122 FERC ¶ 61,174
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

New Dominion Energy Cooperative	Docket No. ER05-18-002
Old Dominion Electric Cooperative	Docket No. ER05-309-002

OPINION NO. 499

ORDER ON INITIAL DECISION

(Issued: February 25, 2008)

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New Dominion Energy Cooperative	Docket No. ER05-18-002
Old Dominion Electric Cooperative	Docket No. ER05-309-002

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APPEARANCES

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UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Joseph T. Kelliher, Chairman;
Suedeen G. Kelly, Marc Spitzer,
Philip D. Moeller, and Jon Wellinghoff.

New Dominion Energy Cooperative — Docket No. ER05-18-002

Old Dominion Electric Cooperative — Docket No. ER05-309-002

OPINION NO. 499

ORDER ON INITIAL DECISION

(Issued February 25, 2008)

1. In 2004 and 2005, Old Dominion Electric Cooperative (Old Dominion) and New Dominion Energy Cooperative (New Dominion) (collectively, Applicants) filed rate applications under section 205 of the Federal Power Act (FPA) in Docket Nos. ER05-18-000 and ER05-309-000 and other dockets in connection with a reorganization. When these filings were made, Old Dominion's operations in Virginia were not part of the PJM Interconnection, L.L.C. (PJM). Subsequently, on May 1, 2005, Dominion Virginia Power[1] joined PJM so that Old Dominion's operations in Virginia became subject to PJM.

2. The Commission set the filings for hearing. On April 7, 2006, all of the Member Cooperatives of Old Dominion except Northern Virginia Electric Cooperative (NOVEC) and Commission Trial Staff (Staff) became subject to a settlement approved by the Commission.[2] On February 5, 2007, the Presiding Administrative Law Judge (ALJ) issued her Initial Decision as to the issues disputed by NOVEC and Commission Trial

[1] Also referred to in this order as Virginia Electric and Power Company and VEPCO.

[2] *New Dominion Energy Cooperative*, 115 FERC ¶61,025 (2006).

Staff (Staff).[3] NOVEC and Staff except to the holdings of the Initial Decision. The Commission affirms the Initial Decision on all issues except one, as discussed below.

<u>Background</u>

3. NOVEC is the largest of the twelve Member Cooperatives of Old Dominion, a public utility that operates as a not-for-profit electric generation and transmission cooperative. The Member Cooperatives are customer-owned electric distribution cooperatives that provide electric service at retail to residential, commercial, and industrial consumers in established service territories in Virginia, Delaware, Maryland, and parts of West Virginia.[4] Those service territories are located in several different zones within the PJM Interconnection, L.L.C. (PJM). NOVEC is located in PJM's Virginia Electric and Power Company zone.[5]

4. The Member Cooperatives own Old Dominion and, as relevant here, are also its customers for generation capacity and energy. They purchase substantially all of their power (generation capacity and energy) requirements from Old Dominion under full requirements wholesale power contracts (WPCs). Thus, Old Dominion currently provides generation, transmission, ancillary and other related services to NOVEC and the eleven other Member Cooperatives.

5. Old Dominion has a cost-based tariff for generation capacity and energy pursuant to which it passes through the costs that it incurs for generation capacity and energy to the Member Cooperatives. The provisions of Old Dominion's tariff permit it to collect all of the costs that it incurs through rate formulas and subsequent true-ups for uncollected costs. The tariff includes separate formulas for the recovery of demand-related and energy-related expenses.

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[3] *New Dominion Energy Cooperative,* 118 FERC ¶ 63,024 (2007) (Initial Decision).

[4] The Member Cooperatives of Old Dominion, which will become the Member Cooperatives of New Dominion, are: A&N Electric Cooperative; BARC Electric Cooperative; Community Electric Cooperative; Choptank Electric Cooperative; Delaware Electric Cooperative; Mecklenburg Electric Cooperative; Northern Neck Electric Cooperative; NOVEC; Prince George Electric Cooperative; Rappahannock Electric Cooperative; Shenandoah Valley Electric Cooperative; and Southside Electric Cooperative (collectively, Member Cooperatives).

[5] Also referred to at times in PJM tariffs as the Dominion zone.

6. In 2004, the Old Dominion Board of Directors and the Member Cooperatives proposed to create a new entity, New Dominion, pursuant to a corporate reorganization. In Opinion No. 491,[6] the Commission approved the proposed reorganization of Old Dominion under section 203 of the Federal Power Act (FPA).[7] The Commission also approved Old Dominion's assignment of its jurisdictional wholesale power contracts to newly created New Dominion, which would then become the Member Cooperatives' full requirements power supplier. The Member Cooperatives would become member cooperatives of New Dominion. They would assign their respective membership interests in Old Dominion to New Dominion in exchange for membership interests in New Dominion. New Dominion would thus become the sole member of Old Dominion and would purchase, on a take-or-pay basis, all of Old Dominion's output and services. In turn, New Dominion would pass on all of the costs it received from Old Dominion to the Member Cooperatives. The Applicants state that the reorganization transaction has not yet been consummated.[8]

7. In a filing in Docket No. ER05-18-000 on October 5, 2004, as amended on January 7, 2005, New Dominion sought re-approval of the rate schedule and formula rate currently on file for Old Dominion for use by New Dominion when the reorganization transaction is consummated. The general terms of the tariff were modified to accommodate the reorganization and also to propose some modifications to terms and conditions. While New Dominion proposed essentially the same rate formulas as were in Old Dominion's tariff, it did propose a few changes to those rate formulas, as well as

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[6] *Old Dominion Elec. Coop.*, Opinion No. 491, 117 FERC ¶ 61,313 (2006), *order denying reh'g*, Opinion No. 491-A, 119 FERC ¶ 61,253 (2007).

[7] 16 U.S.C. § 824b (2000), *amended by* Energy Policy Act of 2005, Pub. L. No. 109-58, § 1289, 119 Stat. 594, 982-83 (2005) (EPAct 2005). EPAct 2005 did not become effective, however, until after this application was filed, and thus does not apply here.

[8] Applicants' March 27, 2007 Brief Opposing Exceptions at 80.

Applicants also state that the currently effective rates for the Member Cooperatives, including NOVEC are the Old Dominion rates that were accepted by the Commission in Docket No. ER05-360-000 to be effective February 19, 2006. *Id.* at 80 n. 118 *citing Old Dominion Electric Cooperative,* 110 FERC ¶ 61,165 (2005). In Docket No. ER05-360-000, Account No. 553 costs are classified as energy related. *Id.* at P 4. Applicants also state the Commission accepted proposed tariff revisions to Old Dominion's tariff in Docket No. ER05-360-000, subject to refund and to the outcome of the proceedings in this proceeding, Docket No. ER05-18-000.

various other tariff changes. The Virginia State Corporation Commission (VSCC) and Bear Island Paper Company, LLC, (Bear Island) protested the filing in Docket No. ER05-18-000. Bear Island operates a newsprint manufacturing facility in Hanover County, Virginia. It is not a Member Cooperative, but rather is a customer of a Member Cooperative, Rappahannock Electric Cooperative (REC).[9]

8. On December 7, 2004, as amended on February 4, 2005, Old Dominion filed, in Docket No. ER05-309-000, an application requesting acceptance of Old Dominion's initial tariff for sales to New Dominion, pursuant to section 205 of the FPA. NOVEC protested the filing in Docket No. ER05-309-000.

9. On March 8, 2005, the Commission accepted Applicants' filings in Docket Nos. ER05-18-000, ER05-18-001, ER05-309-000, and ER05-309-001, suspended them for a nominal period to become effective on the transaction effective date,[10] subject to refund, and established hearing and settlement judge procedures.[11] The Commission also consolidated these dockets for purposes of hearing and decision because they involved common issues of fact and law. In addition, the Commission found that New Dominion's proposed rates are not initial rates but a continuation of Old Dominion's rates.[12]

10. In August, 2005, Applicants filed their direct testimony in Docket Nos. ER05-18-000 and ER05-309-000.

11. On October 13, 2005, Applicants filed an Offer of Partial Settlement (Settlement) in Docket Nos. ER05-18-000 and ER05-309-000 and some related matters. The Settlement resolved all issues in dispute between the Applicants, the VSCC, and Bear Island, and was signed by all three. Of relevance here, the Settlement provided that New Dominion would implement its rate formulas as proposed in its Docket No. ER05-18-000 filing, subject only to certain specified modifications. The modifications included that

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[9] Bear Island operates a newsprint manufacturing facility in Ashland, Virginia. Ex. ODC-9, Settlement Agreement at 2.

[10] The transaction effective date is the date on which all regulatory approvals are secured for the filings in Docket Nos. ER05-18-000, ER05-20-000 (application for market-based rate authority), and ER05-309-000 (Old Dominion's initial tariff for sales to New Dominion). *New Dominion Energy Cooperative*, 110 FERC ¶ 61,275, at P 1-2 (2005).

[11] *New Dominion Energy Cooperative*, 110 FERC ¶ 61,275 (2005).

[12] *Id.* P 27 n.12.

Account No. 553 costs, Maintenance of Generating and Electric Equipment,[13] would be classified as demand related rather than energy related. The Settlement also provided Applicants and Bear Island would enter into a Demand Side Management (DSM) Agreement in which Applicants could curtail Bear Island's demand to 24 MW from June 1 though September 30. In the DSM Agreement, Applicants and Bear Island agreed that for purposes of calculating the monthly demand charge from REC to Bear Island, Applicants would bill REC for 24 MW each month. In addition, the Settlement deleted the phrase "unless the Board decides otherwise" from the Prior Period Adjustment for Demand Revenues provision. The Explanatory Statement of the Settlement provided, "It is the Applicants' intent, with respect to the specific issues resolved in the Settlement, that the *Mobile-Sierra* standard apply; therefore the Settlement cannot be changed unless a showing is made that the public interest requires it."[14]

12. NOVEC protested the Settlement. It argued that the Settlement would have the effect of reducing the demand-related costs New Dominion allocates to REC and would thereby shift those costs to the other Member Cooperatives, including NOVEC. No other Member Cooperative opposed the Settlement. On April 7, 2006, the Commission approved the Settlement as to the settling parties.[15] The Commission stated that, since NOVEC was not one of the settling parties, it is not bound by the Settlement, and a hearing with respect to NOVEC's rate issues would still be held in this docket.

13. In July and August, 2006, Trial Staff and NOVEC filed direct and answering testimony. In September, 2006, Applicants filed rebuttal testimony. The hearing was held from October 17 through October 19, 2006. The ALJ issued her Initial Decision on February 5, 2007.[16] The rates determined at the hearing and reviewed in this order apply only to NOVEC.[17] Applicants state that the rates determined for NOVEC in this

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[13] Part 101, 18 C.F.R. (2007).

[14] Explanatory Statement at 10.

[15] *New Dominion Energy Cooperative*, 115 FERC ¶ 61,025 at P 11-13 (2006) (Settlement Order).

[16] Initial Decision, 118 FERC ¶ 63,024 (2007).

[17] The terms New Dominion' rates, New Dominion's tariff, and the as-filed rates will be used in this order to mean New Dominion's cost of service tariff proposed in its filing of October 5, 2004 in Docket No. ER05-18-000. This tariff applies only to NOVEC so that, here, it will be identified as the NOVEC tariff. The term Settlement tariff will be used to mean New Dominion's cost of service tariff accepted by the

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proceeding will be applicable to NOVEC on the effective date of the reorganization transaction. Because the reorganization transaction has not yet been consummated,[18] NOVEC continues to pay wholesale rates for generation capacity and energy to Old Dominion.

Discussion

14. At issue in this proceeding are matters affecting the rates that New Dominion will charge NOVEC, the one Member Cooperative that was severed from the Settlement. For the reasons discussed below, the Commission generally affirms the ALJ's initial decision, including her finding that New Dominion's proposal to apply the Settlement rates to NOVEC is just and reasonable. The Commission reverses the ALJ's decision on only one issue involving tariff language giving the Applicants discretion concerning the implementation of a prior period adjustment for demand revenues, and the Commission requires that the discretionary language be removed.

