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STATE CORPORATION COMMISSION

November 1, 2022

The Honorable Glenn A. Youngkin
Governor, Commonwealth of Virginia

Members of the Virginia General Assembly

Dear Governor Youngkin and Members of the Virginia General Assembly:

Enclosed please find the Report of the State Corporation Commission Assessing the Rates and Terms and Conditions of Incumbent Electric Utilities in the Commonwealth Pursuant to the Seventh Enactment Clause of Chapter 933 (SB 1416) of the 2007 Acts of Assembly. It has been prepared in consultation with the Office the Attorney General.

Please let us know if we may be of further assistance.

Respectfully submitted,

Jehmal T. Hudson
Chair

Judith Williams Jagdmann
Commissioner

Enclosure

Commonwealth of Virginia

State Corporation Commission

Report to the Governor and Members of the Virginia General Assembly

Assessing the Rates and Terms and Conditions of Incumbent Electric Utilities in the Commonwealth Pursuant to the Seventh Enactment Clause of Chapter 933 (SB 1416) of the 2007 Acts of Assembly

November 1, 2022

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GLOSSARY OF TERMS

A&N .... A&N Electric Cooperative
AC………………………..Alternating Current
AEP .... American Electric Power
APCo .... Appalachian Power Company
BARC .... BARC Electric Cooperative
Biennial Review .... review of a utility's rates, terms, and conditions for two successive 12-month periods
CBEC............................... Craig-Botetourt Electric Cooperative
CCRO .... Customer Credit Reinvestment Credit
CPCN............................... certificate of public convenience and necessity
CVEC .... Central Virginia Electric Cooperative
Chapter 933 .... Chapter 933 of the 2007 Acts of Assembly
Chapter 24……………….Chapter 24 of Title 56 of the Code of Virginia, Electric Utility Integrated Resource Planning (§ 56-597 *et seq*.)
Chapter 10……………….Title 56 of the Code of Virginia, § 56-232 *et seq*.
Clause, the .... Seventh Enactment Clause of Chapter 933
Commission...................... State Corporation Commission
Code……………………..The Code of Virginia
DEV................................. Virginia Electric and Power Company d/b/a Dominion Energy Virginia
Dominion………………...Virginia Electric and Power Company d/b/a Dominion Energy Virginia
DSM .... demand-side management
E&R................................. environmental and reliability
E-RAC .... environmental rate adjustment clause
EEI................................... Edison Electric Institute
earnings band................... earnings either 70 basis points above or below the fair combined return
EPA………………………Environmental Protection Agency
FERC .... Federal Energy Regulatory Commission
fair combined return .... fair rate of return on common equity
General Assembly……….Virginia General Assembly
GTSA............................... Grid Transformation and Security Act
IOU .... investor-owned electric utility
IRP................................... integrated resource plan
KU .... Kentucky Utilities, Inc.
kW………………………kilowatt
kWh .... kilowatt-hour
LG&E .... Louisville Gas & Electric
MEC .... Mecklenburg Electric Cooperative
MW.................................. megawatt
NNEC .... Northern Neck Electric Cooperative
NOVEC .... Northern Virginia Electric Cooperative
ODEC .... Old Dominion Electric Cooperative
PGEC............................... Prince George Electric Cooperative
PIPP……………………..Percentage of Income Payment Program
PJM.................................. PJM Interconnection, LLC
PPA.................................. Purchase Power Agreement
PURPA…………………..Public Regulatory Policies Act of 1978
Rappahannock .... Rappahannock Electric Cooperative
RAC................................. rate adjustment clause
REC .... renewable energy certificates
ROE .... return on common equity
RPS .... renewable energy portfolio standard
RPS eligible sources……..renewable energy facilities, as that term (renewable energy) is defined in § 56-576, located within the Commonwealth or within the PJM region.
Regulation Act.................. Virginia Electric Utility Regulation Act
RTO…………………......Regional Transmission Organization

SCC .... State Corporation Commission
SEC................................... Southside Electric Cooperative
SVEC................................ Shenandoah Valley Electric Cooperative
Staff .... Commission Staff
T-RAC .... transmission rate adjustment clause
Triennial Review……….. Commission to review the IOUs' rates, terms, and conditions of service on a triennial basis
WVPSC………………….West Virginia Public Service Commission
VCEA .... Virginia Clean Economy Act

EXECUTIVE SUMMARY

On April 4, 2007, the General Assembly of Virginia ("General Assembly") enacted House Bill 3068 and Senate Bill 1416, which became Chapters 888 and 933 of the 2007 Acts of Assembly (collectively, "Chapter 933"). The Seventh Enactment Clause of Chapter 933 ("the Clause"), among other things, directs the State Corporation Commission ("Commission" or "SCC"), in consultation with the Office of Attorney General, to conduct a five-year assessment of "the rates and terms and conditions of incumbent electric utilities in the Commonwealth" including analysis of "the amount, reliability and type of generation facilities needed to serve Virginia native load compared to that available to serve such load." The following report ("Report") provides the Commission's updated assessment on the referenced matters, involving principally Dominion Energy Virginia ("DEV" or "Dominion"), Appalachian Power Company ("APCo"), and the electric cooperatives.

Rate Assessment

- DEV's residential bill for 1,000 kilowatt-hours ("kWh") of energy usage per month, which was $90.59 as of July 1, 2007, increased by $46.34 (51.15%) to $136.93[1] per month as of July 1, 2022.
- The increase in the rate adjustment clause ("RACs") component of DEV's bill was the largest. This component accounts for $30.92 of the total bill increase since July 1, 2007.
- The fuel factor component increased by $13.06, while the base rates component increased by $2.36.
- APCo's residential bill for 1,000 kWh per month was $66.61 as of July 1, 2007. APCo's residential bill increased by $55.64 (83.53%) to $122.25 per month as of July 1, 2022.

[1] The July 1, 2022, monthly bill amount includes an increase to DEV's fuel factor, which was effective July 1, 2022. The change in the fuel factor increased the total monthly bill of a residential customer using 1,000 kWh by $14.93. See *Application of Virginia Electric and Power Company to revise its fuel factor pursuant to § 56-249.6 of the Code of Virginia*, Case No. PUR-2022-00064, Doc. Con. Cen. No. 220820050, Order Establishing 2022-2023 Fuel Factor (September 16, 2022).

- The majority of APCo's residential bill increase is attributable to the RAC component, which increased by $35.13 over this period.

- The fuel factor component increased by $9.88,[2] while the base rates component increased by $10.63.

- The range of the increases experienced by the electric cooperatives over this period extends from a low of 7.89% to a high of 86.95%.

Reliability and Needed Generating Facilities

- DEV, APCo, and the electric cooperatives are, either directly or indirectly through purchased power agreements ("PPAs"), members of the PJM[3] regional transmission organization ("RTO") whose primary mission is to ensure the safety, reliability, and security of the bulk electric power system.

- DEV relies on its generating resources, PPAs, demand-side management ("DSM") initiatives, and short-term energy purchases for satisfying its load serving obligations to customers. In April 2021, DEV announced that it would elect to procure its capacity through the Fixed Resource Requirement alternative to the PJM capacity market auction.[4] By electing to participate in this alternative, DEV will be unable to participate in the capacity market that PJM coordinates and will instead be required to meet any forecasted capacity needs through construction of additional capacity resources, bilateral contracts with other utilities and merchant generators, or a combination of the two.

- Since October of 2017, DEV has purchased, developed, or entered into PPAs with approximately 340 megawatts ("MW") of solar resources, some of which were built

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[2] APCo filed an application to increase its fuel factor on September 15, 2022, in Case No. PUR-2022-00139. In its application, APCo proposes to increase its fuel factor from 2.300 cents per kilowatt-hour ("¢/kWh") to 4.319 ¢/kWh, effective on an interim basis November 1, 2022, subject to modification. The rate impact of this request is an increase of approximately $20.19 on a monthly residential bill of 1,000 kWh.

[3] PJM Interconnection, LLC ("PJM").

[4] To elect this alternative, DEV was required by PJM to demonstrate that it has sufficient resources to meet the reliability requirement for its service area. DEV must maintain this alternative for a minimum of five consecutive years beginning June 1, 2022. *See Commonwealth of Virginia, ex rel. State Corporation Commission, In re: Virginia Electric and Power Company's 2021 Update to its Integrated Resource Plan pursuant to Va. Code 56-597 et seq.* Case No. PUR-2021-00201, Doc. Con. Cen. No. 210910060, 2021 Update to the 2020 IRP (September 1, 2021) ("2021 DEV IRP Update") at 10-11.

for current or future compliance with the requirements of the Grid Transformation and Security Act ("GTSA")[5] and the Virginia Clean Economy Act ("VCEA").[6]

- The Commission has also determined that DEV's purchasing, developing, or entering PPAs for 914 MW of solar resources and 103 MW of energy storage resources with expected commercial operation dates of 2022 and 2023 were prudent, and some of these projects, if applicable, received certificates of public convenience and necessity ("CPCNs") permitting their construction.[7] Through its approved offshore wind pilot project, DEV also developed two 6 MW wind turbines in 2020 off the shoreline of Virginia Beach, Virginia.[8]

- The Commission granted DEV's request for approval of a rate adjustment clause, designated Rider SNA, for costs associated with preparing Petitions for Subsequent License Renewal to the Nuclear Regulatory Commission to extend the operating licenses of, and the projects reasonably appropriate to upgrade or replace systems and equipment deemed to be necessary to operate safely and reliability, Dominion's Surry Units 1 and 2 and North Anna Units 1 and 2 in an extended period of operation.[9]

- DEV's 2022 Update to its 2020 IRP[10] anticipates adding approximately 13,692 MW of solar, 2,600 MW of off-shore wind, 2,620 MW of storage, and retiring approximately 2,561 MW of generating resources over the next 15 years, based on its VCEA-compliant IRP plan.[11]

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[5] 2018 Va. Acts, ch. 296 (Senate Bill 966), entitled the Grid Transformation and Security Act in the Act's 24th enactment clause.

[6] 2020 Va. Acts, chs. 1193 (HB 1526) and 1194 (SB 851). *See* Code § 56-585.5.

