

August 30, 2018

Ms. Kimberly D. Bose  
Secretary  
Federal Energy Regulatory Commission  
888 First Street, N.E.  
Washington, D.C. 20426

**Re:    *Virginia Electric and Power Company,*  
      **Docket No. ER18-2355-000**  
      **Amendment to Transmission Interconnection Agreement****

Dear Secretary Bose:

Pursuant to Section 205 of the Federal Power Act (“FPA”)<sup>1</sup> and Part 35 of the Rules and Regulations of the Federal Energy Regulatory Commission<sup>2</sup> (“FERC” or “Commission”), Virginia Electric and Power Company, doing business as Dominion Energy Virginia in the Commonwealth of Virginia and Dominion Energy North Carolina in the State of North Carolina (collectively “Dominion”), on its behalf and on behalf of Duke Energy Progress, LLC (“DEP”), hereby tenders for filing amendments to a transmission interconnection agreement (“Interconnection Agreement” or “IA”) between Dominion and DEP. The amendment reflects a change in the point of interconnection for the existing “Battleboro – Rocky Mount 115 kV Interconnection Point”.

The amendment to the Interconnection Agreement is being submitted by PJM Interconnection, L.L.C. (“PJM”) under PJM’s Service Agreement Tariff (“Tariff”).<sup>3</sup> The Interconnection Agreement, as amended, has been designated as Service Agreement No. 3453. PJM will act as the designated filer for the Interconnection Agreement and DEP will be a non-designated filer.

As explained more fully below and to the extent necessary, Dominion and DEP respectfully requests the amendments to the Interconnection Agreement to become effective on October 26, 2018, the expected in-service date of the new point of interconnection for the existing “Battleboro – Rocky Mount 115 kV Interconnection Point”.

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<sup>1</sup> 16 U.S.C. § 824d (2012).

<sup>2</sup> 18 C.F.R. Part 35 (2018).

<sup>3</sup> Pursuant to Order No. 714, this filing is submitted by PJM on behalf of Dominion and DEP as part of an XML filing package that conforms with the Commission’s regulations. PJM has agreed to make all filings on behalf of the PJM Transmission Owners in order to retain administrative control over the PJM Tariff. Thus, Dominion and DEP have requested PJM submit this amended Service Agreement No. 3453 in the e-Tariff system as part of PJM’s electronic Service Agreements Tariff.

## I. BACKGROUND

Dominion owns and operates electric facilities for the transmission and distribution of electric power and energy in the Commonwealth of Virginia and the State of North Carolina. DEP owns and operates electric facilities for the transmission and distribution of electric power and energy in the State of North Carolina and the State of South Carolina. The Interconnection Agreement sets forth the terms and conditions governing the interconnection of the Dominion and DEP transmission facilities at the specified interconnection points.

On January 28, 2013, the Commission originally accepted the Interconnection Agreement for filing by unpublished letter order.<sup>4</sup> On February 5, 2015, the Commission accepted revisions to the IA to reflect a transaction whereby Dominion sold certain transmission towers, related transmission facilities and easement rights in Pitt County, North Carolina to DEP.<sup>5</sup> Additionally, on September 2, 2015, the Commission accepted revisions to the IA to reflect the addition of a new point of delivery on the DEP side of the Hornertown-Rocky Mount 230 kV Interconnection Point and a new Dominion substation requiring the renaming of the Carson-Wake 500 kV Interconnection Point to the Heritage-Wake 500 kV Interconnection Point.<sup>6</sup> Furthermore, on November 28, 2016, the Commission accepted revisions to the IA to reflect the reconfiguration and renaming of the Halifax – Person 230 kV Interconnection Point to the Sedge Hill – Person 230 kV Interconnection Point and to reflect a corporate name change and other administrative edits to the IA.<sup>7</sup> Lastly, on July 12, 2017, the Commission accepted revisions to the IA reflecting a new Dominion substation (“Hathaway Switching Station”) which resulted in the reconfiguration and renaming of the “Hornertown – Rocky Mount 230 kV Interconnection Point” to “Rocky Mount – Hathaway West (Line No. 2181) 230 kV Interconnection Point” as well as the reconfiguration and renaming of the “Edgecombe – Rocky Mount 230 kV Interconnection Point” to “Rocky Mount – Hathaway East (Line No. 2058) 230 kV Interconnection Point.”<sup>8</sup>

Section 1.1.2 of Appendix I to the Interconnection Agreement describes the “Battleboro – Rocky Mount 115 kV Interconnection Point,” and Figure 2 to Appendix I is a one-line of that interconnection point.

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<sup>4</sup> See *Virginia Electric and Power Company*, Docket No. ER13-477-000 (Jan. 28, 2013) (unpublished letter order) (accepting Interconnection Agreement for filing).

<sup>5</sup> See *Virginia Electric and Power Company*, Docket Nos. ER15-618-000, et al. (Feb. 5, 2015) (unpublished letter order) (accepting revisions to Interconnection Agreement).

<sup>6</sup> See *Virginia Electric and Power Company*, Docket No. ER15-1799-001, et al. (Sept. 2, 2015) (unpublished letter order) (accepting revisions to Interconnection Agreement).

<sup>7</sup> See *Virginia Electric and Power Company*, Docket No. ER17-22-000, et al. (Nov. 28, 2016) (unpublished letter order) (accepting revisions to Interconnection Agreement).

<sup>8</sup> See *Virginia Electric and Power Company*, Docket No. ER17-1651-000, et al. (Jul. 12, 2017) (unpublished letter order) (accepting revisions to Interconnection Agreement).

Dominion identified the need to replace a circuit switcher within Dominion-owned Battleboro Substation and install a line switch in order to isolate the transformer within Battleboro Substation from the “Battleboro – Rocky Mount 115 kV Interconnection Point”.

To accommodate the changes within the Battleboro Substation, the project requires the replacement of a structure directly outside the fence of Battleboro Substation. The new structure will now reflect the point of interconnection where the DEP-owned conductor at the jumper loop connects to Dominion’s conductors on the Dominion-owned structure.

The work within the Battleboro Substation and the construction of the new structure is scheduled to become commercially operational on or around October 26, 2018.

## II. INSTANT FILING

Dominion hereby tenders for filing amendments to the Interconnection Agreement reflecting the new point of interconnection on the existing Battleboro – Rocky Mount 115 kV Interconnection Point between Dominion and DEP.

Regarding these amendments, the Interconnection Agreement has been amended as follows:

- Section 1.1.2 of Appendix I to the Interconnection Agreement has been amended to state:

The point hereby designated and hereinafter called “**Battleboro – Rocky Mount 115 kV** Interconnection Point.” The point of interconnection is within the 115 kV single circuit transmission line extending from the 115 kV bus in DEP’s Rocky Mount Station to the 115 kV bus in Dominion Energy’s Battleboro Station. The change of ownership occurs on a Dominion ~~DEP~~ structure located directly outside ~~inside~~ Dominion’s Battleboro Station. Bi-directional 115 kV metering equipment is installed at the Rocky Mount Station, and is owned, operated, and maintained by DEP. (See Figure 2)

In addition to the foregoing amendments, the Interconnection Agreement has also been modified as follows:

- All references to “Dominion Energy” have been replaced with “Dominion” within the Interconnection Agreement.
- The page numbers have been removed from the Table of Contents;
- The Preamble to the Interconnection Agreement has been amended to reflect the date of the amendments;

- A new WHEREAS clause has been added to reflect the filing history of the Interconnection Agreement and its amendments;
- Section 11.1 has been modified to provide that once the amended Interconnection Agreement becomes effective it will supersede the previous version of the Interconnection Agreement;
- Section 12.4 has been modified to provide the revised job titles for Dominion personnel that shall receive notices and communication made pursuant to the IA;
- The signature pages have been updated to reflect the execution date; and
- Appendix I Figure 2 has been modified to reflect the new point of interconnection for the “Battleboro – Rocky Mount 115 kV Interconnection Point”.

### **III. EFFECTIVE DATE AND REQUESTS FOR WAIVER**

To the extent necessary, Dominion respectfully requests waiver of the Commission’s 60-day prior notice requirement to allow the amendments to the Interconnection Agreement to become effective on October 26, 2018. Waiver is appropriate because the amendments to the Interconnection Agreement are being filed within 30 days of the requested effective date<sup>9</sup> and the construction work within the Battleboro Substation and the construction of the new structure is scheduled to be in-service on or around October 26, 2018.

Also, to the extent necessary, Dominion respectfully requests any other waivers that may be necessary to accept this filing.

### **IV. MISCELLANEOUS**

The amendments to the Interconnection Agreement represent the negotiated agreement of Dominion and DEP. Dominion is authorized to state that DEP agrees to the contents of this filing. *See* 18 C.F.R. § 35.13(b)(6) (2018).

In accordance with 18 C.F.R. § 35.13(b)(7) (2018), there are no expenses or costs included in this filing that have been alleged or judged in any administrative or judicial proceeding to be illegal, duplicative, or unnecessary costs that are demonstrably the product of discriminatory employment practices, within the meaning of 18 C.F.R. § 35.13(d)(3) (2018).

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<sup>9</sup> *See Prior Notice and Filing Requirements Under Part II of the Federal Power Act*, 64 FERC ¶ 61,139 at 61,983-84 (1993).

## **V. COMMUNICATIONS**

Correspondence relating to this filing should be addressed to:<sup>10</sup>

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## **VI. SERVICE**

Dominion has served a copy of this filing on DEP and on the recipients listed in Attachment D. Electronic service is permitted as of November 3, 2008, under the Commission's

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<sup>10</sup> Waiver of 18 C.F.R. § 385.203(b)(3) (2016) is respectfully requested to permit six persons to be added to the Commission's official service list in this proceeding.

regulations pursuant to Order No. 714 and the Commission's "Notice of Effectiveness of Regulations" issued on October 28, 2008, in Docket No. RM01-5-000.<sup>11</sup>

## VII. CONTENTS

In accordance with the Commission's eTariff regulations, an XML filing package is being submitted containing the following materials:

1. This transmittal letter;
2. Redline revisions to the Interconnection Agreement delineating the proposed changes ("Attachment A");
3. A clean version of the Interconnection Agreement in .rtf format for viewing in the Commission's eTariff Viewer along with a PDF format for publishing in eLibrary ("Attachment B");
4. The signature pages of the Interconnection Agreement in PDF format ("Attachment C"); and
5. A list of the recipients ("Attachment D").

Dominion thanks the Commission for its consideration of this filing. Please direct any questions to the undersigned counsel.

Very truly yours,

Virginia Electric and Power Company

/s/ Cheri M. Yochelson

Cheri M. Yochelson

*Counsel for Virginia Electric and Power Company*

Enclosures

cc (w/enclosures): List of Recipients

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<sup>11</sup> *Electronic Tariff Filings: Notice of Effectiveness of Regulations*, 73 Fed. Reg. 65,599 (November 4, 2008).

ATTACHMENT A  
REDLINE REVISIONS TO  
INTERCONNECTION AGREEMENT  
SERVICE AGREEMENT NO. 3453

# **INTERCONNECTION AGREEMENT**

**between**

**DUKE ENERGY PROGRESS, LLC**

**and**

**VIRGINIA ELECTRIC AND POWER COMPANY, doing  
business as DOMINION ENERGY VIRGINIA in the  
Commonwealth of Virginia and as DOMINION ENERGY  
NORTH CAROLINA in the State of North Carolina**



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Appendix VI	Special Terms and Conditions

## INTERCONNECTION AGREEMENT

**THIS INTERCONNECTION AGREEMENT** (“Agreement”) is made and entered into as of this 29<sup>th</sup> day of November, 2012, as amended on December 11, 2014, on May 4, 2015, on September 28, 2016, ~~and~~ on May 16, 2017, and on October 26, 2018, between Duke Energy Progress, LLC (“DEP”), and Virginia Electric and Power Company, doing business as Dominion Energy Virginia in the Commonwealth of Virginia and as Dominion Energy North Carolina in the State of North Carolina (“Dominion ~~Energy~~”). DEP and Dominion ~~Energy~~ may be referred to herein individually as a “Party” or collectively as the “Parties”. For the avoidance of doubt, the terms “Party” and “Parties” as used herein shall not include PJM Interconnection, L.L.C. (“PJM”), or any successor regional transmission organization (“RTO”).

### WITNESSETH:

WHEREAS, DEP is a North Carolina corporation, owning and operating electric facilities for the transmission and distribution of electric power and energy in the States of North Carolina and South Carolina;

WHEREAS, Dominion ~~Energy~~ is a Virginia corporation, owning and operating electric facilities for the transmission and distribution of electric power and energy in the Commonwealth of Virginia and the State of North Carolina, and a Transmission Owning member of PJM;

WHEREAS, the Parties entered into an Interchange Agreement between Carolina Power & Light Company and Virginia Electric and Power Company, dated July 9, 1970 (“1970 Agreement”), designated as Carolina Power & Light Company’s Rate Schedule FPC No. 96 and Virginia Electric and Power Company’s Rate Schedule FPC No. 95, as subsequently modified and amended, and other agreements as appropriate; pursuant to which the systems of the Parties are interconnected by transmission lines, with such points of interconnection herein called “Interconnection Points,” and are operating in synchronism;

WHEREAS, Service Schedule A – 1994 Reserve (“Service Schedule A, Reserve”) was a part of and under the 1970 Agreement;

WHEREAS, the Parties wished to cancel the 1970 Agreement and other agreements as appropriate;

WHEREAS, the Parties wished to establish, the terms and conditions upon which they will continue the interconnected operation of their respective transmission systems inclusive of Service Schedule A, Reserve;

WHEREAS, the Federal Energy Regulatory Commission (“FERC”) originally accepted this Agreement for filing by unpublished letter order issued on January 28, 2013 in Docket No. ER13-477-000 designated as Original Service Agreement No. 3453 (“2012 Agreement”);

WHEREAS, on July 2, 2013, Progress Energy Inc., successor in interest to Carolina Power & Light Company, which did business as Progress Energy Carolinas, Inc. (“PEC”), completed its merger with Duke Energy Corporation, parent of DEP, and following the merger, PEC changed its name to DEP;

WHEREAS, FERC accepted revisions to the 2012 Agreement by unpublished letter order issued on February 5, 2015 in Docket Nos. ER15-618-000, *et al.*, designated as Service Agreement No. 3453 (“2014 Agreement”);

WHEREAS, FERC accepted revisions to the 2014 Agreement by unpublished letter order issued on September 2, 2015 in Docket Nos. ER15-1799-000, *et al.*, designated as Service Agreement No. 3453 (“2015 Agreement”);

WHEREAS, FERC accepted revisions to the 2015 Agreement by unpublished letter order issued on November 28, 2016 in Docket Nos. ER17-22-000, *et al.*, designated as Service Agreement No. 3453 (“2016 Agreement”);

WHEREAS, FERC accepted revisions to the 2017 Agreement by unpublished letter order issued on July 12, 2017 in Docket Nos. ER17-1651-000, *et al.*, designated as Service Agreement No. 3453 (“2017 Agreement”);

WHEREAS, Dominion ~~Energy~~’s transmission facilities (including conductors, circuit breakers, switches, transformers, metering equipment, data acquisition system (“DAS”) equipment, and other associated equipment, at such voltage as is acceptable to both parties, used to control or measure the transfer of energy from one place to another) are owned, operated or controlled by Dominion ~~Energy~~, including any modifications, additions or upgrades made thereto (collectively, the “Dominion ~~Energy~~–Transmission System”, or “Transmission System”) and are currently under the functional and operational control of PJM;

WHEREAS, PJM is registered with the North American Electric Reliability Corporation (“NERC”) as, among other things, a Balancing Authority and Reliability Coordinator, and is the Balancing Authority and Reliability Coordinator for Dominion ~~Energy~~;

WHEREAS, DEP’s transmission facilities (including conductors, circuit breakers, switches, transformers, metering equipment, DAS equipment, and other associated equipment, at such voltage as is acceptable to both parties, used to control or measure the transfer of energy from one place to another) are owned, operated or controlled by DEP, including any modifications, additions or upgrades made thereto (collectively, the “DEP Transmission System”, or “Transmission System”);

WHEREAS, DEP is registered with the NERC as, among other things, a Balancing Authority, and is the Balancing Authority for DEP;

WHEREAS, the FERC has required PJM to be a signatory to this Agreement, pursuant to FERC’s Order on Rehearing and Compliance dated July 26, 2005 in Docket Numbers ER05-31-002 and EL05-70-001, 112 FERC ¶ 61,128 at P 10 (2005), in order to ensure that PJM is kept fully apprised of the matters addressed herein and so that PJM may be kept aware of any reliability and planning issues that may arise; and

WHEREAS, Dominion ~~Energy~~ and DEP are each registered with NERC as, among other things, Transmission Owners (“TOs”) and, as NERC-registered TOs, Dominion ~~Energy~~ and DEP are

each obligated to comply with the requirements of NERC Reliability Standards as applicable to the Interconnection Points under this Agreement.

NOW, THEREFORE, in consideration of the premises and mutual covenants herein set forth, the Parties hereto agree as follows:

## **ARTICLE 1 – INTERCONNECTED OPERATION**

### **1.1 Interconnected Operation**

The DEP Transmission System and the Dominion ~~Energy~~ Transmission System shall be interconnected at the Interconnection Points specified in this Agreement. The Parties, by amendment to this Agreement, may mutually agree to add, discontinue or modify the Interconnection Points and such additional, discontinued or modified Interconnection Points shall be reflected as an amendment to this Agreement pursuant to Article 10.3.

### **1.2 Continuity of Interconnected Operation**

The Parties shall, during the term of the Agreement, continue in service the existing transmission lines, interconnection facilities and essential terminal equipment necessary to maintain the Interconnection Points specified in this Agreement.

## **ARTICLE 2 – SERVICE CONDITIONS**

### **2.1 Avoidance of Unauthorized Use and Control of System Disturbance**

Each Party shall have facilities or contractual arrangements adequate to serve its own load and shall exercise reasonable care to design, construct, maintain, and operate its Transmission System, in accordance with Good Utility Practice, and in accordance with Applicable Laws and Regulations and in such manner as to avoid the unauthorized utilization of the generation or transmission facilities of any other person (hereinafter referred to as “Unauthorized Use”). Neither Party shall be obligated to receive or deliver real or reactive power when to do so might introduce objectionable operating conditions on its Transmission System. Any Party may install and operate on its Transmission System such relays, disconnecting devices, and other equipment, as it may deem appropriate for the protection of its Transmission System or prevention of Unauthorized Use. Each Party shall maintain and operate its respective Transmission System so as to minimize, in accordance with Good Utility Practice, the likelihood of a disturbance originating in either Transmission System, which might cause impairment to the service of the other Party or of any transmission system interconnected with the Transmission System of the other Party.

### **2.2 Interruption of Service**

The interconnections provided under this Agreement may be interrupted, upon such notice as is reasonable, under the following circumstances: (a) by operation of automatic equipment installed for power system protection; (b) after consultation with the other Party if practicable, when a Party deems it desirable for installation, maintenance, inspection, repairs or replacements of equipment; (c) to comply with a directive issued by the Balancing Authority or Reliability

Coordinator of either Party; or (d) at any time that, in the sole judgment of the interrupting Party, such action is necessary to preserve the integrity of, or to prevent or limit any instability on, or to avoid or mitigate a burden on its system. If synchronous operation of the Parties' Transmission Systems through a particular line or lines becomes interrupted, the Parties shall cooperate so as to remove the cause of such interruption as soon as practicable and restore said lines to normal operating condition.

### 2.3 Operating Responsibilities

Each Party shall maintain its Transmission System, including the transmission equipment and facilities, in a manner consistent with Good Utility Practice in order to permit Dominion ~~Energy~~ to operate its Transmission System as required by this Agreement and PJM, and to permit DEP to operate its Transmission System as required by this Agreement. Operating arrangements for facility maintenance shall be coordinated between operating personnel of the Parties' respective control centers. Except as may be necessary and appropriate in an emergency, operating arrangements shall be coordinated with PJM in accordance with PJM Requirements as between Dominion ~~Energy~~ and PJM, and in accordance with the PJM-DEP Joint Operating Agreement as between DEP and PJM.

### 2.4 Energy Losses

The energy losses on the interconnected facilities shall be assigned to the appropriate Party based on the Interconnection Points of the interconnected facilities or according to procedures developed by the Operating Committee and subject to any PJM Requirement as between Dominion ~~Energy~~ and PJM, and any requirements as stipulated in the PJM-DEP Joint Operating Agreement as between DEP and PJM.

### 2.5 Compliance with NERC Reliability Standards

Prior to the execution of this Agreement, the Parties shall develop and execute the NERC Coordination Guide. The NERC Coordination Guide shall delineate the coordination of each Party's responsibilities as NERC-registered TOs to comply with NERC Reliability Standards as applicable to the Interconnection Points under this Agreement and shall not be filed at FERC. After this Agreement is executed, the Operating Committee shall maintain the NERC Coordination Guide in accordance with Article 6.2(d) of this Agreement.

## **ARTICLE 3 – INTERCONNECTION POINTS, METERING POINTS AND METERING AND DATA ACQUISITION SYSTEM EQUIPMENT**

### 3.1 Interconnection Points

All electric energy delivered under this Agreement shall be of the character commonly known as three-phase 60 Hz energy and shall be delivered at the Interconnection Points specified under Article 1 of this Agreement at standard nominal voltage or such other voltages as may be specified in this Agreement.

### 3.2 Metering and Data Acquisition System Equipment

Measurement of electric energy for the purposes of determining load and effecting settlements, and monitoring and telemetering of power flows under this Agreement shall be made by metering and DAS equipment installed and maintained, by either DEP or Dominion ~~Energy~~ at the Interconnection Points consistent with the provisions of Appendix II and III of this Agreement. Any aspects of metering and DAS equipment not specifically provided for by this Agreement shall be referred to the Operating Committee pursuant to Article 6.

## **ARTICLE 4 – RECORDS**

### 4.1 Copies of Records

Each Party shall provide to a requesting Party copies of records maintained in accordance with FERC's record retention requirements to the extent such records document any transactions that have occurred under this Agreement.

## **ARTICLE 5 – INVOICING AND PAYMENT; TAXES**

### 5.1 Purpose of Invoicing

Any invoice that is issued pursuant to this Agreement shall be for: (a) the establishment of any new Interconnection Point; (b) the modification of an existing Interconnection Point; or (c) service under Service Schedule A, Reserve. As per Article 6.2 (b) of this Agreement, the Operating Committee shall establish the terms and conditions applicable to invoicing.

### 5.2 Timeliness of Payment

Unless otherwise agreed upon, all invoices, if any, issued pursuant to this Agreement shall be rendered as soon as practicable in the month following the calendar month in which expenses were incurred and shall be due and payable, unless otherwise agreed upon within thirty (30) days of receipt of such invoice. Payment shall be made by electronic transfer or such other means as shall cause such payment to be available for the use of the payee. Interest on unpaid amounts shall accrue daily at the then current prime interest rate (the base corporate loan interest rate) published in the Wall Street Journal, or, if no longer so published, in any mutually agreeable publication, plus two percent (2%) per annum, but will in no event exceed the maximum interest rate allowed pursuant to Virginia law, and shall be payable from the due date of such unpaid amount and until the date paid.

### 5.3 Disputed Invoices

In the case of a disputed invoice, all invoices shall be paid in full under the conditions specified in Article 5.2 of this Agreement. Disputes will then be brought before the Operating Committee for resolution per Article 6.4 of this Agreement. If, after thirty (30) days, the Operating Committee has not resolved the dispute, then such dispute shall be resolved pursuant to the arbitration procedures specified in Article 8 of this Agreement.

#### 5.4 Invoice Adjustments

Other than as required by law, regulatory action or metering test adjustments, invoice adjustments shall be made within six (6) months of the rendition of the initial invoice.

#### 5.5 Tax Reimbursement

If, as part of any compensation to be paid under this Agreement during the term of this Agreement, any direct tax, including, but not limited to sales, excise, or similar taxes (other than taxes based on or measured by net income) is levied and/or assessed against either Party by any taxing authority on the power and/or energy manufactured, generated, produced, converted, sold, purchased, transmitted, interchanged, exchanged, exported or imported by the supplying Party to the other Party, then such supplying Party shall be fully compensated by the other Party for such direct taxes.

#### 5.6 Contribution In-Aid of Construction

The Parties intend that all costs paid by a Party to another Party, for the establishment, discontinuance, relocation or modification of an Interconnection Point, shall be non-taxable contributions to capital, and shall not be taxable as contributions in-aid of construction ("CIAC"). This presumption notwithstanding, in the event federal or state income taxes are imposed upon the Party with respect to such payments paid by the other Party as a CIAC by the Internal Revenue Service ("IRS") and/or a state department of revenue ("State"), the Party paying the CIAC shall reimburse the other Party for the tax effect of such CIAC computed in accordance with FERC rules and including any interest and penalty charged to the Party by the IRS and/or State.

### **ARTICLE 6 – OPERATING COMMITTEE**

#### 6.1 Operating Committee

An Operating Committee shall administer the interconnected operation of the Parties' Transmission Systems as provided for in this Agreement. Each Party shall appoint one member and one alternate to the Operating Committee and designate, in writing, said appointments to the other Party. Such representatives and alternates shall be persons familiar with NERC Reliability Standards and the transmission and substation facilities of the Parties they represent and shall be fully authorized to perform the principal duties listed below.

#### 6.2 Duties of the Operating Committee

The principal duties of the Operating Committee shall be as follows:

- a. to establish operating and control procedures as necessary to implement this Agreement;
- b. to establish accounting and invoicing procedures as necessary to implement this Agreement;



- c. to coordinate transmission and generator maintenance schedules to an extent agreed by the Parties;
- d. to maintain the NERC Coordination Guide; and
- e. to perform those duties, which this Agreement requires to be done by the Operating Committee, and such other duties as may be required for the proper functioning of this Agreement.

### 6.3 Limitations on Operating Committee Duties

The Operating Committee shall not amend or modify any of the terms or conditions of this Agreement.

### 6.4 Operating Committee Disputes

If the Operating Committee is unable to agree on any matter coming within its scope of duties, then such matter shall be resolved pursuant to Article 8 of this Agreement.

### 6.5 Meeting of the Operating Committee

After this Agreement becomes effective pursuant to Article 9 of this Agreement, the Operating Committee shall meet at least once each year to: (a) review all documentation established and maintained in accordance with the duties of the Operating Committee pursuant to Article 6.2 of this Agreement to assess whether any revisions are required; and (b) discuss any other matters related to the performance of Operating Committee duties pursuant to Article 6.2 of this Agreement. Other meetings may be called as reasonably necessary by any Operating Committee Representative from either Party.

## **ARTICLE 7 – INDEMNITY**

### 7.1 Indemnity

To the extent permitted by law, each Party shall indemnify, save harmless, and defend the other Party including its directors, officers, employees, Affiliates and agents (collectively, the “Indemnified Party”) from and against any losses, liabilities, costs, expenses, suits, actions, claims, and all other obligations arising out of injuries or death to persons or damage to property caused by or in any way attributable to its ownership or operation of its Transmission System, except that the Party’s obligation to indemnify the Indemnified Party shall not apply to the extent of any liabilities arising from the Indemnified Party’s negligence or intentional misconduct or that portion of any liabilities that arise out of the Indemnified Party’s contributing negligence or intentional misconduct.

## **ARTICLE 8 – ARBITRATION**

### 8.1 Submission to Arbitration

In the event either Party has a dispute, or asserts a claim, that arises out of or in connection with

this Agreement or its performance, such Party (the “disputing Party”) shall provide the other Party with written notice of the dispute or claim (“Notice of Dispute”). Such dispute or claim shall be referred to a designated senior representative of each Party for resolution on an informal basis as promptly as practicable after receipt of the Notice of Dispute by the other Party. In the event the designated representatives are unable to resolve the claim or dispute through unassisted or assisted negotiations within thirty (30) calendar days of the other Party’s receipt of the Notice of Dispute, such claim or dispute may, upon mutual agreement of the Parties, be submitted to arbitration and resolved in accordance with the arbitration procedures set forth below. If a dispute or claim is submitted to arbitration, the arbitration can only be terminated upon mutual agreement of the Parties. In the event the Parties do not agree to submit such claim or dispute to arbitration, each Party may exercise whatever rights and remedies it may have in equity or at law consistent with the terms of this Agreement.

## 8.2 Technical Issues Arbitrator

With respect to Disputes, which the Parties mutually agree are exclusively technical in nature, the Parties may, if they mutually agree, submit such Disputes to a technical issues arbitrator (“TIA”) for final and non-appealable resolution. The TIA, which shall be an individual or firm to be mutually agreed upon by both Parties, shall be an unbiased technical expert in transmission and distribution system design and operational matters.