A. Demand Rate Calculation in New Dominion's Rates

1. Background and Initial Decision

15. New Dominion's proposed tariff contains a demand charge to collect demand-related costs for generation services.[19] The proposed tariff contains essentially the same

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Commission in its *Order Approving Partial Contested Settlement* on April 7, 2006, in Docket No. ER05-18-003 and other dockets. *New Dominion Energy Cooperative,* 115 FERC ¶ 61,025 (2007). The Settlement tariff applies to the other eleven Member Cooperatives.

[18] Applicants' March 27, 2007 Brief Opposing Exceptions at 80.

Applicants also state that the currently effective rates for the Member Cooperatives, including NOVEC are the Old Dominion rates that were accepted by the Commission in Docket No. ER05-360-000 to be effective February 19, 2006. *Id.* at 80 n. 118 *citing Old Dominion Electric Cooperative,* 110 FERC ¶ 61,165 (2005). In Docket No. ER05-360-000, Account No. 553 costs are classified as energy related. *Id.* at P 4. Applicants also state the Commission accepted proposed tariff revisions to Old Dominion's tariff in Docket No. ER05-360-000, subject to refund and to the outcome of the proceedings in this proceeding, Docket No. ER05-18-000.

formula for calculating the demand charge as Old Dominion has used since 1992.[20] First, New Dominion proposes to calculate the per unit demand charge by dividing its total demand costs by the "Total Delivery Point kW Demand" of all its Member Cooperatives from April through December "(less 300 kW minimum per Delivery Point)."[21] Section E(I)(b) of the proposed tariff defines the Member Cooperatives' Delivery Point Demand as their "Delivered Demand" during the 60-minute "clock-hour in each calendar month during which the combined system . . . peak demand occurs."[22] The combined system, as relevant here, consists of Dominion Virginia Power[23] and New Dominion's VE area members.[24] Once the per unit demand charge is determined, New Dominion proposes to bill demand costs to each Member Cooperative by multiplying the per unit demand charge by each Member Cooperative's Delivery Point kW demand

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[19] Filing of October 5, 2004, Docket No. ER05-18-000, Attachment C, New Dominion Energy Cooperative, FERC Electric Tariff, Original Volume No. 1, Original Sheet Nos. 9 and 10.

[20] Tr., at 211, 249.

[21] Filing of October 5, 2004, Docket No. ER05-18-000, Attachment C, New Dominion Energy Cooperative, FERC Electric Tariff, Original Volume No. 1, Original Sheet No. 11; Ex. ODC-1 at 16; Ex. ODC-4 at Original Sheet No. 13.

[22] Filing of October 5, 2004, Docket No. ER05-18-000, Attachment C, New Dominion Energy Cooperative, FERC Electric Tariff, Original Volume No. 1, proposed Original Sheet Nos. 3 and 4; Ex. ODC-1 at 16; Ex. ODC-4 at Original Sheet Nos. 3, 4, and 5.

[23] Dominion Virginia Power is also known as the Virginia Electric and Power Company and VEPCO.

[24] Filing of October 5, 2004, Docket No. ER05-18-000, Attachment C, New Dominion Energy Cooperative, FERC Electric Tariff, Original Volume No. 1, Original Sheet Nos. 3 and 4. Section E of New Dominion's proposed tariff contains four areas, the VE Area, the DE Area, the PE Area, and the APCo Area. Each area has its own definition of combined system. Bear Island is located in the VE Area. The combined system for the VE Area consists of Dominion Virginia Power and New Dominion's VE Area members. The VE area members are BARC Electric Cooperative, Community Electric Cooperative, Mecklenburg Electric Cooperative, Northern Neck Electric Cooperative, NOVEC, Prince George Electric Cooperative, REC, Shenandoah Valley Electric Cooperative, and Southside Electric Cooperative.

during the relevant peak periods during April through December (i.e. the same billing determinants as used in calculating the per unit demand charge).[25] This would have the effect of allocating demand costs to each Member Cooperative based upon their proportionate share of the combined system's peak demand during each month from April through December.

16. As Old Dominion currently does, New Dominion proposed to recalculate the demand rate to be charged its customers pursuant to this formula annually. Projected demand costs and Delivery Point kW demand for the next year are used for this purpose, and the revised demand charge is generally put into effect on April 1 of each year.[26] The tariff also includes a "Prior Period Adjustment for Demand Revenues" in order to true up differences between actual and estimated costs and delivery point demand.[27] Any differential between allowed demand costs collected under the formula and actual demand costs included for the period is allocated to each member cooperative based on "actual demand billing units,"[28] and refunded or collected during the following year.

17. During 2003 and 2004, Demand Side Management Agreements were in effect between Old Dominion, REC, and Bear Island.[29] Those agreements provided that Old Dominion could curtail Bear Island's demand to 26 MW for up to five hours during up to 90 days each year. Section 3.2 of each agreement provided that "for purposes of calculating the monthly demand charge from REC to [Bear Island] for service to the Bear Island delivery point, Old Dominion will bill REC for 26,000 kW each month for the term of this agreement."[30] Thus, in calculating REC's demand charges for 2003 and 2004, Old Dominion adjusted REC's Delivery Point kW demand to reflect deliveries of

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[25] Filing of October 5, 2004, Docket No. ER05-18-000, Attachment C, New Dominion Energy Cooperative, FERC Electric Tariff, Original Volume No. 1, proposed Original Sheet No. 12; Ex. ODC-1 at 16; Ex. ODC-4 at Original Sheet No. 14. Tr., at 251.

[26] Filing of October 5, 2004, Docket No. ER05-18-000, Attachment C, New Dominion Energy Cooperative, FERC Electric Tariff, Original Volume No. 1, proposed Original Sheet No. 8; Ex. ODC-4 at Original Sheet No. 8. Tr., at 212-213, 218-219, 269.

[27] Tr., at 270.

[28] *Id.*

[29] Ex. NVC-13.

[30] *Id.*, at p. 3 of each agreement.

only 26 MW to Bear Island. Old Dominion did not use REC's actual metered deliveries to Bear Island during the relevant monthly combined system peak demands, as section E(I)(b) of the tariff generally requires.

18. When the 2004 DSM Agreement expired on December 31, 2004, it was not replaced with a new DSM Agreement.[31] Thus, as of January 7, 2005, when New Dominion made its amended formula rate filing in this docket, there was no DSM Agreement in effect between the Applicants, REC, and Bear Island.

19. However, in the October 2005 Settlement, both Old and New Dominion agreed, among other things, to enter into a new DSM Agreement with REC and Bear Island. In the DSM Agreement, which Applicants stated was not subject to Commission jurisdiction, [32] Applicants and Bear Island agreed that Applicants could curtail Bear Island's demand to 24 MW for forty-five days during the months of June through September.[33] In the DSM Agreement, they also agreed that, "[f]or purposes of calculating the monthly demand charge from REC" to Bear Island, Applicants "will bill REC for 24,000 kW [24 MW] each month for the Term of [the DSM Agreement]."[34] The settlement did not provide for any change in New Dominion's proposed tariff provisions concerning the Member Cooperatives' Delivery Point kW Demand to be used in calculating and billing the demand charge. Thus, the proposed tariff continues to define that demand as the Member Cooperatives' "Delivered Demand" during the 60-minute "clock-hour in each calendar month during which the combined system . . . peak demand occurs." Nevertheless, consistent with the prior practice when the 2003 and 2004 DSM Agreements were in effect, all parties understood the settlement to require that New Dominion would use Bear Island's 24 MW contract demand under the new DSM Agreement in calculating the demand rates for the Settling parties.

20. At the hearing, Applicants contended that New Dominion should calculate the demand charge for NOVEC each month using the same method as approved in the Settlement for the settling parties. Thus, New Dominion would adjust the deliveries to

[31] Tr., at 227.

[32] Offer of Settlement of October 13, 2005, Explanatory Statement at 6.

[33] *Id.*, Settlement Agreement, Attachment 2, Agreement for Demand Side Management Services, sections 1.1 and 1.2.

[34] *Id.*, Settlement Agreement, Attachment 2, Agreement for Demand Side Management Services (unexecuted), section 3.2.

REC during the relevant monthly combined system peak demands to reflect deliveries of only 24 MW to Bear Island, consistent with the DSM Agreement.

21. Applicants argued that the DSM Agreement demand of 24 MW is the appropriate measure of Bear Island's demand for New Dominion to use in determining the demand rate to apply to NOVEC because it has been their practice, when a DSM Agreement is in effect, to use the contract demand units agreed to in the DSM Agreement in the denominator of the demand rate formula. They asserted that failure to use the DSM Agreement demand of 24 MW would violate Commission precedent requiring a matching between the demand determinants used in calculating the unit charges for a service and the demand units to which the unit charges will be applied for billing purposes.[35] They also stated the DSM Agreement benefits NOVEC because it reduces the amount of capacity costs that NOVEC must pay.

22. NOVEC and Staff objected to the use of contract demand of 24 MW for Bear Island to calculate the demand rate for NOVEC. They contended that Applicants must use Bear Island's Actual Combined Peak (CP) Demand in calculating the demand rate applicable to NOVEC. They argued that section E(I) of New Dominion's proposed tariff requires that the demand rate be based on each Member Cooperative's actual metered demand. NOVEC argued that using the contract demand for Bear Island subjects NOVEC to higher rates because the 24 MW contract demand for Bear Island is too low, pointing out that Bear Island's average demand is 68 MW. Staff argued that using contract demand for Bear Island violates the filed rate doctrine and cost causation principles.

23. At the hearing, NOVEC also asserted that Applicants should implement a dual rate formula with one calculation for NOVEC and a second calculation for the other Member Cooperatives. NOVEC urged that Applicants should determine NOVEC's demand rate first and that they should do this by calculating costs using Bear Island's actual demand at the combined peak for the months of April through December. Then, NOVEC asserted, Applicants should subtract the demand costs to be paid by NOVEC from the

[35] *Citing Kentucky Utils. Co.*, 81 FERC ¶ 61,299 at n.2 (1997); *Southern Co. Servs., Inc.*, 61 FERC ¶ 61,339 at 62,336-37 (1992)*; Montaup Elec.Co.*, 38 FERC ¶ 61,252 at 61,859 (1987).

Applicants' total demand costs and collect the remainder from the other eleven Member Cooperatives through application of the rate formulas adopted as part of the Settlement.[36]

24. In the Initial Decision, the ALJ found that it is not unjust and unreasonable to allow Applicants to use the 24 MW contract demand for Bear Island in calculating the demand rate for NOVEC as well as for the other Member Cooperatives. Accordingly, she rejected NOVEC's proposed dual rate formula going forward and NOVEC's carve-out proposal for the current year's rates. She found that using the 24 MW figure as Bear Island's billing demand to calculate the demand rate represents a reasonable attempt to match costs to their source. She also rejected NOVEC and Staff's concerns regarding violation of the filed rate doctrine and cost causation principles.

25. The ALJ based her holdings on several findings. First, she found that the Commission approved use of the 24 MW demand figure when it approved the Settlement. She further found that the Commission's approval showed that the Commission was aware of this alteration in Applicants' method of calculating the demand rate and, thus, that there was no violation of the filed rate doctrine. She also found that the Commission had considered and rejected NOVEC's concerns that the DSM Agreement would increase the rates NOVEC would pay when it found in the Settlement Order that NOVEC raised no genuine issue of fact.[37] The ALJ also found that use of the 24 MW demand figure for Bear Island yielded a demand rate that is consistent with the costs actually caused by Bear Island.