[7] *See Petition of Virginia Electric and Power Company, For approval of its 2021 RPS Development Plan under § 56-585.5 D 4 of the Code of Virginia,* Case No. PUR-2021-00146, Doc. Con. Cen. No. 220320113, Final Order (March 15, 2022).

[8] *Petition of Virginia Electric and Power Company, For a prudency determination with respect to the Coastal Virginia Offshore Wind Project pursuant to Virginia Code § 56-585.1:4 F,* Case No. PUR-2018-00121, 2018 S.C.C. Ann. Rept. 491, Final Order (November 2, 2018).

[9] *Petition of Virginia Electric and Power Company, For approval of a rate adjustment clause, designated Rider SNA under § 56-585.1 A 6 of the Code of Virginia*, Case No. PUR-2021-00229, Doc. Con. Cen. No. 220710001, Final Order (July 1, 2022).

[10] *Commonwealth of Virginia, ex rel. State Corporation Commission, In re: Virginia Electric and Power Company's 2022 Update to the 2020 Integrated Resource Plan pursuant to Va. Code 56-597 et seq.* Case No. PUR-2022-00147, Doc. Con. Cen. No. 220910018, 2022 Update to the 2020 IRP (September 1, 2022) ("2022 DEV IRP Update").

[11] The VCEA compliant plan is referred to as Plan B in the 2022 DEV IRP Update. This plan was filed on September 1, 2022, for informational purposes only and has not been evaluated by the Commission. *See id.* at 2-4.

- APCo, as a PJM member, has elected to rely on its generating resources, PPAs, DSM initiatives, and short-term energy purchases to satisfy its load-serving obligations to customers.

- In 2018, APCo entered into a PPA for a 120 MW wind farm located in Indiana.[12] Since October of 2017, APCo has entered into 55 MW of solar PPAs. APCo also has a portfolio of 630 MW of PPAs consisting of five wind farms, one hydro-electric facility, and three solar facilities expected to come online in 2022.[13]

- Over the next 15 years, APCo anticipates that 1,785 MW of nameplate capacity solar, 1,154 MW of nameplate capacity wind, and 400 MW of energy storage will be added to its portfolio.[14] During this same time, wind contracts of approximately 375 MW (nameplate) will expire.[15]

- In Case No. PUR-2020-00015,[16] the Commission required APCo to perform a unit-by-unit retirement analysis for the Amos and Mountaineer coal units located in West Virginia and provide that analysis in APCo's 2022 IRP, which is currently pending before the Commission.[17] APCo is also separately seeking Commission approval for investments at Amos and Mountaineer, which is currently pending before the Commission.[18]

- APCo's internal capacity (owned capacity, capacity acquired through long-term non-utility generation PPAs, and DSM reductions) is projected to be sufficient for

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[12] Although located in Indiana, this plant's output is reserved for APCo's Virginia jurisdiction.

[13] *Commonwealth of Virginia, ex rel., State Corporation Commission, In re: Appalachian Power Company's Integrated Resource Plan filing pursuant to Va. Code § 56-597 et seq.*, Case No. PUR-2022-00051, Doc. Con. Cen. No. 220440132 ("2022 APCo IRP") at ES-1.

[14] These values are based on APCo's Hybrid Plan which APCo states is VCEA compliant. *Id.* at ES-4.

[15] *Id*. at ES-2.

[16] *Appalachian Power Company Application For A 2020 Triennial Review Of Rates, Terms, and Conditions for Provisions Of Generation, Distribution, and Transmission Services,* Case No. PUR-2020-00015, 2020 S.C.C. Ann. Rept. 435, Final Order (December 15, 2020) ("2020 APCo Triennial Review").

[17] 2022 APCo IRP at 85-87.

[18] *Petition of Appalachian Power Company For approval of a rate adjustment clause, the E-RAC, for costs to comply with state and federal environmental regulations pursuant to § 56-585.1 A 5 E of the Code of Virginia*, Case No. PUR-2022-00001, Doc. Con. Cen. No. 220420263, Order for Notice and Hearing (April 21, 2022). In the previous E-RAC Proceeding in 2021, APCo was denied recovery by the Commission of capital costs pertaining to upgrades related to the requirements of the Environmental Protection Agency's Steam Electric Effluent Limitation Guidelines. *Petition of Appalachian Power Company For approval of a rate adjustment clause, the E-RAC, for costs to comply with state and federal environmental regulations pursuant to § 56-585.1 A 5 E of the Code of Virginia*, Case No. PUR-2020-00258, 2021 S.C.C. Ann. Rept. 330, Order Granting Rate Adjustment Clause (August 23, 2021).

meeting its capacity obligations through 2036.[19] APCo plans to continue purchasing energy, as is needed and economical, from the PJM market.

Peer Group Comparison

- The Clause requires the Commission to report every five years on a comparison of Virginia IOUs to those in their peer groups that meet the criteria of Code § 56-585.1 A 2. The Commission, through its Staff ("Staff"), developed several rate comparisons that utilize information from various Edison Electric Institute ("EEI") publications to assess the competitiveness of DEV's and APCo's rates as compared to those of the statutorily defined peer groups. This data can be found in Appendices 4, 5, and 6.

- Out of the 11 companies in the peer group, DEV is ranked 4th in the category of annualized residential rates, 3rd for annualized commercial rates, and 5th for annualized industrial rates.[20]

- APCo is 6th in annualized residential, commercial, and industrial rates.

- At this time, APCO's and DEV's electricity rates appear to be competitive with their peer utilities, although pending and future rate requests, with a specific regard to fuel factor cases, could impact the competitiveness of electricity rates in the future.

[19] For purposes of this expectation, APCo assumes the continued availability of the capacity and energy produced by the Amos and Mountaineer coal generation facilities.

[20] This calculation was made by averaging individual customer class rates and ranking the composite averages.

I. INTRODUCTION AND STATUTORY BACKGROUND

The Commission appreciates the opportunity to provide this update to the Governor and the General Assembly on the matters detailed herein. After an overview of the applicable laws, in accordance with the Clause, this Report will provide an assessment of the rates, terms and conditions of DEV, APCo, and a comparison of the rates and service reliability of the statutory peer group utilities to DEV and APCo. As a general matter, the Commission is seeing upward pressure on utility rates, not just for investor-owned electric utilities, but across all regulated utilities. Factors contributing to increased utility costs include inflation, pandemic recovery, supply chain limitations, and high natural gas and other commodity prices, as well as geopolitical events. The Commission is keenly aware of the economic pressures that are impacting all utility customers and takes seriously its responsibility to review rate recovery requests. In each case, the Commission evaluates the request pursuant to the applicable laws, as well as the findings of fact supported by the evidence in the record.

On April 4, 2007, the General Assembly enacted Chapter 933. The Clause, which provides the statutory basis for this Report, directs:

> That the State Corporation Commission, in consultation with the Office of Attorney General, shall submit a report to the Governor and General Assembly by November 1, 2012, and every five years thereafter, assessing the rates and terms and conditions of incumbent electric utilities in the Commonwealth. Such report shall include an analysis of, among other matters, the amount, reliability and type of generation facilities needed to serve Virginia native load compared to that available to serve such load, and provide a comparison of such utilities to those in the peer group of such utilities that meet the criteria enumerated in subdivision A 2 of § 56-585.1 of the Code of Virginia.

Chapter 933[21] at the time of its 2007 enactment established (i) a new mechanism for regulating the rates of IOUs,[22] (ii) a limited means by which electric utility consumers may purchase electric generation service from competing suppliers, and (iii) RACs through which certain utility costs—including costs associated with new generation facilities—could be recovered through rate riders separate and apart from base rates where the costs otherwise would have been recovered.[23] Prior to Chapter 933's enactment, the rates, terms and conditions of electric utility service provided by the IOUs were established and regulated on a cost-of-service basis under Chapter 10 (§ 56-232 *et seq*.) of Title 56 of the Code ("Chapter 10").

Triennial Reviews Overview

The ratemaking mechanism referenced above (contained principally in § 56-585.1 of the Code) initially required the Commission to review the IOUs' rates, terms, and conditions of service on a biennial basis.[24] Subsequently, the 2018 GTSA amended § 56-585.1 of the Code to direct that these reviews occur on a triennial basis ("Triennial Review"), with the first such Triennial Reviews occurring for APCo in 2020 and for Dominion in 2021.

[21] Chapter 933 substantially rewrote existing Chapter 23 (§ 56-576 *et seq*.) of Title 56 of the Code, then titled the "Virginia Electric Utility Restructuring Act." Subsequent to Chapter 933's enactment, Chapter 23 was re-titled in the published Code as the "Virginia Electric Utility Regulation Act" ("Regulation Act"). The Regulation Act's provisions have been regularly amended and augmented by the General Assembly since its 2007 enactment.

[22] With some exceptions, Chapter 23 of Title 56 of the Code does not apply to one investor-owned utility in Virginia, namely Kentucky Utilities d/b/a Old Dominion Power Company ("ODP"). *See* Code § 56-580 G. That utility's rates are established pursuant to Chapter 10 (§§ 56-232, et seq.) of Title 56 of the Code. The Commonwealth's electric cooperatives are not subject to the Regulation Act's principal provisions, e.g., triennial reviews, etc., but certain provisions within the Regulation Act address or affect their utility operations. For purposes of this Report, unless the context indicates otherwise, the term "IOUs" refers to DEV and APCo.

[23] The Commission is required by § 56-585.1 to consider petitions for RACs on a stand-alone basis, without regard to the other costs or revenues of the utility.

[24] In 2015, the General Assembly passed legislation that suspended Biennial Reviews for APCo and Dominion by establishing a Transitional Rate Period that ended December 31, 2017, for APCo and December 31, 2019, for DEV. 2015 Va. Acts ch. 6 (SB 1349).

When the Commission conducts Triennial Reviews pursuant to the provisions of Code § 56-585.1, it determines fair rates of return on common equity ("fair combined return" or "ROE") for each utility's generation and distribution services and also for the utility's RACs on a going-forward basis, using any methodology the Commission finds consistent with the public interest. The provisions of Code § 56-585.1, however, direct that such rates of return may not be set lower than (i) the average ROE reported to the Securities and Exchange Commission for the three most recent annual periods by a majority of a peer group of other vertically integrated IOUs in the southeastern United States, or (ii) the authorized returns of common equity that are set by applicable state regulatory commissions for the same selected peer group members.[25]

Additionally, § 56-585.1 of the Code requires specific Commission actions if the Commission determines that a utility has earned 70 basis points above or below the fair combined return (the "earnings band") established by the Commission in the utility's prior Triennial Review. The SCC is required to increase an IOU's rates to a level necessary to provide the opportunity to recover fully the costs of providing the utility's services and to earn such fair combined return, if it is determined in a Triennial Review that a utility's earnings on its generation and distribution services were below the earnings band, excluding provisions for new generation facilities.