## 8.3 External Arbitration Procedures

Any arbitration initiated under this Agreement shall be conducted before a single neutral arbitrator appointed by the Parties. If the Parties fail to agree upon a single arbitrator within ten (10) calendar days of the submission of the dispute to arbitration, each Party shall choose one arbitrator who shall sit on a three-member arbitration panel. The two arbitrators so chosen shall within twenty (20) calendar days select a third arbitrator to chair the arbitration panel. In either case, the arbitrators shall be knowledgeable in electric utility matters, including electric transmission and bulk power issues, and shall not have any current or past substantial business or financial relationships with any party to the arbitration (except prior arbitration). The arbitrator(s) shall provide each of the Parties an opportunity to be heard and, except as otherwise provided herein, shall conduct the arbitration in accordance with the Commercial Arbitration Rules of the American Arbitration Association (“Arbitration Rules”) and any applicable FERC regulations or PJM rules; provided, however, in the event of a conflict between the Arbitration Rules and the terms of this Article 8, the terms of this Article 8 shall prevail.

## 8.4 Arbitration Decisions

Unless otherwise agreed by the Parties, the arbitrator(s) shall render a decision within ninety (90) calendar days of appointment and shall notify the Parties in writing of such decision and the reasons therefore. The arbitrator(s) shall be authorized only to interpret and apply the provisions of this Agreement and shall have no power to modify or change any provision of this Agreement in any manner. The decision of the arbitrator(s) shall be final and binding upon the Parties, and judgment on the award may be entered in any court having jurisdiction. The decision of the arbitrator(s) may be appealed solely on the grounds that the conduct of the arbitrator(s), or the decision itself, violated the standards set forth in the Federal Arbitration Act or the

Administrative Dispute Resolution Act. The final decision of the arbitrator must also be filed with FERC if it affects jurisdictional rates, terms and conditions of service under this Agreement.

#### 8.5 Costs

Each Party shall be responsible for its own costs incurred during the arbitration process and for the following costs, if applicable: (a) the cost of the arbitrator chosen by the Party to sit on the three member panel and one half of the cost of the third arbitrator chosen; or (b) one half the cost of the single arbitrator jointly chosen by the Parties.

### **ARTICLE 9 – TERM AND TERMINATION OF AGREEMENT**

#### 9.1 Term and Termination

This Agreement shall be effective as of the date first written above, or such later date as the last necessary regulatory approval hereof shall be obtained (unless an earlier date is specified by the regulatory authority having jurisdiction), and shall remain in effect until the date falling on the tenth (10th) anniversary of the date hereof (the “Initial Term”) and, thereafter, for successive twelve (12) month periods (“Renewal Terms”). Either Party may terminate this Agreement after the Initial Term by providing to the other Party thirty-six (36) months’ advance written notice of its intent to terminate this Agreement, in which case this Agreement shall terminate at the end of such thirty-six (36) month notice period without regard to the expiration of any Renewal Term. Notwithstanding the above, this Agreement may be terminated earlier: (a) if the Parties mutually agree; or (b) as otherwise expressly provided for in this Agreement.

#### 9.2 Breach and Default

A Party shall be considered in default of this Agreement (“Default”) if it fails to cure a Breach in accordance with the terms of this Article 9.2. A breach (“Breach”) shall mean the failure of a Party to perform or observe any material term or condition of this Agreement; provided that no Breach shall exist where such failure to discharge an obligation (other than the payment of money) is the result of Force Majeure as defined in this Agreement or the result of an act of omission of the other Party. Upon a Breach, the non-breaching Party shall give written notice of such Breach to the breaching Party. The breaching Party shall have thirty (30) calendar days from receipt of the Breach notice within which to cure such Breach; provided however, if such Breach is not capable of cure within thirty (30) calendar days, the breaching Party shall commence such cure within thirty (30) calendar days after notice and continuously and diligently complete such cure within ninety (90) calendar days from receipt of the Breach notice; and, if cured within such time, the Breach specified in such notice shall cease to exist.

#### 9.3 Right to Terminate

Upon the occurrence and during the continuance of a Default, the non-defaulting Party shall have the right: (a) to terminate this Agreement by providing written notice to the defaulting Party and making a filing at FERC to terminate this Agreement; provided that any such termination shall not take effect until FERC approval; or (b) to take any other action at law or in equity as may be permitted under this Agreement. The provisions of this Article 9 will survive termination of this Agreement.

#### 9.4 Renegotiable Events

If one of the following conditions occurs, the Parties shall negotiate in good faith to amend this Agreement or to take other appropriate action so as to protect each Party's interest in this Agreement. This Agreement shall serve as the document upon which such negotiations shall be based and the Parties shall make as minimal modifications as necessary to effectuate the original intent and purpose of this Agreement. If the Parties are unable to reach agreement, either Party shall have the right to unilaterally file with the FERC, pursuant to Section 205 or Section 206 of the Federal Power Act as appropriate, proposed amendments to this Agreement that the Party deems reasonably necessary to protect its interests:

- a. Any change to Applicable Laws and Regulations having a material impact upon the effectiveness or enforceability of any provision of this Agreement;
- b. This Agreement is not approved or accepted for filing by the FERC without modification or condition;
- c. PJM or the Reliability Council prevents, in whole or in part, either Party from performing any provisions of this Agreement in accordance with its terms;
- d. Dominion ~~Energy~~ withdraws from PJM, or DEP becomes a transmission owner of an Independent System Operator, a Regional Transmission Organization, or similar entity;
- e. Either Dominion ~~Energy~~ or DEP is no longer a NERC-registered TO;
- f. PJM Requirements are modified in a manner that materially affects Dominion ~~Energy~~'s ability to perform its obligations under this Agreement;
- g. The PJM-DEP Joint Operating Agreement is modified in a manner that materially affects DEP's ability to perform its obligations under this Agreement; or
- h. PJM, either voluntarily or involuntarily, is dissolved.

### **ARTICLE 10 – REGULATORY AUTHORITIES**

#### 10.1 Regulatory Authorities

This Agreement is made subject to the jurisdiction of any Governmental Authority or authorities having jurisdiction over the Parties, the DEP Transmission System, the Dominion ~~Energy~~ Transmission System, this Agreement, or the subject matter hereof.

#### 10.2 Adverse Regulatory Change

The Parties agree to jointly submit and support the filing of this Agreement with the FERC. Any changes or conditions imposed by the FERC or any other Governmental Authority with competent jurisdiction in connection with such submission or otherwise in respect of this Agreement, any of which are unacceptable to a Party after the Parties' good faith attempt to

negotiate a resolution to such objectionable change or condition, shall be cause for termination of this Agreement upon thirty (30) days' prior written notice by the non-consenting Party to the other Parties hereto.

### 10.3 Amendments to the Agreement

#### 10.3.1 Amendments

In the event that the Parties agree to amend this Agreement, the Parties shall, if required, file any such amendment or modification with the FERC.

#### 10.3.2 Section 205 and 206 Rights

Nothing contained in this Agreement shall preclude either Party from exercising its rights under Section 205 and 206 of the Federal Power Act to file for a change in any rate, term, condition or service provided under this Agreement.

## **ARTICLE 11 – CANCELLATION OF PRIOR AGREEMENTS**

### 11.1 Cancellation of Prior Agreements

When this Agreement becomes effective pursuant to Article 9 of this Agreement, this Agreement shall supersede in its entirety the 2017<sup>6</sup> Agreement, with all subsequent modifications and amendments, and other agreements as appropriate.

## **ARTICLE 12 – GENERAL**

### 12.1 Force Majeure

No Party shall be in default in respect to any obligation hereunder because of Force Majeure. A Party unable to fulfill any obligation by reason of Force Majeure shall use diligence to remove such disability with appropriate dispatch. Each Party shall: (a) provide prompt written notice of such Force Majeure event to the other Party which notice shall include an estimate of the expected duration of such event; and (b) attempt to exercise all reasonable efforts to continue to perform its obligations under this Agreement.

### 12.2 Waivers

No failure or delay on the part of either Party in exercising any of its rights under this Agreement, no partial exercise by either Party of any of its rights under this Agreement, and no course of dealing between the Parties shall constitute a waiver of the rights of either Party under this Agreement. Any waiver shall be effective only by a written instrument signed by the Party granting such waiver, and such shall not operate as a waiver of, or continuing waiver with respect to any subsequent failure to comply therewith.

### 12.3 Liability

- a. Except to the extent of the other Party's negligence or intentional misconduct, each Party shall be responsible for all physical damage to or destruction of the property, equipment and/or facilities owned by it and its Affiliates, regardless of who brings the claim and regardless of who caused the damage, and shall not seek recovery or reimbursement from the other Party for such damage; but in any such case, DEP and Dominion ~~Energy~~ shall exercise Due Diligence to remove the cause of any disability at the earliest practicable time.
- b. **TO THE FULLEST EXTENT PERMITTED BY LAW AND NOTWITHSTANDING ARTICLE 7.1 OR ANY OTHER PROVISION OF THIS AGREEMENT, IN NO EVENT SHALL A PARTY, ITS AFFILIATES, OR ANY OF THEIR RESPECTIVE OWNERS, OFFICERS, DIRECTORS, EMPLOYEES, AGENTS, SUCCESSORS OR ASSIGNS BE LIABLE TO THE OTHER PARTY, ITS AFFILIATES OR ANY OF THEIR RESPECTIVE OWNERS, OFFICERS, DIRECTORS, EMPLOYEES, AGENTS, SUCCESSORS OR ASSIGNS, WHETHER IN CONTRACT, WARRANTY, TORT, NEGLIGENCE, STRICT LIABILITY, OR OTHERWISE, FOR ANY SPECIAL, INDIRECT, INCIDENTAL, EXEMPLARY, CONSEQUENTIAL (INCLUDING, WITHOUT LIMITATION, REPLACEMENT POWER COSTS, LOST PROFITS OR REVENUES, LOSS OF GOOD WILL OR LOST BUSINESS OPPORTUNITIES) OR PUNITIVE DAMAGES RELATED TO OR RESULTING FROM PERFORMANCE OR NONPERFORMANCE OF THIS AGREEMENT OR ANY ACTIVITY ASSOCIATED WITH OR ARISING OUT OF THIS AGREEMENT.**
- c. Nothing in this Agreement shall be construed to create or give rise to any liability on the part of PJM and the Parties expressly waive any claims that may arise against PJM under this Agreement.
- d. The Parties acknowledge and understand that the signature of the authorized ~~officer-representative~~ of PJM on this Agreement is for the limited purpose of acknowledging that representatives of PJM have read the terms of this Agreement. The Parties and PJM further state that they understand that FERC desires that Dominion ~~Energy~~ keep PJM fully apprised pursuant to its obligations as a TO of the matters addressed herein as well as any reliability and planning issues that may arise under this Agreement, and that the signature of the PJM ~~officer-representative~~ shall not in any way be deemed to imply that PJM is taking responsibility for the actions of any Party, that PJM has any affirmative duties under this Agreement or that PJM is liable in any way under this Agreement.

#### 12.4 Written Notices

Notices and communication made pursuant to this Agreement shall be deemed to be properly given if delivered in writing, postage paid to the following:

If to Dominion ~~Energy~~ **Planning**: Director, Electric Transmission ~~System Operations Center~~ **OC and Planning**  
Virginia Electric and Power Company  
P.O. Box 26666  
Richmond, VA 23261

and

Manager, Electric Transmission Planning **& Strategic Initiatives**  
Virginia Electric and Power Company  
P.O. Box 26666  
Richmond, VA 23261

If to DEP: Director System Operations  
Duke Energy Progress, LLC  
3401 Hillsborough Street  
Raleigh, North Carolina 27607

If to PJM: Vice President-Government Policy  
PJM Interconnection, L.L.C.  
1200 G Street, N.W., Suite 600  
Washington D.C. 20005

and

General Counsel  
PJM Interconnection, L.L.C.  
2750 Monroe Blvd.  
Audubon, PA 19403

The above listed titles and addresses for a Party or PJM may be changed by written notice to all other Parties and PJM.

#### 12.5 Special Terms and Conditions Applicable to Interconnection Points

The Parties may establish special terms and conditions applicable to Interconnection Point(s) that

are specified in this Agreement (“Special Terms and Conditions”). The Special Terms and Conditions shall be reflected in an Appendix to this Agreement and shall be in addition to any other terms and conditions provided for in this Agreement. Any conflict between the Special Terms and Conditions and any other provision of this Agreement shall be resolved in favor of the Special Terms and Conditions.

#### 12.6 Agreement Validity

The validity and meaning of this Agreement shall be governed by and construed in accordance with federal law where applicable and, when not in conflict with or preempted by federal law, the applicable laws of the State of North Carolina.

#### 12.7 Defined Terms

All capitalized terms used in this Agreement shall have the meanings as defined: (a) in the body of this Agreement; (b) in the Appendices appended hereto; and (c) the “Glossary of Terms Used in NERC Reliability Standards,” as may be modified from time to time (“NERC Glossary”). Any provisions of the PJM Tariff or the PJM-DEP Joint Operating Agreement relating to this Agreement that use any such defined term shall be construed using the definition given to such defined term in this Agreement. In the event of any conflict between defined terms set forth in the PJM Tariff or the PJM-DEP Joint Operating Agreement and the defined terms in this Agreement, such conflict shall be resolved in favor of defined terms set forth in this Agreement.

### **ARTICLE 13 – ASSIGNMENT**

#### 13.1 Assignment

This Agreement shall inure to the benefit of and be binding upon the successors and assigns of the Parties. Successors and assigns of PJM shall become signatories to this Agreement for the limited purpose described in Article 12.3(d) of this Agreement. This Agreement shall not be assigned by any Party without the written consent of the other Party, which consent shall not be unreasonable withheld, except to a successor to which substantially all of the business and assets of such Party shall be transferred or to an Affiliate of the assigning Party for the purposes of a corporate restructuring.



IN WITNESS WHEREOF, three (3) copies of this Agreement, each to be considered an original, has been executed by the Parties' respective officers lawfully authorized so to do, this ~~12<sup>th</sup>~~-27<sup>th</sup> day of ~~May~~August, 2018~~7~~.

DUKE ENERGY PROGRESS, LLC

By: /s/ Sam Holeman

Printed Name: Sam Holeman

Title: VP Transmission System Planning & Operations

Service Agreement No. 3453

IN WITNESS WHEREOF, three (3) copies of this Agreement, each to be considered an original, has been executed by the Parties' respective officers lawfully authorized so to do, this ~~12<sup>th</sup>~~-27<sup>th</sup> day of ~~August~~May, 2018~~7~~.

VIRGINIA ELECTRIC AND POWER COMPANY, D/B/A DOMINION ENERGY VIRGINIA  
AND DOMINION ENERGY NORTH CAROLINA

By: /s/ Bobby E. McGuire

Printed Name: Bobby E. McGuire

Title: Authorized Representative

Service Agreement No. 3453

~~IN WITNESS WHEREOF, three (3) copies of this Agreement, each to be considered an original, has been executed by PJM for the limited purpose of acknowledging that a representative of PJM has read this Agreement as of 27<sup>th</sup> day of August, 2018.~~

~~The signature below of the authorized representative of PJM is for the limited purpose of acknowledging that a representative of PJM has read this Agreement as of this 29<sup>th</sup> day of August, 2018.~~

PJM INTERCONNECTION, L.L.C.

By: /s/ Steven R. Herling

Printed Name: Steven R. Herling

Title: Vice President, Planning

By: /s/ Kenneth Seiler

Printed Name: Kenneth Seiler

Title: Executive Director, System Planning

Service Agreement No. 3453

~~RE: Service Agreement No. 3453~~

**APPENDIX I**  
**Interconnection Points and Metering Points**

1.1 The systems of the Parties shall be interconnected through the transmission lines and substations at the Interconnection Points described below:

- 1.1.1 The point hereby designated and hereinafter called “**Kerr Dam Plant – Henderson 115 kV** Interconnection Point.” The point of interconnection is within the 115 kV single circuit transmission line extending from the 115 kV bus in DEP’s Henderson Station to the 115 kV bus in Army Corps of Engineers’ Kerr Dam Plant Station. The change of ownership occurs at mid-span at the North Carolina – Virginia State Line between a Dominion ~~Energy~~ structure and a DEP structure. Bi-directional 115 kV metering equipment is installed at the Kerr Dam Plant Station, and is owned, operated, and maintained by the Army Corps of Engineers. (See Figure 1)
- 1.1.2 The point hereby designated and hereinafter called “**Battleboro – Rocky Mount 115 kV** Interconnection Point.” The point of interconnection is within the 115 kV single circuit transmission line extending from the 115 kV bus in DEP’s Rocky Mount Station to the 115 kV bus in Dominion ~~Energy~~’s Battleboro Station. The change of ownership occurs on a ~~Dominion Energy~~ ~~DEP~~ structure located ~~directly outside~~ ~~inside~~ Dominion Energy’s Battleboro Station. Bi-directional 115 kV metering equipment is installed at the Rocky Mount Station, and is owned, operated, and maintained by DEP. (See Figure 2)
- 1.1.3 The point hereby designated and hereinafter called “**Rocky Mount – Hathaway West (Line No. 2181) 230 kV** Interconnection Point.” The point of interconnection is within the 230 kV double circuit transmission line extending from the 230 kV bus in DEP’s Rocky Mount Station to the 230 kV bus in Dominion ~~Energy~~’s Hathaway Station. The change of ownership occurs at a DEP structure. Bi-directional 230 kV metering equipment is installed at the Rocky Mount 230 kV Station with Rocky Mount POD#4 load netted back to the bi-directional meter, and is owned, operated, and maintained by DEP. (See Figure 3)
- 1.1.4 The point hereby designated and hereinafter called “**Rocky Mount - Hathaway East (Line No. 2058) 230 kV** Interconnection Point.” The point of interconnection is within the 230 kV double circuit transmission line extending from the 230 kV bus in DEP’s Rocky Mount Station to the 230 kV bus in Dominion ~~Energy~~’s Hathaway Station. The change of ownership occurs at a DEP structure. Bi-directional 230 kV metering equipment is installed at the Rocky Mount Station, and is owned, operated, and maintained by DEP. (See Figure 4)
- 1.1.5 The point hereby designated and hereinafter called “**Greenville – Everetts 230 kV** Interconnection Point.” The point of interconnection is within the 230 kV single circuit transmission line extending from the 230 kV bus in DEP’s

Greenville Station to the 230 kV bus in Dominion-~~Energy~~'s Everetts Station. The change of ownership occurs at a Dominion ~~Energy~~-structure. Bi-directional 230 kV metering equipment is installed at the Greenville Station, and is owned, operated, and maintained by DEP. (See Figure 5)

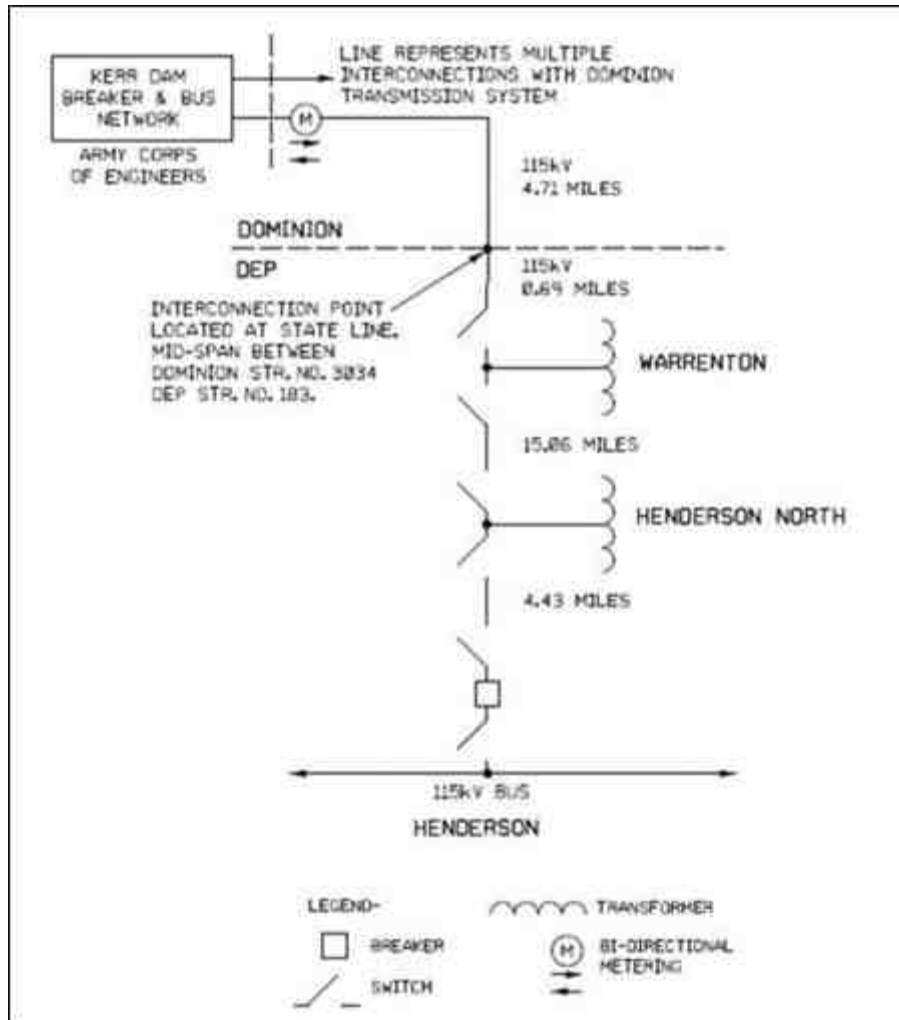
- 1.1.6 The point hereby designated and hereinafter called “**Sedge Hill – Person 230 kV Interconnection Point.**” The point of interconnection is within the 230 kV single circuit transmission line extending from the 230 kV bus in DEP’s Person Station to the 230 kV bus in Dominion-~~Energy~~’s Sedge Hill Station. The change of ownership occurs at a DEP structure. Bi-directional 230 kV metering equipment is installed at the Sedge Hill Station, and is owned, operated, and maintained by Dominion-~~Energy~~. (See Figure 6)

- 1.1.7 The point hereby designated and hereinafter called “**Heritage – Wake 500 kV Interconnection Point.**” The point of interconnection is within the 500 kV single circuit transmission line extending from the 500 kV bus in DEP’s Wake Station to the 500 kV bus in Dominion-~~Energy~~’s Heritage Station. The change of ownership occurs at a Dominion ~~Energy~~-structure. Bi-directional 500 kV metering equipment is installed at the Heritage Station, and is owned, operated, and maintained by Dominion-~~Energy~~. (See Figure 7)

~~Note 1: All references to “Dominion Energy” within the Figures to this Appendix I are now replaced with “Dominion Energy” as described in the opening recitals to this Agreement.~~

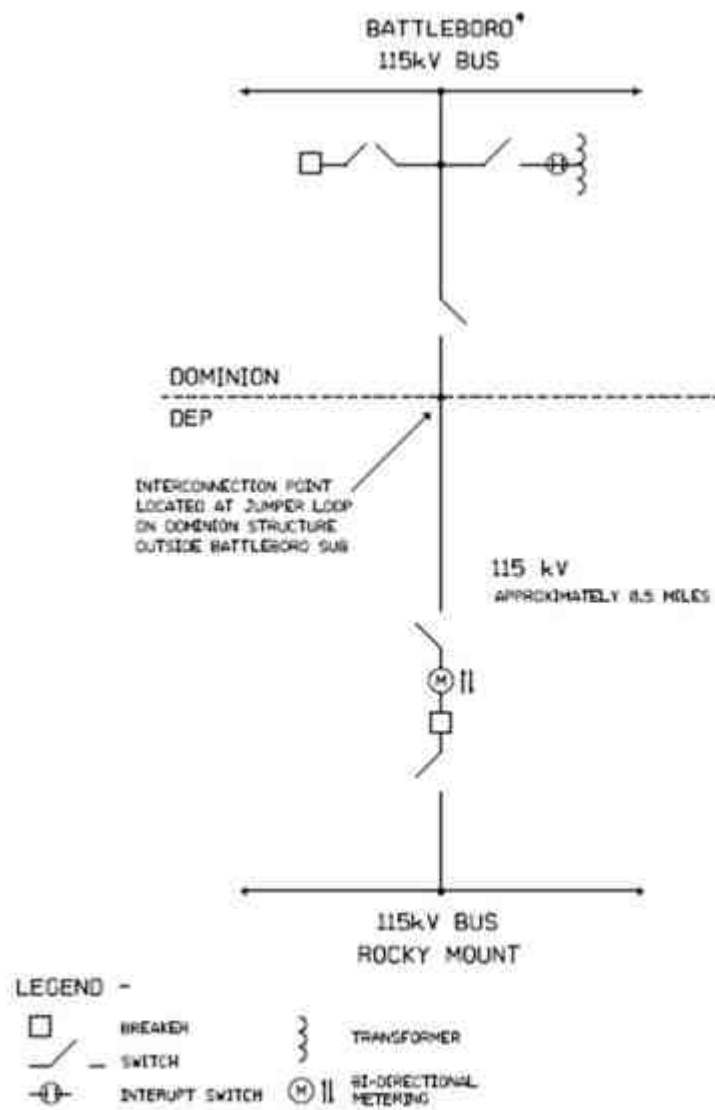
## APPENDIX I

**Figure 1**  
**Kerr Dam Plant – Henderson 115 kV Interconnection Point**

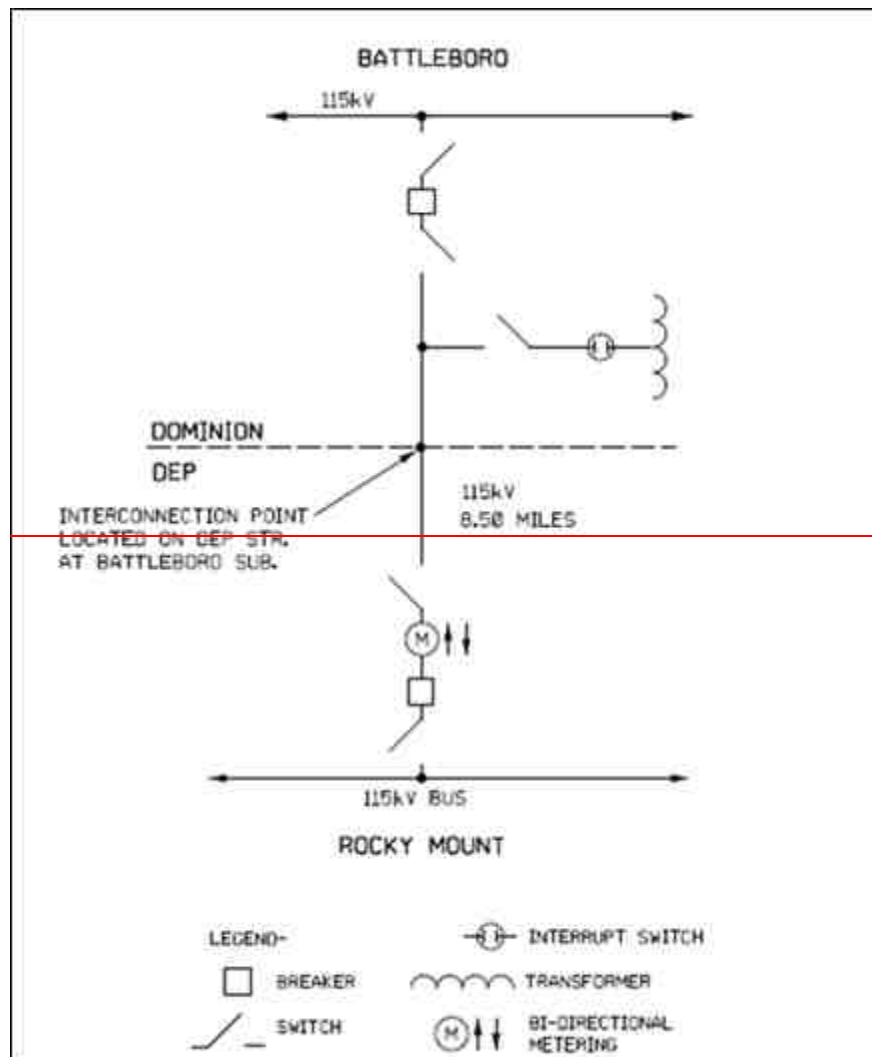


## APPENDIX I

**Figure 2**  
**Battleboro – Rocky Mount 115 kV Interconnection Point**



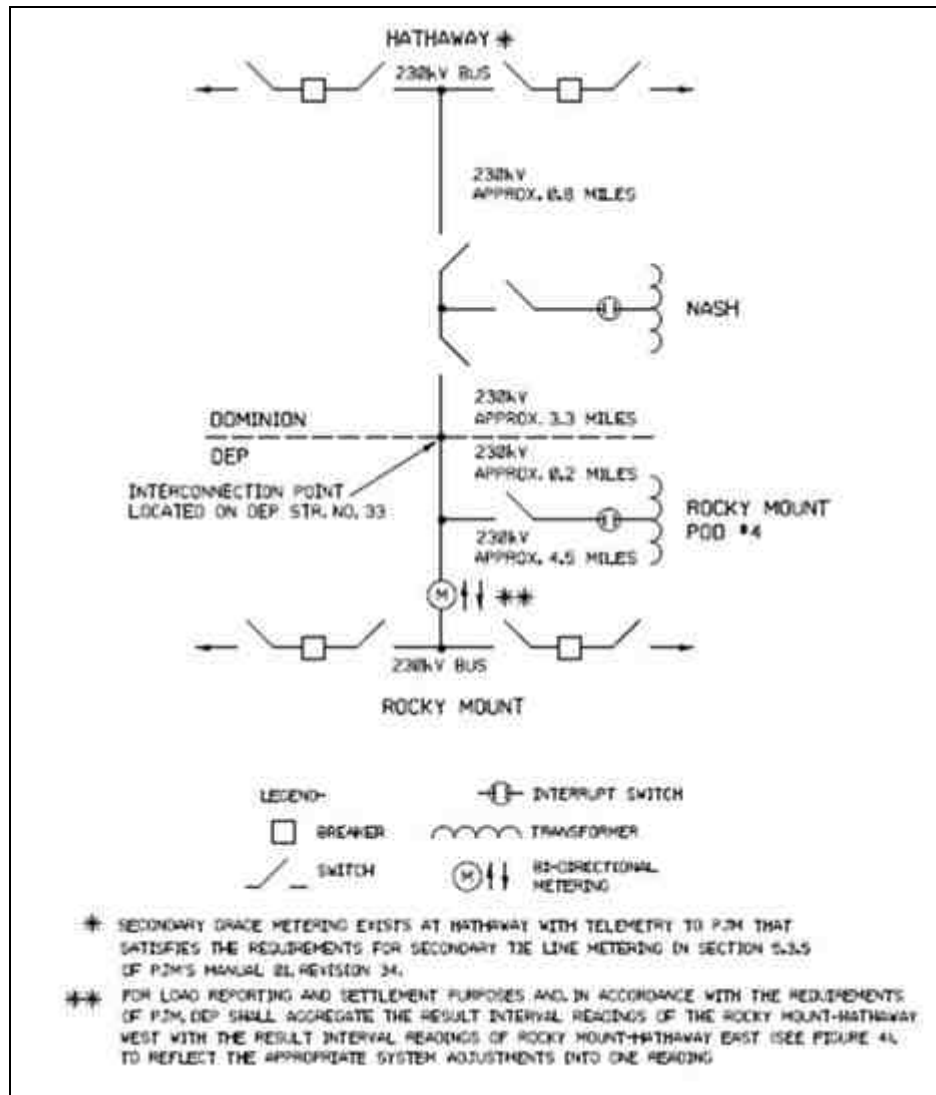
\*SECONDARY GRADE METERING EXISTS AT BATTLEBORO WITH TELEMETRY TO PJM THAT SATISFIES THE REQUIREMENTS FOR SECONDARY TIE LINE METERING PURSUANT TO PJM'S MANUAL 02, REVISION 00.