26. The ALJ also found that all the other eleven Member Cooperatives were bound by the Settlement so that objections to the DSM Agreement based on its impact on Member Cooperatives other than NOVEC lacked merit. She found that the Settlement Order accepted the Settlement rate formulas in full as applied to the other Member Cooperatives and did not contemplate later revision to ensure that NOVEC was not impacted by the

[36] NOVEC also argued that Applicants had been using the DSM Agreement contract demand of 24 MW to determine its current rates for all the Member Cooperatives, including NOVEC, and that Applicants must correct the rates currently in effect as they apply to NOVEC by carving NOVEC out from the impact of the DSM Agreement. The current rates are those of Old Dominion in Docket No. ER05-360-000. To the extent necessary, the Commission will examine the current rates in further proceedings in Docket No. ER05-360-000.

[37] Initial Decision at P 79 *citing New Dominion Energy Cooperative*, 115 FERC ¶ 61,025 at P 10.

Settlement. The ALJ went on to find that REC was not receiving preferential treatment with respect to the 24 MW contract demand used for Bear Island. She found Bear Island is a party to a demand-side management agreement with Applicants and that other customers could negotiate similar agreements with Applicants.

2. Exceptions and Discussion

a. Whether the Order Approving the Settlement for Consenting Parties and Severing NOVEC and the Filed Rate Doctrine Require that the Demand Rate for NOVEC Must Be the Demand Rate in New Dominion's October 5, 2004 Filing

27. On exceptions, NOVEC claims, first, that it was carved out of the Settlement and that, therefore, both the Commission's order approving the Settlement and the Filed Rate Doctrine require that it must be charged rates pursuant to the so-called "As-Filed Formula" proposed in New Dominion's section 205 filing. NOVEC asserts that the As-Filed Formula does not provide for any adjustment to a Member Cooperative's actual delivered demand during the relevant nine monthly combined system peak demands to reflect any DSM Agreement that may be in effect with a particular customer. NOVEC states that the As-Filed Formula provides for New Dominion to calculate its per unit demand charge by dividing its demand costs by the "Total Delivery Point kW Demand" of Member Cooperatives from April through December less 300 kW minimum per Delivery Point.[38] Section E(I)(b) of the tariff defines "Delivery Point kW Demand" as:

> the 60 minute integrated kW demand during the same hourly period in which the New Dominion Monthly Demand is determined. This 60 minute period represents the clock-hour in each calendar month during which the combined system (Dominion Virginia Power and New Dominion's VE area members) peak demand occurs.[39]

[38] Filing of October 5, 2004, Docket No. ER05-18-000, Attachment C, New Dominion Energy Cooperative, FERC Electric Tariff, Original Volume No. 1, Original Sheet No. 11; Ex. ODC-1 at 16; Ex. ODC-4 at Original Sheet No. 13.

[39] *Id.*

NOVEC asserts that this definition refers only to the Member Cooperatives' actual metered demand during the relevant period and thus does not permit the use of contract demand contained in a DSM Agreement.[40]

28. NOVEC contends that, by severing it from the Settlement, the Commission's order approving the Settlement required that the Applicants calculate NOVEC's demand charge pursuant to the As-Filed Formula without recognition of Bear Island's DSM Agreement. NOVEC also argues that this result is required by the Filed Rate Doctrine, because New Dominion did not propose in its section 205 filing to reflect DSM Agreements in the calculation of its demand charges.[41]

29. The Commission finds NOVEC is mistaken that either the Commission's order approving the Settlement or the filed rate doctrine necessarily requires that NOVEC's demand charge be calculated without any recognition of Bear Island's DSM Agreement. Instead, the Commission finds that, if the Applicants can show, based upon the record developed at the hearing, that use of Bear Island's 24 MW is just and reasonable, then they may calculate NOVEC's demand charge in that manner.

30. First, there is nothing in the order approving the Settlement requiring that NOVEC's demand charge be calculated pursuant to what NOVEC describes as the As-Filed Formula. Consistent with the Commission's settlement rules, the Commission severed NOVEC from the settlement and approved the settlement as uncontested for the remaining, consenting parties.[42] That means the Settlement itself could not impose any rate determinations on NOVEC. However, severance does not guarantee the severed, contesting parties any particular result in a case. Its purpose is simply to give the contesting parties "an opportunity to litigate their objections on the merits."[43] To that end, the Commission established the instant hearing to determine on the merits the just

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[40] Filing of October 5, 2004, Attachment C, New Dominion Energy Cooperative, FERC Electric Tariff, Original Volume No. 1, proposed Original Sheet No. 3, proposed sections E(I) (a) and (b) and proposed Original Sheet No. 11.

[41] NOVEC states that, after its demand charge is calculated pursuant to the As-Filed Formula, the Applicants would recover all remaining demand costs from the other Member Cooperatives as provided in the Settlement.

[42] 18 C.F. R. § 385.602(h)(1)(iii)(2007).

[43] *Trailblazer Pipeline Co.*, 85 FERC ¶ 61,345, at 62,345 (1998). *UMDG vs. FERC*, 732 F.2d 202 (D.C. Cir. 1984).

and reasonable rates New Dominion may charge NOVEC. The settlement order did not limit in any way the possible outcomes of that hearing. Thus, the settlement order did not prevent the Applicants from seeking to show at the hearing that it is just and reasonable to calculate their demand charges to NOVEC using Bear Island's 24 MW contract demand under its DSM Agreement.

31. Second, if the Commission finds that the Applicants' proposed method of determining NOVEC's demand charge is just and reasonable, the Filed Rate Doctrine is not an obstacle to New Dominion's use of that method. As stated above, New Dominion's proposed tariff will not go into effect until the reorganization of Old Dominion is consummated, and that has not yet happened. Thus, the Commission's findings with respect to New Dominion's proposed tariff in this proceeding will only have a prospective effect. The Commission may, on a prospective basis, authorize a utility to charge any rate which the Commission finds to be just and reasonable, even if that rate is different from the rate originally filed by the pipeline.[44] In that situation, charging the new just and reasonable rate authorized by the Commission will not violate the Filed Rate Doctrine, because the new rate approved by the Commission is the filed rate.

32. In any event, even if New Dominion's proposed tariff had gone into effect, we do not believe that New Dominion's use of Bear Island's 24 MW contract demand under the DSM Agreement to determine NOVEC's demand charge would violate the Filed Rate Doctrine. NOVEC contends that use of the contract demand under the DSM Agreement would violate New Dominion's proposed tariff, because section E(I)(b) of that tariff defines the Delivery Point kW Demand to be used in calculating the demand charge as the Member Cooperatives' "60 minute integrated kW demand" during the monthly combined system peak. NOVEC asserts that this can only refer to the Member Cooperatives' actual metered demand during the relevant peak periods, not to contract demand under a DSM Agreement. However, Old Dominion's existing tariff contains the same definition of Delivery Point kW Demand, and there is no dispute that Old Dominion's past practice, during the period before 2005 when Bear Island had DSM Agreements, was to use the contract demand under those DSM Agreements in calculating its demand charges.

33. Moreover, the Settlement did not change the section E(I)(b) definition of Delivery Point kW Demand, despite the fact the Settlement provided for the Applicants, REC, and Bear Island to enter into the DSM Agreement including a provision for use of Bear

[44] *See FPC v. Tennessee Gas Co.*, 371 U.S. 145, 153 (1962), and *ANR Pipeline co. v. FERC*, 863 F.2d 959 (D.C. Cir. 1988).

Island's 24 MW contract demand in the calculation of the Applicants' demand charges. Therefore, the same tariff provision NOVEC relies on to claim use of Bear Island's 24 MW violates New Dominion's proposed tariff applies not only to NOVEC, but also to the settling parties. The Commission nevertheless approved the Settlement with the understanding that Settlement would permit New Dominion to use Bear Island's 24 MW contract demand to calculate its demand charges to the settling parties. It thus appears that Old Dominion, the Member Cooperatives, and the Commission have consistently understood both Old Dominion's existing tariff and New Dominion's proposed tariff to permit the use of the contract demand in a DSM Agreement to be used in calculating demand charges, despite the section E(I)(b) definition of Delivery Point kW Demand relied upon by NOVEC. In these circumstances, the Commission concludes that the Filed Rate Doctrine does not provide a basis for rejecting New Dominion's proposal to use Bear Island's 24 MW contract demand under the DSM Agreement to calculate NOVEC's demand charge does not violate the Filed Rate Doctrine.

34. Therefore, the issue of whether to accept the Applicants' proposed method of determining NOVEC's demand charge turns on whether the Applicants have satisfied their burden under FPA section 205 to show that their proposal is just and reasonable. We discuss that issue in the next section.

b. What is the Just and Reasonable Demand Rate for NOVEC and Whether It Is Just and Reasonable to Use 24 MW of Demand for Bear Island to Calculate NOVEC's Demand Rate

(1) Exceptions

35. On exceptions NOVEC and Staff contend that using Bear Island's contract demand of 24 MW to calculate NOVEC's demand rate is unjust and unreasonable because it is contrary to New Dominion's as-filed rates. They assert sections E(I)(a) and (b) of the tariff require the use of Delivered Demand to calculate the demand rate and that Delivered Demand is the integrated kW demand during the hourly Combined Peak for the system, with the system defined as Dominion Virginia Power and New Dominion's VE area members.[45] Based on this tariff language, NOVEC and Staff assert the proposed tariff requires the use of each Member Cooperative's actual metered demand during the

[45] Filing of October 5, 2004, Docket No. ER05-18-000, Attachment C, New Dominion Energy Cooperative, FERC Electric Tariff, Original Volume No. 1, Original Sheet Nos. 3 and 4; Ex. ODC-4, Original Sheet No. 3; Ex. ODC-9, Original Sheet No. 3.

relevant peak periods, without regard to contract demands which may have been agreed to as part of a DSM.

36. NOVEC also asserts that using 24 MW of contract demand for Bear Island also results in a higher demand charge for NOVEC than using Bear Island's actual metered demand because this figure is too low. NOVEC asserts the DSM Agreement limits the contractual billing demand to 24 MW [46] while Bear Island's average demand is 68 MW.[47] NOVEC asserts REC is able to reduce its total demand by 44 MW because it uses the 24 MW contract demand for Bear Island.[48] NOVEC states that, on an annual basis, this reduction in demand units results in a reduction of almost $6 million in REC's demand charges.[49] NOVEC states that since Applicants' rate formulas are designed to recover all of their costs, the alleged undercharge to REC shifts costs to the other Member Cooperatives. NOVEC asserts its demand costs are increased by nearly $1.8 million on an annual basis because Applicants use the DSM contract demand of 24 MW for Bear Island.[50] NOVEC argues that requiring Member Cooperatives other than REC to bear these costs is inconsistent with the principle that costs should be allocated based upon cost causation. NOVEC contends, in essence, that the Applicants incur demand costs to serve the full metered demand of each cooperative, and therefore those costs should be allocated based upon the full metered demand of all the cooperatives without exception. NOVEC also argues that the alleged cost shift is unduly discriminatory.

37. Applicants respond that the DSM Agreement is specifically contoured for use in the Virginia Electric and Power area of PJM South.[51] They note that PJM allocates

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[46] *Citing* NVC-14 at 3.

[47] *Citing* Tr. at 273:1-3.

[48] NOVEC explains that 68 MW (average demand) minus 24 MW (contractual demand) equals 44 MW.

[49] NOVEC assumes that Applicants' average embedded demand cost is $11.24/kW. It states that 44 MW times $11,240 per MW/month times 12 months equals $5,934,720. NOVEC Brief on Exceptions at 24.

[50] *Citing* Ex. NVC-4 (corrected), line 16.

[51] PJM South is the VACAR Control Zone; the VACAR Control Zone is the transmission facilities of Virginia Electric and Power Company. PJM Interconnection, L.L.C., FERC Electric Tariff, Sixth Revised Volume No. 1, sections 1.32F, Eighth Revised Sheet no. 41, and section 1.49C, Ninth Revised Sheet No. 44.

demand costs to Old Dominion based on PJM's five hourly summer coincident peak demands. Therefore, Old Dominion's Virginia Power area capacity obligations and costs are based on its overall demand during the times of those summer coincident peaks. Applicants advise that, as they have successfully in the past, they will direct Bear Island to reduce its demand to no more than 24 MW at the significant times which PJM is likely to use in allocating demand costs to Old and New Dominion. This will benefit all the Member Cooperatives, including NOVEC, by reducing the demand costs Old and New Dominion will flow through to them.[52] Applicants contend that, if NOVEC prevails, NOVEC would be permitted to share in the cost reducing benefits of the DSM Agreement while, at the same time, avoid having its demand rate set using the 24 MW billing demand under the DSM Agreement.