If the Commission determines in a Triennial Review that a utility's earnings return on its generation and distribution services exceeded the earnings band, the SCC is required to direct that 70% of such excess earnings be credited to customers' bills over a period of between 6 and 12 months. However, the GTSA's amendments to § 56-585.1 of the Code authorize utilities to off-set or reduce any such excess earnings by the amount of costs incurred for the construction of wind

[25] Section 56-585.1 also authorizes the Commission to increase or decrease the resulting combined fair rate of return based on the Commission's consideration of the utility's performance consistent with Commission precedent predating Chapter 933's enactment.

and solar generation, new energy storage facilities, or for electric grid transformation projects.[26] These off-sets are described in the Code as "customer credit reinvestment offsets" ("CCRO").[27]

Additionally, if the SCC determines that a utility's earnings exceed this earnings band, § 56-585.1 of the Code requires the Commission to order reductions to the utility's rates, provided that rates may not be reduced to levels below what would provide the utility with the opportunity to recover fully its costs and to earn a fair combined return on its generation and distribution services, excluding provisions for new generation facilities.

Rate Adjustment Clauses Overview

As stated above, § 56-585.1 of the Code (and related provisions in the Regulation Act) authorizes Virginia's IOUs to seek Commission approval of RACs to recover certain identified costs. Currently, IOUs may seek RAC recovery for the following: (i) costs for transmission services provided by their RTO (PJM) under applicable rates, terms and conditions approved by the Federal Energy Regulatory Commission ("FERC"), costs of FERC-approved demand response programs, and utilities' costs to construct, operate and maintain transmission lines and substations installed in order to provide service to a business park; (ii) deferred environmental and reliability costs authorized under prior capped rates; (iii) costs of providing incentives for the utility to design and operate fair and effective peak-shaving and energy efficiency programs; (iv) costs of compliance with the mandatory renewable energy portfolio standard ("RPS"); (v) projected and actual costs of projects that the Commission finds to be necessary to mitigate impacts to marine

[26] Code § 56-585.1 A 8.

[27] *Id.* and Code § 56-585.1 A 6. The Code further provides that to the extent a utility off-sets earnings above its earnings band with CCROs, the amounts so off-set cannot be recovered in the utility's rates for generation and distribution services, or through RACs. However, the costs of utility investments in wind or solar generation, or in electric grid transformation projects that are not utilized as CCROs to reduce excess earnings may be recovered through generation and distribution services, or through RACs. Code § 56-585.1 A 8. *See also,* § 56-585.5 D.

life caused by construction of offshore wind generating facilities; (vi) costs of projects that the SCC finds to be necessary for the utility to comply with state or federal environmental laws or regulations applicable to generation facilities used to serve the utility's native load obligations,[28] including the costs of allowances purchased through a market-based trading program for carbon dioxide emission; and (vii) projected and actual costs, not currently in rates, for utilities to design, implement, and operate programs approved by the Commission to provide incentives to (a) low-income, elderly, and disabled individuals, or (b) organizations providing residential services to low-income, elderly, and disabled individuals to utilize solar generation. IOUs also may propose RACs for utility vegetation management programs, and the undergrounding of certain electric distribution lines. Additionally, while not designated as a RAC, Dominion's and APCo's retail customers pay a Universal Service Fee to support the Percentage of Income Payment Program ("PIPP").[29]

Section 56-585.1 of the Code also allows IOUs to propose RACs for (i) a coal-fired generation facility that utilizes Virginia coal and is located in the coalfield region of the Commonwealth; (ii) one or more other generation facilities; (iii) one or more major unit modifications of generation facilities, to meet the utility's projected native load obligations, or other costs reasonably appropriate to extend the combined operating license for or the operating life of one or more generation facilities utilizing nuclear power; (iv) one or more pumped hydroelectricity generation and storage facilities that utilize on-site or off-site renewable energy resources as all or a portion of their power source and such facilities and associated resources are

[28] Recovery under this provision has included Dominion's cost of removing and disposing of coal ash associated with its coal-fired generation units.

[29] Code § 56-585.6.

located in the coalfield region of the Commonwealth; and (v) one or more electric distribution grid transformation projects.

VCEA Overview

Additionally, provisions within the VCEA approved by the 2020 General Assembly[30] authorize IOUs' cost recovery for certain zero-carbon electricity generating capacity and energy storage projects that the IOUs are directed to undertake.[31] The costs of these projects may be recovered through (i) the utilities' rates for generation and distribution services; (ii) RACs; or (iii) the use of CCROs applied to earnings above utilities' earnings bands in Triennial Reviews.[32]

The VCEA established a schedule for the Commonwealth's IOUs to retire carbon-emitting electric generation by 2045.[33] The phase-out of such generation operates in tandem with the VCEA's mandatory RPS requirements under which Virginia's IOUs must procure and retire renewable energy certificates ("RECs") (i) originating from renewable sources ("RPS eligible

[30] 2020 Va. Acts, chs. 1193 (HB 1526) and 1194 (SB 851). *See,* Code § 56-585.5.

[31] APCo is required to construct, acquire or purchase the energy, capacity and environmental attributes of 600 MW of generating capacity using energy derived from sunlight or onshore wind by 2030. Dominion is similarly required to construct, acquire or purchase the energy, capacity and environmental attributes of 16,100 MW of such generating capacity by 2035. For both utilities, the VCEA establishes dates by which incremental compliance toward these statutory goals must be attained. *Id.* Additionally, APCo is required to construct or acquire 400 MW of energy storage by 2035, while Dominion is required to construct or acquire energy storage capacity of 2,700 MW by 2035. *Id.*

[32] Code § 56-585.5.

[33] *Id.* The VCEA contains provisions, however, enabling the Commission, upon the application of IOUs, to provide relief from the fossil-fueled generation retirement requirements under this statute (i) for purposes of reliability or security, and (ii) on a case-by-case basis. Specifically, Code § 56-585.5 B 4 provides as follows; "A Phase I or Phase II Utility may petition the Commission for relief from the requirements of this subsection [establishing scheduled retirements of carbon-emitting electric generation] on the basis that the requirement would threaten the reliability or security of electric service to customers. The Commission shall consider in-state and regional transmission entity resources and shall evaluate the reliability of each proposed retirement on a case-by-case basis in ruling upon any such petition."

sources"), and (ii) ultimately representing 100% of their total electric energy sold to retail customers in the Commonwealth by 2045 for Dominion, and by 2050 for Appalachian.[34]

Under the VCEA's RPS provisions, IOUs are required to make annual filings (commencing in 2020 and ending in 2035) seeking Commission approval for the utilities' procurement of zero-carbon electricity generating capacity and energy storage resources directed by the VCEA. As noted above, the IOUs may recover the costs of these resources through their rates for generation and distribution services, RACs, or through the use of CCROs.[35]

<u>Regulation of Electric Cooperatives</u>

As a general matter, the Commission's rate regulation of Virginia's electric distribution cooperatives remains ongoing under Chapter 10. However, these electric cooperatives, without SCC approval, may (i) increase their rates for distribution services by not more than 5% over any three year period, and (ii) make certain other changes to their terms and conditions of service.[36] Additionally, legislation enacted in the 2022 Session of the General Assembly authorizes the cooperatives, by the affirmative resolutions of their respective boards of directors, to adopt, without prior Commission approval, any voluntary tariff and associated cost recovery of that tariff. These board-approved voluntary tariffs are required to be filed with the Commission for informational purposes.[37]

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[34] *Id*. RPS eligible sources are generally described as renewable energy facilities, as that term (renewable energy) is defined in § 56-576, located within the Commonwealth or within the PJM region. Different qualifying RPS eligible sources are specifically identified for the period 2021-2024, and for 2025 and all years after. *Id.*

[35] Code § 56-585.5 D.

[36] Code § 56-585.3.

[37] *Id.*

The electric cooperatives have implemented a number of rate changes since 2007 using both traditional Commission processes and the new provisions of Code § 56-585.3. The electric cooperatives also have passed on to customers the costs of purchased power through changes in the cooperatives' power cost adjustment and wholesale power cost adjustment clauses. Also of note, several Virginia electric cooperatives administratively filed Schedule NeoGV - PURPA Cogeneration tariffs,[38] as well as changes to net energy metering tariffs. Additional detail related to the rate changes of the electric cooperatives over the last five years is provided in Appendix 1.

Integrated Resource Plans Overview

During its 2008 session, the General Assembly passed bills that became Chapters 476 and 903 of the 2008 Acts of Assembly. These duplicate enactments added to Title 56 of the Code, Chapter 24, Electric Utility Integrated Resource Planning (§ 56-597 *et seq.*) ("Chapter 24"). Pursuant to Chapter 24, Virginia's IOUs were required to file Integrated Resource Plans ("IRPs") detailing the IOU's forecast of its load obligations and plans to meet forecasted obligations through supply-side and demand-side resources over the ensuing 15 years to promote reasonable prices, reliable service, energy independence, and environmental responsibility.[39]

In 2018, the GTSA amended the IRP statutes.[40] Among other things, each IOU must file an updated integrated resource plan by May 1, in each year immediately preceding the year the utility is subject to a Triennial Review filing. Most recently, amendments to the IRP legislation

[38] Schedule NeoGV PURPA Cogeneration is available to customers with Small Power Production or Cogeneration Facilities which qualify under Section 210 of the Public Regulatory Policies Act of 1978 ("PURPA"), and which have a total design capacity of 100 kilowatts ("kW") alternating current ("AC") nameplate or less. Power generated by the customers' facilities is purchased by the cooperative under Schedule NeoGV. Power is sold to the customer under the terms of the applicable rate schedule. Power generated by customers' facilities which have a total design capacity of more than 100 kW AC may be purchased by the cooperative through separate, independently negotiated arrangements.