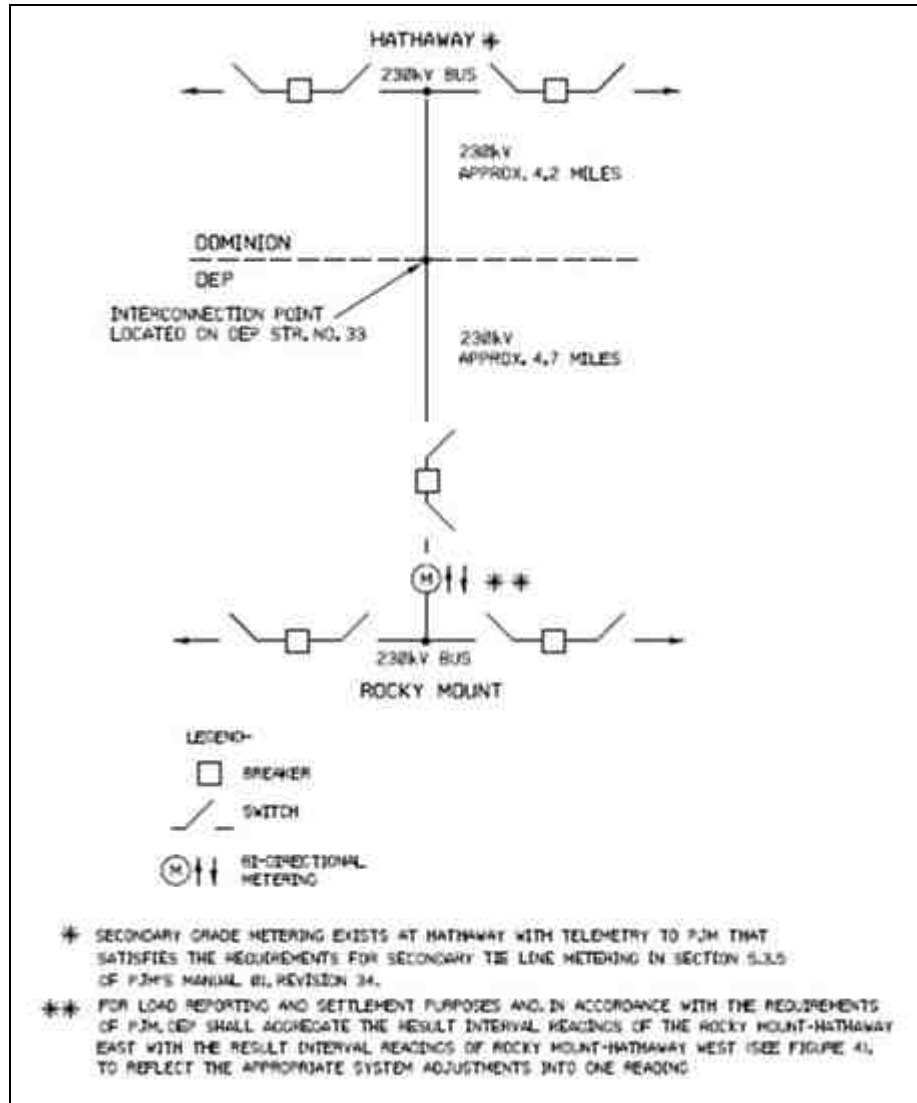
## APPENDIX I

**Figure 3**  
**Rocky Mount – Hathaway West (Line No. 2181) 230 kV Interconnection Point**



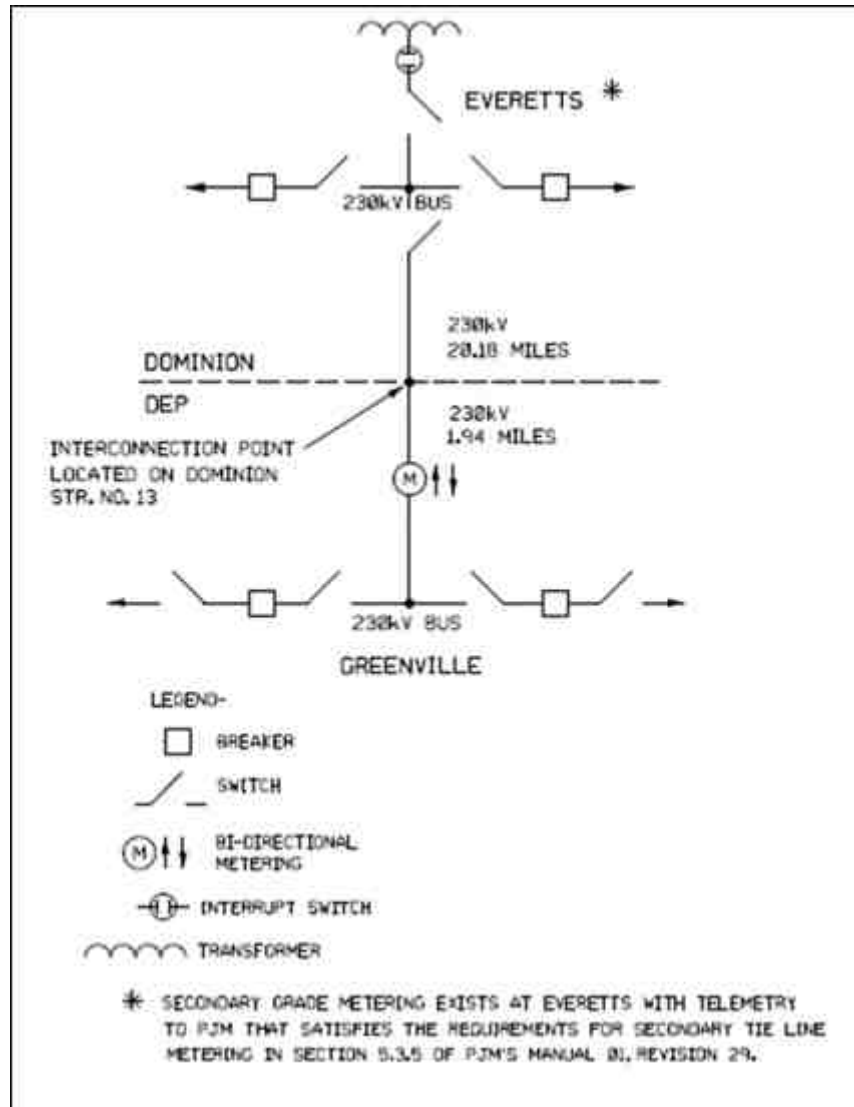
## APPENDIX I

**Figure 4**  
**Rocky Mount – Hathaway East (Line No. 2058) 230 kV Interconnection Point**



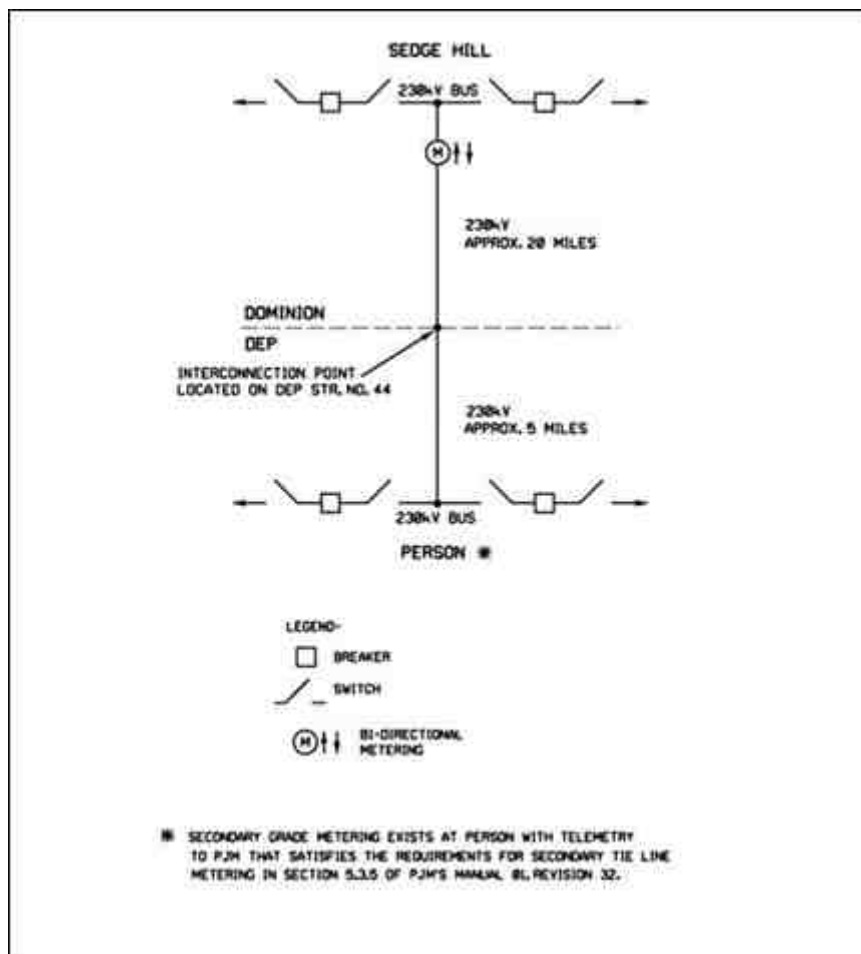
## APPENDIX I

**Figure 5**  
**Greenville – Everetts 230 kV Interconnection Point**



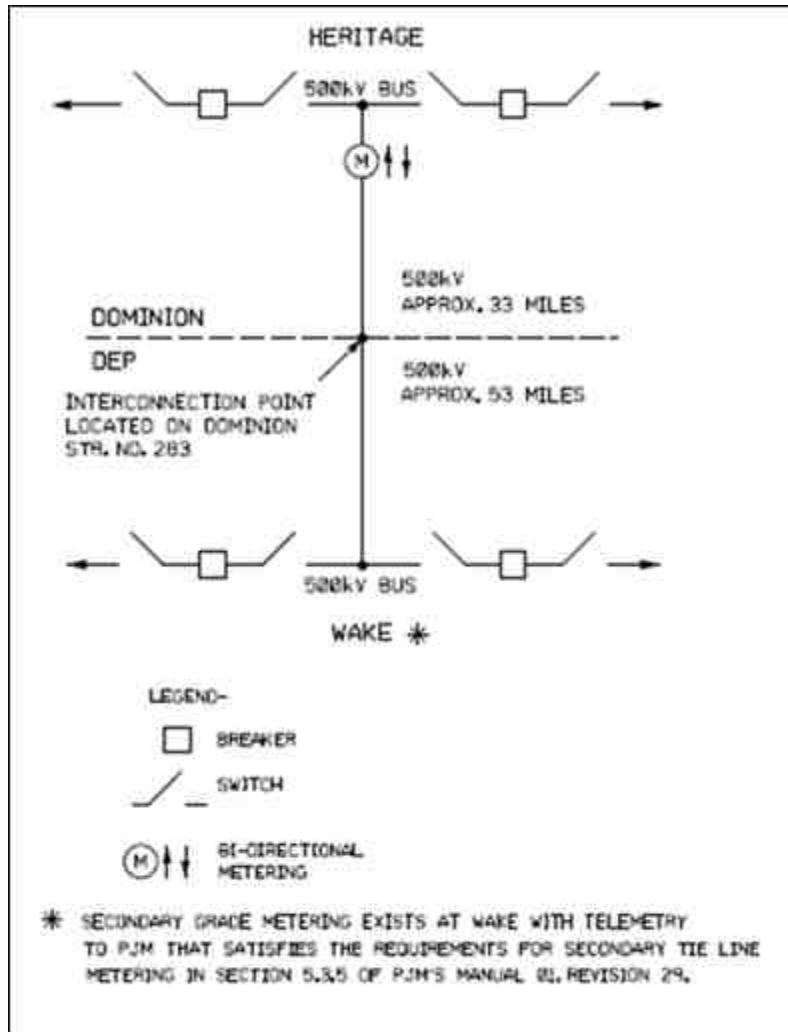
## APPENDIX I

**Figure 6**  
**Sedge Hill – Person 230 kV Interconnection Point**



## APPENDIX I

**Figure 7**  
**Heritage – Wake 500 kV Interconnection Point**



## **APPENDIX II**

### **Metering Requirements**

#### **1.1 Metering Points**

Electric power and energy delivered at the Interconnection Points shall be measured by suitable metering equipment provided by the Parties at the Metering Points and at such other points, voltages, and ownership as may be agreed upon by the Parties.

#### **1.2 Metering Equipment**

Suitable and reliable metering equipment shall be installed at each Metering Point, and shall include potential and current transformers, revenue meters, test switches and such other equipment as may be needed. The design standard established by this Appendix II shall apply to all new interconnection metering installations. However, any modification, addition or upgrade to any of the existing facilities after the date of this Agreement, shall be performed in compliance with this standard.

1.2.1 General Requirements. All metering quantities shall be measured at the Interconnection Point and its metering accuracy shall meet the required NERC Reliability Standards, PJM Requirements as to Dominion—~~Energy~~, any requirements in the PJM-DEP Joint Operating Agreement as to DEP, and the American National Standards Institute (“ANSI”) standards. The Parties may agree by amendment to this Agreement to install metering at locations other than the Interconnection Points, however, measured metering quantities shall be compensated to the Interconnection Point, provided that the Parties shall exercise commercially reasonable efforts to avoid such compensating metering installations. Based upon mutual agreement between interconnection Parties, metering can be installed at a location different from the Interconnection Point, however, measured metering quantities shall be compensated to the Interconnection Point.

All reasonable costs for the meter changes or upgrades requested by the Party shall be borne by the requesting Party, unless agreed otherwise.

1.2.2 Industry Standard Requirements. At least (N-1) metering elements will be used to measure all real and reactive power crossing the Interconnection Points, where N is the number of wires in service including the ground wire. The revenue quality metering package (consisting of instrument transformers, meters, sockets, and test switches) shall be installed, calibrated, and tested (at the requesting Party’s expense) in accordance with the latest approved version of (but not limited to) the ANSI standards listed below, or their successors(s) including the standard testing procedures and guidelines of the Party that owns the metering equipment:

ANSI C12.1:	Code For Electricity Metering
ANSI C12.7:	Requirements for Watt-Hour Meter Socket

ANSI C12.9:	Test Switches for Transformer-Rated Meters
ANSI C12.11:	Instrument Transformers for Revenue Metering, 10 kV Through 350 kV BIL
ANSI C12.10:	Electromechanical Watt-hour Meters
ANSI C12.16:	Solid State Electricity Meters
ANSI C12.20:	For Electricity Meters 0.2 and 0.5 Accuracy Class
ANSI C37.90.1:	Surge Withstand Capability (SWC) Test
ANSI/IEEE C57.13:	Standard Requirements for Instrument Transformers

To the extent that the above requirement conflicts with the manuals, standards or guidelines of the applicable Reliability Council regarding interchange metering and transactions, the manuals, standards and guidelines of such Reliability Council shall control.

- 1.2.3 Metering Equipment Maintenance and Testing. Upon installation and unless otherwise specified, the revenue meters shall be inspected and tested in accordance with the latest applicable ANSI standards and at least once every two (2) years, or at any other mutually agreed frequency thereafter. More frequent meter tests can be performed at the request of any Party, and the test will be performed at the requesting Party's expense if the meter is found to be within the established ANSI tolerances. The Party that owns the metering shall inform the other Party with at least (3) three weeks advance notice or more, of impending metering tests, and invite the other Party to attend and witness the tests.

The accuracy of the revenue meter shall be maintained at two tenths of one percent (0.2%) accuracy or better, and the meter test shall require a meter standard with accuracy traceable to the National Institute of Standards and Technology ("NIST").

If at any test of metering equipment an inaccuracy shall be disclosed exceeding two percent (2%), the account between the Parties for service theretofore delivered shall be adjusted to correct for the inaccuracy disclosed over the shorter of the following two periods: (1) for the 30-day period immediately preceding the day of the test, or (2) for the period that such inaccuracy may be determined to have existed. No meter shall be left in service if the percent accuracy error is found to be more than +/- 1%.

The Party that owns the metering equipment shall maintain records that demonstrate compliance with all meter tests and maintenance conducted in accordance with Good Utility Practice for the life of the Interconnection Point. The other Party shall have reasonable access to such records, and the Party that owns the metering equipment will provide such records to the other Party upon request. If revenue metering equipment fails to function, the energy registration shall be determined from the best available data, including the check metering, if applicable. The Instrument Transformers ("IT") shall also be inspected and

maintained based on Section 1.2.2 of this Appendix II, and existing standards and practices of the Party that owns the metering equipment.

- 1.2.4 Current Transformer Requirements. Each metering point shall have a dedicated set of metering class of current transformers. Unless otherwise agreed upon by the Parties, all metering shall be type 3.0 element metering, and have three (3) metering accuracy current transformers.

Current transformers shall meet or exceed an accuracy class of 0.3% (as defined in IEEE C57.13), or better. Current transformers shall comply with the minimum BIL rating as specified in standards IEEE C57.13 and ANSI C12.11.

The mechanical and thermal short time current ratings of the current transformer shall exceed or withstand the available fault current, while the secondary burden of the current transformer shall not exceed its stated name plate burden rating.

- 1.2.5 Voltage Transformers Requirements. Each metering point shall have a dedicated set of metering class of voltage transformers. Unless otherwise agreed upon by the Parties, all metering shall be type 3.0 element metering, and have three (3) metering accuracy voltage transformers. Voltage transformers shall meet or exceed an accuracy class of 0.3% (as defined in IEEE C57.13). The secondary of the voltage transformer shall be exclusively used for the revenue meters only, so as not to exceed the secondary burden of the stated voltage transformer's name plate burden rating provided, however, that voltage transformers with two secondary windings, may have one winding dedicated to the revenue meters, and the other winding used for relaying purposes or for other station metering. The nameplate burden rating on either winding must not be exceeded.

Voltage transformers shall comply with the minimum BIL rating as specified in standards IEEE C57.13 and ANSI C12.11.

### 1.3 Remote Meter Access and Data Communications

For all Interconnection Points, the Party that owns the metering equipment at such Interconnection Point, unless otherwise mutually agreed, shall be responsible for installation of the communications facilities. The Party that owns the metering equipment shall also be responsible for operation and maintenance, and on-going monthly costs of the communication facilities

- 1.3.1 Remote Billing Data Retrieval. The Owning Party may provide appropriate communication capability of electronic remote interrogation of the billing data in a manner that is compatible with commonly used billing data systems such as MV-90.
- 1.3.2 Real Time Communications. Revenue meters shall be capable of communicating with data acquisition system ("DAS") equipment such as Remote Terminal Unit ("RTU") to provide the following real-time bi-directional power and energy data: instantaneous power flows, per phase and three-phase averaged Root-Mean-



Squared (“RMS”) voltages, per phase and three-phase averaged RMS currents and frequency with at least two decimal points.

- 1.3.3 Energy Flow Data. A continuous accumulating record of active and reactive energy flows shall be provided by means of the registers on the meters. The deployed revenue meter(s) shall be capable of providing bi-directional energy data flow in either kyz pulse signals format, or accumulated counters to RTU. All Parties shall share the same data register buffers regardless of the types of employed data communication methods. If the accumulation counter method is used, only one Party shall be responsible for freezing the accumulator buffers and the owner of the metering equipment shall freeze them. The accumulator freezing signals shall be synchronized to Universal Coordinated Time (“UCT”) within 1/ 2 seconds.

#### 1.4 Metering Device Requirements

All revenue meters shall be programmable and capable of measuring, recording, and displaying bi-directional active and reactive energy and four quadrant power quantities. Also, the revenue meters shall be programmable for compensating for power transformer and line losses and, when applicable, such compensation shall be used in determining the settlement of power transferred at the Interconnection Point. The revenue meters may preferably have at least one serial communication, one Ethernet port, hard-wired “kyz” pulse output, and internal modem for data communication.

The revenue meters’ internal clocks and real-time DAS equipment shall be synchronized with Universal Time Coordination (“UTC”) with at least 5 seconds resolution. The Global Position System clock receiver used at each Interconnection Point shall be capable of providing unmodulated Inter-Range Instrumentation Group – Time Code Format B signals to support the UTC time synch requirement.

#### 1.5 Revenue and Additional Metering

Each Metering Point shall have a revenue meter that shall be powered by the station control battery or by automatic transfer to an alternate AC source. The meters at Metering Points associated with new Interconnection Points, or associated with the modification, addition or upgrade to any existing Interconnection Points, shall meet the applicable NERC Reliability Standards, PJM Requirements as to Dominion ~~Energy~~, any requirements in the PJM-DEP Joint Operating Agreement as to DEP, and the ANSI standards. Each Party may arrange to have additional metering at any existing Interconnection Point. The Parties will cooperate to determine correct meter values as needed; however, in the event of a discrepancy between the Parties’ meters, Dominion ~~Energy~~ will accept DEP revenue meter data for certain Interconnection Points; and DEP will accept Dominion ~~Energy~~ revenue meter data for certain Interconnection Points.

#### 1.6 Meter Access

A Party whose metering equipment is located within a station owned by the other Party shall have reasonable access to said metering equipment for purposes of meter reading, inspection,

testing, and other such valid operating purposes. Such access shall not be unreasonably withheld.

#### 1.7 Meter Removal

Upon termination of this Agreement or when the metering is no longer needed, the Party that owns the meter equipment in another Party's station shall remove the metering equipment from the premises of the other Party within one (1) year after termination or within one (1) year after the Party that owns the meter equipment determines that the interchange metering is no longer needed.

### **APPENDIX III**

#### **DAS Equipment: Ownership, Installation and Maintenance**

##### **1.1 Need for Data Acquisition Provisions**

In recognition that the coordination of the system operations by the Parties may be facilitated by the sharing of power flow and other real-time information from meters and other equipment at the Interconnection Points, the Parties may agree to cooperate on the installation and operation of data acquisition system (“DAS”) equipment including, but not limited to, remote terminal units (“RTU”), meters, MW/MVAR and Volt transducers, telecommunication devices, lease lines, and any related equipment at points which shall from time to time be mutually agreed upon. Therefore, the Parties establish this Appendix III to govern the general principles of such DAS arrangements. Each of these general principles may be modified within and by a specific agreement for a specific DAS arrangement.

Pursuant to a separately negotiated and executed agreement, a Party’s RTU, or equivalent devices, may be shared by the other Party. Therefore, pursuant to such agreement, the RTU shall support multiple dedicated communication ports with mutually agreed upon communication protocols. If a backup telemetry system or data is required by one Party for their own use, the requesting Party shall be responsible for installing and/or maintaining the field devices and associated telecommunication system at their cost. Where there are protocol restrictions because of existing legacy systems, industry standard protocols such as DNP 3.0 shall be offered. If a proprietary communication protocol is to be used solely for one Party, the requesting Party shall be responsible for the cost of adding the customized communication protocol to the RTU.

The following real-time data shall be provided to all parties as minimum requirements: three phase bi-directional energy flows (e.g., MWh, MVARh), three phase instantaneous power flows (e.g. MW, MVAR), per phase RMS voltages, per phase RMS currents, and frequency measurement with at least two decimal points resolution shall be provided. In addition to the real-time data, the status of all switching devices associated with the interconnection circuit(s) shall be provided. For the energy flow data, either or both accumulated data or hourly interval data shall be provided based on mutually agreed formats. If accumulated data is used, the owner of the RTU will freeze the accumulated data buffers at the beginning of each clock hour and the other Party shall read the frozen data. This shall be accomplished in a manner that provides both Parties with the same accumulator data readings even though the accumulator data reading frequencies may not be synchronized. For Dominion-~~Energy~~, any real-time data requirements defined in the PJM manuals, including PJM Manual 01 – Control Center and Data Exchange Requirements and PJM Manual 03 – Transmission Operations, shall be provided to PJM to allow PJM to comply with its roles as Reliability Coordinator, Balancing Authority, and Transmission Operator.

For purposes of this Appendix III, the term “Other Party” means a Party that wishes to obtain information from an Owning Party through the installation of DAS equipment.

- 1.1.1 The DAS equipment covered herein shall be associated with the Interconnection Points. When requests for additional data, or a DAS equipment upgrade, are received from the Other Party by the Owning Party, the Parties shall cooperate

with each other, based on Good Utility Practice. Unless otherwise mutually agreed, the Other Party requesting the additional data or equipment upgrade will bear the cost associated with such requests.

- 1.1.2 Commissioning Test Procedures. When new interconnection metering or DAS equipment is installed, replaced or upgraded, a commissioning test shall be performed based on mutually agreed test procedure. Before the equipment is placed in service, the following processes shall be followed, as a minimum requirement:

The Owning Party shall inform the Other Party of the commissioning test.

The Owning Party shall set up a three-way conference call between the interconnection site and operation centers of both Parties.

Bi-directional test currents shall be injected to the interconnection energy meter and the instantaneous analog data values displayed by the meter shall be checked against the corresponding readings received at each control center. This verification test will be made at the 0, 2.5 and 5 Amp cases, and with unity and 50% power factors.

The pulse accumulator counter data shall be tested in the same manner and the accumulator freeze functionality shall be verified.

A test to determine the Roll-Over Count for each accumulator data point in the DAS shall be performed to verify that the Roll-Over Count is properly processed by both operation centers.

## 1.2 DAS Arrangements

The details of individual DAS arrangements, for new or existing Interconnection Points, shall be in writing and signed by an Operating Committee Representative from each Party. The DAS arrangements shall cover such details as responsibilities for the provision and installation of equipment, equipment location, ownership, project scheduling, testing and commissioning, maintenance, and cost reimbursement, if applicable, and shall be considered a part of this Agreement as if they had been included herein.

## 1.3 Ownership, Installation and Maintenance of DAS Equipment

Unless otherwise mutually agreed, ownership of such DAS equipment shall be shared by the Parties as herein described; provided, however, the Owning Party shall have the responsibility to install all the DAS equipment.