38. Applicants assert that their proposed rate formulas provide for the use of billing demand when there is a DSM Agreement in place.[53] Applicants also state that it has been their practice to use the contract billing demand whenever there is a DSM Agreement in place. They state that in previous years when Bear Island had a DSM Agreement, the Bear Island Delivery Point kW Demand for purposes of the divisor in the demand rate calculation was the contract demand per the operative DSM Agreement.[54] They also assert that use of the DSM Agreement contract demand is required by the Commission's policy that there must be a match between the demand determinants used in calculating the unit charges for service and the demand determinants to which the unit charges will be applied for billing purposes.

39. Applicants also respond that Bear Island's demand units, absent the DSM Agreement, would not be based on its average hourly demand so that the 68 MW figure that NOVEC uses is incorrect. They state that if there were no DSM Agreement, Bear Island's coincident peak demands would be used to determine Bear Island's demand in calculating the Demand Rate and that Bear Island has regularly shed load at the time of the VEPCO/Old Dominion monthly one-hour peak to keep its demand in line with the 24 MW DSM Agreement Demand. They assert that consequently, there would be no adverse cost shift to NOVEC from using the DSM Agreement demand of 24 MW to calculate NOVEC's demand rate.

[52] Applicants' Brief Opposing Exceptions at 53.

[53] Applicants cite Tr. at 244:4-245:2.

[54] Applicants cite Exs. ODC-11; NVC-6; and NVC-13.

(2) Commission Decision

40. The Commission affirms the ALJ's holding that the Applicants' proposal to calculate their demand charges to NOVEC using Bear Island's 24 MW contract demand under its DSM Agreement is just and reasonable. The Commission rejects NOVEC's assertion that the Applicants' proposed demand cost allocation method improperly departs from cost causation principles and is unduly discriminatory.

41. As the United States Court of Appeals for the District of Columbia Circuit has held, "Properly designed rates should produce revenues from each class of customers which match, as closely as practicable, the cost to serve each class or individual customer."[55] Consistent with this principle, the Commission has generally required electric utilities to allocate demand costs based upon some measure of their firm customers' peak demand for service, because demand costs are incurred in order to serve that peak demand.[56] For example, in Opinion No. 185, the Commission held,

> Even a limited right of interruption, if it enables the company to keep a customer from imposing demands on the system during peak periods, gives a company the ability to control its capacity costs. Therefore, that customer shares no responsibility for capacity costs under a peak responsibility method.[57]

42. The Applicants' proposal to calculate their demand charges to NOVEC using Bear Island's 24 MW contract demand under its DSM Agreement is consistent with this precedent. The Applicants incur their demand costs based upon their Member Cooperatives' peak demands for service during the four summer months, June to September. Old Dominion's transmission and generation capacity obligations are determined by PJM. PJM establishes capacity obligations for both generation and transmission based on measures of peak use in a zone during the summer.

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[55] *Alabama Electric Co-op, Inc. v. FERC*, 684 F.2d 20,26 (D.C. Cir. 1982).

[56] *Kentucky Utilities Co.*, 15 FERC ¶ 61,002 at 61,003 (1981)(Opinion No. 116).

[57] *Delmarva Power and Light Co.*, 24 FERC ¶ 61,199 at 61,462 (1983). *Louisiana Public Service Commission v. Entergy Corporation*, 111 FERC ¶ 61,080 at 61,369-70 (2005). *See Occidental Chemical Corp. v. PJM Interconnection, L.L.C.*, 102 FERC ¶ 61,275 at 61,853 (2003).

43. Old Dominion's obligation to provide for or purchase generation capacity is determined under PJM's Reliability Assurance Agreement (RAA).[58] The obligation for generation capacity is based on "the weather-adjusted coincident summer peak" of the zone in which it is located, as determined in accordance with the procedures set forth in the PJM Manuals.[59] The Manuals prescribe that the weather-adjusted coincident summer peak in the zone is determined using five coincident peaks,[60] with the peaks being measured during the months of June through September.[61] Old Dominion's obligation to pay for transmission capacity in the Virginia and Electric Power Company zone is determined under PJM's open access transmission tariff. The obligation is based on Old Dominion's daily load "coincident with the annual peak of the Zone" in which it is located.[62]

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[58] PJM RAA, Article 7.

[59] *Id.*, Schedule 8, Original Sheet No. 37. (*See also PJM Primer for Municipalities and Cooperatives: Capacity Obligations and ALM* (February 2006).)

[60] *See PJM Manual No. 20, PJM Reserve Requirements* at 14, Revision 02 (April 30, 2004) [noted on PJM's website as under revision for implementation of the Reliability Pricing Model]:

"The Adjusted Planning Period Peak Load for each zone is determined by the following formula:

APPPL = P - (ALM * ALM F)

Where:

APPPL	Adjusted Planning Period Peak Load
P	Weather Normalized 5CP Zonal peak load (See PJM Manual for ***Load Data Systems***)
ALM	Active Load Management that is nominated into the eCapacity system (See PJM Manual for ***Load Data Systems***)
ALM F	Active Load Management Factor, as approved by the Reliability Committee. This factor represents the reliability benefit of implementing ALM a maximum of 10 times in the summer peak period."

[61] *PJM Manual 19: Load Data Systems* at 25 (Revision 11) (June 1, 2007).

[62] PJM OATT, section 34.1, Seventh Revised Sheet No. 93.

44. Applicants assert that the Bear Island DSM Agreement was specifically contoured for use in the Virginia Electric and Power zone of PJM because it permits Applicants to curtail Bear Island's demand to 24 MW during the months of June through September, when the five coincident peaks are measured that establish the Applicants' obligation to pay generation capacity costs in PJM. The Commission agrees with Applicants that the DSM Agreement reflects the manner in which capacity obligations for generation are established in PJM. It provides that Applicants can curtail Bear Island's demand during the four months of June through September when the five coincident summer peaks occur that determine the obligation for generation capacity.

45. Thus, despite the limited nature of the Applicants' right to curtail Bear Island under the DSM agreement, the DSM agreement enables the Applicants to control their demand costs by enabling them to reduce service to Bear Island to 24 MW during the crucial periods that determine the demand costs PJM allocates to the Applicants. The Commission also agrees with Applicants that Bear Island's demand will be 24 MW during PJM's five coincident summer peaks since Applicants can curtail Bear Island during these peaks and have every incentive to do so. Thus, consistent with Opinion No. 185 and the other precedent discussed above, using 24 MW of contract demand to allocate demand costs to Bear Island matches cost incurrence for Old Dominion's capacity obligations for Bear Island to Bear Island's responsibility for those costs.[63]

46. The Commission recognizes that, while PJM allocates demand costs to the Applicants based on Old Dominion's peak June-September summer usage, the Applicants then allocate those costs among their Member Cooperatives' firm, non-curtailable services based on the Member Cooperatives' coincident peak usage in each of the nine months April to December. Thus, the Applicants' rights to curtail Bear Island pursuant to the DSM Agreement do not extend to every month the Applicants use to allocate demand costs among their customers. However, this does not change the fact that the Applicants incur demand costs from PJM based only on the Member Cooperatives' peak June-September summer usage. The fact the Applicants may then use a somewhat different method to allocate those costs among the firm non-interruptible services they provide to the Member Cooperatives[64] does not justify allocating a share of

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[63] This is consistent with Commission precedent which requires that demand billing should reflect cost incurrence. *E.g.*, *Montaup Elect. Co.*, 38 FERC ¶ 61,252 at 61,860 (1987). The crux of this precedent is to insure that billing demand provisions do not improperly shift revenue responsibility from one customer to another customer.

[64] No party in this proceeding has sought to modify the Applicants' proposed method of allocating demand costs among firm non-interruptible services so that it would exactly match PJM's demand cost allocation method. Because the parties did not raise or

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those costs to the interruptible service to Bear Island, i.e., service in excess of 24 MW. As we have already held, the Applicants do not incur demand costs to provide that interruptible service to Bear Island. However, they do incur demand costs to provide all other services to the Member Cooperatives, because all other services are firm and non-interruptible.[65]

47. For the same reasons, we reject NOVEC's contention that allocating demand costs based on Bear Island's 24 MW contract demand is unduly discriminatory. NOVEC asserts that it and other Member Cooperatives also "have load management programs,"[66] but, unlike REC and Bear Island, do not receive any guaranteed cap on the demand costs that will be allocated to them. However, NOVEC has not provided evidence that it has a DSM agreement with the Applicants similar to the Bear Island DSM Agreement or that it sought, and the Applicants refused to negotiate, a similar agreement. The Bear Island DSM Agreement permits the Applicants to order Bear Island to reduce its demand to 24

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discuss that issue at the hearing, we will not pursue that matter in this proceeding. However, the Applicants should address this matter in their next section 205 filing and either modify their demand cost allocation method to match PJM's or explain why such a modification would not be just and reasonable.

[65] NOVEC estimates that allocating demand costs based on Bear Island's 24 MW contract demand shifts about $1.8 million in annual demand costs from REC and Bear Island to NOVEC. NOVEC Brief on Exceptions at 24. NOVEC's estimate is based on its assumption that, absent the DSM Agreement's limit on the costs to be allocated Bear Island, Bear Island's usage during the monthly coincident peak periods the Applicants use for the allocation of demand costs among Member Cooperatives would equal its average daily usage of about 68 MW, or 44 MW in excess of the 24 MW contract demand under the DSM Agreement. *Id*. However, as the Applicants point out, during 2005 when Bear Island did not have a DSM Agreement in place, it reduced its usage during the relevant coincident peaks to somewhat less than 24 MW in order to minimize its responsibility for demand costs. Ex. ODC-8 at 24. Ex. ODC-11. This strongly suggests that a refusal to give effect to the DSM Agreement's 24 MW limit on the demand costs allocated to Bear Island would lead Bear Island to take actions comparable to those it took in 2005. That would result in NOVEC continuing to bear the demand costs it claims the DSM Agreement shifts to it. In any event, regardless of the cost shifting effects of the DSM Agreement, exempting Bear Island's interruptible service from an allocation of demand costs is consistent with Commission precedent and cost causation principles for the reasons discussed above.

[66] Ex. NVC-1 at 12-13. NOVEC Brief on Exceptions at 27-28.

MW during the peak summer periods PJM uses to allocate demand costs to the Applicants. There is nothing in the record to indicate that NOVEC's load management program gives the Applicants any right to interrupt service to NOVEC or a customer of NOVEC. Nor has NOVEC presented any evidence to show whether and how its "load management programs" serve to limit its demand during the periods used by PJM to allocate demand costs to the Applicants. In short, there is nothing in the record to indicate that any portion of the service Applicants provide to NOVEC is interruptible in the same manner as Applicants' service to Bear Island through REC. Thus, Applicants appropriately treat the interruptible Bear Island service differently than the non-interruptible service to NOVEC.

48. The Commission thus approves New Dominion's proposal to use Bear Island's 24 MW contract demand under the DSM Agreement in calculating NOVEC's demand charge. This means that New Dominion will use the same formula to determine NOVEC's demand charge as it will use to determine the other Member Cooperative's demand charges under the Settlement. As a result, the various issues argued by the parties concerning how dual formula rates would be implemented are moot, and will not be addressed in this order.