[39] Code § 56-597 (definition of "Integrated Resource Plan").

[40] 2018 Va. Acts, ch. 296 (Senate Bill 966).

require the IOUs to evaluate and potentially propose: (i) long-term electric distribution grid planning and proposed electric distribution grid transformation projects; and (ii) a long-term plan for energy efficiency measures.[41] Additionally, as part of preparing any IRP, each utility is now required to conduct a facility retirement study for owned facilities located in the Commonwealth that emit carbon dioxide as a byproduct of combusting fuel and to include the study results in its IRP.[42]

Each IRP is reviewed by the Commission in a public proceeding in which the Commission must ultimately determine whether the IRP is "reasonable and in the public interest."[43]

II. RATE ASSESSMENT

Since Chapter 933 became effective on July 1, 2007, DEV, APCo and the electric cooperatives have initiated numerous rate changes or have undergone extensive rate reviews. The following section discusses those rate reviews and rate changes. Appendices 2-3 to this Report present a comparison of the July 1, 2007, and July 1, 2022, monthly charges for residential customers using 1,000 kWh of electricity for DEV and APCo.[44]

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[41] Code § 56-599.

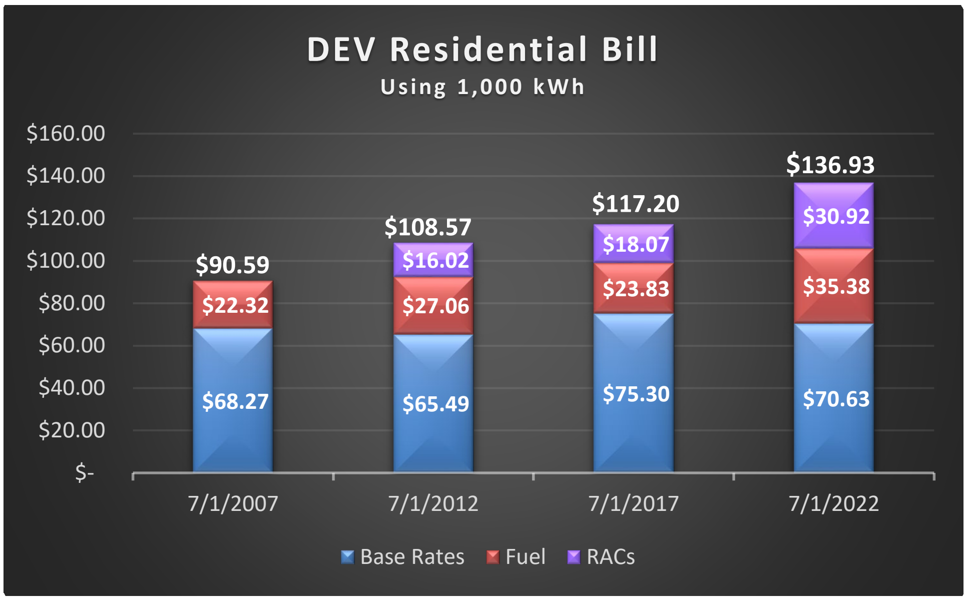
[42] 2021 Va. Acts, Special Session I, chs. 41 and 42 (HB 1834 and SB 1247, respectively).

[43] Code § 56-599 C. In years when an IRP is not filed, IOUs are required to file an update, which is filed on an informational basis and not a formal litigated proceeding before the Commission.

[44] One thousand (1,000) kWh is a commonly used reference point for a "typical" residential customer in Virginia.

A. Dominion Energy Virginia

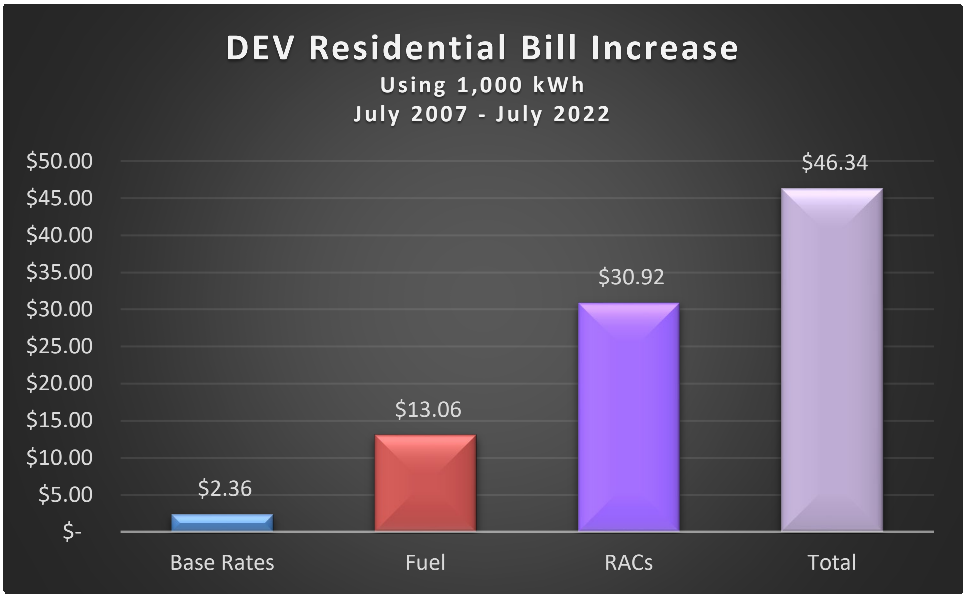
Below is a chart that reflects the magnitude of the three financial components[45] of DEV customer bills as of the effective date of the Regulation Act (July 1, 2007),[46] and each five years thereafter for a residential customer using 1,000 kWh per month.



As the chart above indicates, DEV's monthly residential bill was $90.59 as of July 1, 2007. The bill has increased by $46.34 (51.15%) to $136.93 per month as of July 1, 2022. As reflected on the chart below, the RAC component of the bill experienced the largest increase over this period.

[45] These three components are base rates, the fuel factor, and RACs.

[46] 2007 Va. Acts. chs. 888 and 933.



The following chart itemizes a residential customer's bill by rate recovery mechanism as of July 1, 2022.

DEV Electric Utility Bills
As of July 1, 2022

Recovery Mechanism	Description	Current Residential Bill	Proposed Increase if Pending	Proposed Bill	Requested Effective Date
Base Rates	Base	$ 70.63	$ -	$ 70.63	-
Fuel Factor	Fuel	$ 35.38	$ -	$ 35.38	7/1/22
Rider T1	Transmission	$ 6.90	$ (3.69)	$ 3.21	9/1/22
Rider R	Bear Garden Gas CC	$ 1.14	$ -	$ 1.14	-
Rider W	Warren Gas CC	$ 2.34	$ (0.38)	$ 1.96	4/1/23
Rider BW	Brunswick Gas CC	$ 2.10	$ 0.70	$ 2.80	9/1/22
Rider GV	Greensville Gas CC	$ 2.75	$ -	$ 2.75	-
Rider S	VCHEC	$ 3.70	$ -	$ 3.70	-
Rider B	Biomass	$ 0.30	$ 0.33	$ 0.63	4/1/23
Rider US-2	Solar	$ 0.17	$ 0.05	$ 0.22	9/1/22
Rider US-3	Solar	$ 0.96	$ -	$ 0.96	-
Rider US-4	Solar	$ 0.30	$ -	$ 0.30	-
Rider CE	Solar	$ 1.32	$ 1.13	$ 2.45	-
Rider SNA	Nuclear Relicensing	$ -	$ 2.11	$ 2.11	9/1/22
Rider RPS	RECs	$ 0.18	$ 1.64	$ 1.82	9/1/22
Rider RGGI	RGGI	$ -	$ -	$ -	7/1/22*
Rider OSW	Offshore Wind	$ -	$ 1.45	$ 1.45	9/1/22
Rider PPA	Renewable PPAs	$ -	$ (0.07)	$ (0.07)	9/1/22
Riders C1A/C2A/etc.	Energy Efficiency	$ 1.31	$ 0.29	$ 1.60	9/1/22
Rider U	Strategic Undergrounding	$ 2.50	$ (0.51)	$ 1.99	4/1/23
Rider GT	Grid Transformation	$ 1.16	$ -	$ 1.16	-
Rider E	Coal Ash	$ 1.25	$ 0.70	$ 1.95	9/1/22
Rider CCR	Coal Ash	$ 2.95	$ 0.01	$ 2.96	12/1/22
Rider RBB	Rural Broadband	$ 0.03	$ 0.14	$ 0.17	12/1/22
PIPP USF**	PIPP	$ 0.03	$ -	$ 0.03	-
Rider VCR***	Voluntary Credit Rider	$ (0.47)	$ -	$ (0.47)	
Total		**$ 136.93**	**$ 3.90**	**$ 140.83**	

*The Commission granted DEV's petition to reset Rider RGGI to zero and recover the unrecovered RGGI compliance costs through base rates.

**Current PIPP collections are designed to fund the estimated start-up costs of DSS needed to establish the PIPP. The PIPP will commence no later than one year after DSS publishes guidelines for the adoption, implementation, and general administration of the PIPP and Percentage of Income Payment Fund.

***Rider VCR provides bill credits to customers pursuant to the stipulation in DEV's 2021 triennial review.

1. DEV Base Rate Reviews

On March 31, 2021, DEV filed its application for the 2021 Triennial Review provided for by Code § 56-585.1 A, docketed as Case No. PUR-2021-00058 ("DEV 2021 Triennial Review").[47] As filed, DEV presented a combined generation and distribution base rate earned ROE of 9.61%[48] for the combined test periods of 2017 through 2020, which is within the 70 basis point band above and below the 9.20% ROE approved by the Commission in Case No. PUR-2019-00050 to be used to measure earnings in DEV's first Triennial Review.[49] DEV's earned ROE was driven in large part by the impairment of the unrecovered balances of several generating units it had retired in 2019 and 2020, which it treated as a period expense[50] subject to the provisions of Code § 56-585.1 A 8.