- 1.3.1 The Owning Party of the facilities to which DAS equipment is to be attached shall provide, install, own and maintain the relays, transducers, wiring, protection equipment and associated materials ("Owning Party Equipment") required to support the installation of the Other Party's data acquisition equipment ("Other Party's Equipment"). Provided, however, that if the Interconnection Point is

established for the benefit of and at the request of a Party, the Party benefiting and requesting the interconnection shall install, own and maintain, the DAS equipment arrangement and shall provide access to the DAS data to the Other Party. Equipment that is shared in common between the Owning Party and the Other Party (such as duplicating relays, test switches, etc.) shall likewise be provided, installed, owned and maintained by the Owning Party, and shall be part of the Owning Party's Equipment, unless agreed otherwise. Unless otherwise mutually agreed, each Party will maintain its own equipment on their side of the Interconnection Point.

- 1.3.2 The Other Party shall provide the Owning Party documents listing and describing the Other Party's Equipment that the Other Party will supply for installation by the Owning Party. These documents will generally consist of a hardware list, detailed drawings, and a circuit diagram. If the Owning Party does not stock the DAS equipment or other components specified by the Other Party, then the Other Party will supply the necessary components including spare parts. The Owning Party reserves the right to refuse to install any material supplied by the Other Party that has not been approved by the Owning Party for use in its installations.
- 1.3.3 The Other Party shall provide, own and maintain as part of the Other Party's Equipment, the data communication circuits (leased line), including any necessary data circuit protection equipment, and be responsible for the costs of such circuit. Where deemed appropriate by the Owning Party, the Other Party personnel shall be permitted to work independently on its equipment. Generally, however, work performed by the Other Party's personnel shall be performed under the supervision of the Owning Party personnel, unless such equipment is located outside or is only accessible from outside the Owning Party's facilities.
- 1.3.4 Unless otherwise agreed, the Owning Party will provide station battery voltage to power the DAS equipment at 48, 125, or 250 Volt DC, and the corresponding DC circuit should be fused (or circuit breaker) at 15, 5, or 5 ampere, respectively. Under no circumstances shall the Other Party connect either the positive or negative side of this circuit to ground. The Other Party's Equipment shall be connected to the station's grounding conductor through the Owning Party's breaker control panel. The Owning Party shall also provide station service power for the data acquisition equipment via a 115 V, 60 Hz, with a 15 ampere (fused or circuit breaker) AC circuit.

#### 1.4 Location and Site Access

The Owning Party shall permit the Other Party to locate its data acquisition equipment and data circuit protection equipment in the Owning Party's station control building, if adequate space exists or is available, or outside the Owning Party's station switchyard, if no control house is available. In choosing equipment location, consideration shall be given to NERC Reliability Standards, equipment security, protection and access needs of both Parties. In cases where escorted access to the station control house or outdoor equipment is required, the Other Party shall notify the Owning Party at least 24 hours prior to any planned visit. If access is needed on

a short notice, the Parties shall endeavor to arrange such visits by mutual agreement. The Owning Party shall not unreasonably withhold access to the equipment to the Other Party; provided, however, the Owning Party may deny access based upon safety considerations, operating condition, NERC Reliability Standards or other relevant criteria.

#### 1.5 Proprietary and Confidential Information

Unless circumstances of reasonable cause are disclosed by a Party, the Other Party shall treat all shared telemetry information as confidential and proprietary and shall take such precautions as may be reasonable and necessary to prevent such information from being made known or disclosed to any person or entity except in accordance with this Agreement. However, provided that if a Party is required by law, legal process or action of a court or government agencies to disclose any information, such Party shall promptly notify the Other Party of such requirement so that action, deemed appropriate in the circumstances, may be taken to protect confidential and proprietary information against disclosure.

#### 1.6 Cost Estimate, Invoicing and Payment

Prior to the installation of the Other Party's equipment, both the Owning Party and the Other Party shall prepare an estimate of the costs associated with such installation. All invoices and payment terms and conditions, and invoice disputes and resolutions, shall be handled pursuant to Article 5 of this Agreement.

## **APPENDIX IV**

### **Definitions**

“Affiliate”- shall mean with respect to a corporation, partnership or other entity, each such other corporation, partnership or other entity that either directly or indirectly, through one or more intermediaries, controls, is controlled by, or is under common control with, such corporation, partnership or other entity.

“Applicable Laws and Regulations”- shall mean all duly promulgated applicable federal, state and local laws, regulations, rules, ordinances, codes, decrees, judgments, directives, or judicial or administrative orders, permits and other duly authorized actions of any Governmental Authority having jurisdiction over the relevant Parties, their respective facilities, and/or the respective services they provide.

“Due Diligence” – shall mean the exercise of good faith efforts to perform a required act on a timely basis using the necessary technical and manpower resources.

“Force Majeure” - shall mean any cause beyond the control of the affected Party, including but not restricted to, acts of God, flood, drought, earthquake, storm, fire, lightning, epidemic, war, riot, civil disturbance or disobedience, labor dispute, labor or material shortage, sabotage, acts of public enemy, explosions, orders, regulations or restrictions imposed by governmental, military, or lawfully established civilian authorities, which, in any of the foregoing cases, by exercise of Due Diligence such Party could not reasonably have been expected to avoid, and which, by the exercise of due diligence, it has been unable to overcome. Force Majeure does not include: (i) a failure of performance that is due to an affected Party’s own negligence or intentional wrongdoing; (ii) any removable or remediable causes (other than settlement of a strike or labor dispute) which an affected Party fails to remove or remedy within a reasonable time; or (iii) economic hardship of an affected Party.

“Good Utility Practice”- shall mean any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in the region; including those practices required by Section 215(a)(4) of the Federal Power Act.

“Governmental Authority” - shall mean any federal, state, local or other governmental, regulatory or administrative agency, court, commission, department, board, or other governmental subdivision, legislature, rulemaking board, tribunal, arbitrating body, or other governmental authority, having responsibility over the Parties, their respective facilities, or the respective services they provide, and exercising or entitled to exercise any administrative, executive, police, or taxing authority or power; provided, however, that such term does not include Dominion-~~Energy~~, DEP, or any Affiliate thereof.

“Interconnection Point”- shall mean each point of electrical connection between the Dominion ~~Energy~~ Transmission System and the DEP Transmission System as set forth in Appendix I and Appendix VI to this Agreement.

“Metering Point” – shall mean each point at which the electrical energy flowing between the Parties at an Interconnection Point is measured.

“NERC Reliability Standards” – shall mean mandatory and enforceable requirements administered by the North American Electric Reliability Corporation (“NERC”), approved by the FERC under Section 215 of the Federal Power Act, to provide for reliable operation of the bulk-power system.

“Owning Party” – shall mean the Party that owns certain facilities as delineated in Appendix II and Appendix III to this Agreement.

“Party”- shall mean either Dominion ~~Energy~~ or DEP. Party shall not include PJM.

“Parties”- shall mean Dominion ~~Energy~~ and DEP. Parties shall not include PJM.

“PJM-DEP Joint Operating Agreement” – shall mean that Amended and Restated Joint Operating Agreement between PJM and DEP, dated February 2, 2010, designated as PJM Rate Schedule No. 50 and DEP Rate Schedule No. 188, as subsequently modified and amended.

“PJM Requirement” – shall mean any rule, charge, procedure, or other requirements of PJM, including the PJM Tariff, applicable to FERC-jurisdictional service provided over the Dominion ~~Energy~~ Transmission System.

“PJM Tariff” – shall mean PJM’s Open Access Transmission Tariff.

“Reliability Council” – shall mean the North American Electric Reliability Corporation or any successor agency assuming or charged with similar responsibilities related to the operation and reliability of the North American electric interconnected transmission grid, including any regional or other subordinate council of which the Parties are a member with respect to the electric transmission facilities addressed in this Agreement.

“Roll-Over Count” shall mean a test that shows at what point the accumulator register rolls-over to zero when it reaches a predetermined maximum count.



**APPENDIX V**  
**Service Schedule A, Reserve**

**SECTION 1 - DURATION**

- 1.1 This Service Schedule shall continue in effect until termination or expiration of this Agreement unless superseded on any earlier date by a new service schedule or until terminated as provided for in Section 1.2 below of this Appendix V.
- 1.2 Notwithstanding Article 9.1 of this Agreement, either Party upon at least three years' prior written notice to the other Party may terminate this schedule.

**SECTION 2 - DEFINITIONS**

- 2.1 Emergency Reserve Capacity is defined as the capacity provided during the first 12 hours (or the remainder of the calendar day, if greater than 12 hours) following the emergency loss of a resource. The period during which Emergency Reserve Capacity is supplied shall be defined as the Emergency Period.
- 2.2 Daily Reserve Capacity is defined as the capacity provided immediately following an Emergency Period, or capacity provided as a matter of efficiency, or as otherwise mutually agreed.
- 2.3 Contingency Reserve is defined as capacity that may be made available following the emergency loss of a resource.

**SECTION 3 - SERVICES TO BE RENDERED**

- 3.1 In the event of an emergency loss of a resource, each Party will make available to the other Party, up to the total available Contingency Reserve capacity on its system and, upon request, will attempt to obtain capacity and/or energy from a third-party system.
- 3.2 In the event either Party desires to purchase capacity to supply a portion of its Contingency Reserve rather than supply it from its own resources, each Party will make available to the other such capacity to the extent that it is available.

**SECTION 4 - COMPENSATION**

**4.1 DEMAND CHARGE**

- 4.1.1 When Emergency Reserve Capacity is provided there will be no demand charge. If the Party suffering the outage requires assistance for a longer period than the Emergency Period, then that Party will purchase Daily Reserve Capacity, unless otherwise mutually agreed. When Daily Reserve Capacity is provided, the receiving Party will pay the delivering Party a reserve Demand Rate per kW per

day not to exceed the rate calculated in accordance with Appendix A or B, whichever is applicable.

- 4.1.2 In the event the delivering Party provides capacity to the receiving Party from a third-party system, the receiving Party will pay the delivering Party a Demand Rate equal to (1) the Demand Rate charged by the third-party, plus (2) a Transmission Use Rate per kW per day not to exceed the rate calculated in accordance with Appendix A or B, whichever is applicable. In transactions where no demand charge is made by the third-party, the receiving Party will pay the delivering Party a Transmission Use Rate per kW per day or per kWh, whichever is less, not to exceed the rate calculated in accordance with Appendix A or B, whichever is applicable.

## 4.2 ENERGY

- 4.2.1 When the energy delivered is generated on the system of the delivering Party, the receiving Party will pay the delivering Party a rate per kWh equal to (1) the out-of-pocket cost, plus (2) cost of transmission losses to make the delivery, plus (3) 10 percent of the sum of (1) and (2) under this Section of this Appendix V, or 5 mills per kWh, whichever is less; or at option of the delivering Party, the energy may be returned in kind.
- 4.2.2 For energy delivered by the delivering Party from a third-party the receiving Party will pay the delivering Party a rate per kWh equal to: (1) the rate per kWh paid to the third-party; plus (2) the cost of supplying the associated transmission losses on the system of the delivering Party; plus (3) one mill per kWh for miscellaneous and unquantifiable incremental costs incurred for transmission services; or by mutual agreement the energy may be returned in kind. In return-in-kind transactions the receiving Party will pay the delivering Party (1) the cost of supplying the associated transmission losses on the system of the delivering Party; plus (2) one mill per kWh to provide compensation for miscellaneous and unquantifiable incremental costs incurred for transmission services.

## 4.3 APPLICABLE TAXES

- 4.3.1 Where applicable, taxes will be added to the billings under 4.1 and 4.2 including but not limited to:

Support of South Carolina Public Service Commission  
South Carolina Gross Receipts Tax  
South Carolina Generation Tax  
North Carolina Gross Receipts Tax

Any new or additional applicable taxes enacted after the date of this Service Schedule shall be included in billings under this Service Schedule.

**APPENDIX A**

DETERMINATION OF INTERCHANGE DEMAND RATE  
PURSUANT TO SERVICE SCHEDULE A, RESERVE

**VIRGINIA ELECTRIC AND POWER COMPANY**

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**[RESERVED FOR FUTURE USE]**

**APPENDIX B**

DETERMINATION OF INTERCHANGE DEMAND RATE  
PURSUANT TO SERVICE SCHEDULE A, RESERVE

DUKE ENERGY PROGRESS, LLC

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This Appendix incorporates the provisions applicable to pricing of the reserve service being rendered under this Interconnection Agreement. All investments associated with production will be based on a projected, end-of-year test period. In addition to the rates calculated under the following provisions. DEP will provide transmission services in accordance with the provisions of DEP's Open Access Transmission Tariff. Unless otherwise mutually agreed to by DEP and Dominion-~~Energy~~, the rate shall be calculated on an annual basis and will be applicable to service rendered during the 12 months beginning July 1 of the test year.

### RESERVE

The rate for Reserve sales consists of a production demand rate.

The annual production demand rate is the sum of the total production demand cost (Appendix page 3 of 8) and applicable taxes (Appendix page 5 of 8). The annual production demand rate per kW is divided by 312 for a daily rate.

### TOTAL PRODUCTION DEMAND COST

The total production demand cost is determined by subtracting the accumulated deferred income tax credit per kW from the production demand cost per kW and adding the demand-related production expense per kW and the allowed CWIP per kW.

An explanation of the components used in calculating the total production demand cost is as follows:

- A. Production demand cost per kW – This cost is the sum of the production-related demand costs per kW of the generating plants contributing to the sale. Individual generating plant production related demand cost per kW is the product of the weighted investment per kW for that plant and the applicable annual carrying charge. The annual carrying charge consists of the components listed below and explained on pages 7 and 8 of 8 of this appendix.

- |  |                            |
|--|----------------------------|
| 1. Cost of Capital                     | 7. General Plant           |
| 2. Income Taxes                        | 8. Working Capital         |
| 3. Ad Valorem and Labor-Related Taxes  | (a) Cash Working Capital   |
| 4. Depreciation                        | (b) Materials and Supplies |
| 5. Decommissioning Expenses            | (c) Prepayments            |
| 6. Administrative and General Expenses |                            |

- B. Accumulated deferred income tax credit per kW – This credit is determined by summing the products of the weighted accumulated deferred income tax per kW and the annual carrying charge, consisting of the cost of capital and income tax components, for each generating plant contributing to the sale.

- C. Demand-related production expense per kW – This cost is determined by summing the products of demand-related production expense per kW and the percent participation for each generating plant contributing to the sale. The

demand-related portion of Accounts 500-554 is determined through an analysis of each FERC account. The purchased capacity, including related O&M from jointly owned units, is included in the calculation of demand-related production expenses. This purchased capacity is booked in Account 555.

- D. Allowed CWIP per kW – This cost is determined by summing the products of the FERC allowed production-related CWIP and the annual carrying charge, consisting of the cost of capital and income tax components for each generating plant contributing to the sale where CWIP is projected for the test period.

APPLICABLE TAXES

The Service Schedule with which this Appendix is used provides for adding to the cost any taxes which might be applicable to the transactions. Such taxes may include, but are not limited to:

Support of South Carolina Public Service Commission

South Carolina Gross Receipts Tax

South Carolina Excise Tax (kWh Tax)

North Carolina Gross Receipts Tax

North Carolina Sales Tax



### COST FOR CAPACITY RESERVES

The cost for capacity reserves is determined by taking 20 percent of the total production demand cost.

### CARRYING CHARGES

The carrying charges will include the appropriate following components which are determined using projected values with an end-of-year test period:

1. Cost of Capital – The capital structure is based on end-of-year ratios of debt, preferred stock, and common equity. The cost of each capital component is computed using the end-of-year embedded cost of debt and preferred stock and the return on common equity as set forth in the Exhibit No. 1 to this Appendix as the same may be changed subject to appropriate filing with the FERC.
2. Income Taxes – Income taxes are the product of the current statutory tax rates applied to the return on preferred stock and common equity as computed above.
3. Ad Valorem and Labor-Related Taxes – This component is the result of dividing the sum of ad valorem and labor-related taxes by the total end-of-year net plant investment in the computation period.
4. Depreciation – The depreciation rates are the rates last allowed by the FERC adjusted to apply to net plant investment. These rates differ for the type of plant. The allowed rates are adjusted by the ratio of gross plant investment to net plant investment.
5. Decommissioning – The decommissioning component will only be applicable in the case of nuclear production. The annual decommissioning accrual is divided by the end-of-year net nuclear production plant investment to determine this percentage.
6. Administrative and General Expenses – The A&G expenses for the computation period are allocated between power production plant, transmission plant, and distribution plant based on the labor ratios of these items. The A&G expenses so determined are divided by the end-of-year net plant investment for power production plant.

7. General Plant – The general plant is allocated between power production plant, transmission plant, and distribution plant based on the labor ratios of these items. The carrying charge applicable to general plant consists of the cost of capital, income taxes, ad valorem and labor-related taxes, and depreciation (all as determined above). This carrying charge is applied to the general plant applicable to power production. The cost of general plant applicable to power production is divided by its respective end-of-year net plants.
8. Working Capital – Working capital is composed of the three portions defined below: cash working capital, materials and supplies, and prepayments. A carrying charge, consisting of cost of capital and income taxes (both described above), will be applied to each of the three in determining the annual cost for working capital. The working capital percentage is determined by dividing the annual cost by the end-of-year net plant investment.
  - a. Cash Working Capital – This portion is calculated by taking one-eighth of the applicable operation and maintenance expenses. In the case of production, the O&M expenses should be exclusive of purchased power and nuclear fuel.
  - b. Materials and Supplies – This is the end-of-year balance of the appropriate materials and supplies.
  - c. Prepayments – This is the end-of-year balance of the appropriate prepaid expenditures, such as taxes and insurance.

**DEMAND RATE FOR  
RESERVE INTERCHANGE SALES**

Year Ending December 31, 1989

Annual updates, pursuant to the Appendix, will require a filing when changes are made to the return on common equity, CWIP balances, and acquisition adjustments and that such filings will be governed by the applicable parts of Sections 35.13 and 35.26 of the Commission's Regulations, as modified by Order No. 448 or any superseding Commission Regulation or Order.

**RESERVE**

Demand Rate

Total Production Demand Cost                      \$44.03 /kW/year

Applicable Taxes    0.00 /kW/year

Total    \$44.03 /kW/year / 312    =    \$0.141 /kW/day

**TOTAL PRODUCTION DEMAND COST**

Year Ending December 31, 1989

1.	Production Demand Cost/kW	\$42.67 /kW/year
2.	Less: Accumulated Deferred Income Tax/kW	4.93 /kW/year
3.	Plus: Demand-Related Production Expenses/kW	6.29 /kW/year
4.	Plus: Allowed CWIP/kW	<u>0.00</u> /kW/year
5.	Total Production Demand Cost/kW	\$44.03 /kW/year

# **PRODUCTION DEMAND COST**

(1) Generating Plants	(2) Net Plant Investment	(3) Installed Capacity (MW)	(4) Investment/ kW (2) / (3)	(5) Percent Participation	(6) Weighted Investment Cost/kW (4) x (5)	(7) Annual Carrying Charge	(8) Annual Carrying Cost/kW (6) x (7)
Asheville	\$27,489,000	392	70.13	4.11%	2.88	24.63%	\$ 0.71
Cape Fear	\$32,904,000	316	104.13	8.42%	8.77	24.63%	2.16
Lee	\$19,945,000	407	49.00	10.33%	5.06	24.63%	1.25
Mayo (1)	\$354,547,490	661	536.38	17.40%	93.33	24.63%	22.99
Robinson	\$12,631,000	174	72.59	2.73%	1.98	24.63%	0.49
Roxboro	\$263,464,000	2,371	111.12	42.62%	47.36	24.63%	11.66
Sutton	\$60,364,000	613	98.47	10.83%	10.66	24.63%	2.63
Weatherspoon	\$10,780,000	176	61.25	3.30%	2.02	24.63%	0.50
Brunswick	\$610,688,000	1,290	473.40	0.26%	1.23	22.40%	<u>0.28</u>

Total Production Demand Cost \$42.67 /kW/year

(1) Includes capacity charge capital costs and buy-back capacity from another part owner of Mayo Unit No. 1.

$$\begin{array}{rclcl}
 \$341,523,000 & + & \frac{\$3,207,932}{24.63\%} & = & \$354,547,490 \\
 625 \text{ MW} & + & 36 \text{ MW} & = & 661 \text{ MW}
 \end{array}$$

### ACCUMULATED DEFERRED INCOME TAX

(1) Generating Plants	(2) Accumulated Deferred Income Tax	(3) Installed Capacity (MW)	Accumulated Deferred Income Tax/kW (2) / (3)	(5) Percent Participation	(6) Weighted Accumulated Deferred Income Tax Cost/kW (4) x (5)	(7) Annual Carrying Charge	(8) Accumulated DIT/kW (6) x (7)
Asheville	\$6,623,000	392	16.90	4.11%	0.69	13.93%	\$0.10
Cape Fear	\$4,983,000	316	15.77	8.42%	1.33	13.93%	\$0.18
Lee	\$4,375,000	407	10.75	10.33%	1.11	13.93%	\$0.15
Mayo	\$61,814,000	625	98.90	17.40%	17.21	13.93%	\$2.40
Robinson	\$2,867,000	174	16.48	2.73%	0.45	13.93%	\$0.06
Roxboro	\$62,996,000	2,371	26.57	42.62%	11.32	13.93%	\$1.58
Sutton	\$15,988,000	613	26.08	10.83%	2.82	13.93%	\$0.39
Weatherspoon	\$1,504,000	176	8.55	3.30%	0.28	13.93%	\$0.04
Brunswick	\$114,359,000	1,290	88.65	0.26%	0.23	13.93%	<u>\$0.03</u>
Total Accumulated DIT							\$4.93 /kW/year

### DEMAND-RELATED PRODUCTION EXPENSE

(1) Generating Plants	(2) Demand-Related Production Expense	(3) Installed Capacity (MW)	(4) Demand-Related Production Expense/kW (2) / (3)	(5) Percent Participation	(6) Weighted Demand-Related Production Expense/kW (4) x (5)
Asheville	\$3,275,908	392	8.36	4.11%	\$0.34
Cape Fear	\$3,574,254	316	11.31	8.42%	\$0.95
Lee	\$3,043,852	407	7.48	10.33%	\$0.77
Mayo (2)	\$3,612,449	661	5.47	17.40%	\$0.95
Robinson	\$1,584,039	174	9.10	2.73%	\$0.25
Roxboro	\$9,515,784	2,371	4.01	42.62%	\$1.71
Sutton	\$4,188,124	613	6.83	10.83%	\$0.74
Weatherspoon	\$2,316,999	176	13.16	3.30%	\$0.43
Brunswick	\$72,120,046	1,290	55.91	0.26%	<u>\$0.15</u>
Total Demand-Related Production Expense					\$6.29 /kW/year

(2) Includes capacity charge demand-related O&M and buy-back capacity from another part owner of Mayo Unit No.1.

\$3,111,867      +      \$500,582      =      \$3,612,449

625 MW      +      36 MW      =      661 MW



### CONSTRUCTION WORK IN PROGRESS

(1) Generating Plants	(2) Allowed Construction Work In Progress	(3) Installed Capacity (MW)	(4) Cost/kW (2) / (3)	(5) Percent Participation	(6) Weighted Cost/kW (4) / (5)	(7) Annual Carrying Charge	(8) Allowed CIP/kW (6) x (7)
Asheville	\$0	392	0.00	4.11%	0.00	13.93%	\$0.00
Cape Fear	\$0	316	0.00	8.42%	0.00	13.93%	\$0.00
Lee	\$0	407	0.00	10.33%	0.00	13.93%	\$0.00
Mayo	\$0	625	0.00	17.40%	0.00	13.93%	\$0.00
Robinson	\$0	174	0.00	2.73%	0.00	13.93%	\$0.00
Roxboro	\$0	2,371	0.00	42.62%	0.00	13.93%	\$0.00
Sutton	\$0	613	0.00	10.83%	0.00	13.93%	\$0.00
Weatherspoon	\$0	176	0.00	3.30%	0.00	13.93%	\$0.00
Brunswick	\$0	1,290	0.00	0.26%	0.00	13.93%	<u>\$0.00</u>
Total CWIP							\$0.00 /kW/year

## CARRYING CHARGE RATE FOR PRODUCTION COST

	Steam Production	Nuclear Production
Cost of Capital	10.19%	10.19%
Income Taxes	3.74%	3.74%
Ad Valorem and Labor-Related Taxes	0.92%	0.92%
Depreciation	5.76%	3.89%
Decommissioning Expense	0.00%	0.57%
A&G Expenses	2.28%	2.28%
General Plant	0.65%	0.65%
Working Capital		
Cash	1.06%	0.14%
Materials and Supplies	0.00%	0.00%
Prepayments	<u>0.03%</u>	<u>0.02%</u>
Total	24.63%	22.40%

## PRODUCTION CARRYING CHARGES

All year-end investments are from 1989 projected values. Original cost must be reduced by depreciation.

### 1. Cost of Capital (3)

	<u>% Capital Structure</u>	<u>Cost of Each %</u>	<u>Cost Component</u>
Debt	49.54%	8.45%	4.19%
Preferred	6.82%	8.76%	0.60%
Equity	43.64%	12.38%	<u>5.40%</u>
Total			10.19%

### 2. Income Taxes

State			6.67%	
Federal			34.00%	
Income Tax on Preferred and Common Equity:				
Net Income Before Taxes			100.00%	
State Income Taxes			<u>6.67%</u>	
			93.33%	
Federal	93.33%	x	34.00%	<u>31.73%</u>
				61.60%

Income Tax

$$\frac{1 - .6160}{.6160} \times (0.60 + 5.40) = 3.74\%$$

### 3. Ad Valorem and Labor-Related Taxes (4)

$$\frac{\$59,402,000}{\$6,438,127,000} = 0.92\%$$

### 4. Depreciation (5)

These are the current FERC approved composite rates for the applicable accounts. These composite rates are then adjusted to apply to net plant investment.

Steam Production	3.43%	x	$\frac{\$1,324,039,000}{\$788,481,000}$	=	5.76%
Nuclear Production	3.19%	x	$\frac{\$4,406,238,000}{\$3,615,512,000}$	=	3.89%

(3) FERC Benchmark Return on Common Equity for the period February 1, 1989 to April 30, 1989.

(4) Analysis of Company books.

Exhibit No. 1 to Appendix B  
Page 9 of 10

(6) Analysis of Company books. Power Production-related A&G allocated on the basis of Labor.

(7) Analysis of Company books. Power Production-related General Plant allocated on the basis of Labor.

b. Materials and Supplies

Nuclear and Steam Production

\$0

13.93%

x

\$0

=

0.00%

c. Prepayments

Steam Production

13.93%

x

\$1,665,933

=

\$232,064

\$232,064

=

0.03%

-----  
\$788,481,000

Nuclear Production

13.93%

x

\$5,544,057

=

\$772,287

\$772,287

=

0.02%

-----  
\$3,615,512,000

**SUPPLEMENTAL INFORMATION  
DUKE ENERGY PROGRESS, LLC**

**DERIVATION OF LABOR RATIOS FOR A&G AND GENERAL PLANT ALLOCATIONS**

1.	Distribution of Salaries and Wages	
	a. Production	\$130,888,000
	b. Transmission	7,309,000
	c. Distribution	<u>38,845,000</u>
	d. Total	\$177,042,000
2.	Labor Ratios	
	a. Production ( 1.a./1.d.)	0.7393
	b. Transmission ( 1.b./1.d.)	0.0413
	c. Distribution (1.c./1.d.)	0.2194
	d. Total	1.0000
3.	A&G Expense (page 9 of 10)	
	a. Total A&G Expense	\$137,649,000
	b. Allocated Production A&G Expense (3.a. x 2.a.)	\$101,763,906
4.	General Plant Expense (page 9 of 10)	
	a. Total Net Generating Plant	\$198,135,000
	b. Allocated Net Production-related General Plant (4.a. x 2.a)	\$146,481,206

## **APPENDIX VI**

### **Special Terms and Conditions**

In accordance with Article 12.5 of this Agreement, this Appendix sets forth Special Terms and Conditions applicable to Interconnection Point(s).