B. Reactive Power Rate in New Dominion's Rates

49. In this section we address various issues associated with New Dominion's proposed reactive power rate. New Dominion did not propose to change its reactive power rate. Staff, however, contended it was unjust and unreasonable. The discussion below presents the basic facts concerning the reactive power rate; determines the burden of proof with respect to the reactive power rate; decides whether the reactive power rate is unjust and unreasonable; and rules on whether there is an alternative that is just and reasonable. For the reasons discussed below, the Commission affirms the ALJ's findings that Staff bore the burden of proving that the reactive power rate is unjust and unreasonable, that Staff did not meet this burden, and that, therefore, New Dominion's proposed reactive power rate will remain unchanged.

1. Background and Initial Decision

50. At the time of New Dominion's filing in October, 2004, VEPCO had not yet joined PJM and Old Dominion still received some of its reactive power charges from VEPCO. VEPCO's reactive power rate was $0.06/rkVA,[67] and it billed this rate based upon its customers' highest average rkVA measured in any 30-minute interval during the

[67] Tr. 326-327.

current billing month. Old Dominion's tariff contained the same reactive power rate, and thus it flowed through its reactive power costs to its Member Cooperatives on the same basis as it incurred those costs from VEPCO.[68] In its October 2004 filing, New Dominion proposed to carry over Old Dominion's existing $0.06/rkVA[69] reactive power rate into its new tariff. New Dominion also proposed to continue to bill this rate to its Member Cooperatives based on each member's highest average rkVA measured in any 30-minute interval during the month.[70]

51. On May 1, 2005, VEPCO joined PJM, and beginning in May 2005, Applicants have obtained their reactive power service through the PJM market, rather than from VEPCO.[71] Thus, VEPCO is no longer charging the Applicants its $0.06/rkVA reactive power rate. Old Dominion is now charged for a "reactive supply and voltage control from generation sources service," pursuant to Schedule 2 of PJM's tariff.[72] Schedule 2 allocates reactive power costs to network customers based on a measure of peak demand. Specifically it allocates network customers' reactive power costs based on "the sum of a Network Customer's daily values of DCPZ . . . (as . . . defined in section 34.1) . . . for all days of the month"[73] Section 34.1 defines DCPZ as "the daily load of the Network Customer located within a Zone coincident with the annual peak of the Zone" as

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[68] Tr. 327.

[69] Old Dominion Filing of March 3, 2005, Attachment 1, Revised Sheet No. 14 (Docket No. ER05-360-001) accepted by Director Letter Order of September 9, 2005. rkVA stands for reactive kilovolt ampere.

[70] *See* New Dominion Filing of October 5, 2004, Attachment D, Original Sheet No. 12, section E.I.(c).

[71] Exs. S-6 at 7; S-7, STAFF-ODEC-1: "As of May 2005, with the integration of DVP [VEPCO] into PJM, Old Dominion's entire load is located within the PJM control area. . . . Old Dominion currently procures all of its reactive power requirements from PJM. In addition, Old Dominion receives all of its reactive power credits for its generating resources through PJM. . . ."

[72] PJM Interconnection, L.L.C., FERC Electric Tariff, Sixth Revised Volume No. 1, Schedule 2, Sheet Nos. 228- 230B. Tr. 333.

[73] PJM Interconnection, L.L.C., FERC Electric Tariff, Sixth Revised Volume No. 1, Schedule 2, Sixth Revised Sheet No. 229.

adjusted.[74] To obtain the allocation factor, the Network Customer's daily coincident peak load for all the days of the month is divided by the total transmission use in the zone on a megawatt basis (presumably for the month).[75] The allocation factor is then applied to the reactive power revenue requirement for the zone to obtain the costs allocated to the network customer.[76]

52. In October 2005, after this change in the manner that Old Dominion receives and pays for reactive power service, the Applicants filed the Settlement. The Settlement nevertheless provided for the Applicants to continue to charge their Member Cooperatives the existing $0.06/rkVA[77] reactive power rate, and the Applicants continue to propose to charge that same rate to NOVEC. It appears that the $0.06/rkVA charge generally underrecovers the reactive power costs Old Dominion incurs from PJM. The Applicants state that the excess reactive power costs not collected through the $0.06/rkVA charge are recovered through the demand charge discussed in the preceding section of this order.[78] This means that those excess costs are allocated among the Member Cooperatives based upon the nine monthly system coincident peaks used to allocate the demand charge. In summary, the Applicants initially use a peak measure of monthly reactive power demand to allocate reactive power costs, followed by a peak measure of monthly kW demand for uncollected reactive power costs.[79]

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[74] *Id.,* section 34.1, Seventh Revised Sheet No. 93.

[75] *Id.,* Schedule 2, Sixth Revised Sheet No. 229.

[76] *Id.,* Schedule 2, Fourth Revised Sheet No. 228. For example, the monthly reactive power service revenue requirement in the Dominion Zone is approximately $2,652,000. *Id.,* Sixteenth Revised Sheet No. 230B.

[77] Old Dominion Filing of March 3, 2005, Attachment 1, Revised Sheet No. 14 (Docket No. ER05-360-001) accepted by Director Letter Order of September 9, 2005. rkVA stands for reactive kilovolt ampere.

[78] Ex. ODC-8 at 46.

[79] Under its proposed tariff, New Dominion allocates reactive power costs based on a peak measure of power, the highest average rkVA measured in any 30-minute interval during the month. New Dominion charges a flat rate of $0.06/rkVA for reactive power. Any reactive power costs not collected by the flat rate are collected through the true up mechanism for demand costs which is based on the average combined monthly peak in kW for energy from April through December. Filing of October 5, 2004,

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53. At the instant hearing for the purpose of determining on the merits whether New Dominion's proposed rates are just and reasonable with respect to NOVEC, Staff challenged New Dominion's proposed reactive power rate as unjust and unreasonable. While recognizing that New Dominion was proposing to continue Old Dominion's existing reactive power rates, Staff asserted the Applicants bore the burden of proof on this issue because, among other things, the unchanged rate components in their filing are an integral part of the overall cost of service and their filing constituted an increase in the cost of service.[80] Staff asserted the reactive power rate is unjust and unreasonable because it does not match PJM's allocation of charges for reactive power.

54. Staff asserted that the $0.06/rkVA rate in New Dominion's proposed tariff has no connection to the reactive power costs paid by Applicants. Staff asserted that Applicants credit the revenues from the reactive demand charge against each Member's billing demand in order to allocate demand costs.[81] It also asserted Applicants undercollect reactive power costs which leaves an uncollected amount that is then allocated based on coincident kW peak demands and collected through the demand charge. Staff asserted Applicants are thus using a hybrid of kW demand and reactive demand which differs from PJM's method. Staff asserted that PJM collects reactive power costs based on metered reactive power demand. Staff asserted that, as a result, there are cost shifts among the Member Cooperatives that are unjust and unreasonable. Staff recommended that Applicants allocate their reactive power costs based on each Member's reactive power demand.

55. No party other than Staff sought a change in New Dominion's proposed reactive power rate in this proceeding. The Applicants recognized that their existing reactive power rate no longer matches the manner in which they incur these costs from PJM. However, they pointed out that the Settlement requires that they continue the existing reactive power rate at least with respect to the 11 Member Cooperatives who are subject to the Settlement. They accordingly asserted that the existing rate should remain in effect

Attachment C, New Dominion energy Cooperative, FERC Electric Tariff, Original Volume No. 1, proposed Original Sheet Nos. 3,8, 10, and 11.

[80] *Citing East Tenn. Natural Gas Co. v. FERC*, 863 F.2d 932, 942 (D.C. Cir. 1988) (*East Tennessee*); *North Penn Gas Co. v. FERC*, 707 F.2d 763, 769 (3d Cir. 1983) (*North Penn*); *City of Batavia v. FERC*, 672 F.2d 64, 76–77 (D.C. Cir. 1982) (*Batavia*); *Laclede*, 670 F.2d at 42; *Northern Border Pipeline Co.*, 89 FERC ¶ 61,185 at 61,576 (1999) (*Northern Border*).

[81] Tr. 320:22-25; 323:2-5.

until their next FPA section 205 rate filing, at which time they will propose a revised reactive power rate, applicable to all members, with full cost and rate design support. NOVEC did not oppose this approach.

56. The ALJ found that Staff bore the burden of proof on the reactive power rate. She found first that Applicants had not proposed to change the reactive power rate so that the proponent of the change, Staff, would bear the burden of proof under *Transco*.[82] She also found that the holding in *North Penn* that the utility bears the burden of proof with regard to unchanged portions of a rate which are an integral part of a proposed rate change did not apply to the reactive power rate. She found that "[t]he reactive power rate is not an integral part of the Applicants' rate proposals, which could result in an increase"[83] and, in fact, Staff claimed that the reactive power charge may result in under-collection. She also found that "[r]egardless, the reactive power charge is more a matter of cost allocation."[84] She held that, therefore, the burden of proof with respect to the reactive power rate came within the general rule that when the Commission proposes a change to a utility's existing rates, it must follow the procedures in section 206.[85] Those procedures require that the Commission prove the public utility's existing provision is unjust and unreasonable and the Commission's proposed rate is just and reasonable.

57. The ALJ held that Staff failed to bear its burden of proof. She found that Applicants incur generator-supplied reactive power costs from PJM based on monthly

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[82] *Referring to Public Service Commission of New York v. FERC,* 642 F.2d 1335, 1345 (D.C. Cir 1980) (*Transco*). The courts have held that provisions of the Natural Gas Act and the Federal Power Act that are similar are to be interpreted in the same way. Thus holdings that apply to sections 4 and 5 of the Natural Gas Act also apply to sections 205 and 206 of the Federal Power Act.

As the ALJ noted, the *Batavia* line of cases concern only the Commission's suspension and refund authority, not the burden of proof. Initial Decision at P 51 n.157 *citing ANR,* 771 F.2d at 513-14.

[83] Initial Decision at P 52. *See also Northern Border Pipeline Co.,* 89 FERC ¶ 61,185 at pp. 61,575-76 and n. 10 (1999). *See also Trunkline Gas Company,* 90 FERC ¶ 61,017, at pp. 61,050-51 and 61,076 (2000).

[84] Initial Decision at P 52.

[85] *Referring to Transco,* 642 F.2d at 1345.

coincident peak demands rather than on metered reactive demands.[86] She found further that Applicants' unchanged method for collecting reactive power demand costs matches the way they are incurred under the PJM tariff. The ALJ also held Staff had failed to propose an alternative method for Applicants to recover reactive power costs and thus had failed to bear its burden of proving that the method it proposed is just and reasonable. The ALJ also pointed out that the Applicants had proposed that, in lieu of revising their reactive power rate in this proceeding, they would propose changes in their next section 205 filing, and concluded that no change in their reactive power rate was required at this time.

2. Burden of Proof

(a) Exceptions

58. On exceptions, Staff asserts the ALJ erred in finding that Staff bears the burden of proof as to the reactive power rate and allocation methodology. It asserts that Applicants propose to change the formula rate[87] and that reactive power charges are an integral part of the formula rate.[88] They assert that, therefore, Applicants, not Staff, bear the burden of proof with respect to reactive power charges.[89]

59. In opposing exceptions, Applicants assert they do not bear the burden of proof with respect to the reactive power rate and allocation method because they did not seek to change these provisions. They contend that because Staff did seek to change them, Staff

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[86] Ex. ODC-8 at 46:17-20.

[87] Staff asserts Applicants' rate filings do not constitute an initial rate (*New Dominion Energy Cooperative*, 110 FERC ¶ 61,275, at P 27 and n.12 (2005) and that New Dominion proposes to change Old Dominion's formula rate to: (i) include federal and state income taxes; (ii) remove references to nuclear decommissioning expenses; and (iii) provide for a single, consolidated analysis of all operations within PJM, which includes revisions to the load forecasting methodology and the description of how power is delivered to the Member Cooperatives. Staff Brief on Exceptions at 27 n.54.

