerns that the CARE Plan might adversely affect non-participating customer classes. It addressed these concerns by including a provision for an additional earnings test on behalf of such customer classes. If the sharable earnings calculated under the earnings test for the CARE Plan for such customer classes are greater than those that result from the first performance-based regulation ("PBR"), the difference will be added to the PBR sharable earnings for the non-participating customer class.[17]

Conclusion

The Commission noted that the projected price of natural gas over the life of the CARE Plan is "characterized by significant uncertainties" and that it was therefore difficult to accurately predict the benefits to customers from the CARE Plan.[18] Still, it found that the projections used to measure the Care Plan's benefits were reasonable and that the measures to be implemented under the CARE Plan were cost effective. It acknowledged that "the estimated lifetime total of natural gas savings of 3,271,687 Mcf" projected over the life of the CARE Plan represented "a significant reduction in the consumption of natural gas," consistent with the intent of the statute.[19] ❇

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15 Final Order at 3-4.
16 Final Order at 10.
17 Final Order at 4.
18 Final Order at 11.
19 Editorial Note: The Commission also recently decided Washington Gas's application for approval of a CARE plan, which is available on the Commission's website under Case No. PUE-2009-00064.

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