1. **The Littleton Interconnection Point.**

a. **Description:** The point hereby designated and hereinafter called “**Littleton Interconnection Point**” is shown in Figure 1 of this Appendix VI. The point of interconnection is within the 115 kV single circuit transmission line extending from the 115 kV bus in DEP’s Littleton Station to Dominion-~~Energy~~’s 115 kV transmission line that runs between the Army Corps of Engineers’ Kerr Dam Station and Dominion-~~Energy~~’s Carolina Station. The 24 kV bi-directional metering equipment compensated to 115 kV at the Littleton Interconnection Point is installed at the Littleton Station, and is owned, operated, and maintained by DEP.

b. **Facilities:** The Parties installed, own and operate their respective facilities as described below:

i. **Facilities installed by Dominion-~~Energy~~:**

1. Two 115 kV air break switches in the Dominion ~~Energy~~-115 kV Transmission Line No. 90, one on either side of an approximately 3.22 mile tap built by DEP to the station near the Town of Littleton, North Carolina. DEP paid for initial installation of the two air break switches and shall pay for ongoing replacement and maintenance of the two air break switches as such costs are incurred.
2. A suitable point of connection between the two 115 kV air break switches on Dominion ~~Energy~~-Transmission Line No. 90 at a location mutually agreeable to DEP and Dominion ~~Energy~~ designed to provide DEP with sufficient clearance to tap the transmission line for service to the Town of Littleton, North Carolina.

ii. **Facilities installed by DEP:**

1. A structure located in close proximity to, but not on, Dominion ~~Energy~~’s transmission right of way permitting the installation of taps from Dominion-~~Energy~~’s 115 kV Transmission Line No. 90 to DEP’s 115 kV tap line.
2. A 115 kV air break switch near Dominion-~~Energy~~’s, transmission line permitting disconnection of DEP’s 115 kV tap line. Such air

break, switch is double-locked to permit operation by Dominion ~~Energy~~ in the emergency restoration of Transmission Line No. 90.

3. A 115 kV tap line approximately 3.22 miles long from Dominion ~~Energy~~'s Transmission Line No. 90 to DEP's 115 kV substation site near the Town of Littleton, North Carolina.
4. A 25,000 kVA 115/24 kV Station with suitable protective devices and bi-directional metering near the Town of Littleton, North Carolina.

iii. General:

1. Each Party shall, as mutually agreed upon, maintain or cause to be maintained in good operating order, the facilities at the Littleton Interconnection Point.
2. If new facilities are to be constructed, each Party shall exercise due diligence in completing its construction in time to satisfy a reasonably determined energization date.
3. If, at any time, after the initial energization of the Littleton Interconnection Point, upgrades (other than upgrades to facilitate the physical interconnection of facilities as otherwise addressed in this Appendix VI) to Dominion ~~Energy~~'s Transmission System become necessary that would not be necessary but for the Littleton Interconnection Point, the Parties shall arrange mutually agreeable terms for DEP's payment for the incremental initial and ongoing cost of such upgrades attributable to the Littleton Interconnection Point, or the Littleton Interconnection Point shall be terminated prior to the time such upgrades would be required to be completed. Dominion ~~Energy~~ shall exercise due diligence in communicating the anticipated need of such upgrades to DEP as soon as practicable upon identification of such need.
4. Either Party on whose property facilities of the other Party are at any time located or to be located shall provide freedom of access to the other Party for the purpose of constructing, reconstructing, maintaining, operating, or removing such facilities.

c. Service to be Rendered:

- i. All energy transmitted hereunder shall be supplied at sixty (60) cycle alternating current at such potential and of such phase as may be mutually agreed upon.



- ii. All energy transmitted hereunder shall be measured at the point of supply, or at the nearest suitable and convenient point, by meters installed and maintained by DEP or as mutually agreed upon.
- iii. Dominion ~~Energy~~ will exercise reasonable care to maintain the continuity of its service, but shall not be responsible for any damage or loss of revenue caused by any interruption of such service.
- iv. It is the intent of the Parties that the amount of energy received by DEP's customers connected to Dominion ~~Energy~~'s system under this Agreement during any calendar month shall be approximately the same as the amount delivered by DEP during such month. If, however, during any calendar month there is a difference between the total number of kilowatt hours received and delivered by a Party under this Agreement, the difference shall be settled by the deficient Party delivery such kilowatt hours difference to the other Party during the succeeding month.

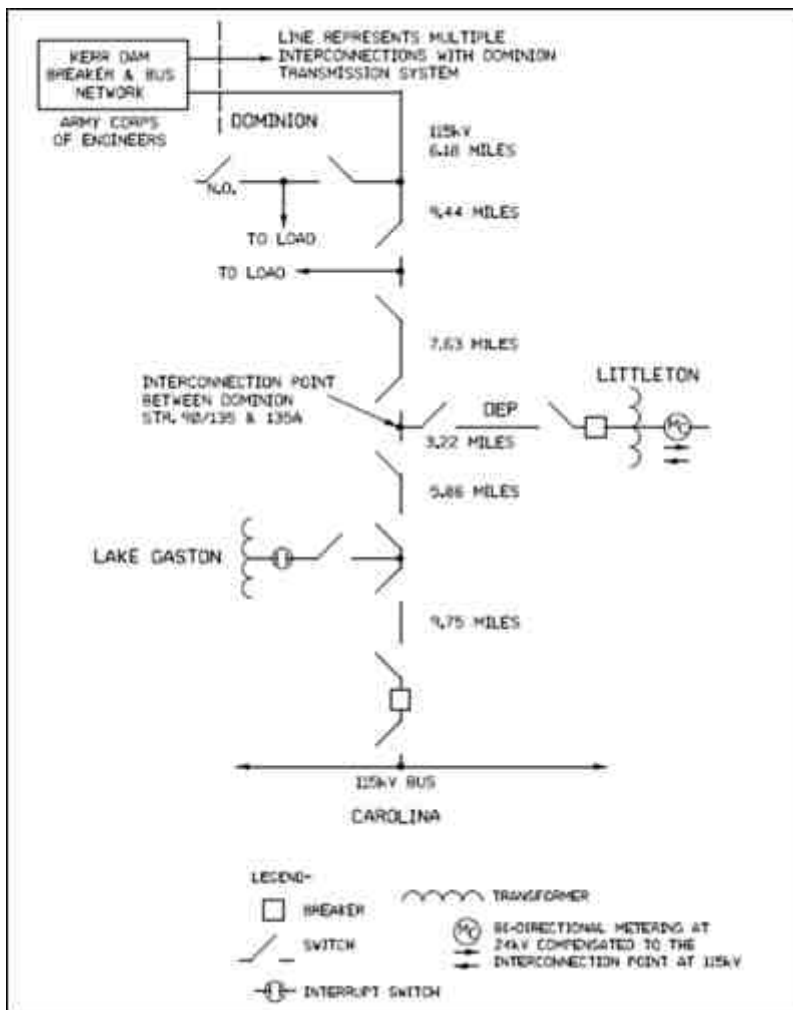
d. Term:

- i. At any time after the initial energization of the Littleton Interconnection Point either Party, by giving not less than ninety days written notice to the other Party, may from time to time call for a reconsideration of the terms and conditions applicable to the Littleton Interconnection Point; provided, that no such reconsideration shall be called for at intervals of less than one (1) year except as appropriate to maintain adequate reliability of each Party's Transmission System. If such reconsideration is called for, the authorized representatives of the Parties shall meet as promptly as convenient and discuss any of the applicable terms and conditions. No Party shall be under any obligation to agree to any modification or supplement not satisfactory to it. Any agreement modifying or supplementing such terms and conditions shall specify the date such modification or supplement shall become effective and shall be incorporated herein.
- ii. Notwithstanding any other provision herein, either Party may discontinue service at the Littleton Interconnection Point upon three years written notice to the other Party.

~~Note 1: All references to "Dominion Energy" within Figure 1 to this Appendix VI are now replaced with "Dominion Energy" as described in the opening recitals to this Agreement.~~

## APPENDIX VI

**Figure 1**  
**Littleton Interconnection Point**



**ATTACHMENT B**  
**AMENDMENT TO INTERCONNECTION AGREEMENT**  
**SERVICE AGREEMENT NO. 3453**

# **INTERCONNECTION AGREEMENT**

**between**

**DUKE ENERGY PROGRESS, LLC**

**and**

**VIRGINIA ELECTRIC AND POWER COMPANY, doing  
business as DOMINION ENERGY VIRGINIA in the  
Commonwealth of Virginia and as DOMINION ENERGY  
NORTH CAROLINA in the State of North Carolina**

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### **ARTICLE 2 – SERVICE CONDITIONS**

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## **INTERCONNECTION AGREEMENT**

**THIS INTERCONNECTION AGREEMENT** (“Agreement”) is made and entered into as of this 29<sup>th</sup> day of November, 2012, as amended on December 11, 2014, on May 4, 2015, on September 28, 2016, on May 16, 2017, and on October 26, 2018, between Duke Energy Progress, LLC (“DEP”), and Virginia Electric and Power Company, doing business as Dominion Energy Virginia in the Commonwealth of Virginia and as Dominion Energy North Carolina in the State of North Carolina (“Dominion ”). DEP and Dominion may be referred to herein individually as a “Party” or collectively as the “Parties”. For the avoidance of doubt, the terms “Party” and “Parties” as used herein shall not include PJM Interconnection, L.L.C. (“PJM”), or any successor regional transmission organization (“RTO”).

### **W I T N E S S E T H:**

WHEREAS, DEP is a North Carolina corporation, owning and operating electric facilities for the transmission and distribution of electric power and energy in the States of North Carolina and South Carolina;

WHEREAS, Dominion is a Virginia corporation, owning and operating electric facilities for the transmission and distribution of electric power and energy in the Commonwealth of Virginia and the State of North Carolina, and a Transmission Owning member of PJM;

WHEREAS, the Parties entered into an Interchange Agreement between Carolina Power & Light Company and Virginia Electric and Power Company, dated July 9, 1970 (“1970 Agreement”), designated as Carolina Power & Light Company’s Rate Schedule FPC No. 96 and Virginia Electric and Power Company’s Rate Schedule FPC No. 95, as subsequently modified and amended, and other agreements as appropriate; pursuant to which the systems of the Parties are interconnected by transmission lines, with such points of interconnection herein called “Interconnection Points,” and are operating in synchronism;

WHEREAS, Service Schedule A – 1994 Reserve (“Service Schedule A, Reserve”) was a part of and under the 1970 Agreement;

WHEREAS, the Parties wished to cancel the 1970 Agreement and other agreements as appropriate;

WHEREAS, the Parties wished to establish, the terms and conditions upon which they will continue the interconnected operation of their respective transmission systems inclusive of Service Schedule A, Reserve;

WHEREAS, the Federal Energy Regulatory Commission (“FERC”) originally accepted this Agreement for filing by unpublished letter order issued on January 28, 2013 in Docket No. ER13-477-000 designated as Original Service Agreement No. 3453 (“2012 Agreement”);

WHEREAS, on July 2, 2013, Progress Energy Inc., successor in interest to Carolina Power & Light Company, which did business as Progress Energy Carolinas, Inc. (“PEC”), completed its merger with Duke Energy Corporation, parent of DEP, and following the merger, PEC changed its name to DEP;

WHEREAS, FERC accepted revisions to the 2012 Agreement by unpublished letter order issued on February 5, 2015 in Docket Nos. ER15-618-000, *et al.*, designated as Service Agreement No. 3453 (“2014 Agreement”);

WHEREAS, FERC accepted revisions to the 2014 Agreement by unpublished letter order issued on September 2, 2015 in Docket Nos. ER15-1799-000, *et al.*, designated as Service Agreement No. 3453 (“2015 Agreement”);

WHEREAS, FERC accepted revisions to the 2015 Agreement by unpublished letter order issued on November 28, 2016 in Docket Nos. ER17-22-000, *et al.*, designated as Service Agreement No. 3453 (“2016 Agreement”);

WHEREAS, FERC accepted revisions to the 2017 Agreement by unpublished letter order issued on July 12, 2017 in Docket Nos. ER17-1651-000, *et al.*, designated as Service Agreement No. 3453 (“2017 Agreement”);

WHEREAS, Dominion’s transmission facilities (including conductors, circuit breakers, switches, transformers, metering equipment, data acquisition system (“DAS”) equipment, and other associated equipment, at such voltage as is acceptable to both parties, used to control or measure the transfer of energy from one place to another) are owned, operated or controlled by Dominion, including any modifications, additions or upgrades made thereto (collectively, the “Dominion Transmission System”, or “Transmission System”) and are currently under the functional and operational control of PJM;

WHEREAS, PJM is registered with the North American Electric Reliability Corporation (“NERC”) as, among other things, a Balancing Authority and Reliability Coordinator, and is the Balancing Authority and Reliability Coordinator for Dominion;

WHEREAS, DEP’s transmission facilities (including conductors, circuit breakers, switches, transformers, metering equipment, DAS equipment, and other associated equipment, at such voltage as is acceptable to both parties, used to control or measure the transfer of energy from one place to another) are owned, operated or controlled by DEP, including any modifications, additions or upgrades made thereto (collectively, the “DEP Transmission System”, or “Transmission System”);

WHEREAS, DEP is registered with the NERC as, among other things, a Balancing Authority, and is the Balancing Authority for DEP;

WHEREAS, the FERC has required PJM to be a signatory to this Agreement, pursuant to FERC’s Order on Rehearing and Compliance dated July 26, 2005 in Docket Numbers ER05-31-002 and EL05-70-001, 112 FERC ¶ 61,128 at P 10 (2005), in order to ensure that PJM is kept fully apprised of the matters addressed herein and so that PJM may be kept aware of any reliability and planning issues that may arise; and

WHEREAS, Dominion and DEP are each registered with NERC as, among other things, Transmission Owners (“TOs”) and, as NERC-registered TOs, Dominion and DEP are each



obligated to comply with the requirements of NERC Reliability Standards as applicable to the Interconnection Points under this Agreement.

NOW, THEREFORE, in consideration of the premises and mutual covenants herein set forth, the Parties hereto agree as follows:

## **ARTICLE 1 – INTERCONNECTED OPERATION**

### **1.1 Interconnected Operation**

The DEP Transmission System and the Dominion Transmission System shall be interconnected at the Interconnection Points specified in this Agreement. The Parties, by amendment to this Agreement, may mutually agree to add, discontinue or modify the Interconnection Points and such additional, discontinued or modified Interconnection Points shall be reflected as an amendment to this Agreement pursuant to Article 10.3.

### **1.2 Continuity of Interconnected Operation**

The Parties shall, during the term of the Agreement, continue in service the existing transmission lines, interconnection facilities and essential terminal equipment necessary to maintain the Interconnection Points specified in this Agreement.

## **ARTICLE 2 – SERVICE CONDITIONS**

### **2.1 Avoidance of Unauthorized Use and Control of System Disturbance**

Each Party shall have facilities or contractual arrangements adequate to serve its own load and shall exercise reasonable care to design, construct, maintain, and operate its Transmission System, in accordance with Good Utility Practice, and in accordance with Applicable Laws and Regulations and in such manner as to avoid the unauthorized utilization of the generation or transmission facilities of any other person (hereinafter referred to as “Unauthorized Use”). Neither Party shall be obligated to receive or deliver real or reactive power when to do so might introduce objectionable operating conditions on its Transmission System. Any Party may install and operate on its Transmission System such relays, disconnecting devices, and other equipment, as it may deem appropriate for the protection of its Transmission System or prevention of Unauthorized Use. Each Party shall maintain and operate its respective Transmission System so as to minimize, in accordance with Good Utility Practice, the likelihood of a disturbance originating in either Transmission System, which might cause impairment to the service of the other Party or of any transmission system interconnected with the Transmission System of the other Party.

### **2.2 Interruption of Service**

The interconnections provided under this Agreement may be interrupted, upon such notice as is reasonable, under the following circumstances: (a) by operation of automatic equipment installed for power system protection; (b) after consultation with the other Party if practicable, when a Party deems it desirable for installation, maintenance, inspection, repairs or replacements of equipment; (c) to comply with a directive issued by the Balancing Authority or Reliability

Coordinator of either Party; or (d) at any time that, in the sole judgment of the interrupting Party, such action is necessary to preserve the integrity of, or to prevent or limit any instability on, or to avoid or mitigate a burden on its system. If synchronous operation of the Parties' Transmission Systems through a particular line or lines becomes interrupted, the Parties shall cooperate so as to remove the cause of such interruption as soon as practicable and restore said lines to normal operating condition.

### 2.3 Operating Responsibilities

Each Party shall maintain its Transmission System, including the transmission equipment and facilities, in a manner consistent with Good Utility Practice in order to permit Dominion to operate its Transmission System as required by this Agreement and PJM, and to permit DEP to operate its Transmission System as required by this Agreement. Operating arrangements for facility maintenance shall be coordinated between operating personnel of the Parties' respective control centers. Except as may be necessary and appropriate in an emergency, operating arrangements shall be coordinated with PJM in accordance with PJM Requirements as between Dominion and PJM, and in accordance with the PJM-DEP Joint Operating Agreement as between DEP and PJM.

### 2.4 Energy Losses

The energy losses on the interconnected facilities shall be assigned to the appropriate Party based on the Interconnection Points of the interconnected facilities or according to procedures developed by the Operating Committee and subject to any PJM Requirement as between Dominion and PJM, and any requirements as stipulated in the PJM-DEP Joint Operating Agreement as between DEP and PJM.

### 2.5 Compliance with NERC Reliability Standards

Prior to the execution of this Agreement, the Parties shall develop and execute the NERC Coordination Guide. The NERC Coordination Guide shall delineate the coordination of each Party's responsibilities as NERC-registered TOs to comply with NERC Reliability Standards as applicable to the Interconnection Points under this Agreement and shall not be filed at FERC. After this Agreement is executed, the Operating Committee shall maintain the NERC Coordination Guide in accordance with Article 6.2(d) of this Agreement.

## **ARTICLE 3 – INTERCONNECTION POINTS, METERING POINTS AND METERING AND DATA ACQUISITION SYSTEM EQUIPMENT**

### 3.1 Interconnection Points

All electric energy delivered under this Agreement shall be of the character commonly known as three-phase 60 Hz energy and shall be delivered at the Interconnection Points specified under Article 1 of this Agreement at standard nominal voltage or such other voltages as may be specified in this Agreement.

### 3.2 Metering and Data Acquisition System Equipment

Measurement of electric energy for the purposes of determining load and effecting settlements, and monitoring and telemetering of power flows under this Agreement shall be made by metering and DAS equipment installed and maintained, by either DEP or Dominion at the Interconnection Points consistent with the provisions of Appendix II and III of this Agreement. Any aspects of metering and DAS equipment not specifically provided for by this Agreement shall be referred to the Operating Committee pursuant to Article 6.

## **ARTICLE 4 – RECORDS**

### 4.1 Copies of Records

Each Party shall provide to a requesting Party copies of records maintained in accordance with FERC's record retention requirements to the extent such records document any transactions that have occurred under this Agreement.

## **ARTICLE 5 – INVOICING AND PAYMENT; TAXES**

### 5.1 Purpose of Invoicing

Any invoice that is issued pursuant to this Agreement shall be for: (a) the establishment of any new Interconnection Point; (b) the modification of an existing Interconnection Point; or (c) service under Service Schedule A, Reserve. As per Article 6.2 (b) of this Agreement, the Operating Committee shall establish the terms and conditions applicable to invoicing.

### 5.2 Timeliness of Payment

Unless otherwise agreed upon, all invoices, if any, issued pursuant to this Agreement shall be rendered as soon as practicable in the month following the calendar month in which expenses were incurred and shall be due and payable, unless otherwise agreed upon within thirty (30) days of receipt of such invoice. Payment shall be made by electronic transfer or such other means as shall cause such payment to be available for the use of the payee. Interest on unpaid amounts shall accrue daily at the then current prime interest rate (the base corporate loan interest rate) published in the Wall Street Journal, or, if no longer so published, in any mutually agreeable publication, plus two percent (2%) per annum, but will in no event exceed the maximum interest rate allowed pursuant to Virginia law, and shall be payable from the due date of such unpaid amount and until the date paid.

### 5.3 Disputed Invoices

In the case of a disputed invoice, all invoices shall be paid in full under the conditions specified in Article 5.2 of this Agreement. Disputes will then be brought before the Operating Committee for resolution per Article 6.4 of this Agreement. If, after thirty (30) days, the Operating Committee has not resolved the dispute, then such dispute shall be resolved pursuant to the arbitration procedures specified in Article 8 of this Agreement.

#### 5.4 Invoice Adjustments

Other than as required by law, regulatory action or metering test adjustments, invoice adjustments shall be made within six (6) months of the rendition of the initial invoice.

#### 5.5 Tax Reimbursement

If, as part of any compensation to be paid under this Agreement during the term of this Agreement, any direct tax, including, but not limited to sales, excise, or similar taxes (other than taxes based on or measured by net income) is levied and/or assessed against either Party by any taxing authority on the power and/or energy manufactured, generated, produced, converted, sold, purchased, transmitted, interchanged, exchanged, exported or imported by the supplying Party to the other Party, then such supplying Party shall be fully compensated by the other Party for such direct taxes.

#### 5.6 Contribution In-Aid of Construction

The Parties intend that all costs paid by a Party to another Party, for the establishment, discontinuance, relocation or modification of an Interconnection Point, shall be non-taxable contributions to capital, and shall not be taxable as contributions in-aid of construction ("CIAC"). This presumption notwithstanding, in the event federal or state income taxes are imposed upon the Party with respect to such payments paid by the other Party as a CIAC by the Internal Revenue Service ("IRS") and/or a state department of revenue ("State"), the Party paying the CIAC shall reimburse the other Party for the tax effect of such CIAC computed in accordance with FERC rules and including any interest and penalty charged to the Party by the IRS and/or State.

### **ARTICLE 6 – OPERATING COMMITTEE**

#### 6.1 Operating Committee

An Operating Committee shall administer the interconnected operation of the Parties' Transmission Systems as provided for in this Agreement. Each Party shall appoint one member and one alternate to the Operating Committee and designate, in writing, said appointments to the other Party. Such representatives and alternates shall be persons familiar with NERC Reliability Standards and the transmission and substation facilities of the Parties they represent and shall be fully authorized to perform the principal duties listed below.

#### 6.2 Duties of the Operating Committee

The principal duties of the Operating Committee shall be as follows:

- a. to establish operating and control procedures as necessary to implement this Agreement;
- b. to establish accounting and invoicing procedures as necessary to implement this Agreement;

- c. to coordinate transmission and generator maintenance schedules to an extent agreed by the Parties;
- d. to maintain the NERC Coordination Guide; and
- e. to perform those duties, which this Agreement requires to be done by the Operating Committee, and such other duties as may be required for the proper functioning of this Agreement.

### 6.3 Limitations on Operating Committee Duties

The Operating Committee shall not amend or modify any of the terms or conditions of this Agreement.

### 6.4 Operating Committee Disputes

If the Operating Committee is unable to agree on any matter coming within its scope of duties, then such matter shall be resolved pursuant to Article 8 of this Agreement.

### 6.5 Meeting of the Operating Committee

After this Agreement becomes effective pursuant to Article 9 of this Agreement, the Operating Committee shall meet at least once each year to: (a) review all documentation established and maintained in accordance with the duties of the Operating Committee pursuant to Article 6.2 of this Agreement to assess whether any revisions are required; and (b) discuss any other matters related to the performance of Operating Committee duties pursuant to Article 6.2 of this Agreement. Other meetings may be called as reasonably necessary by any Operating Committee Representative from either Party.

## **ARTICLE 7 – INDEMNITY**

### 7.1 Indemnity

To the extent permitted by law, each Party shall indemnify, save harmless, and defend the other Party including its directors, officers, employees, Affiliates and agents (collectively, the “Indemnified Party”) from and against any losses, liabilities, costs, expenses, suits, actions, claims, and all other obligations arising out of injuries or death to persons or damage to property caused by or in any way attributable to its ownership or operation of its Transmission System, except that the Party’s obligation to indemnify the Indemnified Party shall not apply to the extent of any liabilities arising from the Indemnified Party’s negligence or intentional misconduct or that portion of any liabilities that arise out of the Indemnified Party’s contributing negligence or intentional misconduct.

## **ARTICLE 8 – ARBITRATION**

### 8.1 Submission to Arbitration

In the event either Party has a dispute, or asserts a claim, that arises out of or in connection with

this Agreement or its performance, such Party (the “disputing Party”) shall provide the other Party with written notice of the dispute or claim (“Notice of Dispute”). Such dispute or claim shall be referred to a designated senior representative of each Party for resolution on an informal basis as promptly as practicable after receipt of the Notice of Dispute by the other Party. In the event the designated representatives are unable to resolve the claim or dispute through unassisted or assisted negotiations within thirty (30) calendar days of the other Party’s receipt of the Notice of Dispute, such claim or dispute may, upon mutual agreement of the Parties, be submitted to arbitration and resolved in accordance with the arbitration procedures set forth below. If a dispute or claim is submitted to arbitration, the arbitration can only be terminated upon mutual agreement of the Parties. In the event the Parties do not agree to submit such claim or dispute to arbitration, each Party may exercise whatever rights and remedies it may have in equity or at law consistent with the terms of this Agreement.

## 8.2 Technical Issues Arbitrator

With respect to Disputes, which the Parties mutually agree are exclusively technical in nature, the Parties may, if they mutually agree, submit such Disputes to a technical issues arbitrator (“TIA”) for final and non-appealable resolution. The TIA, which shall be an individual or firm to be mutually agreed upon by both Parties, shall be an unbiased technical expert in transmission and distribution system design and operational matters.

## 8.3 External Arbitration Procedures

Any arbitration initiated under this Agreement shall be conducted before a single neutral arbitrator appointed by the Parties. If the Parties fail to agree upon a single arbitrator within ten (10) calendar days of the submission of the dispute to arbitration, each Party shall choose one arbitrator who shall sit on a three-member arbitration panel. The two arbitrators so chosen shall within twenty (20) calendar days select a third arbitrator to chair the arbitration panel. In either case, the arbitrators shall be knowledgeable in electric utility matters, including electric transmission and bulk power issues, and shall not have any current or past substantial business or financial relationships with any party to the arbitration (except prior arbitration). The arbitrator(s) shall provide each of the Parties an opportunity to be heard and, except as otherwise provided herein, shall conduct the arbitration in accordance with the Commercial Arbitration Rules of the American Arbitration Association (“Arbitration Rules”) and any applicable FERC regulations or PJM rules; provided, however, in the event of a conflict between the Arbitration Rules and the terms of this Article 8, the terms of this Article 8 shall prevail.

## 8.4 Arbitration Decisions

Unless otherwise agreed by the Parties, the arbitrator(s) shall render a decision within ninety (90) calendar days of appointment and shall notify the Parties in writing of such decision and the reasons therefore. The arbitrator(s) shall be authorized only to interpret and apply the provisions of this Agreement and shall have no power to modify or change any provision of this Agreement in any manner. The decision of the arbitrator(s) shall be final and binding upon the Parties, and judgment on the award may be entered in any court having jurisdiction. The decision of the arbitrator(s) may be appealed solely on the grounds that the conduct of the arbitrator(s), or the decision itself, violated the standards set forth in the Federal Arbitration Act or the

Administrative Dispute Resolution Act. The final decision of the arbitrator must also be filed with FERC if it affects jurisdictional rates, terms and conditions of service under this Agreement.

#### 8.5 Costs

Each Party shall be responsible for its own costs incurred during the arbitration process and for the following costs, if applicable: (a) the cost of the arbitrator chosen by the Party to sit on the three member panel and one half of the cost of the third arbitrator chosen; or (b) one half the cost of the single arbitrator jointly chosen by the Parties.

### **ARTICLE 9 – TERM AND TERMINATION OF AGREEMENT**

#### 9.1 Term and Termination

This Agreement shall be effective as of the date first written above, or such later date as the last necessary regulatory approval hereof shall be obtained (unless an earlier date is specified by the regulatory authority having jurisdiction), and shall remain in effect until the date falling on the tenth (10th) anniversary of the date hereof (the “Initial Term”) and, thereafter, for successive twelve (12) month periods (“Renewal Terms”). Either Party may terminate this Agreement after the Initial Term by providing to the other Party thirty-six (36) months’ advance written notice of its intent to terminate this Agreement, in which case this Agreement shall terminate at the end of such thirty-six (36) month notice period without regard to the expiration of any Renewal Term. Notwithstanding the above, this Agreement may be terminated earlier: (a) if the Parties mutually agree; or (b) as otherwise expressly provided for in this Agreement.

#### 9.2 Breach and Default

A Party shall be considered in default of this Agreement (“Default”) if it fails to cure a Breach in accordance with the terms of this Article 9.2. A breach (“Breach”) shall mean the failure of a Party to perform or observe any material term or condition of this Agreement; provided that no Breach shall exist where such failure to discharge an obligation (other than the payment of money) is the result of Force Majeure as defined in this Agreement or the result of an act of omission of the other Party. Upon a Breach, the non-breaching Party shall give written notice of such Breach to the breaching Party. The breaching Party shall have thirty (30) calendar days from receipt of the Breach notice within which to cure such Breach; provided however, if such Breach is not capable of cure within thirty (30) calendar days, the breaching Party shall commence such cure within thirty (30) calendar days after notice and continuously and diligently complete such cure within ninety (90) calendar days from receipt of the Breach notice; and, if cured within such time, the Breach specified in such notice shall cease to exist.