The evidentiary hearing for the DEV 2021 Triennial Review was held on October 25, 2021. On November 18, 2021, the Commission issued its Final Order in DEV 2021 Triennial Review,[51] where the Commission approved a stipulation proposed by the majority of case participants, and which was unopposed by any party to the case. In so doing, the Commission approved customer

[47] *Application of Virginia Electric and Power Company, For a 2021 triennial review of the rates, terms and conditions for the provision of generation, distribution, and transmission services pursuant to § 56-585.1 A of the Code of Virginia*, Case No. PUR-2021-00058, Doc. Con. Cen. No. 210340128, Application (filed March 31, 2021), *amended by* Doc. Con. Cen. No. 210530106, Amended Application (May 18, 2021) (including an amended application, supplemental testimony and filing schedules reflecting a revision to its earned return in the combined earnings test analysis).

[48] This ROE includes the earnings reduction resulting from $206 million of customer accounts receivable written off pursuant to House Bill 5005, 2020 Va. Acts, Special Session I, ch. 56, and House Bill 1800, 2021 Va. Acts, Special Session I, ch. 552. The earned ROE was 10.42% excluding this write-off.

[49] *Application of Virginia Electric and Power Company, For the determination of the fair rate of return on common equity pursuant to § 56-585.1:1 C of the Code of Virginia*, Case No. PUR-2019-00050, 2019 S.C.C. Ann. Rept. 400, Final Order (November 21, 2019).

[50] A period expense reduces earnings in the year it is recorded by the utility for financial reporting purposes.

[51] *Application of Virginia Electric and Power Company, For a 2021 triennial review of the rates, terms and conditions for the provision of generation, distribution and transmission services pursuant to § 56-585.1 of the Code of Virginia*, Case No. PUR-2021-00058, 2021 S.C.C. Ann. Rept. 444, Final Order (November 18, 2021).

refunds totaling $330 million, the statutory maximum annual rate reduction of $50 million,[52] and CCROs of $309 million. For a residential customer using 1,000 kWh per month, this resulted in a decrease of approximately $0.90 per month effective January 1, 2022, and refunds totaling approximately $67.00 over the 2022-2023 period.

The Commission also approved a 9.35% ROE as fair and reasonable for the 2021 – 2023 period that will be the subject of DEV's next Triennial Review.[53]

2. DEV Rate Adjustment Clauses

As noted earlier, Chapter 933 authorizes the establishment of a number of RACs. These RACs as of July 1, 2022, are illustrated in the DEV Electric Utility Bills table above.[54]

3. DEV Fuel Factor

DEV's fuel factor has been modified several times since Chapter 933 became effective. These changes are driven by increases or decreases in DEV's generating fuel and purchased power costs. Collectively, fuel factor revisions have increased rates by $13.06 per month for a residential customer using 1,000 kWh since July 1, 2007.[55]

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[52] Code § 56-585.1 A 8 c.

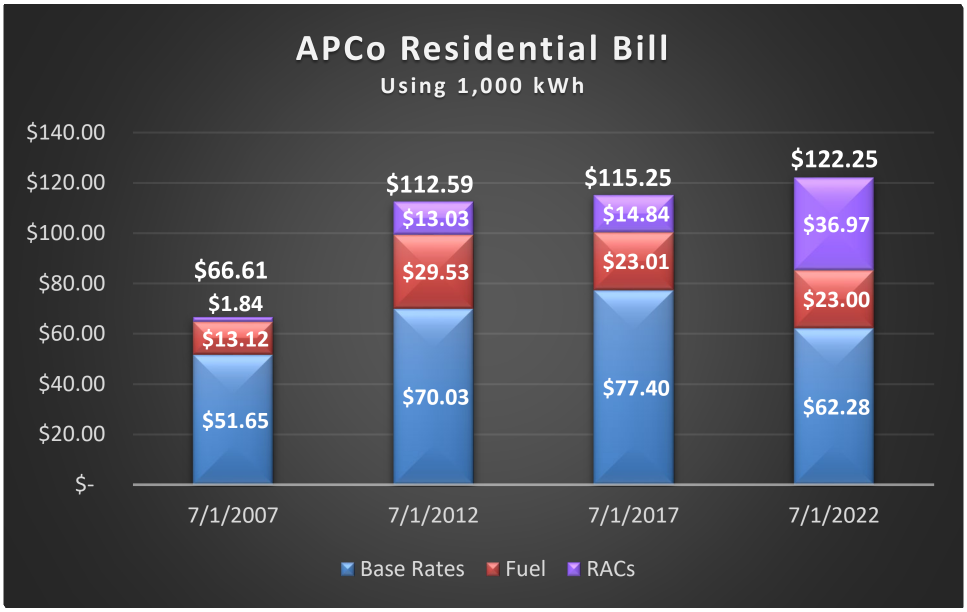
[53] *Application of Virginia Electric and Power Company, For a 2021 triennial review of the rates, terms and conditions for the provision of generation, distribution and transmission services pursuant to § 56-585.1 of the Code of Virginia*, Case No. PUR-2021-00058, 2021 S.C.C. Ann. Rept. 444, Final Order (November 18, 2021).

[54] With one exception, which is the PIPP, they are designated as "Riders" in the table.

[55] As of July 1, 2007, fuel-related charges were $22.32, or 24.6%, of the total monthly bill for a DEV residential customer using 1,000 kWh. As of July 1, 2022, fuel-related charges represent $35.38, or 25.8%.

B. Appalachian Power Company

Below is a chart that reflects the magnitude of the three financial components[56] of APCo customer bills as of the effective date of the Regulation Act (July 1, 2007), and each five years thereafter for a residential customer using 1,000 kWh per month.[57]

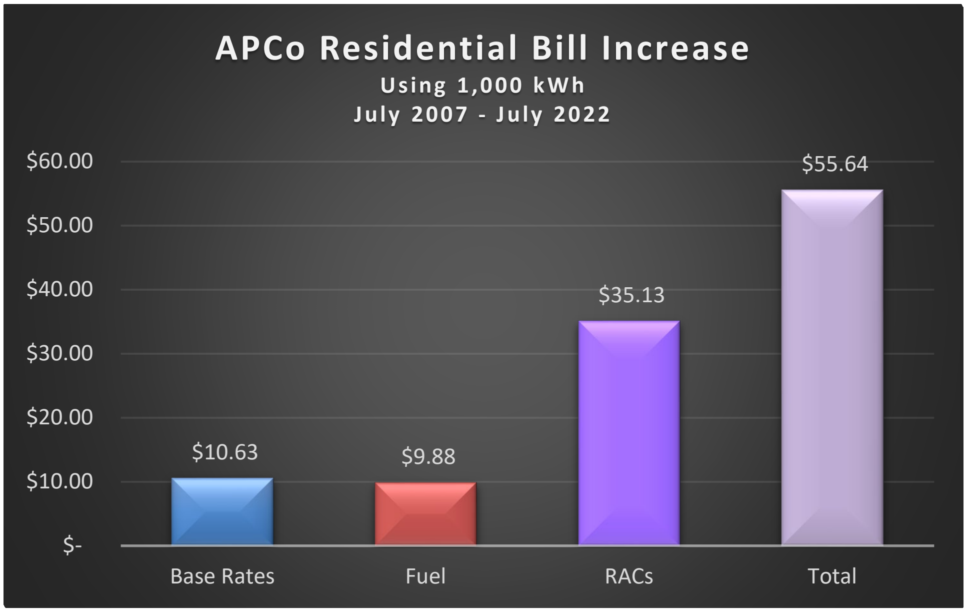


As the chart above indicates, APCo's monthly residential bill was $66.61 as of July 1, 2007. The bill has increased by $55.64 (83.53%) to $122.25 per month as of July 1, 2022. As reflected on the chart below, the RAC component of the bill experienced the largest increase over this period.

As noted in footnotes 61 and 62, as of the date of this report, two additional significant rate increases are in effect on an interim basis pending a hearing and final order. These increases amount to an additional $28.74 on a residential bill of 1,000 kWh. As of November 1, 2022, a residential bill for an APCo customer using 1,000 kWh is approximately $156.55.

[56] Like DEV, these three components are base rates, the fuel factor, and RACs.

[57] The base rate component decreased between July 1, 2017, and July 1, 2022, principally due to the shift of certain transmission costs from base rates to APCo's transmission RAC, the T-RAC, during that time.



The following chart itemizes a residential customer's bill by rate recovery mechanism as of July 1, 2022.[58]

[58] The TRR Rider Credit is a temporary base rate rider credit to return to customers the impacts of the 2018 Tax Cuts and Jobs Act.

APCo Electric Utility Bills
As of July 1, 2022

Recovery Mechanism	Description	Current Residential Bill	Proposed Increase if Pending	Proposed Bill	Requested Effective Date
Base Rates	Base*	$ 65.40	$ -	$ 65.40	-
Fuel Factor	Fuel**	$ 23.00	$ -	$ 23.00	-
TRR Rider Credit	Tax Reform	$ (3.12)	$ -	$ (3.12)	-
PIPP USF	PIPP***	$ 0.04	$ -	$ 0.04	-
T-RAC	Transmission	$ 31.55	$ 2.88	$ 34.43	8/1/22
G-RAC	Dresden Gas CC	$ 2.55	$ -	$ 2.55	-
EE-RAC	Energy Efficiency	$ 1.12	$ 0.34	$ 1.46	9/1/22
DR-RAC	Demand Response	$ 0.22	$ -	$ 0.22	-
E-RAC	Coal Ash	$ 2.11	$ 0.80	$ 2.91	12/1/22
BC-RAC	Rural Broadband	$ 0.54	$ (0.69)	$ (0.15)	2/1/23
RPS-RAC (legacy)	Voluntary RPS	$ (1.16)	$ -	$ (1.16)	-
RPS-RAC (new)	Mandatory RPS	$ -	$ 2.37	$ 2.37	8/1/22
Total		$ 122.25	$ 5.70	$ 127.95	

*As a result of a Supreme Court decision reversing in part the Commission's decision in APCo's 2020 Triennial Review, an interim base rate increase went into effect on October 1, 2022, in the amount of $8.55.
**On September 15, 2022, APCo filed an application proposing to increase its monthly fuel factor charge by $20.19 (to a total of $43.19 per month) which is effective November 1, 2022 on an interim basis. This application is currently pending before the Commission.

***Current PIPP collections are designed to fund the estimated start-up costs of DSS needed to establish the PIPP. The PIPP will commence no later than one year after DSS publishes guidelines for the adoption, implementation, and general administration of the PIPP and Percentage of Income Payment Fund.