[88] *Citing Transco, North Penn Gas Company v. FERC,* 707 F.2d 763 (3rd Cir. 1983), *and Northern Border.*

[89] *Citing Ocean State Power II*, 69 FERC ¶ 61,544, 61,545 n.39 (1994); *Enron Power Enterprise Corp.*, 52 FERC ¶ 61,193 at 61,711 (1990). *See also Alabama Power Company v. FERC,* 993 F.2d 1557, 1567-68 (D.C. Cir. 1993).

bears the burden of showing that they are unjust and unreasonable and that Staff's proposed provisions are just and reasonable.[90] Applicants assert Staff seeks a change in rate methodology, not a new, increased fixed rate. They also state their filings were not intended to seek a rate increase but rather a change in their rate formulas. Applicants assert that *Northern Border* does not apply because whether the changes to their rate formulas represent a rate increase has not been established by substantial evidence. They state that a line and accounts for income taxes have previously been included in the rate formula. They assert that the income tax provision of the rate formula was amended to allow for the inclusion of other accounts needed due to New Dominion's status as a taxable entity.

(b) <u>Commission Decision</u>

60. The Commission affirms, as explained below, the ALJ's finding that Staff bears the burden of proof under section 206 of the FPA with respect to Applicants' unchanged reactive power rate and allocation method.

61. In *Transco,* the court considered the burden of proof under section 5 of the Natural Gas Act (NGA). Section 5 of the NGA is interpreted in the same way as section 206 of the Federal Power Act,[91] and so, is applicable here. In *Transco,* the pipeline made a filing for a rate increase under section 4 of the NGA. The pipeline did not propose to change the zones into which its system was divided. The zones served to allocate costs among three different regions along its system. However, the Commission determined that instead of using a zonal method of cost allocation, the pipeline should use an Mcf-mile method of cost allocation. The Commission contended that since the pipeline had filed for higher rates under section 4(e), it bore the burden of proof with respect to its zonal method of cost allocation. The court disagreed. It stated that a company does not bear the burden of proof on those portions of its filing that represent no departure from the status quo.[92] It found that the zone allocations were no part of Transco's argument

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[90] *Relying on, inter alia, Transco* at 1345; *City of Winnfield, Louisiana v. FERC,* 744 F.2d 871 (D.C. Cir. 1984) (*Winnfield*); *ANR Pipeline Co. v. FERC,* 771 F.2d 507 (D.C. Cir. 1985) (*ANR*).

[91] Cases under the Natural Gas Act and the Federal Power Act typically are read *in pari material*, that is, in the same way when they involve similar provisions. *See, e.g., FPC v. Sierra Pacific Power Co.,* 350 U.S. 348, 353 (1956) and *Arkansas-Louisiana Gas Co. v. Hall,* 453 U.S. 571, 578 n.7 (1981).

[92] *Transco,* 642 F.2d at 1345.

for higher rates.[93] The court held the Commission had to proceed under section 5 in order to change Transco's zones.

62. Other cases further considered the burden of proof. In particular, in *North Penn*, the court considered an unchanged component of the pipeline's overall cost of service, the pipeline's stored gas allowance.[94] The pipeline used the same methodology in its proposed rate increase for determining its stored gas allowance as it had used in its previous rate case. The Commission adopted a different method for determining the stored gas allowance which resulted in a lower allowance and in a lower rate and ordered North Penn to refund the difference between the new lower rate and the higher rate that its customers had been paying.

63. North Penn argued that when the Commission changed the method of computing the stored gas allowance, it was using powers granted by section 5(a) and hence bore the burden of proof and had no authority to order a refund. However, the court held that the working capital allowance was part of the rate increase sought by the pipeline. Specifically, it held that the working capital allowance was an integral part of the rate increase and that North Penn had not met its burden of showing the necessity for all of the increase it requested since it had not shown that its proposed stored gas allowance was just and reasonable.[95] Consequently, the court found the Commission was authorized to order refunds for the excessive stored gas allowance under section 4(e).[96]

64. In *Northern Border*, the Commission considered an unchanged depreciation rate in a general rate increase filed under section 4 of the NGA. There, the Commission recognized that the courts have been concerned that the Commission not blur the line between its sections 4 and 5 authority under the NGA. The Commission stated that, in general, where the pipeline has not proposed a change in its rates or tariff, NGA section 5 places on the Commission the burden of showing the existing rate or tariff provisions are unjust and unreasonable and justifying the replacement rate. Also, any change must be

[93] *Id.*

[94] The stored gas allowance is part of working capital; working capital, in turn, is a component of the pipeline's rate base on which it earns a return.

[95] *North Penn*, 707 F.2d at 767.

[96] *Cf. Nantahala Power and Light Co. v. FERC*, 727 F.2d 1342, 1351 (4th Cir. 1984) (depreciation an integral part of the rate increase (construing section 205 of the Federal Power Act)).

prospective only. However, the Commission stated, NGA section 4 provides for different procedures where the pipeline proposes a rate increase or other changes.[97]

65. The Commission stated it has held that these provisions of section 4 govern any pipeline proposal to increase its rates based upon a proposed increase in its overall cost of service.[98] That includes both the individual cost of service components the pipeline proposed to increase and those that it left unchanged. As the Commission explained in *Tennessee* and *Northwest*, each component of the pipeline's cost of service is an integral part of the pipeline's proposed overall rate increase. Therefore, the pipeline's burden under NGA section 4 of "showing that an increased rate or charge is just and reasonable" necessarily includes the burden of supporting each component of the cost of service, the unchanged as well as the changed components. Moreover, the Commission stated, to the extent the pipeline fails to sustain that burden, the Commission may order refunds of the overall increase in the cost of service. It found this result is consistent with the fact that section 4 speaks solely of "increased rates or charges," without distinguishing between the cost components that make up those rates and charges.

66. Thus, *North Penn*, *Northern Border*, and other cases establish the principle that the applicant bears the burden of proof under FPA section 205 or NGA section 4 with respect to unchanged components of the utility's cost of service that are an integral part of its proposed overall rate increase. However, in cases involving changes in rate methodology features such as the allocation of costs among customers or the design of the utility rates, the Commission must proceed under FPA section 206 or NGA section 5.

67. In this case, the Commission finds that Staff is seeking a change in the Applicants' design of their reactive power rates and the allocation of those costs among the Member

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[97] NGA section 4 provides in relevant part:

> Where increased rates or charges are . . . made effective [at the expiration of the suspension period], the Commission may . . . upon completion of the hearing and decision . . . order such natural gas company to refund, with interest, the portion of such increased rates or charges by its decision found not justified. At any hearing involving a rate or charge sought to be increased, the burden of proof to show that an increased rate or charge is just and reasonable shall be upon the natural gas company.

[98] *Citing Tennessee Gas Pipeline Co*., 25 FERC ¶ 61,020, at 61,108 (1983), *reh'g denied on this issue*, 26 FERC ¶ 61,109, at 61,263-64 (1984) (*Tennessee*), and *Northwest Pipeline Corp*., 87 FERC ¶ 61,266 (1999) (*Northwest*).

Cooperatives. Therefore, the Commission would have to proceed under FPA section 206 in order to adopt Staff's proposed changes in the Applicants' reactive power rates. It may be, as Staff points out, that the Applicants' section 205 filing may increase the overall rates they charge the Member Cooperatives, because the Applicants proposed to add various line items related to taxes to their formula rates.[99] But Staff is not attacking the Applicants' existing reactive power rates on the ground that those rates contribute to an overall rate increase by the Applicants. Staff does not propose to decrease the amount of reactive power costs that are to be collected. Any cost increase that might exist is not at issue here. Instead, Staff is concerned that the current reactive power rate undercollects reactive power costs and that the uncollected reactive power costs are unfairly shifted among the Member Cooperatives by the existing methods (reactive power demand and combined peak kW demand) used to allocate these uncollected costs. Staff's concern is the allocation of reactive power costs among the Member Cooperatives and not any increase in these costs or in Applicants' rates.

68. As a result, the Commission finds that the reasons for shifting the burden of proof to Applicants with respect to unchanged rate components that are an integral part of a rate increase are not present in this case. The rationale for shifting the burden of proof to Applicants in such a case is that all of the cost items are part of the rate increase and that any cost item that is not supported may give rise to a refund of a portion of the increase. Here, the focus of Staff's concern is the method by which reactive power costs are allocated, not the amount of these costs. Under these circumstances, the Commission finds that the interests and concerns that *North Penn* and *Northern Border* are designed to promote are not at issue and do not support placing the burden of proof on Applicants with respect to their unchanged reactive power rate and allocation method. The Commission finds that the procedures of section 206 apply and that Staff, as the

[99] The new tax-related accounts Applicants included in New Dominion's tariff are Account No. 408.2, Taxes other than income taxes, other income; Account No. 409.2, Income taxes, other income and deductions; Account No. 409.3, Income taxes, extraordinary items; Account No. 410.1, Provision for deferred income taxes, utility operating income; Account No. 410.2, Provision for deferred income taxes, other income and deductions; Account No. 411.1, Provision for deferred income taxes—Credit, utility operating income; Account No. 411.2, Provision for deferred income taxes—Credit, other income and deductions; Account No. 411.4, Investment tax credit adjustments, utility operations. Ex. ODC-4, Original Sheet No. 11; Filing of October 5, 2004, Attachment D, Original Sheet No. 19. The Commission notes, however, that income tax on utility operating income, Account No. 409.1, was already included in Applicants' formula rates.

proponent of change, bears the burden of proving that Applicants' reactive power rate and methodology are unjust and unreasonable.

3. Whether New Dominion's Reactive Power Rate Is Just and Reasonable

(a) Exceptions

69. We now turn to Staff's exceptions on the merits concerning the reactive power rate and allocation methodology. On exceptions, Staff asserts that the ALJ erred in finding Applicants' reactive power cost allocation method and rate to be just and reasonable. It asserts that Applicants' current method of collecting a portion of reactive power costs based on reactive demand and the remaining, uncollected reactive power costs based on kW demand[100] is unjust and unreasonable because using kW demand will shift costs in an arbitrary manner among the Member Cooperatives.[101] Staff also asserts that the historic reactive power rate of $0.06/rkVA is unrelated to the current PJM rate.[102] Last, Staff asserts it has proposed a just and reasonable alternative methodology, namely that Applicants should allocate reactive power costs based on each Member's metered reactive power demand. Staff states that:

> it is fundamental ratemaking that reactive power costs should be based on reactive power demand . . . . With respect to the specifics of rate design, Staff notes that one may allocate the charges paid by New Dominion for reactive power services on the basis of reactive power demand per year, per month, or per hour. Regardless of the specific rate design employed, basing reactive power costs on each Member's reactive power demand remains just and reasonable.[103]

70. In their brief opposing exceptions, Applicants assert the ALJ correctly held that the reactive power allocation methodology and rate are just and reasonable. Applicants

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[100] Tr. 323:6-20; Ex. ODC-8 at 46:18-23.

[101] Tr. 326:4-8 (stating that the ratios of kilowatt demand among the Member Cooperatives are not identical to the ratios of reactive demand among the Member Cooperatives).

[102] Exs. S-6, at 7:5-8; S-7 at 1; Tr. 327:6-19. *See also Sea Robin Pipeline Company v. FERC,* 795 F.2d 182, 188 (D. C. Cir. 1986).

[103] Staff Brief on Exceptions at 40.

assert that they were not required to put forward any evidence supporting their reactive power methodology and rate because they did not propose to change these provisions. They assert that at the time of filing in October 2004 they did not know when VEPCO would join PJM or what the cost of reactive power would be when it did. Applicants assert that their allocation method, based partly on rkVA demands and partly on combined peak kW demands, more closely matches the manner in which the net costs are incurred under the PJM OATT than Staff's recommended approach and therefore is just and reasonable. They assert their testimony showed that in Schedule 2 of its OATT, PJM allocates reactive power revenue requirements based on the demands of the customers in the zone coincident with the peak demand (kW) of the zone,[104] not on metered reactive (rkVA) demands. Applicants also assert that in its testimony, Staff did not propose any change to the reactive power charge or to the reactive power cost allocation method and thus failed to meet its burden of proof under section 206 of the FPA that Staff's proposed rate is just and reasonable.