#### 9.3 Right to Terminate

Upon the occurrence and during the continuance of a Default, the non-defaulting Party shall have the right: (a) to terminate this Agreement by providing written notice to the defaulting Party and making a filing at FERC to terminate this Agreement; provided that any such termination shall not take effect until FERC approval; or (b) to take any other action at law or in equity as may be permitted under this Agreement. The provisions of this Article 9 will survive termination of this Agreement.

#### 9.4 Renegotiable Events

If one of the following conditions occurs, the Parties shall negotiate in good faith to amend this Agreement or to take other appropriate action so as to protect each Party's interest in this Agreement. This Agreement shall serve as the document upon which such negotiations shall be based and the Parties shall make as minimal modifications as necessary to effectuate the original intent and purpose of this Agreement. If the Parties are unable to reach agreement, either Party shall have the right to unilaterally file with the FERC, pursuant to Section 205 or Section 206 of the Federal Power Act as appropriate, proposed amendments to this Agreement that the Party deems reasonably necessary to protect its interests:

- a. Any change to Applicable Laws and Regulations having a material impact upon the effectiveness or enforceability of any provision of this Agreement;
- b. This Agreement is not approved or accepted for filing by the FERC without modification or condition;
- c. PJM or the Reliability Council prevents, in whole or in part, either Party from performing any provisions of this Agreement in accordance with its terms;
- d. Dominion withdraws from PJM, or DEP becomes a transmission owner of an Independent System Operator, a Regional Transmission Organization, or similar entity;
- e. Either Dominion or DEP is no longer a NERC-registered TO;
- f. PJM Requirements are modified in a manner that materially affects Dominion's ability to perform its obligations under this Agreement;
- g. The PJM-DEP Joint Operating Agreement is modified in a manner that materially affects DEP's ability to perform its obligations under this Agreement; or
- h. PJM, either voluntarily or involuntarily, is dissolved.

### **ARTICLE 10 – REGULATORY AUTHORITIES**

#### 10.1 Regulatory Authorities

This Agreement is made subject to the jurisdiction of any Governmental Authority or authorities having jurisdiction over the Parties, the DEP Transmission System, the Dominion Transmission System, this Agreement, or the subject matter hereof.

#### 10.2 Adverse Regulatory Change

The Parties agree to jointly submit and support the filing of this Agreement with the FERC. Any changes or conditions imposed by the FERC or any other Governmental Authority with competent jurisdiction in connection with such submission or otherwise in respect of this Agreement, any of which are unacceptable to a Party after the Parties' good faith attempt to



negotiate a resolution to such objectionable change or condition, shall be cause for termination of this Agreement upon thirty (30) days' prior written notice by the non-consenting Party to the other Parties hereto.

### 10.3 Amendments to the Agreement

#### 10.3.1 Amendments

In the event that the Parties agree to amend this Agreement, the Parties shall, if required, file any such amendment or modification with the FERC.

#### 10.3.2 Section 205 and 206 Rights

Nothing contained in this Agreement shall preclude either Party from exercising its rights under Section 205 and 206 of the Federal Power Act to file for a change in any rate, term, condition or service provided under this Agreement.

## **ARTICLE 11 – CANCELLATION OF PRIOR AGREEMENTS**

### 11.1 Cancellation of Prior Agreements

When this Agreement becomes effective pursuant to Article 9 of this Agreement, this Agreement shall supersede in its entirety the 2017 Agreement, with all subsequent modifications and amendments, and other agreements as appropriate.

## **ARTICLE 12 – GENERAL**

### 12.1 Force Majeure

No Party shall be in default in respect to any obligation hereunder because of Force Majeure. A Party unable to fulfill any obligation by reason of Force Majeure shall use diligence to remove such disability with appropriate dispatch. Each Party shall: (a) provide prompt written notice of such Force Majeure event to the other Party which notice shall include an estimate of the expected duration of such event; and (b) attempt to exercise all reasonable efforts to continue to perform its obligations under this Agreement.

### 12.2 Waivers

No failure or delay on the part of either Party in exercising any of its rights under this Agreement, no partial exercise by either Party of any of its rights under this Agreement, and no course of dealing between the Parties shall constitute a waiver of the rights of either Party under this Agreement. Any waiver shall be effective only by a written instrument signed by the Party granting such waiver, and such shall not operate as a waiver of, or continuing waiver with respect to any subsequent failure to comply therewith.

### 12.3 Liability

- a. Except to the extent of the other Party's negligence or intentional misconduct, each Party shall be responsible for all physical damage to or destruction of the property, equipment and/or facilities owned by it and its Affiliates, regardless of who brings the claim and regardless of who caused the damage, and shall not seek recovery or reimbursement from the other Party for such damage; but in any such case, DEP and Dominion shall exercise Due Diligence to remove the cause of any disability at the earliest practicable time.
- b. **TO THE FULLEST EXTENT PERMITTED BY LAW AND NOTWITHSTANDING ARTICLE 7.1 OR ANY OTHER PROVISION OF THIS AGREEMENT, IN NO EVENT SHALL A PARTY, ITS AFFILIATES, OR ANY OF THEIR RESPECTIVE OWNERS, OFFICERS, DIRECTORS, EMPLOYEES, AGENTS, SUCCESSORS OR ASSIGNS BE LIABLE TO THE OTHER PARTY, ITS AFFILIATES OR ANY OF THEIR RESPECTIVE OWNERS, OFFICERS, DIRECTORS, EMPLOYEES, AGENTS, SUCCESSORS OR ASSIGNS, WHETHER IN CONTRACT, WARRANTY, TORT, NEGLIGENCE, STRICT LIABILITY, OR OTHERWISE, FOR ANY SPECIAL, INDIRECT, INCIDENTAL, EXEMPLARY, CONSEQUENTIAL (INCLUDING, WITHOUT LIMITATION, REPLACEMENT POWER COSTS, LOST PROFITS OR REVENUES, LOSS OF GOOD WILL OR LOST BUSINESS OPPORTUNITIES) OR PUNITIVE DAMAGES RELATED TO OR RESULTING FROM PERFORMANCE OR NONPERFORMANCE OF THIS AGREEMENT OR ANY ACTIVITY ASSOCIATED WITH OR ARISING OUT OF THIS AGREEMENT.**
- c. Nothing in this Agreement shall be construed to create or give rise to any liability on the part of PJM and the Parties expressly waive any claims that may arise against PJM under this Agreement.
- d. The Parties acknowledge and understand that the signature of the authorized representative of PJM on this Agreement is for the limited purpose of acknowledging that representatives of PJM have read the terms of this Agreement. The Parties and PJM further state that they understand that FERC desires that Dominion keep PJM fully apprised pursuant to its obligations as a TO of the matters addressed herein as well as any reliability and planning issues that may arise under this Agreement, and that the signature of the PJM representative shall not in any way be deemed to imply that PJM is taking responsibility for the actions of any Party, that PJM has any affirmative duties under this Agreement or that PJM is liable in any way under this Agreement.

#### 12.4 Written Notices

Notices and communication made pursuant to this Agreement shall be deemed to be properly given if delivered in writing, postage paid to the following:

If to Dominion :        Director, Electric Transmission System Operations Center  
                                 Virginia Electric and Power Company  
                                 P.O. Box 26666  
                                 Richmond, VA 23261

and

                                 Manager, Electric Transmission Planning & Strategic Initiatives  
                                 Virginia Electric and Power Company  
                                 P.O. Box 26666  
                                 Richmond, VA 23261

If to DEP:                Director System Operations  
                                 Duke Energy Progress, LLC  
                                 3401 Hillsborough Street  
                                 Raleigh, North Carolina 27607

If to PJM:                Vice President-Government Policy  
                                 PJM Interconnection, L.L.C.  
                                 1200 G Street, N.W., Suite 600  
                                 Washington D.C. 20005

and

                                 General Counsel  
                                 PJM Interconnection, L.L.C.  
                                 2750 Monroe Blvd.  
                                 Audubon, PA 19403

The above listed titles and addresses for a Party or PJM may be changed by written notice to all other Parties and PJM.

#### 12.5 Special Terms and Conditions Applicable to Interconnection Points

The Parties may establish special terms and conditions applicable to Interconnection Point(s) that are specified in this Agreement (“Special Terms and Conditions”). The Special Terms and

Conditions shall be reflected in an Appendix to this Agreement and shall be in addition to any other terms and conditions provided for in this Agreement. Any conflict between the Special Terms and Conditions and any other provision of this Agreement shall be resolved in favor of the Special Terms and Conditions.

#### 12.6 Agreement Validity

The validity and meaning of this Agreement shall be governed by and construed in accordance with federal law where applicable and, when not in conflict with or preempted by federal law, the applicable laws of the State of North Carolina.

#### 12.7 Defined Terms

All capitalized terms used in this Agreement shall have the meanings as defined: (a) in the body of this Agreement; (b) in the Appendices appended hereto; and (c) the “Glossary of Terms Used in NERC Reliability Standards,” as may be modified from time to time (“NERC Glossary”). Any provisions of the PJM Tariff or the PJM-DEP Joint Operating Agreement relating to this Agreement that use any such defined term shall be construed using the definition given to such defined term in this Agreement. In the event of any conflict between defined terms set forth in the PJM Tariff or the PJM-DEP Joint Operating Agreement and the defined terms in this Agreement, such conflict shall be resolved in favor of defined terms set forth in this Agreement.

### **ARTICLE 13 – ASSIGNMENT**

#### 13.1 Assignment

This Agreement shall inure to the benefit of and be binding upon the successors and assigns of the Parties. Successors and assigns of PJM shall become signatories to this Agreement for the limited purpose described in Article 12.3(d) of this Agreement. This Agreement shall not be assigned by any Party without the written consent of the other Party, which consent shall not be unreasonable withheld, except to a successor to which substantially all of the business and assets of such Party shall be transferred or to an Affiliate of the assigning Party for the purposes of a corporate restructuring.

IN WITNESS WHEREOF, three (3) copies of this Agreement, each to be considered an original, has been executed by the Parties' respective officers lawfully authorized so to do, this 27<sup>th</sup> day of August, 2018.

DUKE ENERGY PROGRESS, LLC

By: /s/ Sam Holeman

Printed Name: Sam Holeman

Title: VP Transmission System Planning & Operations

Service Agreement No. 3453

IN WITNESS WHEREOF, three (3) copies of this Agreement, each to be considered an original, has been executed by the Parties' respective officers lawfully authorized so to do, this 27<sup>th</sup> day of August, 2018.

VIRGINIA ELECTRIC AND POWER COMPANY, D/B/A DOMINION ENERGY VIRGINIA  
AND DOMINION ENERGY NORTH CAROLINA

By: /s/ Bobby E. McGuire

Printed Name: Bobby E. McGuire

Title: Authorized Representative

Service Agreement No. 3453

The signature below of the authorized representative of PJM is for the limited purpose of acknowledging that a representative of PJM has read this Agreement as of this 29<sup>th</sup> day of August, 2018.

PJM INTERCONNECTION, L.L.C.

By: /s/ Kenneth Seiler

Printed Name: Kenneth Seiler

Title: Executive Director, System Planning

Service Agreement No. 3453

**APPENDIX I**  
**Interconnection Points and Metering Points**

1.1 The systems of the Parties shall be interconnected through the transmission lines and substations at the Interconnection Points described below:

- 1.1.1 The point hereby designated and hereinafter called “**Kerr Dam Plant – Henderson 115 kV** Interconnection Point.” The point of interconnection is within the 115 kV single circuit transmission line extending from the 115 kV bus in DEP’s Henderson Station to the 115 kV bus in Army Corps of Engineers’ Kerr Dam Plant Station. The change of ownership occurs at mid-span at the North Carolina – Virginia State Line between a Dominion structure and a DEP structure. Bi-directional 115 kV metering equipment is installed at the Kerr Dam Plant Station, and is owned, operated, and maintained by the Army Corps of Engineers. (See Figure 1)
- 1.1.2 The point hereby designated and hereinafter called “**Battleboro – Rocky Mount 115 kV** Interconnection Point.” The point of interconnection is within the 115 kV single circuit transmission line extending from the 115 kV bus in DEP’s Rocky Mount Station to the 115 kV bus in Dominion’s Battleboro Station. The change of ownership occurs on a Dominion structure located directly outside Dominion Energy’s Battleboro Station. Bi-directional 115 kV metering equipment is installed at the Rocky Mount Station, and is owned, operated, and maintained by DEP. (See Figure 2)
- 1.1.3 The point hereby designated and hereinafter called “**Rocky Mount – Hathaway West (Line No. 2181) 230 kV** Interconnection Point.” The point of interconnection is within the 230 kV double circuit transmission line extending from the 230 kV bus in DEP’s Rocky Mount Station to the 230 kV bus in Dominion’s Hathaway Station. The change of ownership occurs at a DEP structure. Bi-directional 230 kV metering equipment is installed at the Rocky Mount 230 kV Station with Rocky Mount POD#4 load netted back to the bi-directional meter, and is owned, operated, and maintained by DEP. (See Figure 3)
- 1.1.4 The point hereby designated and hereinafter called “**Rocky Mount - Hathaway East (Line No. 2058) 230 kV** Interconnection Point.” The point of interconnection is within the 230 kV double circuit transmission line extending from the 230 kV bus in DEP’s Rocky Mount Station to the 230 kV bus in Dominion’s Hathaway Station. The change of ownership occurs at a DEP structure. Bi-directional 230 kV metering equipment is installed at the Rocky Mount Station, and is owned, operated, and maintained by DEP. (See Figure 4)
- 1.1.5 The point hereby designated and hereinafter called “**Greenville – Everetts 230 kV** Interconnection Point.” The point of interconnection is within the 230 kV single circuit transmission line extending from the 230 kV bus in DEP’s

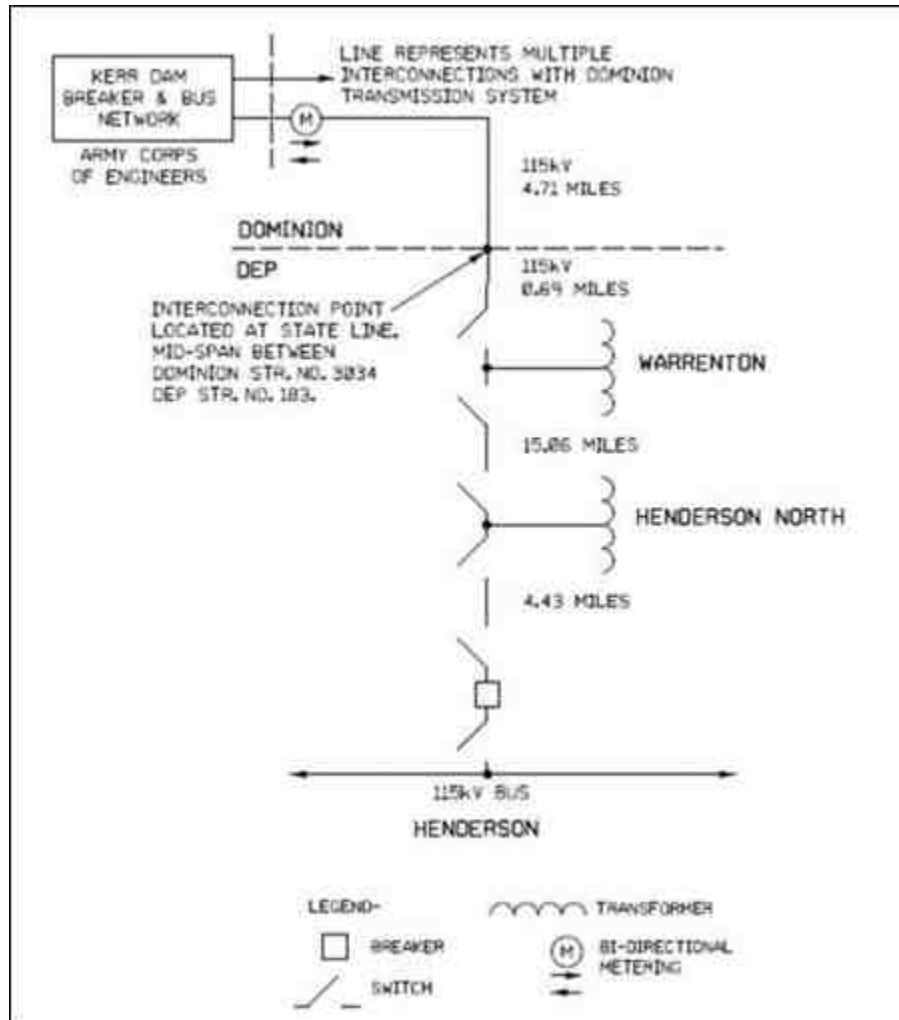


Greenville Station to the 230 kV bus in Dominion's Everetts Station. The change of ownership occurs at a Dominion structure. Bi-directional 230 kV metering equipment is installed at the Greenville Station, and is owned, operated, and maintained by DEP. (*See* Figure 5)

- 1.1.6 The point hereby designated and hereinafter called "**Sedge Hill – Person 230 kV Interconnection Point.**" The point of interconnection is within the 230 kV single circuit transmission line extending from the 230 kV bus in DEP's Person Station to the 230 kV bus in Dominion's Sedge Hill Station. The change of ownership occurs at a DEP structure. Bi-directional 230 kV metering equipment is installed at the Sedge Hill Station, and is owned, operated, and maintained by Dominion. (*See* Figure 6)
- 1.1.7 The point hereby designated and hereinafter called "**Heritage – Wake 500 kV Interconnection Point.**" The point of interconnection is within the 500 kV single circuit transmission line extending from the 500 kV bus in DEP's Wake Station to the 500 kV bus in Dominion's Heritage Station. The change of ownership occurs at a Dominion structure. Bi-directional 500 kV metering equipment is installed at the Heritage Station, and is owned, operated, and maintained by Dominion. (*See* Figure 7)

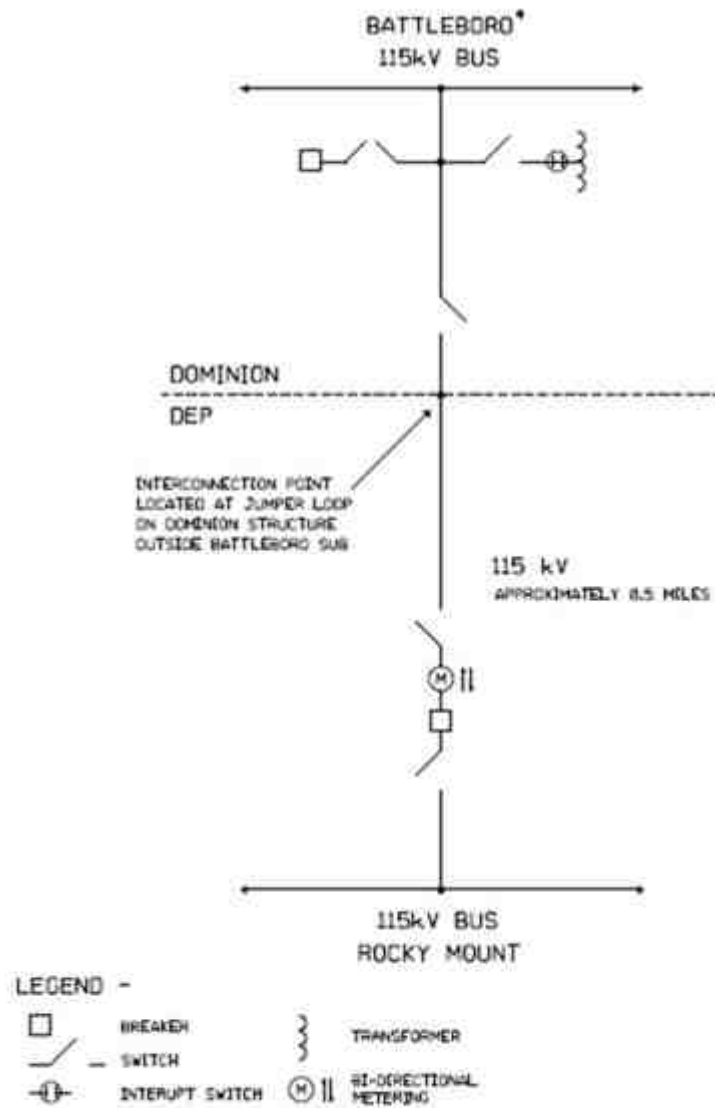
## APPENDIX I

**Figure 1**  
**Kerr Dam Plant – Henderson 115 kV Interconnection Point**



## APPENDIX I

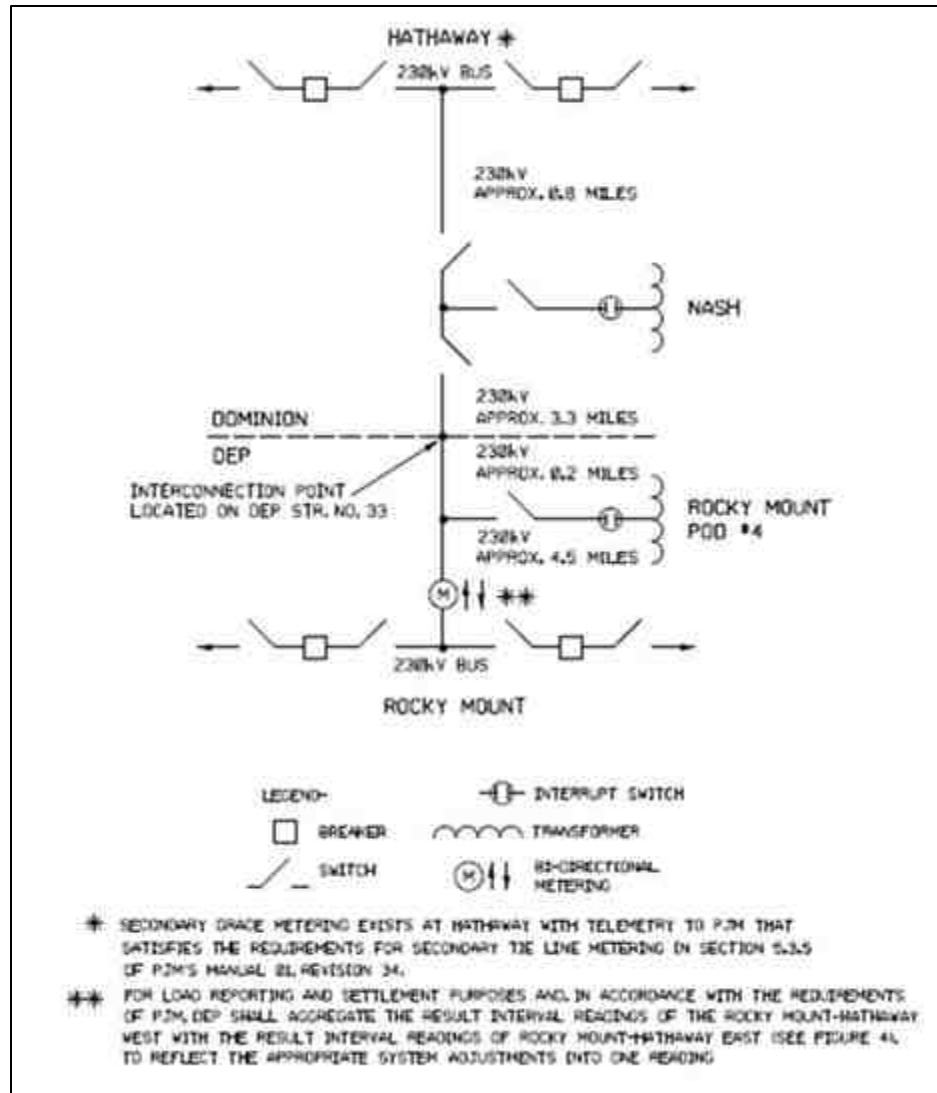
**Figure 2**  
**Battleboro – Rocky Mount 115 kV Interconnection Point**



\*SECONDARY GRADE METERING EXISTS AT BATTLEBORO WITH TELEMETRY TO PJM THAT SATISFIES THE REQUIREMENTS FOR SECONDARY TIE LINE METERING PURSUANT TO PJM'S MANUAL 2L REVISION 38.