1. <u>APCo Base Rate Reviews</u>

On November 24, 2020, the Commission issued its Final Order in the 2020 APCo Triennial Review, finding that APCo earned an ROE of 9.48% for the 2017 – 2019 triennial period.[59] APCo and the Division of Consumer Counsel within the Office of the Attorney General both filed notices of appeal of the Commission's decision to the Supreme Court of Virginia. On August 18, 2022, the Court issued its opinion affirming in part, reversing in part, and remanding the case to the

[59] *Application of Appalachian Power Company, For a 2020 triennial review of its base rates, terms and conditions pursuant to § 56-585.1 of the Code of Virginia*, Case No. PUR-2020-00015, 2020 S.C.C. Ann. Rept. 421, Final Order (November 24, 2020).

Commission for further proceedings consistent with the Court's opinion.[60] On remand, the Commission will recalculate APCo's earned ROE for the 2017-2019 triennial period and determine whether APCo is entitled to a rate increase effective January 1, 2021, and if so by what amount, based on the Court's findings in its opinion. On August 22, 2022, the Commission issued an Order Initiating Remand Proceedings directing APCo to file interim rates for (a) base rates going forward, and (b) a rider designed to collect revenues not collected from January 1, 2021, through September 30, 2022, to be implemented on October 1, 2022.[61]

APCo will file its next Triennial Review application on or before March 31, 2023, which will cover the period 2020-2022.

2. APCo Rate Adjustment Clauses

Similar to DEV, APCo also has proposed and received approval for a number of RACs. These RACs as of July 1, 2022, are illustrated in the APCo Electric Utility Bills table above.

3. APCo Fuel Factor

APCo's fuel factor has been modified several times since the enactment of Chapter 933. These changes are generally driven by increases or decreases in the cost of generating fuel, changes in the market cost of purchased power, a general decline in off-system sales margins, and changes associated with the provision of Chapter 933.[62]

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[60] Supreme Court of Virginia Record Nos. 210391 and 210634.

[61] On September 23, 2022, APCo filed Remand Testimony and proposed interim rates, to be effective on an interim basis on October 1, 2022. According to APCo, the impact on a residential customer using 1,000 kWh a month is an increase of $8.55. *Application of Appalachian Power Company, For a 2020 triennial review of its base rates, terms and conditions pursuant to § 56-585.1 of the Code of Virginia*, Case No. PUR-2020-00015, Direct Testimony of William Castle, Doc. Con. Cen. No. 220930107 (filed September 23, 2022).

[62] As noted previously, APCo filed an application to increase its fuel factor on September 15, 2022, in Case No. PUR-2022-00139. In its application, APCo proposes to increase its fuel factor from 2.300 cents per kilowatt-hour ("¢/kWh") to 4.319 ¢/kWh, effective on an interim basis November 1, 2022, subject to modification. The rate impact of this request is an increase of approximately $20.19 on a monthly residential bill of 1,000 kWh.

C. Electric Cooperatives

Virginia's electric industry includes 13 member-owned electric cooperatives:

- A&N Electric Cooperative ("A&N");
- BARC Electric Cooperative ("BARC");
- Central Virginia Electric Cooperative ("CVEC");
- Community Electric Cooperative;
- Craig-Botetourt Electric Cooperative ("CBEC");
- Mecklenburg Electric Cooperative ("MEC");
- Northern Neck Electric Cooperative ("NNEC");
- Northern Virginia Electric Cooperative ("NOVEC");
- Powell Valley Electric Cooperative;
- Prince George Electric Cooperative;
- Rappahannock Electric Cooperative ("Rappahannock");
- Shenandoah Valley Electric Cooperative ("SVEC"); and
- Southside Electric Cooperative ("SEC").

The electric cooperatives have had various rate changes over the last five years, a summary of which is provided in Appendix 1 of this Report. The chart below reflects the rate changes for each electric cooperative, as well as the IOUs, from July 1, 2007 to July 1, 2022, for a residential customer using 1,000 kWh per month.[63]

[63] Notes on this chart:

- For the electric cooperatives: Wholesale Power Cost Adjustment/Power Cost Adjustment rates are effective July 2022. CBEC's rates are based on the June 30, 2022, billing. NNEC's and SEC's rates use a demand of 7.5 KW.
- Rates are exclusive of local utility and consumption taxes.
- Rates are exclusive of the sales and use tax surcharge, except for the following utilities that have rolled the surcharge into base rates: ODP, CVEC, CBEC, NNEC, NOVEC, Rappahannock and SEC.
- A&N's, DEV's, NNEC's, Rappahannock's, SEC's and SVEC's July 2022 rates are annualized.

Residential Consumer Electric Rates in Virginia

Expressed in $ per 1,000 kWh

UTILITIES	$ July-07	$ July-22	$ Change	% Change
IOUs				
APCo	66.61	122.25	55.64	83.53
DEV	90.59	136.93	46.34	51.15
ODP	67.57	142.68	75.11	111.16
Electric Cooperatives				
A&N	122.59	136.62	14.03	11.44
BARC	123.18	161.14	37.96	30.82
Central Virginia	83.04	138.62	55.58	66.93
Community	122.37	143.87	21.50	17.57
Craig Botetourt	114.90	171.82	56.92	49.54
Mecklenburg	121.71	153.60	31.89	26.20
Northern Neck	126.35	154.53	28.18	22.30
Northern Virginia	129.20	139.40	10.20	7.89
Prince George	118.62	145.91	27.29	23.01
Rappahannock	127.72	129.22	1.50	1.17
Shenandoah Valley	115.12	134.72	19.60	17.03
Southside	133.32	156.10	22.78	17.09

III. NEEDED GENERATION FACILITIES

The Clause directs the Commission in this assessment to "include an analysis of, among other matters, the amount, reliability and type of generation facilities needed to serve Virginia native load compared to that available to serve such load." DEV, APCo, and the electric cooperatives are, either directly or indirectly through purchased power arrangements, members of the PJM RTO whose primary mission is to ensure the safety, reliability, and security of the bulk electric power system. In conjunction with this mission, PJM operates a competitive wholesale electricity market, analyzes and forecasts the future electricity needs of the region, and undertakes a planning process intended to ensure that the growth of the electric transmission system takes place efficiently and in an orderly fashion and that reliability is maintained. PJM's long-term transmission planning process seeks to identify future transmission reliability violations and the upgrades necessary to prevent such violations. This process is intended to assure that the bulk power grid is sufficient to deliver power from available generation resources to loads within the PJM region. Transmission owners within PJM, such as DEV and APCo, are obligated to construct these needed facilities, provided that they can obtain all necessary regulatory and environmental approvals, arrange financing, and acquire needed rights-of-way.

PJM also imposes generating capacity obligations on its load-serving members, such as DEV and APCo, and requires that those members make forward commitments for meeting those obligations. Those commitments reflect sufficient generation capacity needed to cover the utility's load, plus a reserve margin, including consideration of the forced outage rates of generation used to meet those obligations. As such, the "amount and reliability" of generation needed to serve Virginia load is directly impacted by these PJM member obligations.

Virginia's electric utilities supply their customers with power from the utilities' facilities, which are located both inside and outside of Virginia, and from energy purchases from other entities. Power from jurisdictional plants that may be located physically in another state is not considered "imported" in any relevant definition because, from legal and regulatory standpoints, Virginia consumers have the same claim on such power as they do on power from jurisdictional plants physically located in Virginia.

For example, DEV's Mount Storm generating station, while physically located in West Virginia, is dispatched as part of DEV's fleet; is part of DEV's rate base; and its costs are included in rates regulated by the Commission.[64] The same is true of APCo's facilities, some of which are physically located in West Virginia and Ohio. Despite these facilities' locations, the Virginia jurisdictional share of these generation assets is included in APCo's Virginia rate base. These facilities also are dispatched as part of APCo's fleet and are subject to Commission regulation.

Virginia's IOUs also procure energy (as opposed to generating capacity) through purchases from other sources. For instance, DEV and APCo purchase energy from the PJM markets. Such purchases are most often made because it is cheaper for DEV and APCo to purchase energy at certain times than to produce it at company-owned facilities. Under this scenario, the IOU's ratepayers benefit from these utilities paying lower prices for energy.

As noted above, each IOU is required to file an updated IRP plan by May 1, in each year immediately preceding the year the utility is subject to a Triennial Review filing. These IRPs examine the costs associated with future resource alternatives and how those resource alternatives would be dispatched in conjunction with existing resources. This type of analysis seeks to identify the optimum type or mix of future resources to serve Virginia load in a least cost and reliable manner. Thus, IRPs effectively work in conjunction with the PJM processes to address "the amount, reliability and type of generation facilities needed to serve Virginia native load compared to that available to serve such load"[65] by examining each IOU's existing and projected portfolio of supply- and demand-side resources necessary to meet projected demand over a 15-year planning period.

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[64] This unit is not electrically interconnected to any customers in West Virginia.

[65] 2007 Va Acts ch.933, Seventh Enactment Clause.

Informed by DEV's and APCo's IRP filings, the following section briefly discusses the future needs of DEV, APCo, and the electric cooperatives and the respective plans for meeting those needs.

A. Dominion Energy Virginia

As a member of PJM, DEV relies on its generating resources, purchased power contracts, DSM initiatives, and short-term energy purchases for satisfying its load serving obligations. In April 2021, DEV announced that it would elect to procure its capacity through the Fixed Resource Requirement alternative to the PJM capacity market auction.[66] By electing to participate in this alternative, DEV will be unable to participate in the capacity market that PJM coordinates and will instead be required to meet any forecasted capacity needs through construction of additional capacity resources and bilateral contracts with other utilities and merchant generators.

Due to a change that PJM first implemented in its 2020 Load Forecast, PJM now considers DEV to be a *winter peakin*g utility. PJM also considers the DOM Zone to be a winter peaking zone. In other words, the winter peak demand forecast for the DOM Zone exceeds the summer demand peak in all years of the forecast period, according to PJM. Given that the PJM RTO as a whole is still considered by PJM to be a *summer peaking* entity, however, PJM will continue to procure capacity for the DOM Zone at levels commensurate with the DOM Zone coincident summer peak forecast. This could make it difficult for DEV to self-supply its entire energy needs in the winter.[67] This potential energy shortfall can be satisfied through short-term purchases

[66] To elect this alternative, DEV was required by PJM to demonstrate that it has sufficient resources to meet the reliability requirement for their service area. DEV must maintain this alternative for a minimum of five consecutive years beginning June 1, 2022. *See* 2021 DEV IRP Update at 10-11.