(b) <u>Commission Decision</u>

71. The Commission affirms the ALJ and finds that Staff's evidence does not satisfy the burden of (1) proving that the New Dominion reactive power rate and allocation method are unjust and unreasonable in the manner asserted by Staff or (2) showing what just and reasonable replacement reactive power rate should be approved.

72. Contrary to Staff's assertions, PJM does not appear to use metered reactive power demand to allocate reactive power costs. Schedule 2 of PJM's tariff [105] provides the payments for reactive supply and voltage control that are needed to maintain transmission voltages for transactions on PJM's system. Schedule 2 allocates reactive power costs to network customers based on a measure of peak demand. Specifically it allocates network customers' reactive power costs based on "the sum of a Network Customer's daily values of DCPZ . . . (as . . . defined in section 34.1) . . . for all days of the month."[106] Section 34.1 defines DCPZ as "the daily load of the Network Customer located within a Zone coincident with the annual peak of the Zone" as adjusted.[107] To obtain the allocation

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[104] Applicants cite Ex. ODC-8 at 46:17-20.

[105] PJM Interconnection, L.L.C., FERC Electric Tariff, Sixth Revised Volume No. 1, Schedule 2, Sheet Nos. 228- 230B.

[106] PJM Interconnection, L.L.C., FERC Electric Tariff, Sixth Revised Volume No. 1, Schedule 2, Sixth Revised Sheet No. 229.

[107] *Id.*, section 34.1, Seventh Revised Sheet No. 93.

factor, the Network Customer's daily coincident peak load for all the days of the month is divided by the total transmission use in the zone on a megawatt basis (presumably for the month).[108] The allocation factor is then applied to the reactive power revenue requirement for the zone to obtain the costs allocated to the network customer.[109] Thus, PJM uses a peak measure of annual MW demand to allocate reactive power costs, not metered reactive power demand. Because the Applicants do not incur reactive power costs from PJM based on reactive power demand, Staff's proposal to require the Applicants to allocate their reactive power costs to their Member Cooperatives on that basis would not match cost incurrence with cost responsibility.

73. We recognize that the Applicants' existing method of allocating reactive power costs also does not exactly match PJM's method, even though they both use peak measures to allocate these costs. New Dominion initially uses a peak measure of monthly reactive power demand followed by a peak measure of monthly kW demand for uncollected reactive power costs, rather than allocating those costs based solely on a peak measure of reactive power demand.[110] However, the Commission finds that, in the current circumstances, the best approach to this issue is to allow the Applicants' existing reactive power rates to remain in place, until the Applicants' next FPA section 205 when they state they will propose a revised reactive power rate.

74. The Settlement approved by the Commission in April 2006 provides for the Applicants to continue to charge their existing reactive power rate to the eleven settling Member Cooperatives until the next section 205 case. NOVEC also does not seek a change in that rate at this time. Thus, none of the Member Cooperatives are seeking a revised reactive power rate before the next section 205 rate case. The current record in

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[108] *Id.,* Schedule 2, Sixth Revised Sheet No. 229.

[109] *Id.,* Schedule 2, Fourth Revised Sheet No. 228. For example, the monthly reactive power service revenue requirement in the Dominion Zone is approximately $2,652,000. *Id.,* Sixteenth Revised Sheet No. 230B.

[110] Under its proposed tariff, New Dominion allocates reactive power costs based on a peak measure of power, the highest average rkVA measured in any 30-minute interval during the month. New Dominion charges a flat rate of $0.06/rkVA for reactive power. Any reactive power costs not collected by the flat rate are collected through the true up mechanism for demand costs which is based on the average combined monthly peak in kW for energy from April through December. Filing of October 5, 2004, Attachment C, New Dominion Energy Cooperative, FERC Electric Tariff, Original Volume No. 1, proposed Original Sheet Nos. 3,8, 10, and 11.

this proceeding does not provide a basis for us to determine a new just and reasonable reactive power rate, since we have already found that the only proposed modification to the existing rate – that proposed by Staff – is not just and reasonable. Accordingly, we affirm the ALJ's decision not to require a change in the Applicants' reactive power rate at this time. We will consider the issue of how the Applicants should revise their reactive power rates in their next section 205 rate case, based upon the circumstances in existence at that time.

C. Prior Period Adjustment for Demand Revenues (PPA) in New Dominion's Rates

1. Background and Initial Decision

75. New Dominion collects its rates by estimating costs for a budget year, dividing those costs by billing determinants to obtain a demand rate, collecting revenues using the demand rate, and then truing up the revenues received for over- or under-collections based on the actual costs incurred for the year, so that, in the end, it collects its actual costs. To implement the true-up, the NOVEC tariff contains two prior period adjustments, one for energy costs and one for demand costs. The Prior Period Adjustment for Demand Revenues (PPA) provides in relevant part:

> Any differential between allowed demand costs collected under the formula and actual demand costs incurred for the period is allocated to each member distribution cooperative based on actual demand billing units and, unless the Board of Directors decides otherwise, is refunded or collected from each member distribution cooperative within the following calendar year.[111]

76. At the hearing, Staff asserted Applicants could misuse the PPA because the phrase "unless the Board of Directors decides otherwise" gives Applicants too much discretion. Staff asserted this phrase permits Applicants to use the PPA to recover shortfalls in the recovery of their costs that may result from use of the 24 MW DSM Agreement demand for Bear Island in calculating the demand rate and from differences between New Dominion's rates and the Settlement rates resulting from the classification of Account No. 553 and the applicable reactive power rate. Staff alleged that the PPA could allow New Dominion to pass through costs to the Member Cooperatives unrelated to the services rendered.

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[111] Ex. ODC-4, New Dominion Electric Cooperative, FERC Electric Tariff, Original Volume No. 1, Original Sheet No. 10.

77. The ALJ found that under the rulings in the Initial Decision there would be no difference between the New Dominion tariff applicable to NOVEC and the Settlement tariff applicable to the other Member Cooperatives so that the Bear Island DSM Agreement demand of 24 MW would be used to calculate the demand rate for both NOVEC and the other Member Cooperatives. She found that, accordingly, it was now up to Applicants to determine the proper method of recovering any under- or over-collections of costs that may result from implementation of the DSM Agreement. She also found there was no evidence that Applicants had previously misused or would in the future misuse the PPA provision. Consequently, she did not require that the phrase "unless the Board of Directors decides otherwise" be deleted. She found that, in any event, Staff had not suggested any viable solution to the alleged problem of misuse of the PPA provision.

2. Exceptions

78. On exceptions, Staff again asserts that Applicants can misuse the PPA provision. Staff asserts that the New Dominion Board retains unlimited discretion under the PPA as to whether to pass through under-recoveries and over-recoveries and could choose to pass through only under-recoveries.[112] It also asserts that under-recoveries may result from differences between the rate formulas in the Settlement rates and New Dominion's rates. It asserts Applicants intend to use the PPA of New Dominion's tariff to recover under-recoveries associated with implementation of the Settlement[113] and that such recovery is unjust and unreasonable. Staff asserts that a recovery of settlement costs or other misuse of the PPA would allow Applicants to change rates without notice or review by the Commission. Finally, Staff asserts that under- or over-recoveries resulting from the interplay between the Settlement tariff and New Dominion's tariff should be recovered through a separate charge based on the Member Cooperatives' status as owners of New Dominion.

79. In their opposing exceptions, Applicants state the PPA clause is included in the Settlement tariff as well as in New Dominion's tariff. They state that the purpose of the PPA clause is to assist Applicants as cooperatives to match revenues to costs, and, in particular, to provide for the collection of the total actual costs incurred. Applicants state that, contrary to Staff's assertions, Applicants' testimony does not demonstrate that they will use the PPA to shift costs to NOVEC or to recover from NOVEC under recoveries that are associated with the Settlement. They assert their testimony only states that any

[112] *Citing* Ex. ODC-4, Original Sheet No. 10; Tr. 353:15-17.

[113] *Citing* Tr. 354:7-25; 368:3-17; 376:22 – 377:20.

costs Applicants are not able to recover because of the formulas in the Settlement rates and New Dominion's rates will be recovered through a PPA.[114] Their testimony also recognizes that the PPA clause in these tariffs is automatic and will be applied, absent Board action to the contrary.[115]

80. Applicants also assert in their opposing exceptions that the PPA clause does not permit them to assess new charges or costs that are unrelated to the service received, but that the PPA is used to true-up differences between actual and estimated demand costs in accordance with the prescribed formula rates[116] and thus with the accounts and costs already included in the prescribed formulas. Applicants state that each Member Cooperative has notice of how the PPA is being applied through its two representatives on the Board of Directors. Applicants also assert that the PPA clause does not give the New Dominion Board unlimited discretion. They state the added phrase in New Dominion's rates to which Staff objects, "unless the Board of Directors decides otherwise,"[117] has to do with timing and would allow the Board to make an election only as to whether to refund or collect the differences between estimated and actual costs within the next calendar year or retain the differences as patronage capital.[118] Applicants state this phrase does not give them discretion to determine a different method for allocating the expense or revenue involved. They note that the phrase was dropped from the Settlement tariff. Finally, Applicants assert Staff has not proposed any solution or alternative approach to address the problems it contends exist with the PPA.

81. In its opposing exceptions, NOVEC agrees with Staff that the PPA provision does not provide Applicants with the authority to use the PPA provision to implement the Settlement, but disagrees with Staff's proposal to modify New Dominion's rates to provide for a surcharge that would refund or charge all Member Cooperatives, including

[114] Tr. at 354:7-25.

[115] Tr. 368:3-17; 376:22 – 377:20.

[116] *Citing* Exs. ODC-4 at Original Sheet Nos. 10 and 22; ODC-9 at Revised Sheet Nos. 8 and 19.

[117] Ex. ODC-4 at Original Sheet No. 10.

[118] Applicants' Brief Opposing Exceptions at 62. Revenues collected in excess of period expenses constitute Old Dominion's net margins. Any such net margins that are retained are identified as patronage capital and are Old Dominion's principal source of equity. Ex. ODC-1 at 7.

NOVEC, for any under- or over-recoveries associated with the Settlement. It asserts that NOVEC is not a party to or bound by the Settlement and that any under- or over-recoveries associated with the Settlement should be borne by those that are subject to it. NOVEC also asserts that it would be inappropriate to impose the costs of the Settlement on NOVEC as an owner of New Dominion. It states the formula rates allocate costs based on usage not on legal status and have no provisions for charging some costs to the Member Cooperatives as customers and some as owners. NOVEC asserts further that no under- or over-recoveries associated with the implementation of the Settlement will arise if Applicants implement dual rate formulas in a cascading or sequential manner, that is, with New Dominion's rates and cost allocation determined first using the as-filed formula and the remaining costs allocated to the other eleven Member Cooperatives under the Settlement rates.[119]

3. Commission Decision

82. The Commission finds, as Staff asserts, that the phrase "unless the Board of Directors decides otherwise" in the PPA in New Dominion's rates gives Applicants too much discretion and is therefore unjust and unreasonable. The Commission agrees with Applicants that this phrase refers to the timing for exercising the PPA provision. It thus gives the Board discretion as to when to pass through under- and over-recoveries, and it also permits the Board to pass through only under-recoveries and not over-recoveries. It could be used, as Applicants state, to accumulate patronage capital for Applicants. However, the PPA is intended to adjust the revenues collected in a period to the actual costs incurred in the period, that is, it serves the function of matching revenues collected to actual costs incurred in a period of time. The length of the period is not stated, but Applicants budget for expenses on a calendar year basis and their cost accounts are based on the Commission's system of accounts which is also based on an annual cycle. The disputed phrase would disrupt the function of adjusting costs on an annual basis by permitting delays and by allowing an asymmetrical pass-through of under- but not over-recoveries. In addition, the PPA does not mention patronage capital and cannot reasonably be interpreted as a measure designed to provide for or increase New Dominion's patronage capital. Last, at this point, NOVEC is the only Member Cooperative with a PPA that contains the disputed phrase. It was removed from the

[119] NOVEC also states that "under the cascading dual formula approach, the PPA or true up mechanism would work in the same manner as the application of the rate formulas themselves. That is, the PPA provision under the As-Filed Cost Allocation Formula would be applied first to . . . NOVEC . . . and then the PPA provision under the . . . Settlement Formula would be applied to the settling parties." NOVEC Brief Opposing Exceptions at 5.