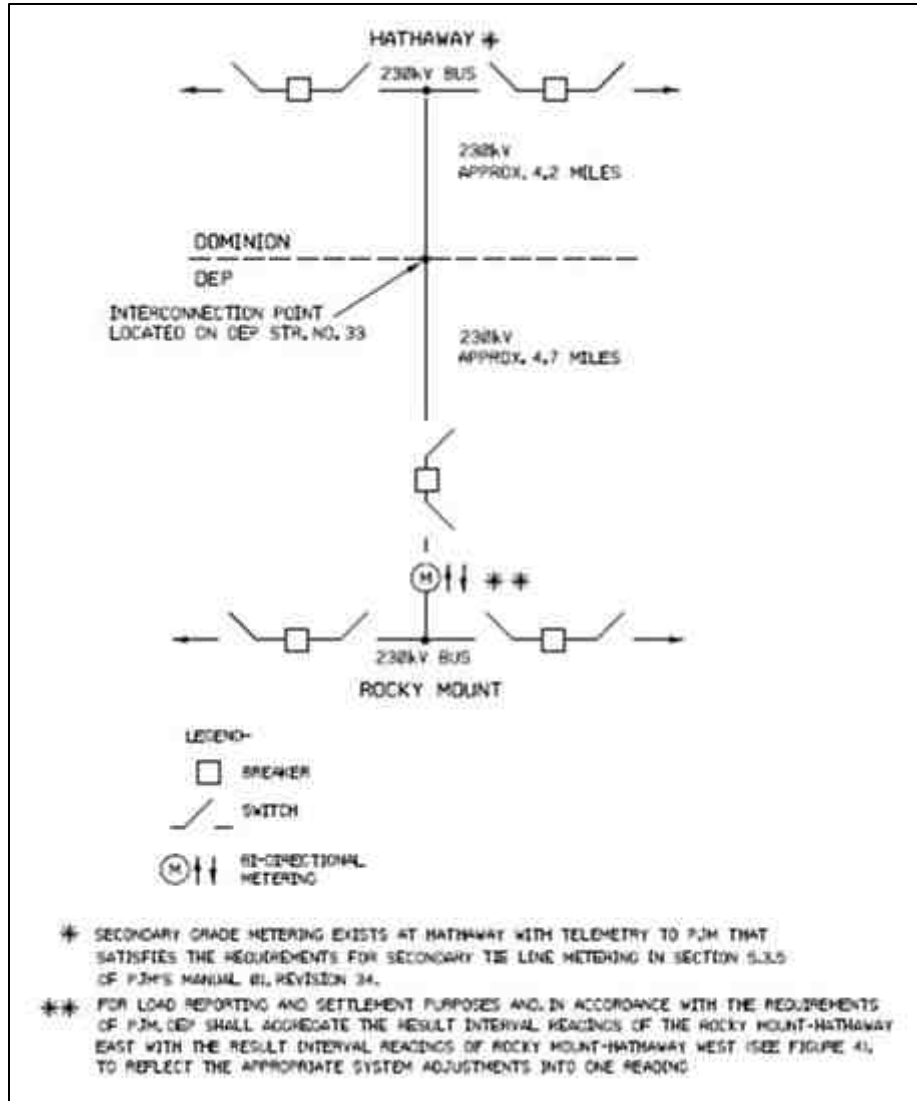
## APPENDIX I

**Figure 3**  
**Rocky Mount – Hathaway West (Line No. 2181) 230 kV Interconnection Point**



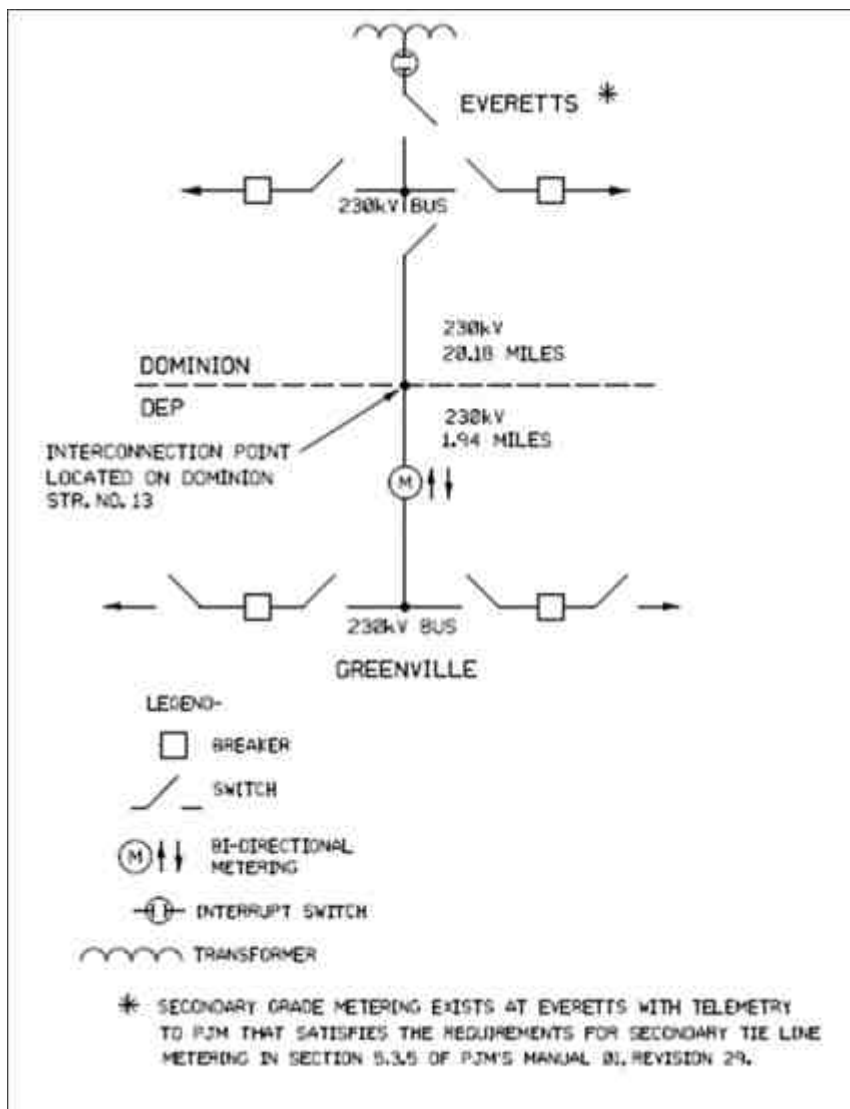
## APPENDIX I

**Figure 4**  
**Rocky Mount – Hathaway East (Line No. 2058) 230 kV Interconnection Point**



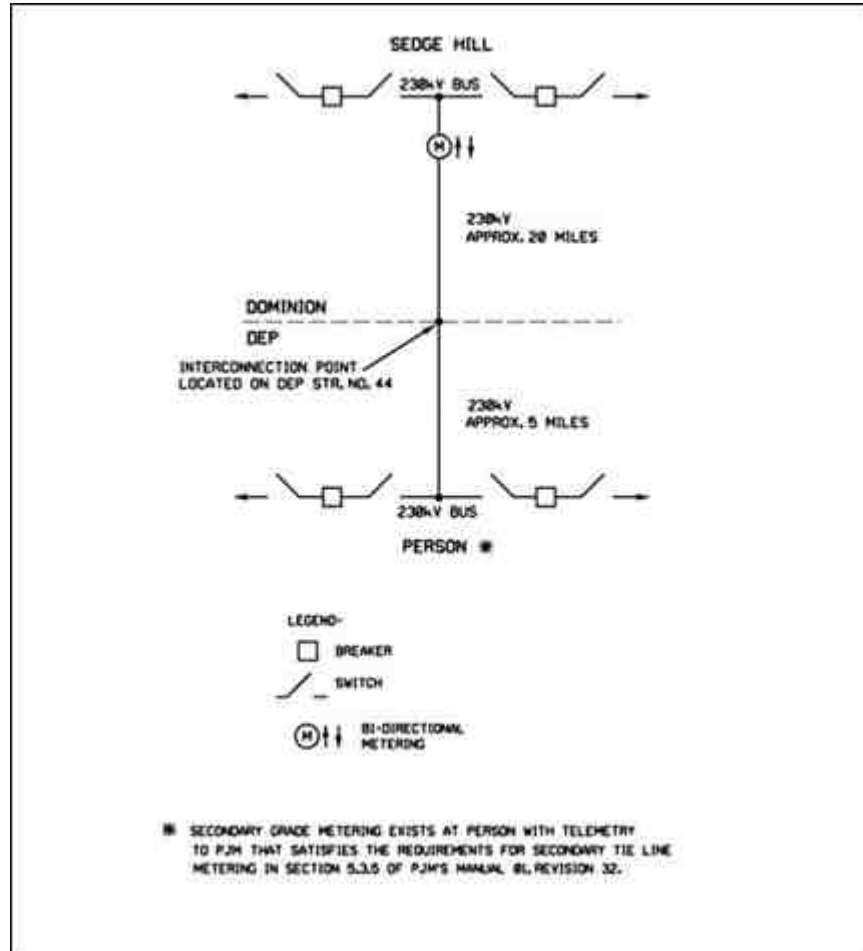
## APPENDIX I

**Figure 5**  
**Greenville – Everetts 230 kV Interconnection Point**



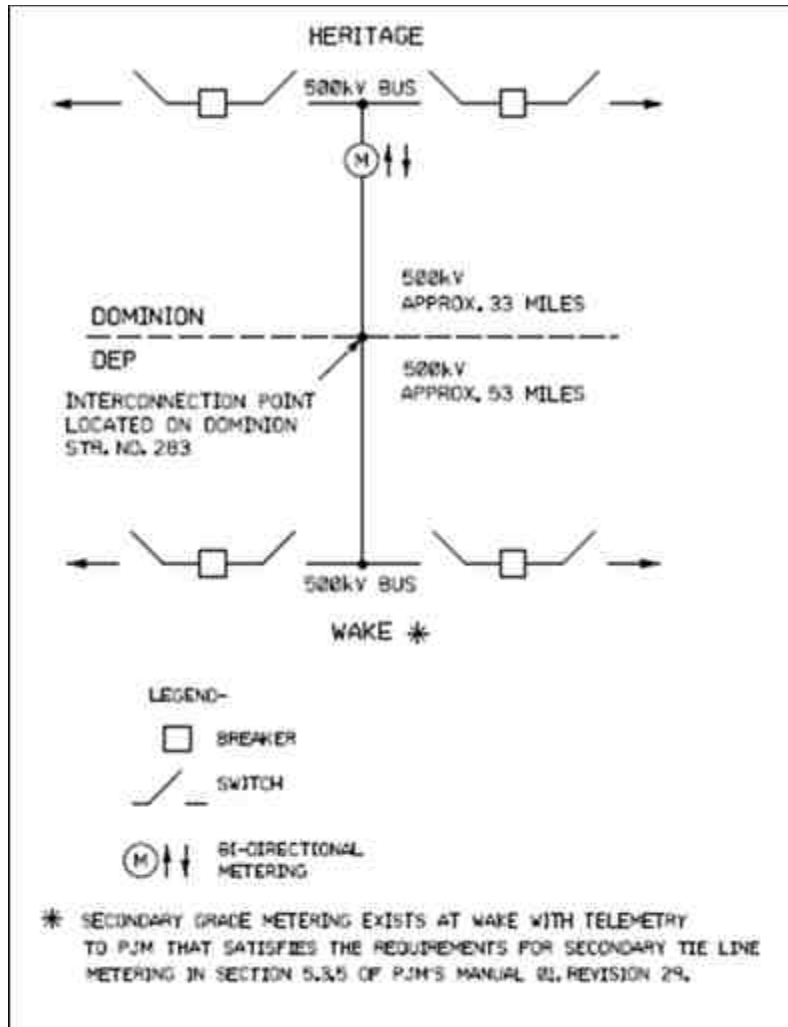
## APPENDIX I

**Figure 6**  
**Sedge Hill – Person 230 kV Interconnection Point**



## APPENDIX I

**Figure 7**  
**Heritage – Wake 500 kV Interconnection Point**





## **APPENDIX II**

### **Metering Requirements**

#### **1.1 Metering Points**

Electric power and energy delivered at the Interconnection Points shall be measured by suitable metering equipment provided by the Parties at the Metering Points and at such other points, voltages, and ownership as may be agreed upon by the Parties.

#### **1.2 Metering Equipment**

Suitable and reliable metering equipment shall be installed at each Metering Point, and shall include potential and current transformers, revenue meters, test switches and such other equipment as may be needed. The design standard established by this Appendix II shall apply to all new interconnection metering installations. However, any modification, addition or upgrade to any of the existing facilities after the date of this Agreement, shall be performed in compliance with this standard.

- 1.2.1 General Requirements. All metering quantities shall be measured at the Interconnection Point and its metering accuracy shall meet the required NERC Reliability Standards, PJM Requirements as to Dominion, any requirements in the PJM-DEP Joint Operating Agreement as to DEP, and the American National Standards Institute (“ANSI”) standards. The Parties may agree by amendment to this Agreement to install metering at locations other than the Interconnection Points, however, measured metering quantities shall be compensated to the Interconnection Point, provided that the Parties shall exercise commercially reasonable efforts to avoid such compensating metering installations. Based upon mutual agreement between interconnection Parties, metering can be installed at a location different from the Interconnection Point, however, measured metering quantities shall be compensated to the Interconnection Point.

All reasonable costs for the meter changes or upgrades requested by the Party shall be borne by the requesting Party, unless agreed otherwise.

- 1.2.2 Industry Standard Requirements. At least (N-1) metering elements will be used to measure all real and reactive power crossing the Interconnection Points, where N is the number of wires in service including the ground wire. The revenue quality metering package (consisting of instrument transformers, meters, sockets, and test switches) shall be installed, calibrated, and tested (at the requesting Party’s expense) in accordance with the latest approved version of (but not limited to) the ANSI standards listed below, or their successors(s) including the standard testing procedures and guidelines of the Party that owns the metering equipment:

ANSI C12.1:	Code For Electricity Metering
ANSI C12.7:	Requirements for Watt-Hour Meter Socket
ANSI C12.9:	Test Switches for Transformer-Rated Meters

ANSI C12.11:	Instrument Transformers for Revenue Metering, 10 kV Through 350 kV BIL
ANSI C12.10:	Electromechanical Watt-hour Meters
ANSI C12.16:	Solid State Electricity Meters
ANSI C12.20:	For Electricity Meters 0.2 and 0.5 Accuracy Class
ANSI C37.90.1:	Surge Withstand Capability (SWC) Test
ANSI/IEEE C57.13:	Standard Requirements for Instrument Transformers

To the extent that the above requirement conflicts with the manuals, standards or guidelines of the applicable Reliability Council regarding interchange metering and transactions, the manuals, standards and guidelines of such Reliability Council shall control.

- 1.2.3 Metering Equipment Maintenance and Testing. Upon installation and unless otherwise specified, the revenue meters shall be inspected and tested in accordance with the latest applicable ANSI standards and at least once every two (2) years, or at any other mutually agreed frequency thereafter. More frequent meter tests can be performed at the request of any Party, and the test will be performed at the requesting Party's expense if the meter is found to be within the established ANSI tolerances. The Party that owns the metering shall inform the other Party with at least (3) three weeks advance notice or more, of impending metering tests, and invite the other Party to attend and witness the tests.

The accuracy of the revenue meter shall be maintained at two tenths of one percent (0.2%) accuracy or better, and the meter test shall require a meter standard with accuracy traceable to the National Institute of Standards and Technology ("NIST").

If at any test of metering equipment an inaccuracy shall be disclosed exceeding two percent (2%), the account between the Parties for service theretofore delivered shall be adjusted to correct for the inaccuracy disclosed over the shorter of the following two periods: (1) for the 30-day period immediately preceding the day of the test, or (2) for the period that such inaccuracy may be determined to have existed. No meter shall be left in service if the percent accuracy error is found to be more than +/- 1%.

The Party that owns the metering equipment shall maintain records that demonstrate compliance with all meter tests and maintenance conducted in accordance with Good Utility Practice for the life of the Interconnection Point. The other Party shall have reasonable access to such records, and the Party that owns the metering equipment will provide such records to the other Party upon request. If revenue metering equipment fails to function, the energy registration shall be determined from the best available data, including the check metering, if applicable. The Instrument Transformers ("IT") shall also be inspected and maintained based on Section 1.2.2 of this Appendix II, and existing standards and practices of the Party that owns the metering equipment.

- 1.2.4 Current Transformer Requirements. Each metering point shall have a dedicated set of metering class of current transformers. Unless otherwise agreed upon by the Parties, all metering shall be type 3.0 element metering, and have three (3) metering accuracy current transformers.

Current transformers shall meet or exceed an accuracy class of 0.3% (as defined in IEEE C57.13), or better. Current transformers shall comply with the minimum BIL rating as specified in standards IEEE C57.13 and ANSI C12.11.

The mechanical and thermal short time current ratings of the current transformer shall exceed or withstand the available fault current, while the secondary burden of the current transformer shall not exceed its stated name plate burden rating.

- 1.2.5 Voltage Transformers Requirements. Each metering point shall have a dedicated set of metering class of voltage transformers. Unless otherwise agreed upon by the Parties, all metering shall be type 3.0 element metering, and have three (3) metering accuracy voltage transformers. Voltage transformers shall meet or exceed an accuracy class of 0.3% (as defined in IEEE C57.13). The secondary of the voltage transformer shall be exclusively used for the revenue meters only, so as not to exceed the secondary burden of the stated voltage transformer's name plate burden rating provided, however, that voltage transformers with two secondary windings, may have one winding dedicated to the revenue meters, and the other winding used for relaying purposes or for other station metering. The nameplate burden rating on either winding must not be exceeded.

Voltage transformers shall comply with the minimum BIL rating as specified in standards IEEE C57.13 and ANSI C12.11.

### 1.3 Remote Meter Access and Data Communications

For all Interconnection Points, the Party that owns the metering equipment at such Interconnection Point, unless otherwise mutually agreed, shall be responsible for installation of the communications facilities. The Party that owns the metering equipment shall also be responsible for operation and maintenance, and on-going monthly costs of the communication facilities

- 1.3.1 Remote Billing Data Retrieval. The Owning Party may provide appropriate communication capability of electronic remote interrogation of the billing data in a manner that is compatible with commonly used billing data systems such as MV-90.
- 1.3.2 Real Time Communications. Revenue meters shall be capable of communicating with data acquisition system ("DAS") equipment such as Remote Terminal Unit ("RTU") to provide the following real-time bi-directional power and energy data: instantaneous power flows, per phase and three-phase averaged Root-Mean-Squared ("RMS") voltages, per phase and three-phase averaged RMS currents and frequency with at least two decimal points.

- 1.3.3 Energy Flow Data. A continuous accumulating record of active and reactive energy flows shall be provided by means of the registers on the meters. The deployed revenue meter(s) shall be capable of providing bi-directional energy data flow in either kyz pulse signals format, or accumulated counters to RTU. All Parties shall share the same data register buffers regardless of the types of employed data communication methods. If the accumulation counter method is used, only one Party shall be responsible for freezing the accumulator buffers and the owner of the metering equipment shall freeze them. The accumulator freezing signals shall be synchronized to Universal Coordinated Time (“UCT”) within 1/ 2 seconds.

#### 1.4 Metering Device Requirements

All revenue meters shall be programmable and capable of measuring, recording, and displaying bi-directional active and reactive energy and four quadrant power quantities. Also, the revenue meters shall be programmable for compensating for power transformer and line losses and, when applicable, such compensation shall be used in determining the settlement of power transferred at the Interconnection Point. The revenue meters may preferably have at least one serial communication, one Ethernet port, hard-wired “kyz” pulse output, and internal modem for data communication.

The revenue meters’ internal clocks and real-time DAS equipment shall be synchronized with Universal Time Coordination (“UTC”) with at least 5 seconds resolution. The Global Position System clock receiver used at each Interconnection Point shall be capable of providing unmodulated Inter-Range Instrumentation Group – Time Code Format B signals to support the UTC time synch requirement.

#### 1.5 Revenue and Additional Metering

Each Metering Point shall have a revenue meter that shall be powered by the station control battery or by automatic transfer to an alternate AC source. The meters at Metering Points associated with new Interconnection Points, or associated with the modification, addition or upgrade to any existing Interconnection Points, shall meet the applicable NERC Reliability Standards, PJM Requirements as to Dominion , any requirements in the PJM-DEP Joint Operating Agreement as to DEP, and the ANSI standards. Each Party may arrange to have additional metering at any existing Interconnection Point. The Parties will cooperate to determine correct meter values as needed; however, in the event of a discrepancy between the Parties’ meters, Dominion will accept DEP revenue meter data for certain Interconnection Points; and DEP will accept Dominion revenue meter data for certain Interconnection Points.

#### 1.6 Meter Access

A Party whose metering equipment is located within a station owned by the other Party shall have reasonable access to said metering equipment for purposes of meter reading, inspection, testing, and other such valid operating purposes. Such access shall not be unreasonably withheld.

### 1.7 Meter Removal

Upon termination of this Agreement or when the metering is no longer needed, the Party that owns the meter equipment in another Party's station shall remove the metering equipment from the premises of the other Party within one (1) year after termination or within one (1) year after the Party that owns the meter equipment determines that the interchange metering is no longer needed.

### **APPENDIX III**

#### **DAS Equipment: Ownership, Installation and Maintenance**

##### **1.1     Need for Data Acquisition Provisions**

In recognition that the coordination of the system operations by the Parties may be facilitated by the sharing of power flow and other real-time information from meters and other equipment at the Interconnection Points, the Parties may agree to cooperate on the installation and operation of data acquisition system (“DAS”) equipment including, but not limited to, remote terminal units (“RTU”), meters, MW/MVAR and Volt transducers, telecommunication devices, lease lines, and any related equipment at points which shall from time to time be mutually agreed upon. Therefore, the Parties establish this Appendix III to govern the general principles of such DAS arrangements. Each of these general principles may be modified within and by a specific agreement for a specific DAS arrangement.

Pursuant to a separately negotiated and executed agreement, a Party’s RTU, or equivalent devices, may be shared by the other Party. Therefore, pursuant to such agreement, the RTU shall support multiple dedicated communication ports with mutually agreed upon communication protocols. If a backup telemetry system or data is required by one Party for their own use, the requesting Party shall be responsible for installing and/or maintaining the field devices and associated telecommunication system at their cost. Where there are protocol restrictions because of existing legacy systems, industry standard protocols such as DNP 3.0 shall be offered. If a proprietary communication protocol is to be used solely for one Party, the requesting Party shall be responsible for the cost of adding the customized communication protocol to the RTU.

The following real-time data shall be provided to all parties as minimum requirements: three phase bi-directional energy flows (e.g., MWh, MVARh), three phase instantaneous power flows (e.g. MW, MVAR), per phase RMS voltages, per phase RMS currents, and frequency measurement with at least two decimal points resolution shall be provided. In addition to the real-time data, the status of all switching devices associated with the interconnection circuit(s) shall be provided. For the energy flow data, either or both accumulated data or hourly interval data shall be provided based on mutually agreed formats. If accumulated data is used, the owner of the RTU will freeze the accumulated data buffers at the beginning of each clock hour and the other Party shall read the frozen data. This shall be accomplished in a manner that provides both Parties with the same accumulator data readings even though the accumulator data reading frequencies may not be synchronized. For Dominion, any real-time data requirements defined in the PJM manuals, including PJM Manual 01 – Control Center and Data Exchange Requirements and PJM Manual 03 – Transmission Operations, shall be provided to PJM to allow PJM to comply with its roles as Reliability Coordinator, Balancing Authority, and Transmission Operator.

For purposes of this Appendix III, the term “Other Party” means a Party that wishes to obtain information from an Owning Party through the installation of DAS equipment.

- 1.1.1 The DAS equipment covered herein shall be associated with the Interconnection Points. When requests for additional data, or a DAS equipment upgrade, are received from the Other Party by the Owning Party, the Parties shall cooperate

with each other, based on Good Utility Practice. Unless otherwise mutually agreed, the Other Party requesting the additional data or equipment upgrade will bear the cost associated with such requests.

- 1.1.2 Commissioning Test Procedures. When new interconnection metering or DAS equipment is installed, replaced or upgraded, a commissioning test shall be performed based on mutually agreed test procedure. Before the equipment is placed in service, the following processes shall be followed, as a minimum requirement:

The Owning Party shall inform the Other Party of the commissioning test.

The Owning Party shall set up a three-way conference call between the interconnection site and operation centers of both Parties.

Bi-directional test currents shall be injected to the interconnection energy meter and the instantaneous analog data values displayed by the meter shall be checked against the corresponding readings received at each control center. This verification test will be made at the 0, 2.5 and 5 Amp cases, and with unity and 50% power factors.

The pulse accumulator counter data shall be tested in the same manner and the accumulator freeze functionality shall be verified.

A test to determine the Roll-Over Count for each accumulator data point in the DAS shall be performed to verify that the Roll-Over Count is properly processed by both operation centers.

## 1.2 DAS Arrangements

The details of individual DAS arrangements, for new or existing Interconnection Points, shall be in writing and signed by an Operating Committee Representative from each Party. The DAS arrangements shall cover such details as responsibilities for the provision and installation of equipment, equipment location, ownership, project scheduling, testing and commissioning, maintenance, and cost reimbursement, if applicable, and shall be considered a part of this Agreement as if they had been included herein.

## 1.3 Ownership, Installation and Maintenance of DAS Equipment

Unless otherwise mutually agreed, ownership of such DAS equipment shall be shared by the Parties as herein described; provided, however, the Owning Party shall have the responsibility to install all the DAS equipment.

- 1.3.1 The Owning Party of the facilities to which DAS equipment is to be attached shall provide, install, own and maintain the relays, transducers, wiring, protection equipment and associated materials ("Owning Party Equipment") required to support the installation of the Other Party's data acquisition equipment ("Other Party's Equipment"). Provided, however, that if the Interconnection Point is

established for the benefit of and at the request of a Party, the Party benefiting and requesting the interconnection shall install, own and maintain, the DAS equipment arrangement and shall provide access to the DAS data to the Other Party. Equipment that is shared in common between the Owning Party and the Other Party (such as duplicating relays, test switches, etc.) shall likewise be provided, installed, owned and maintained by the Owning Party, and shall be part of the Owning Party's Equipment, unless agreed otherwise. Unless otherwise mutually agreed, each Party will maintain its own equipment on their side of the Interconnection Point.

- 1.3.2 The Other Party shall provide the Owning Party documents listing and describing the Other Party's Equipment that the Other Party will supply for installation by the Owning Party. These documents will generally consist of a hardware list, detailed drawings, and a circuit diagram. If the Owning Party does not stock the DAS equipment or other components specified by the Other Party, then the Other Party will supply the necessary components including spare parts. The Owning Party reserves the right to refuse to install any material supplied by the Other Party that has not been approved by the Owning Party for use in its installations.
- 1.3.3 The Other Party shall provide, own and maintain as part of the Other Party's Equipment, the data communication circuits (leased line), including any necessary data circuit protection equipment, and be responsible for the costs of such circuit. Where deemed appropriate by the Owning Party, the Other Party personnel shall be permitted to work independently on its equipment. Generally, however, work performed by the Other Party's personnel shall be performed under the supervision of the Owning Party personnel, unless such equipment is located outside or is only accessible from outside the Owning Party's facilities.
- 1.3.4 Unless otherwise agreed, the Owning Party will provide station battery voltage to power the DAS equipment at 48, 125, or 250 Volt DC, and the corresponding DC circuit should be fused (or circuit breaker) at 15, 5, or 5 ampere, respectively. Under no circumstances shall the Other Party connect either the positive or negative side of this circuit to ground. The Other Party's Equipment shall be connected to the station's grounding conductor through the Owning Party's breaker control panel. The Owning Party shall also provide station service power for the data acquisition equipment via a 115 V, 60 Hz, with a 15 ampere (fused or circuit breaker) AC circuit.

#### 1.4 Location and Site Access

The Owning Party shall permit the Other Party to locate its data acquisition equipment and data circuit protection equipment in the Owning Party's station control building, if adequate space exists or is available, or outside the Owning Party's station switchyard, if no control house is available. In choosing equipment location, consideration shall be given to NERC Reliability Standards, equipment security, protection and access needs of both Parties. In cases where escorted access to the station control house or outdoor equipment is required, the Other Party shall notify the Owning Party at least 24 hours prior to any planned visit. If access is needed on



a short notice, the Parties shall endeavor to arrange such visits by mutual agreement. The Owning Party shall not unreasonably withhold access to the equipment to the Other Party; provided, however, the Owning Party may deny access based upon safety considerations, operating condition, NERC Reliability Standards or other relevant criteria.

#### 1.5 Proprietary and Confidential Information

Unless circumstances of reasonable cause are disclosed by a Party, the Other Party shall treat all shared telemetry information as confidential and proprietary and shall take such precautions as may be reasonable and necessary to prevent such information from being made known or disclosed to any person or entity except in accordance with this Agreement. However, provided that if a Party is required by law, legal process or action of a court or government agencies to disclose any information, such Party shall promptly notify the Other Party of such requirement so that action, deemed appropriate in the circumstances, may be taken to protect confidential and proprietary information against disclosure.

#### 1.6 Cost Estimate, Invoicing and Payment

Prior to the installation of the Other Party's equipment, both the Owning Party and the Other Party shall prepare an estimate of the costs associated with such installation. All invoices and payment terms and conditions, and invoice disputes and resolutions, shall be handled pursuant to Article 5 of this Agreement.

## **APPENDIX IV**

### **Definitions**

“Affiliate”- shall mean with respect to a corporation, partnership or other entity, each such other corporation, partnership or other entity that either directly or indirectly, through one or more intermediaries, controls, is controlled by, or is under common control with, such corporation, partnership or other entity.

“Applicable Laws and Regulations”- shall mean all duly promulgated applicable federal, state and local laws, regulations, rules, ordinances, codes, decrees, judgments, directives, or judicial or administrative orders, permits and other duly authorized actions of any Governmental Authority having jurisdiction over the relevant Parties, their respective facilities, and/or the respective services they provide.

“Due Diligence” – shall mean the exercise of good faith efforts to perform a required act on a timely basis using the necessary technical and manpower resources.

“Force Majeure” - shall mean any cause beyond the control of the affected Party, including but not restricted to, acts of God, flood, drought, earthquake, storm, fire, lightning, epidemic, war, riot, civil disturbance or disobedience, labor dispute, labor or material shortage, sabotage, acts of public enemy, explosions, orders, regulations or restrictions imposed by governmental, military, or lawfully established civilian authorities, which, in any of the foregoing cases, by exercise of Due Diligence such Party could not reasonably have been expected to avoid, and which, by the exercise of due diligence, it has been unable to overcome. Force Majeure does not include: (i) a failure of performance that is due to an affected Party’s own negligence or intentional wrongdoing; (ii) any removable or remediable causes (other than settlement of a strike or labor dispute) which an affected Party fails to remove or remedy within a reasonable time; or (iii) economic hardship of an affected Party.

“Good Utility Practice”- shall mean any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in the region; including those practices required by Section 215(a)(4) of the Federal Power Act.

“Governmental Authority” - shall mean any federal, state, local or other governmental, regulatory or administrative agency, court, commission, department, board, or other governmental subdivision, legislature, rulemaking board, tribunal, arbitrating body, or other governmental authority, having responsibility over the Parties, their respective facilities, or the respective services they provide, and exercising or entitled to exercise any administrative, executive, police, or taxing authority or power; provided, however, that such term does not include Dominion, DEP, or any Affiliate thereof.

“Interconnection Point”- shall mean each point of electrical connection between the Dominion Transmission System and the DEP Transmission System as set forth in Appendix I and Appendix VI to this Agreement.

“Metering Point” – shall mean each point at which the electrical energy flowing between the Parties at an Interconnection Point is measured.

“NERC Reliability Standards” – shall mean mandatory and enforceable requirements administered by the North American Electric Reliability Corporation (“NERC”), approved by the FERC under Section 215 of the Federal Power Act, to provide for reliable operation of the bulk-power system.

“Owning Party” – shall mean the Party that owns certain facilities as delineated in Appendix II and Appendix III to this Agreement.

“Party”- shall mean either Dominion or DEP. Party shall not include PJM.

“Parties”- shall mean Dominion and DEP. Parties shall not include PJM.

“PJM-DEP Joint Operating Agreement” – shall mean that Amended and Restated Joint Operating Agreement between PJM and DEP, dated February 2, 2010, designated as PJM Rate Schedule No. 50 and DEP Rate Schedule No. 188, as subsequently modified and amended.

“PJM Requirement” – shall mean any rule, charge, procedure, or other requirements of PJM, including the PJM Tariff, applicable to FERC-jurisdictional service provided over the Dominion Transmission System.

“PJM Tariff” – shall mean PJM’s Open Access Transmission Tariff.

“Reliability Council” – shall mean the North American Electric Reliability Corporation or any successor agency assuming or charged with similar responsibilities related to the operation and reliability of the North American electric interconnected transmission grid, including any regional or other subordinate council of which the Parties are a member with respect to the electric transmission facilities addressed in this Agreement.

“Roll-Over Count” shall mean a test that shows at what point the accumulator register rolls-over to zero when it reaches a predetermined maximum count.

**APPENDIX V**  
**Service Schedule A, Reserve**

**SECTION 1 - DURATION**

- 1.1 This Service Schedule shall continue in effect until termination or expiration of this Agreement unless superseded on any earlier date by a new service schedule or until terminated as provided for in Section 1.2 below of this Appendix V.
- 1.2 Notwithstanding Article 9.1 of this Agreement, either Party upon at least three years' prior written notice to the other Party may terminate this schedule.