[67] For example, if DEV is only obligated to obtain enough capacity to meet its summer peak, it may not have enough energy to meet its actual system peak which is now occurring in the winter. However, it may be economically

including purchases from the PJM energy market. There is ample available energy within PJM to satisfy these shortfalls, and to date the transmission system has had sufficient deliverability for these short-term energy purchases. As such, DEV's winter energy deficit has not posed, nor is it expected to pose, reliability concerns for Virginia. DEV's internal capacity (owned capacity, capacity acquired through long-term non-utility generation PPAs, and DSM reductions) has also been sufficient for meeting its obligations since 2015.

DEV has constructed a substantial amount of fossil-fuel and renewable generation to meet its capacity obligations and is planning for the retirement of legacy fossil-fuel based generation resources. Prior to the VCEA, DEV constructed the 1,588 MW Greensville Natural Gas Power Plant, which was placed into service in December 2018.[68] Since October of 2017, DEV has purchased, developed, or entered into PPAs with approximately 340 MW of solar resources, some of which was built for current or future compliance with the requirements of the GTSA and VCEA. The Commission has also determined that DEV's purchasing, developing, or entering into PPAs with 914 MW of solar resources and 103 MW of energy storage resources with expected commercial operation dates of 2022 and 2023 is prudent, and some of these projects, if necessary, received CPCNs.[69] DEV's approved offshore wind pilot project developed two 6 MW wind turbines in 2020, located off the shoreline of Virginia Beach, Virginia.[70] In addition, the

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beneficial for Virginia utilities to purchase energy from the PJM market to meet its winter peak, rather than to operate or construct a generating facility to meet this demand.

[68] 2021 DEV IRP Update at Appendix 5A.

[69] *See Petition of Virginia Electric and Power Company, For approval of its 2021 RPS Development Plan under § 56-585.5 D 4 of the Code of Virginia,* Case No. PUR-2021-00146, Doc. Con. Cen. No. 220320113, Final Order (March 15, 2022).

[70] *Petition of Virginia Electric and Power Company, For a prudency determination with respect to the Coastal Virginia Offshore Wind Project pursuant to Virginia Code § 56-585.1:4 F,* Case No. PUR-2018-00121, 2018 S.C.C. Ann. Rept. 491, Final Order (November 2, 2018).

Commission approved DEV's petition for cost recovery associated with preparing Petitions for Subsequent License Renewal to the Nuclear Regulatory Commission to extend the operating license of, and the projects reasonably appropriate to upgrade or replace systems and equipment deemed to be necessary to extend the life of, Dominion's Surry Units 1 and 2 and North Anna Units 1 and 2 nuclear generation facilities from 60 to 80 years.[71]

DEV's 2022 IRP update anticipates adding approximately 13,692 MW of solar, 2,600 MW of off-shore wind, 2,620 MW of storage, and retiring approximately 2,561 MW of generating resources over the next 15 years, based on DEV's VCEA-compliant IRP plan.[72] By constructing these facilities, DEV will continue to meet its internal capacity obligation with fewer purchases from the market.

DEV's forecasted load growth over the next 15 years, based on its 2022 IRP Update, is shown below:[73]

[71] *Petition of Virginia Electric and Power Company, For approval of a rate adjustment clause, designated Rider SNA under § 56-585.1 A 6 of the Code of Virginia*, Case No. PUR-2021-00229, Doc. Con. Cen. No. 220710001, Final Order (July 1, 2022).

[72] The VCEA compliant plan is referred to as Plan B in the 2022 DEV IRP Update. This plan was filed on September 1, 2022, for informational purposes only and has not been evaluated by the Commission. *See* 2022 DEV IRP at 2-4. In the past 5 years, DEV has retired 2,229 MW of fossil-fuel power plants, sold 2 MW of hydro-electric power plants, and anticipates that it will retire approximately 1,819 MW of oil- and coal-fired facilities in 2023. 2022 DEV IRP Update at Appendix 5J.

[73] This data was filed on September 1, 2022, for informational purposes only and has not been evaluated by the Commission.

Appendix 2B (i-iii): Capacity Information Directed by the SCC

	2022 PJM Load Forecast			
	Coincident Peak (CP)		Non-Coincident Peak (NCP)	
Year	DOM Zone Summer Forecast	LSE Equivalent	DOM Zone Summer Forecast	LSE Equivalent
2022	19,890	16,056	20,424	16,515
2023	20,418	16,220	21,013	16,731
2024	21,128	16,446	21,751	16,982
2025	21,977	16,770	22,568	17,278
2026	22,743	17,178	23,375	17,721
2027	23,008	17,331	23,681	17,910
2028	23,352	17,565	23,990	18,113
2029	23,692	17,809	24,358	18,382
2030	24,001	18,030	24,708	18,637
2031	24,414	18,336	25,085	18,913
2032	24,697	18,532	25,434	19,165
2033	25,060	18,793	25,807	19,434
2034	25,356	18,999	26,136	19,669
2035	25,854	19,385	26,568	19,998
2036	26,259	19,687	26,994	20,319
2037	26,669	19,983	27,354	20,572

B. Appalachian Power Company

For more than 60 years APCo was a member of the American Electric Power ("AEP") system, and APCo relied on the AEP Interconnection Agreement with other AEP affiliates to satisfy its load serving obligations. On January 1, 2014, the AEP Interconnection Agreement was terminated.[74] As a result, APCo is now a stand-alone entity and a member of PJM.[75]

Similar to Dominion, as a PJM member, APCo relies on its generating resources, purchased power contracts, DSM initiatives and short-term energy purchases for satisfying its load-serving obligations. PJM also considers APCo to be a winter-peaking utility, while, as previously

[74] *Appalachian Power Co., Kentucky Power Co., Indiana Michigan Power Co., AEP Generation Resources Inc., and Ohio Power Co.,*145 F.E.R.C. ¶ 61,267 (2013).

[75] APCo's participation in PJM's capacity market is also through the Fixed Resource Requirement Alternative. Through this alternative, APCo submits a fixed resource requirement capacity plan and has opted out of PJM's Reliability Pricing Model capacity auction through the 2023/2024 delivery year.

discussed, the PJM RTO as a whole is considered by PJM to be a *summer peaking* entity. Thus, PJM continues to procure capacity for APCo at levels commensurate with the coincident summer peak forecast. This could mean that satisfying PJM capacity requirements, which are designed around a summer peak, could make it difficult for APCo to self-supply its entire energy need in the winter. This potential energy shortfall can be satisfied through short-term purchases including purchases from the PJM market. There is ample available energy within PJM to satisfy these shortfalls, and to date the transmission system has had sufficient deliverability for these short-term energy purchases. As such, APCo's winter energy deficit has not posed, nor is it expected to pose, reliability concerns for Virginia.

APCo has also been increasing its portfolio of Virginia jurisdictional generation assets. In 2018, APCo entered into a PPA for a 120 MW wind farm located in Indiana.[76] Since October of 2017, APCo has entered into 55 MW of solar PPAs. APCo also has a portfolio of 630 MW of PPAs consisting of five wind farms, one hydro-electric facility, and three solar facilities expected to come online in 2022.[77]

Based on its 2022 IRP filed April 29, 2022, over the next 15 years, APCo anticipates that 1,785 MW of nameplate capacity solar, 1,154 MW of nameplate capacity wind, and 400 MW of energy storage will be added to its portfolio.[78] During this same time period, wind contracts of approximately 375 MW (nameplate) will expire.[79] None of APCo's generating units have retired over the previous five-year period.

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[76] Although located in Indiana, this plant's output is reserved for APCo's Virginia jurisdiction.

[77] 2022 APCo IRP at ES-1.

[78] These values are based on APCo's Hybrid Plan which APCo states is VCEA compliant. *Id.* at ES-4.

[79] *Id*. at ES-2.

APCo's forecasted load growth over the next 15 years, based on its 2022 IRP, is shown below:[80]

Exhibit A-9

Appalachian Power Company
Forecast Summer Peak Demand (MW) Coincident with PJM RTO
PJM, APCo IRP and APCo High Economic Scenario Forecasts

Year	APCo Portion of PJM Forecast* of AEP Zone	APCo Typical IRP Forecast** Coincident with PJM RTO	APCo High Forecast Coincident with PJM RTO
2022	5,513.8	5,513.8	5,661.4
2023	5,546.2	5,546.2	5,759.8
2024	5,571.4	5,571.4	5,834.6
2025	5,579.4	5,202.3	5,481.6
2026	5,467.0	5,071.3	5,374.3
2027	5,430.8	5,041.5	5,377.8
2028	5,416.4	5,026.5	5,406.4
2029	5,432.2	5,001.1	5,418.4
2030	5,446.7	4,992.2	5,438.5
2031	5,451.8	4,986.5	5,453.5
2032	5,476.2	4,980.6	5,473.6
2033	5,494.8	4,977.1	5,519.2
2034	5,500.6	4,973.7	5,557.6
2035	5,504.2	4,973.3	5,603.8
2036	5,505.6	4,987.2	5,666.9

* PJM forecast is based on PJM's 2021 Load Forecast.
* * APCo typically uses the PJM coincident forecast through the most recent Base Residual Auciton period, which is usally the first four years of the forecast.

In the 2020 APCo Triennial Review, the Commission required APCo to perform a unit-by-unit retirement analysis for the Amos and Mountaineer coal units located in West Virginia and

[80] APCo's 2022 IRP is currently pending before the Commission, therefore this data has not been validated at this time.

provide its analysis in APCo's 2022 IRP,[81] which is currently pending before the Commission. APCo is also separately seeking Commission approval for investments at Amos and Mountaineer, which is currently pending before the Commission.[82]

APCo's internal capacity (owned capacity, capacity acquired through long-term non-utility generation PPAs, and DSM reductions) is projected to be sufficient for meeting its capacity obligations through 2036.[83] APCo plans to continue purchasing energy, as is needed and economical, from the PJM market.