Settlement rates and so does not apply to the other eleven Member Cooperatives.[120] Thus, the Board of Directors can withhold NOVEC's under- or over-recoveries under the PPA in New Dominion's rates while it is obligated to pass through under- and over-recoveries to the other Member Cooperatives under the Settlement tariff PPA. The Commission finds that such a practice would unduly discriminate against NOVEC. For all of the above reasons, the Commission finds the phrase "unless the Board of Directors decides otherwise" is unjust and unreasonable and that Applicants must delete this phrase from New Dominion's rates.

D. Depreciation Methodology in Applicants' Tariffs

83. Applicants' formula rates each contain a depreciation expense. At the hearing, Staff alleged Applicants believed they could change their depreciation rate methodology without making a rate filing with the Commission. Staff based this belief on Applicants' response to a data request in which Applicants stated that they regard changes in depreciation rates and methods to be changes to cost components and not changes to the formula rate.[121] Staff asserted that, therefore, Applicants' rate methodology was unjust and unreasonable.

84. The ALJ found that section 302 of the FPA, as applied in *Midwest Power Sys., Inc.*,[122] requires a utility company to submit a formal request to the Commission asking for approval of a proposed change in its depreciation rate before implementing the change. She also found that Applicants had agreed to Staff's request that they apply to the Commission for future changes in their depreciation rates. She concluded that no changes to the rate formulas were necessary with respect to Applicants' depreciation methodologies.

85. On exceptions, Staff asks the Commission to clarify that Applicants must file for a change in depreciation rates by directing Applicants to seek formal Commission approval of any proposed change in their depreciation rates before implementing the change. Staff notes that although Applicants have agreed to apply to the Commission for future changes in their depreciation rates, they previously regarded changes in depreciation rates

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[120] Settlement of October 13, 2005, Changes to the Proposed Formula Rate Tariff for New Dominion Energy Cooperative in Docket No. ER05-18-000, Revised Sheet No. 8.

[121] Ex. S-5, Applicants' response to data request Staff-ODEC-40.

[122] 67 FERC ¶ 61,076, at 61,209 (1994) (*Midwest Power*).

and methods to be changes to cost components in the formula rate and not as changes to the formula rate.[123] Staff asserts that a change in depreciation rates requires prior Commission approval, relying on section 302 of the FPA.

86. Applicants support the Initial Decision. They state they have accepted Staff's recommendation and agreed to file any future changes in depreciation rates with the Commission prior to including the changes in depreciation expense in the application of the rate formulas.[124] Applicants state that in the future they will submit a formal request to the Commission before adopting a change in their depreciation rates. They state there is no dispute on this issue and therefore no further action on this issue is needed at this time.

87. The Commission notes that section 302 of the FPA applies to depreciation rates recorded for accounting purposes under the Commission's Uniform System of Accounts. The depreciation expense in Applicants' formula rates is not part of Applicants' accounting systems, but, instead, is part of Applicants' tariffs and indicates the cost of depreciation included in Applicants' wholesale rates. Thus, *Midwest Power* is not applicable here. Moreover, in Order No. 618, the Commission determined that it would not require utilities to make a separate filing to obtain Commission approval before implementing changes in depreciation rates for accounting purposes, but, instead, would monitor utility depreciation practices with respect to accounting on a case-by-case basis.[125]

88. Order No. 618 went on to clarify the filing requirements for depreciation rates used for ratemaking purposes. Although Order No. 618 authorized utilities to change their method of depreciation without making a filing for accounting purposes, it did not authorize them to change prices charged for power sales or transmission services (whether determined by stated rates or formula rates) to reflect a change in depreciation. Order No. 618 stated that to change prices charged for power sales or transmission services (whether determined by stated rates or formula rates) to reflect a change in depreciation, a utility would first have to make a filing with the Commission pursuant to

[123] *Citing* Ex. S-5.

[124] *Citing* Ex. ODC-14 at 8:3-18.

[125] *Depreciation Accounting,* Order No. 618, 65 *Fed. Reg.* 47,664, 47,665 (2000) (promulgating General Instruction 22 of Part 101, 18 C.F.R.).

section 205 or 206 of the FPA, as appropriate, to that effect. [126] Thus, if Applicants wish to change their depreciation rates for ratemaking purposes, they must make a filing with the Commission under section 205 or 206 of the FPA. This is a statutory requirement. It is not necessary that this requirement be included in Applicants' tariffs.

E. Classification of Account No. 553 Costs in Old Dominion's Tariff

89. In Old Dominion's filing in Docket No. ER05-309-000, Applicants originally proposed to classify Account No. 553 costs, Generator Maintenance, as energy expenses.[127] However, when Applicants filed direct testimony in August of 2005, they proposed, instead, to classify Old Dominion's Account No. 553 costs as demand costs.[128] At hearing, NOVEC objected to classifying the Account No. 553 costs as demand costs. The ALJ held that a new section 205 filing was not necessary to allocate these expenses as demand expenses and that classifying Account No. 553 costs as demand expenses is just and reasonable.

90. NOVEC did not file exceptions to the ALJ's rulings concerning Old Dominion's Account No. 553 costs and has, therefore, waived any objections to this decision.[129] The Commission affirms the ALJ's rulings regarding Old Dominion's Account No. 553 costs.

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[126] *Id.* at 47,665 n.25; *accord, 18 C.F.R. Part 35 Promoting Transmission Investment through Pricing Reform*, Order No. 679, 116 FERC ¶ 61,057 at P 154 (2006).

[127] Old Dominion Filing of December 7, 2004, Exhibit B, Original Sheet No. 3 (Docket No. ER05-309-000).

[128] Exs. ODC-6 at 7:18-21; ODC-8 at 13:5-14:3, 15:5-19:8.

New Dominion classified Account No. 553 costs as demand costs in Docket No. ER05-18-000. New Dominion Filing of October 5, 2004, Attachment C, Original Sheet No. 9 (Docket No. ER05-18-000).

Account No. 553 costs were originally classified as demand costs in Old Dominion's rates in Docket No. ER05-360-000. *Old Dominion Electric Cooperative,* 110 FERC ¶ 61,165 (2005). They were subsequently classified as energy costs in a revised filing in Docket No. ER05-360-001. Old Dominion Filing of March 3, 2005, Attachment 1, Revised Sheet No. 12 (Docket No. ER05-360-001). The revised filing was accepted by Director Letter Order of September 9, 2005.

[129] 18 C.F.R. § 385.711(d)(2) and (3) (2007).

Thus, Old Dominion's Account No. 553 costs in Docket No. ER05-309-000 will be classified as demand costs.

F. **Summary Affirmance**

91. The Commission summarily affirms the ALJ's holdings with regard to three issues for the reasons stated in the Initial Decision. These holdings are as follows. The ALJ held that Applicants' filing in Docket No. ER05-18-000 was not so unclear and confusing as to be unjust and unreasonable because a clean copy of this filing was included in the public record of this docket and it was unnecessary for Applicants to introduce this copy into the evidentiary record as the decisional authority could take official notice of it. The ALJ held that no changes are needed to New Dominion's market-based rate tariff because the Commission approved that tariff in Docket Nos. ER05-20-000 and ER05-20-001,[130] but did accept additional language to which Applicants had agreed which stated that all sales to Cooperative Members will be made at cost-based rates, with the exception of specific types of sales to new and expanding load made at the request of a Cooperative Member.[131] Last, the ALJ held that the issue of a possible revised Wholesale Power contract between NOVEC and Applicants is not part of this case.

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[130] 110 FERC ¶ 61,275 at P 30-41 and Ordering Paragraph (F). The Commission notes, in addition, that it did not set any matters for hearing in Docket Nos. ER05-20-000 and ER05-20-001.

[131] The precise language Applicants agreed to include reads as follows (Exs. ODC-14 at 7; ODC-15, New Dominion Energy Cooperative, FERC Electric Tariff, Original Volume No. 1, 2nd Revised Sheet No. 8):

> With the exception of sales made upon request of a Cooperative pursuant to the Board of Directors Policy Manual, "Market-Based Rates for New or Expanding Loads," which provides for sales at market-based rates for Cooperative Load related to new customers, or expansion of existing customers, in excess of 1,000 kW, all sales to Cooperatives will be made pursuant to this tariff. Except as specifically provided above, the Cooperatives will not be subject to market-based rates, including any rates contemplated by FERC Electric Tariff Original Volume No. 2 Market-Based Rates filed on October 5, 2004, and amended on January 7, 2005.

G. The Currently Effective Rates in Docket No. ER05-360-000

92. The currently effective rates for the Member Cooperatives are those of Old Dominion that were accepted in Docket No. ER05-360-000 effective February 16, 2005.[132] There were three disputed issues in Docket No. ER05-360-000--the classification of Account No. 509 and Account No. 553 costs as energy instead of demand costs and an audit. The Commission accepted Docket No. ER05-360-000 subject to the outcome of Docket Nos. ER05-18-000 and ER05-309-000 with respect to the disputed issues, the classification of Account Nos. 509 and 553 costs and the audit.

93. In October 2005 Applicants filed the Settlement in Docket Nos. ER05-18-002, ER05-309-002, and related dockets. The Settlement Agreement provides in section 1.04 that:

> Old Dominion has or will reverse the effects of its accounting and billing of Accounts 509 and 553 as energy-related rather than demand-related during the period January 1, 2003, through February 19, 2005, and will give Bear Island an accounting showing that it has or will receive the benefit of such reversal.

The Commission issued the order accepting the Settlement in Docket No. ER05-360-000 as well as in Docket Nos. ER05-18-003 and ER05-309-003.[133] It stated that the Settlement resolved issues among the Settling Parties arising in Docket No. ER05-360-000, a related docket.[134]

94. NOVEC states that Old Dominion is currently charging rates to all the Member Customers based on the rates accepted in the Settlement.[135] After the Settlement was accepted on April 7, 2006, it appears that Applicants applied the Settlement rates to all the Member Cooperatives, including NOVEC.[136] However, this is not clear.[137]

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[132] Commission Letter Order, 110 FERC ¶ 61,165 (2005).

[133] *New Dominion Energy Cooperative*, 115 FERC ¶ 61,025 (2006).

[134] *Id.* P 1.

[135] NOVEC Brief on Exceptions at 14 *citing* Tr. at 198-199.

[136] Tr. 197-199, 202-203.

[137] As NOVEC stated: “We don’t know what we’re getting.” Tr. 203:7.

95. Consequently, it is unclear how Old Dominion has collected its rates since the Settlement was approved. The Commission will require Applicants to make a compliance filing with respect to the rates Old Dominion has applied to the Member Cooperatives, including NOVEC, from April 7, 2006 to the present. In its compliance filing, Applicants must describe the rates that Old Dominion has collected during this period. In particular, Old Dominion must state what classification has been used for Account No. 509 and Account No. 553 costs. In addition, it must state the units that have been used for Bear Island in the denominator of the demand rate calculation and whether it has collected the Settlement rates during this period.

96. In addition, the holding in this order concerning Account No. 553 costs is applicable to the currently effective rates in Docket No. ER05-360-000. It affirms that Account No. 553 costs are demand costs. In their compliance filing Applicants must also state how they will adjust the rates collected since April 7, 2006 to implement this holding.

The Commission orders:

(A) The Initial Decision is affirmed in part and reversed in part as discussed in the body of this order.

(B) Applicants must file the compliance filing required in this order within 30 days of the issuance of this order.

By the Commission.

(S E A L)

Kimberly D. Bose,
Secretary.