**SECTION 2 - DEFINITIONS**

- 2.1 Emergency Reserve Capacity is defined as the capacity provided during the first 12 hours (or the remainder of the calendar day, if greater than 12 hours) following the emergency loss of a resource. The period during which Emergency Reserve Capacity is supplied shall be defined as the Emergency Period.
- 2.2 Daily Reserve Capacity is defined as the capacity provided immediately following an Emergency Period, or capacity provided as a matter of efficiency, or as otherwise mutually agreed.
- 2.3 Contingency Reserve is defined as capacity that may be made available following the emergency loss of a resource.

**SECTION 3 - SERVICES TO BE RENDERED**

- 3.1 In the event of an emergency loss of a resource, each Party will make available to the other Party, up to the total available Contingency Reserve capacity on its system and, upon request, will attempt to obtain capacity and/or energy from a third-party system.
- 3.2 In the event either Party desires to purchase capacity to supply a portion of its Contingency Reserve rather than supply it from its own resources, each Party will make available to the other such capacity to the extent that it is available.

**SECTION 4 - COMPENSATION**

**4.1 DEMAND CHARGE**

- 4.1.1 When Emergency Reserve Capacity is provided there will be no demand charge. If the Party suffering the outage requires assistance for a longer period than the Emergency Period, then that Party will purchase Daily Reserve Capacity, unless otherwise mutually agreed. When Daily Reserve Capacity is provided, the receiving Party will pay the delivering Party a reserve Demand Rate per kW per

day not to exceed the rate calculated in accordance with Appendix A or B, whichever is applicable.

- 4.1.2 In the event the delivering Party provides capacity to the receiving Party from a third-party system, the receiving Party will pay the delivering Party a Demand Rate equal to (1) the Demand Rate charged by the third-party, plus (2) a Transmission Use Rate per kW per day not to exceed the rate calculated in accordance with Appendix A or B, whichever is applicable. In transactions where no demand charge is made by the third-party, the receiving Party will pay the delivering Party a Transmission Use Rate per kW per day or per kWh, whichever is less, not to exceed the rate calculated in accordance with Appendix A or B, whichever is applicable.

## 4.2 ENERGY

- 4.2.1 When the energy delivered is generated on the system of the delivering Party, the receiving Party will pay the delivering Party a rate per kWh equal to (1) the out-of-pocket cost, plus (2) cost of transmission losses to make the delivery, plus (3) 10 percent of the sum of (1) and (2) under this Section of this Appendix V, or 5 mills per kWh, whichever is less; or at option of the delivering Party, the energy may be returned in kind.
- 4.2.2 For energy delivered by the delivering Party from a third-party the receiving Party will pay the delivering Party a rate per kWh equal to: (1) the rate per kWh paid to the third-party; plus (2) the cost of supplying the associated transmission losses on the system of the delivering Party; plus (3) one mill per kWh for miscellaneous and unquantifiable incremental costs incurred for transmission services; or by mutual agreement the energy may be returned in kind. In return-in-kind transactions the receiving Party will pay the delivering Party (1) the cost of supplying the associated transmission losses on the system of the delivering Party; plus (2) one mill per kWh to provide compensation for miscellaneous and unquantifiable incremental costs incurred for transmission services.

## 4.3 APPLICABLE TAXES

- 4.3.1 Where applicable, taxes will be added to the billings under 4.1 and 4.2 including but not limited to:

Support of South Carolina Public Service Commission  
South Carolina Gross Receipts Tax  
South Carolina Generation Tax  
North Carolina Gross Receipts Tax

Any new or additional applicable taxes enacted after the date of this Service Schedule shall be included in billings under this Service Schedule.

**APPENDIX A**

DETERMINATION OF INTERCHANGE DEMAND RATE  
PURSUANT TO SERVICE SCHEDULE A, RESERVE

**VIRGINIA ELECTRIC AND POWER COMPANY**

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**[RESERVED FOR FUTURE USE]**

**APPENDIX B**

DETERMINATION OF INTERCHANGE DEMAND RATE  
PURSUANT TO SERVICE SCHEDULE A, RESERVE

DUKE ENERGY PROGRESS, LLC

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This Appendix incorporates the provisions applicable to pricing of the reserve service being rendered under this Interconnection Agreement. All investments associated with production will be based on a projected, end-of-year test period. In addition to the rates calculated under the following provisions, DEP will provide transmission services in accordance with the provisions of DEP's Open Access Transmission Tariff. Unless otherwise mutually agreed to by DEP and Dominion, the rate shall be calculated on an annual basis and will be applicable to service rendered during the 12 months beginning July 1 of the test year.

### RESERVE

The rate for Reserve sales consists of a production demand rate.

The annual production demand rate is the sum of the total production demand cost (Appendix page 3 of 8) and applicable taxes (Appendix page 5 of 8). The annual production demand rate per kW is divided by 312 for a daily rate.



### TOTAL PRODUCTION DEMAND COST

The total production demand cost is determined by subtracting the accumulated deferred income tax credit per kW from the production demand cost per kW and adding the demand-related production expense per kW and the allowed CWIP per kW.

An explanation of the components used in calculating the total production demand cost is as follows:

- A. Production demand cost per kW – This cost is the sum of the production-related demand costs per kW of the generating plants contributing to the sale. Individual generating plant production related demand cost per kW is the product of the weighted investment per kW for that plant and the applicable annual carrying charge. The annual carrying charge consists of the components listed below and explained on pages 7 and 8 of 8 of this appendix.
- |  |                            |
|--|----------------------------|
| 1. Cost of Capital                     | 7. General Plant           |
| 2. Income Taxes                        | 8. Working Capital         |
| 3. Ad Valorem and Labor-Related Taxes  | (a) Cash Working Capital   |
| 4. Depreciation                        | (b) Materials and Supplies |
| 5. Decommissioning Expenses            | (c) Prepayments            |
| 6. Administrative and General Expenses |                            |
- B. Accumulated deferred income tax credit per kW – This credit is determined by summing the products of the weighted accumulated deferred income tax per kW and the annual carrying charge, consisting of the cost of capital and income tax components, for each generating plant contributing to the sale.
- C. Demand-related production expense per kW – This cost is determined by summing the products of demand-related production expense per kW and the percent participation for each generating plant contributing to the sale. The

demand-related portion of Accounts 500-554 is determined through an analysis of each FERC account. The purchased capacity, including related O&M from jointly owned units, is included in the calculation of demand-related production expenses. This purchased capacity is booked in Account 555.

- D. Allowed CWIP per kW – This cost is determined by summing the products of the FERC allowed production-related CWIP and the annual carrying charge, consisting of the cost of capital and income tax components for each generating plant contributing to the sale where CWIP is projected for the test period.

APPLICABLE TAXES

The Service Schedule with which this Appendix is used provides for adding to the cost any taxes which might be applicable to the transactions. Such taxes may include, but are not limited to:

Support of South Carolina Public Service Commission

South Carolina Gross Receipts Tax

South Carolina Excise Tax (kWh Tax)

North Carolina Gross Receipts Tax

North Carolina Sales Tax

### COST FOR CAPACITY RESERVES

The cost for capacity reserves is determined by taking 20 percent of the total production demand cost.

### CARRYING CHARGES

The carrying charges will include the appropriate following components which are determined using projected values with an end-of-year test period:

1. Cost of Capital – The capital structure is based on end-of-year ratios of debt, preferred stock, and common equity. The cost of each capital component is computed using the end-of-year embedded cost of debt and preferred stock and the return on common equity as set forth in the Exhibit No. 1 to this Appendix as the same may be changed subject to appropriate filing with the FERC.
2. Income Taxes – Income taxes are the product of the current statutory tax rates applied to the return on preferred stock and common equity as computed above.
3. Ad Valorem and Labor-Related Taxes – This component is the result of dividing the sum of ad valorem and labor-related taxes by the total end-of-year net plant investment in the computation period.
4. Depreciation – The depreciation rates are the rates last allowed by the FERC adjusted to apply to net plant investment. These rates differ for the type of plant. The allowed rates are adjusted by the ratio of gross plant investment to net plant investment.
5. Decommissioning – The decommissioning component will only be applicable in the case of nuclear production. The annual decommissioning accrual is divided by the end-of-year net nuclear production plant investment to determine this percentage.
6. Administrative and General Expenses – The A&G expenses for the computation period are allocated between power production plant, transmission plant, and distribution plant based on the labor ratios of these items. The A&G expenses so determined are divided by the end-of-year net plant investment for power production plant.

7. General Plant – The general plant is allocated between power production plant, transmission plant, and distribution plant based on the labor ratios of these items. The carrying charge applicable to general plant consists of the cost of capital, income taxes, ad valorem and labor-related taxes, and depreciation (all as determined above). This carrying charge is applied to the general plant applicable to power production. The cost of general plant applicable to power production is divided by its respective end-of-year net plants.
8. Working Capital – Working capital is composed of the three portions defined below: cash working capital, materials and supplies, and prepayments. A carrying charge, consisting of cost of capital and income taxes (both described above), will be applied to each of the three in determining the annual cost for working capital. The working capital percentage is determined by dividing the annual cost by the end-of-year net plant investment.
  - a. Cash Working Capital – This portion is calculated by taking one-eighth of the applicable operation and maintenance expenses. In the case of production, the O&M expenses should be exclusive of purchased power and nuclear fuel.
  - b. Materials and Supplies – This is the end-of-year balance of the appropriate materials and supplies.
  - c. Prepayments – This is the end-of-year balance of the appropriate prepaid expenditures, such as taxes and insurance.

**DEMAND RATE FOR  
RESERVE INTERCHANGE SALES**

Year Ending December 31, 1989

Annual updates, pursuant to the Appendix, will require a filing when changes are made to the return on common equity, CWIP balances, and acquisition adjustments and that such filings will be governed by the applicable parts of Sections 35.13 and 35.26 of the Commission's Regulations, as modified by Order No. 448 or any superseding Commission Regulation or Order.

**RESERVE**

Demand Rate

Total Production Demand Cost	\$44.03 /kW/year	
Applicable Taxes	<u>0.00</u> /kW/year	
Total	\$44.03 /kW/year / 312	= \$0.141 /kW/day

**TOTAL PRODUCTION DEMAND COST**

Year Ending December 31, 1989

1.	Production Demand Cost/kW	\$42.67 /kW/year
2.	Less: Accumulated Deferred Income Tax/kW	4.93 /kW/year
3.	Plus: Demand-Related Production Expenses/kW	6.29 /kW/year
4.	Plus: Allowed CWIP/kW	<u>0.00</u> /kW/year
5.	Total Production Demand Cost/kW	\$44.03 /kW/year



# **PRODUCTION DEMAND COST**

(1) Generating Plants	(2) Net Plant Investment	(3) Installed Capacity (MW)	(4) Investment/ kW (2) / (3)	(5) Percent Participation	(6) Weighted Investment Cost/kW (4) x (5)	(7) Annual Carrying Charge	(8) Annual Carrying Cost/kW (6) x (7)
Asheville	\$27,489,000	392	70.13	4.11%	2.88	24.63%	\$ 0.71
Cape Fear	\$32,904,000	316	104.13	8.42%	8.77	24.63%	2.16
Lee	\$19,945,000	407	49.00	10.33%	5.06	24.63%	1.25
Mayo (1)	\$354,547,490	661	536.38	17.40%	93.33	24.63%	22.99
Robinson	\$12,631,000	174	72.59	2.73%	1.98	24.63%	0.49
Roxboro	\$263,464,000	2,371	111.12	42.62%	47.36	24.63%	11.66
Sutton	\$60,364,000	613	98.47	10.83%	10.66	24.63%	2.63
Weatherspoon	\$10,780,000	176	61.25	3.30%	2.02	24.63%	0.50
Brunswick	\$610,688,000	1,290	473.40	0.26%	1.23	22.40%	<u>0.28</u>

Total Production Demand Cost \$42.67 /kW/year

(1) Includes capacity charge capital costs and buy-back capacity from another part owner of Mayo Unit No. 1.

$$\begin{array}{rclcl}
 \$341,523,000 & + & \frac{\$3,207,932}{24.63\%} & = & \$354,547,490 \\
 625 \text{ MW} & + & 36 \text{ MW} & = & 661 \text{ MW}
 \end{array}$$

### ACCUMULATED DEFERRED INCOME TAX

(1) Generating Plants	(2) Accumulated Deferred Income Tax	(3) Installed Capacity (MW)	Accumulated Deferred Income Tax/kW (2) / (3)	(5) Percent Participation	(6) Weighted Accumulated Deferred Income Tax Cost/kW (4) x (5)	(7) Annual Carrying Charge	(8) Accumulated DIT/kW (6) x (7)
Asheville	\$6,623,000	392	16.90	4.11%	0.69	13.93%	\$0.10
Cape Fear	\$4,983,000	316	15.77	8.42%	1.33	13.93%	\$0.18
Lee	\$4,375,000	407	10.75	10.33%	1.11	13.93%	\$0.15
Mayo	\$61,814,000	625	98.90	17.40%	17.21	13.93%	\$2.40
Robinson	\$2,867,000	174	16.48	2.73%	0.45	13.93%	\$0.06
Roxboro	\$62,996,000	2,371	26.57	42.62%	11.32	13.93%	\$1.58
Sutton	\$15,988,000	613	26.08	10.83%	2.82	13.93%	\$0.39
Weatherspoon	\$1,504,000	176	8.55	3.30%	0.28	13.93%	\$0.04
Brunswick	\$114,359,000	1,290	88.65	0.26%	0.23	13.93%	<u>\$0.03</u>
Total Accumulated DIT							\$4.93 /kW/year

# DEMAND-RELATED PRODUCTION EXPENSE

(1) Generating Plants	(2) Demand-Related Production Expense	(3) Installed Capacity (MW)	(4) Demand-Related Production Expense/kW (2) / (3)	(5) Percent Participation	(6) Weighted Demand-Related Production Expense/kW (4) x (5)
Asheville	\$3,275,908	392	8.36	4.11%	\$0.34
Cape Fear	\$3,574,254	316	11.31	8.42%	\$0.95
Lee	\$3,043,852	407	7.48	10.33%	\$0.77
Mayo (2)	\$3,612,449	661	5.47	17.40%	\$0.95
Robinson	\$1,584,039	174	9.10	2.73%	\$0.25
Roxboro	\$9,515,784	2,371	4.01	42.62%	\$1.71
Sutton	\$4,188,124	613	6.83	10.83%	\$0.74
Weatherspoon	\$2,316,999	176	13.16	3.30%	\$0.43
Brunswick	\$72,120,046	1,290	55.91	0.26%	<u>\$0.15</u>
Total Demand-Related Production Expense					\$6.29 /kW/year

(2) Includes capacity charge demand-related O&M and buy-back capacity from another part owner of Mayo Unit No.1.

\$3,111,867 + \$500,582 = \$3,612,449

625 MW + 36 MW = 661 MW

### CONSTRUCTION WORK IN PROGRESS

(1) Generating Plants	(2) Allowed Construction Work In Progress	(3) Installed Capacity (MW)	(4) Cost/kW (2) / (3)	(5) Percent Participation	(6) Weighted Cost/kW (4) / (5)	(7) Annual Carrying Charge	(8) Allowed CIP/kW (6) x (7)
Asheville	\$0	392	0.00	4.11%	0.00	13.93%	\$0.00
Cape Fear	\$0	316	0.00	8.42%	0.00	13.93%	\$0.00
Lee	\$0	407	0.00	10.33%	0.00	13.93%	\$0.00
Mayo	\$0	625	0.00	17.40%	0.00	13.93%	\$0.00
Robinson	\$0	174	0.00	2.73%	0.00	13.93%	\$0.00
Roxboro	\$0	2,371	0.00	42.62%	0.00	13.93%	\$0.00
Sutton	\$0	613	0.00	10.83%	0.00	13.93%	\$0.00
Weatherspoon	\$0	176	0.00	3.30%	0.00	13.93%	\$0.00
Brunswick	\$0	1,290	0.00	0.26%	0.00	13.93%	<u>\$0.00</u>
Total CWIP							\$0.00 /kW/year

## CARRYING CHARGE RATE FOR PRODUCTION COST

	Steam Production	Nuclear Production
Cost of Capital	10.19%	10.19%
Income Taxes	3.74%	3.74%
Ad Valorem and Labor-Related Taxes	0.92%	0.92%
Depreciation	5.76%	3.89%
Decommissioning Expense	0.00%	0.57%
A&G Expenses	2.28%	2.28%
General Plant	0.65%	0.65%
Working Capital		
Cash	1.06%	0.14%
Materials and Supplies	0.00%	0.00%
Prepayments	<u>0.03%</u>	<u>0.02%</u>
Total	24.63%	22.40%

## PRODUCTION CARRYING CHARGES

All year-end investments are from 1989 projected values. Original cost must be reduced by depreciation.

### 1. Cost of Capital (3)

	<u>% Capital Structure</u>	<u>Cost of Each %</u>	<u>Cost Component</u>
Debt	49.54%	8.45%	4.19%
Preferred	6.82%	8.76%	0.60%
Equity	43.64%	12.38%	<u>5.40%</u>
Total			10.19%

### 2. Income Taxes

State			6.67%	
Federal			34.00%	
Income Tax on Preferred and Common Equity:				
Net Income Before Taxes			100.00%	
State Income Taxes			<u>6.67%</u>	
			93.33%	
Federal	93.33%	x	34.00%	<u>31.73%</u>
				61.60%
Income Tax				
	1	-	.6160	
	-----			
	.6160	x	(0.60 + 5.40)	= 3.74%

### 3. Ad Valorem and Labor-Related Taxes (4)

	\$59,402,000	
	-----	
	\$6,438,127,000	= 0.92%

### 4. Depreciation (5)

These are the current FERC approved composite rates for the applicable accounts. These composite rates are then adjusted to apply to net plant investment.

Steam Production	3.43%	x	\$1,324,039,000	
			-----	
			\$788,481,000	= 5.76%
Nuclear Production	3.19%	x	\$4,406,238,000	
			-----	
			\$3,615,512,000	= 3.89%

(3) FERC Benchmark Return on Common Equity for the period February 1, 1989 to April 30, 1989.

(4) Analysis of Company books.

(5) Analysis of Company books.

(7) Analysis of Company books. Power Production-related General Plant allocated on the basis of Labor.

b. Materials and Supplies

Nuclear and Steam Production			\$0		
13.93%	x		\$0	=	0.00%

c. Prepayments

Steam Production

13.93%	x	\$1,665,933	=	\$232,064
		\$232,064		
		-----	=	0.03%
		\$788,481,000		

Nuclear Production

13.93%	x	\$5,544,057	=	\$772,287
		\$772,287		
		-----	=	0.02%
		\$3,615,512,000		



**SUPPLEMENTAL INFORMATION  
DUKE ENERGY PROGRESS, LLC**

**DERIVATION OF LABOR RATIOS FOR A&G AND GENERAL PLANT ALLOCATIONS**

1.	Distribution of Salaries and Wages	
a.	Production	\$130,888,000
b.	Transmission	7,309,000
c.	Distribution	<u>38,845,000</u>
d.	Total	\$177,042,000
2.	Labor Ratios	
a.	Production ( 1.a./1.d.)	0.7393
b.	Transmission ( 1.b./1.d.)	0.0413
c.	Distribution (1.c./1.d.)	0.2194
d.	Total	1.0000
3.	A&G Expense (page 9 of 10)	
a.	Total A&G Expense	\$137,649,000
b.	Allocated Production A&G Expense (3.a. x 2.a.)	\$101,763,906
4.	General Plant Expense (page 9 of 10)	
a.	Total Net Generating Plant	\$198,135,000
b.	Allocated Net Production-related General Plant (4.a. x 2.a)	\$146,481,206

## **APPENDIX VI**

### **Special Terms and Conditions**

In accordance with Article 12.5 of this Agreement, this Appendix sets forth Special Terms and Conditions applicable to Interconnection Point(s).

1. The Littleton Interconnection Point.

a. Description: The point hereby designated and hereinafter called “**Littleton Interconnection Point**” is shown in Figure 1 of this Appendix VI. The point of interconnection is within the 115 kV single circuit transmission line extending from the 115 kV bus in DEP’s Littleton Station to Dominion’s 115 kV transmission line that runs between the Army Corps of Engineers’ Kerr Dam Station and Dominion’s Carolina Station. The 24 kV bi-directional metering equipment compensated to 115 kV at the Littleton Interconnection Point is installed at the Littleton Station, and is owned, operated, and maintained by DEP.

b. Facilities: The Parties installed, own and operate their respective facilities as described below:

i. Facilities installed by Dominion:

1. Two 115 kV air break switches in the Dominion 115 kV Transmission Line No. 90, one on either side of an approximately 3.22 mile tap built by DEP to the station near the Town of Littleton, North Carolina. DEP paid for initial installation of the two air break switches and shall pay for ongoing replacement and maintenance of the two air break switches as such costs are incurred.
2. A suitable point of connection between the two 115 kV air break switches on Dominion Transmission Line No. 90 at a location mutually agreeable to DEP and Dominion designed to provide DEP with sufficient clearance to tap the transmission line for service to the Town of Littleton, North Carolina.

ii. Facilities installed by DEP:

1. A structure located in close proximity to, but not on, Dominion's transmission right of way permitting the installation of taps from Dominion's 115 kV Transmission Line No. 90 to DEP's 115 kV tap line.
2. A 115 kV air break switch near Dominion's, transmission line permitting disconnection of DEP's 115 kV tap line. Such air break, switch is double-locked to permit operation by Dominion in the emergency restoration of Transmission Line No. 90.

3. A 115 kV tap line approximately 3.22 miles long from Dominion's Transmission Line No. 90 to DEP's 115 kV substation site near the Town of Littleton, North Carolina.
4. A 25,000 kVA 115/24 kV Station with suitable protective devices and bi-directional metering near the Town of Littleton, North Carolina.

iii. General:

1. Each Party shall, as mutually agreed upon, maintain or cause to be maintained in good operating order, the facilities at the Littleton Interconnection Point.
2. If new facilities are to be constructed, each Party shall exercise due diligence in completing its construction in time to satisfy a reasonably determined energization date.
3. If, at any time, after the initial energization of the Littleton Interconnection Point, upgrades (other than upgrades to facilitate the physical interconnection of facilities as otherwise addressed in this Appendix VI) to Dominion's Transmission System become necessary that would not be necessary but for the Littleton Interconnection Point, the Parties shall arrange mutually agreeable terms for DEP's payment for the incremental initial and ongoing cost of such upgrades attributable to the Littleton Interconnection Point, or the Littleton Interconnection Point shall be terminated prior to the time such upgrades would be required to be completed. Dominion shall exercise due diligence in communicating the anticipated need of such upgrades to DEP as soon as practicable upon identification of such need.
4. Either Party on whose property facilities of the other Party are at any time located or to be located shall provide freedom of access to the other Party for the purpose of constructing, reconstructing, maintaining, operating, or removing such facilities.

c. Service to be Rendered:

- i. All energy transmitted hereunder shall be supplied at sixty (60) cycle alternating current at such potential and of such phase as may be mutually agreed upon.
- ii. All energy transmitted hereunder shall be measured at the point of supply, or at the nearest suitable and convenient point, by meters installed and maintained by DEP or as mutually agreed upon.

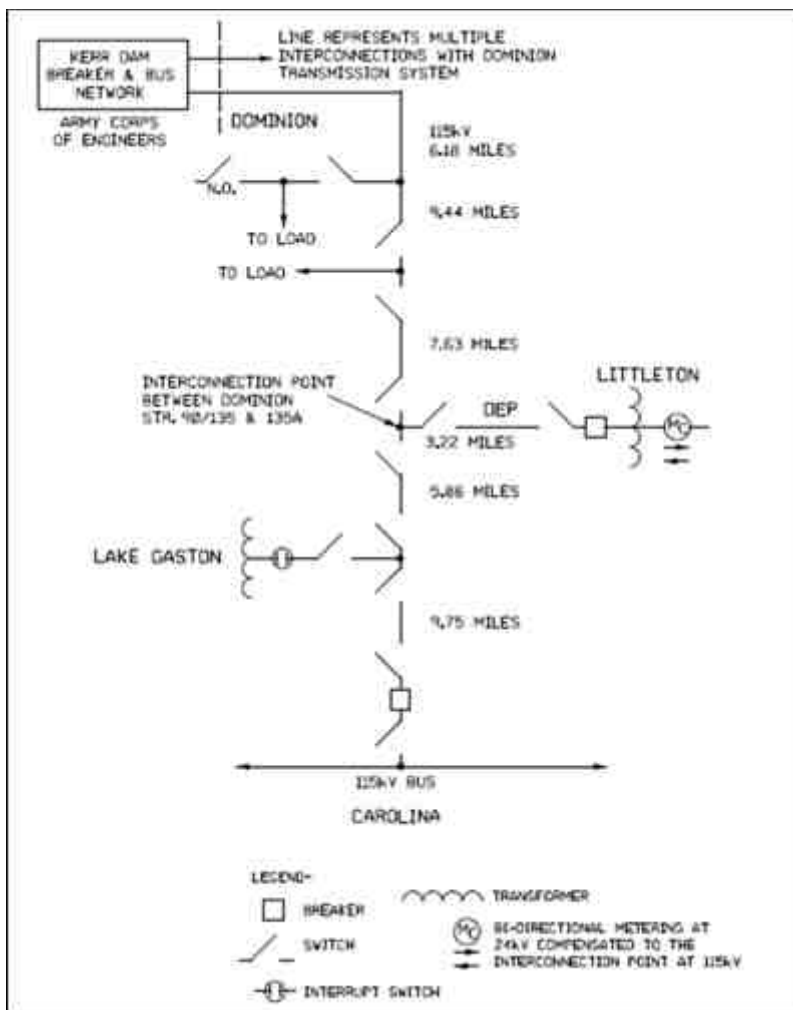
- iii. Dominion will exercise reasonable care to maintain the continuity of its service, but shall not be responsible for any damage or loss of revenue caused by any interruption of such service.
- iv. It is the intent of the Parties that the amount of energy received by DEP's customers connected to Dominion's system under this Agreement during any calendar month shall be approximately the same as the amount delivered by DEP during such month. If, however, during any calendar month there is a difference between the total number of kilowatt hours received and delivered by a Party under this Agreement, the difference shall be settled by the deficient Party delivery such kilowatt hours difference to the other Party during the succeeding month.

d. Term:

- i. At any time after the initial energization of the Littleton Interconnection Point either Party, by giving not less than ninety days written notice to the other Party, may from time to time call for a reconsideration of the terms and conditions applicable to the Littleton Interconnection Point; provided, that no such reconsideration shall be called for at intervals of less than one (1) year except as appropriate to maintain adequate reliability of each Party's Transmission System. If such reconsideration is called for, the authorized representatives of the Parties shall meet as promptly as convenient and discuss any of the applicable terms and conditions. No Party shall be under any obligation to agree to any modification or supplement not satisfactory to it. Any agreement modifying or supplementing such terms and conditions shall specify the date such modification or supplement shall become effective and shall be incorporated herein.
- ii. Notwithstanding any other provision herein, either Party may discontinue service at the Littleton Interconnection Point upon three years written notice to the other Party.

## APPENDIX VI

**Figure 1**  
**Littleton Interconnection Point**



ATTACHMENT C  
COPY OF SIGNATURE PAGES

IN WITNESS WHEREOF, three (3) copies of this Agreement, each to be considered an original, has been executed by the Parties' respective officers lawfully authorized so to do, this 27<sup>th</sup> day of August, 2018.

DUKE ENERGY PROGRESS, LLC

By: \_\_\_\_\_

Printed Name: Sam Holeman

Title: VP Transmission System Planning & Operations

Service Agreement No. 3453

IN WITNESS WHEREOF, three (3) copies of this Agreement, each to be considered an original, has been executed by the Parties' respective officers lawfully authorized so to do, this 27<sup>th</sup> day of August, 2018.

VIRGINIA ELECTRIC AND POWER COMPANY, D/B/A DOMINION ENERGY VIRGINIA  
AND DOMINION ENERGY NORTH CAROLINA

By: 

Printed Name: Bobby E. McGuire

Title: Authorized Representative

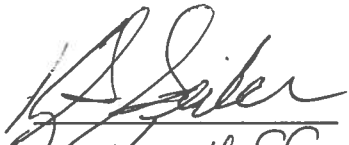
Service Agreement No. 3453



The signature below of the authorized representative of PJM is for the limited purpose of acknowledging that a representative of PJM has read this Agreement as of this 28 day of August, 2018.

PJM INTERCONNECTION, L.L.C.

By:



Printed Name:

Kenneth Seiler

Title:

Executive Director: System Planning

Service Agreement No. 3453

**ATTACHMENT D**  
**LIST OF RECIPIENTS**

## **List of Recipients**

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