C. Electric Cooperatives

The majority of the electric distribution cooperatives are members of and rely on Old Dominion Electric Cooperative ("ODEC") for satisfying their power supply needs. ODEC meets the needs of its members through a combination of its own generation and PPAs. ODEC is a member of PJM and is subject to meeting PJM's load serving obligations, and also undertakes its own planning process for determining how best to meet its future needs. ODEC is regulated by FERC and is not subject to the Virginia IRP process.

Four cooperatives, CBEC, CVEC, NOVEC, and Powell Valley Electric Cooperative, are not members of ODEC and meet their internal needs through a combination of PPAs and owned

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[81] 2022 APCo IRP at 85-87.

[82] *Petition of Appalachian Power Company For approval of a rate adjustment clause, the E-RAC, for costs to comply with state and federal environmental regulations pursuant to § 56-585.1 A 5 E of the Code of Virginia*, Case No. PUR-2022-00001, Doc. Con. Cen. No. 220420263, Order for Notice and Hearing (April 21, 2022). In the previous E-RAC Proceeding in 2021, APCo was denied recovery by the Commission of capital costs pertaining to upgrades related to the requirements of the Environmental Protection Agency's Steam Electric Effluent Limitation Guidelines. *Petition of Appalachian Power Company For approval of a rate adjustment clause, the E-RAC, for costs to comply with state and federal environmental regulations pursuant to § 56-585.1 A 5 E of the Code of Virginia*, Case No. PUR-2020-00258, 2021 S.C.C. Ann. Rept. 330, Order Granting Rate Adjustment Clause (August 23, 2021).

[83] For purposes of this expectation, APCo assumes the continued availability of the capacity and energy produced by the Amos and Mountaineer coal generation facilities.

generation. CBEC and CVEC rely almost entirely on PPAs.[84] Powell Valley Electric Cooperative purchases power from the Tennessee Valley Authority.[85] NOVEC has entered into a number of PPAs, including a long-term 300 MW solar PPA, and purchases some power from short-term markets. NOVEC also operates a 49.9 MW biomass generating facility in Halifax County, Virginia.

IV. PEER GROUP COMPARISON

The Commission continues to monitor electricity rates in the Commonwealth, with a particular focus on changes in rates since the Regulation Act went into effect on July 1, 2007.[86] Section 56-585.1 A 2 e requires that in setting the ROE for an electric IOU, "the Commission shall strive to maintain costs of retail electric energy that are cost competitive with costs of retail electric energy provided by the other peer group investor-owned electric utilities." Further, the Clause requires the Commission to report every five years on a comparison of Virginia IOUs to those in their peer groups that meet the criteria of Code § 56-585.1 A 2. The peer group utilities for DEV and APCo currently meeting statutory requirements include: Alabama Power Company, Duke Energy Carolinas (includes North Carolina and South Carolina), Florida Power & Light Company, Mississippi Power, Duke Energy Progress Inc. (includes North Carolina and South Carolina),

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[84] CVEC owns a small amount of generation. CBEC also purchases power from APCo and DEV.

[85] Powell Valley Electric Cooperative's rates are regulated by its federal wholesale power supplier.

[86] Separate financial reviews of DEV and APCo also were conducted by Staff; those results were included in the "Rate and Capital Outlook" section of the Commission's *Status Report: Implementation of the Virginia Electric Utility Regulation Act Pursuant to § 56-596 B of the Code of Virginia*, dated September 1, 2022. This report can be accessed through the Virginia Legislative Information System.

Duke Energy Florida, Inc., Dominion Energy South Carolina, Tampa Electric Company, Kentucky Utilities, Inc. ("KU"), and Louisville Gas and Electric Company ("LG&E").[87]

Pursuant to these directives, the Commission, through its Staff, developed several rate comparisons that utilize information from various EEI publications in an effort to assess the competitiveness of DEV's and APCo's rates as compared to those of the statutorily defined peer groups. In examining rate competitiveness, this analysis focused on the level of rates and did not attempt to focus on other potential measures of competitiveness such as electrical costs as a percent of income or as a percent of production costs. These comparisons are presented in Appendices 4, 5, and 6.

Typical bills for DEV, APCo, and their statutorily defined peer groups also were examined for differing customer groups and varying ranges of consumption.[88] This analysis focuses on typical bills for residential, commercial, and industrial customers and examines the competitiveness of DEV's rates and APCo's rates that were in effect on January 1, 2022.[89] For purposes of this evaluation, a ranking closer to 1 equates with a lower, more competitive customer rate. For example, a customer of a utility with a ranking of 2 would have a lower rate than a customer of a utility with a ranking of 10.

It should be noted that the typical bill comparisons are based on the annualized rates[90] in effect on January 1, 2022, and as such, do not reflect any subsequent or pending rate changes. Any

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[87] KU and LG&E are excluded from the peer group analysis due to an absence of annualized data across all customer classes. Dominion Energy South Carolina, formerly referred to as South Carolina Electric and Gas, was used as a peer group utility for the purpose of APCo's Triennial Reviews but was also excluded from the peer group analysis as it is an affiliate company of DEV. *See* DEV 2021 Triennial Review, S.C.C. Ann. Rept. 444, Final Order (Nov. 18, 2021); *see also* 2020 APCo Triennial Review, 2020 S.C.C. Ann. Rept. 435, Final Order (Dec. 15, 2020).

[88] Typical bills are presented according to the usage and demand levels reported in the EEI reports.

[89] January 1, 2022, represents the latest information available from EEI.

[90] Annualized rates reflect a weighted average of summer and winter rates for those utilities that have such rates.

pending rate changes could increase or decrease the relative competitiveness of DEV's or APCO's rates, and potentially their ranking, if the rates of the peer group do not change on a comparable basis.

DEV's January 1, 2022, annualized residential rates[91] produce typical bills that rank DEV 5th out of the 11 companies[92] examined and are below the U.S., South Atlantic, and East South Central region EEI averages.[93] DEV's January 1, 2022, annualized commercial rates produce typical bills that range from 2nd to 5th out of the 11 companies examined and remain below the U.S., South Atlantic, and East South Central regional averages. DEV's January 1, 2022, annualized industrial rates produce bills that range from 2nd to 9th out of the 11 companies examined and are below the U.S. and East South Central average and, for the most part, are below the South Atlantic regional averages. In an overall ranking, DEV is 4th in annualized residential rates, 3rd for annualized commercial rates, and 5th for annualized industrial rates.[94]

APCo's January 1, 2022, annualized residential rates produce typical bills that rank APCo 7th out of 11 companies and are below the U.S., South Atlantic, and East South Central regional averages. APCo's January 1, 2022, annualized commercial rates produced typical bills that range from 1st to 8th out of the 11 companies examined and are below the U.S., South Atlantic, and East South Central regional averages. APCo's January 1, 2022, industrial typical bills are ranked 4th to 9th out of the 11 companies examined and are below the U.S., South Atlantic, and East South

[91] These rates are based on a residential customer using 1,000 kWh per month, which is referred to as a "typical bill" by EEI.

[92] Many of the peer group companies serve in more than one state and have differing typical bills depending on the respective state. Consequently, the typical bill comparison may include multiple listings for certain peer group companies.

[93] EEI's South Atlantic region includes Delaware, the District of Columbia, Florida, Georgia, Maryland, North Carolina, South Carolina, Virginia, and West Virginia. EEI's East South Central region includes Alabama, Kentucky, Mississippi, and Tennessee.

[94] This calculation was made by averaging individual customer class rates and ranking the composite averages.

Central regional averages. In an overall ranking, APCo is 6th in annualized residential, commercial, and industrial rates.

Similar comparisons for the remaining peer group utilities may be drawn from the attached Appendices 4, 5, and 6. It should be noted that publicly available reliability-related information for the peer group is limited, and as such, any reliability differences could only be developed on a somewhat superficial level. A review of reliability related information for the peer group utilities did not show any discernible trends in reliability or any indication that DEV's or APCo's overall ability to serve native load was notably different from that of the peer group.

In summary, at this time, APCO's and DEV's electricity rates appear to be fairly competitive with their peer utilities, although pending and future rate requests, with a specific regard to fuel factor cases, could impact the competitiveness of electricity rates in the future.

CLOSING

Enactment Clause 7 of the 2007 Regulation Act requires the Commission to submit a report to the Governor and General Assembly by November 1, 2012, and every five years thereafter, assessing the rates and terms and conditions of incumbent electric utilities in the Commonwealth including an analysis of "the amount, reliability and type of generation facilities needed to serve Virginia native load compared to that available to serve such load." The Commission appreciates the opportunity to update the Governor and General Assembly on the matters detailed herein. The Commission will continue to execute its responsibilities under the Regulation Act and stands ready to implement the laws passed by the General Assembly.

APPENDIX 1

1. A&N Electric Cooperative

On January 30, 2018, A&N filed an application for a community solar pilot program pursuant to § 56-585.1:3 C of the Code in Case No. PUR-2018-00021. The Commission approved A&N's request on July 24, 2018.[95] Additionally, A&N filed a base rate application on February 20, 2018, in Case No. PUR-2018-00031. On September 13, 2018, the Commission issued its Final Order in that proceeding which, among other things, approved a stipulation that resulted in a $2.6 million increase in A&N's base rates.[96]

2. BARC Electric Cooperative

BARC administratively increased its rates by 5% pursuant to § 56-585.3 A 2 of the Code effective January 1, 2019. Also, on December 1, 2021, BARC submitted revised Terms and Conditions for Service effective December 2, 2021. In addition, BARC filed an application on April 1, 2022, seeking approval of a base rate increase of $1.93 million.[97] An evidentiary hearing in this proceeding is currently scheduled for November 16, 2022.

3. Craig-Botetourt Electric Cooperative

CBEC administratively increased its rates by 5% and rebalanced customer charges in accordance with Code § 56-585.3 A 4 effective August 1, 2019.

Additionally, CBEC sought Commission approval of a base rate change in Case No. PUR-2020-00131. By Final Order dated August 11, 2021, the Commission approved a revenue increase of $729,740 effective for service rendered on and after July 1, 2021.[98]

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[95] *Application of A&N Electric Cooperative*, *For approval of a community solar tariff*, Case No. PUR-2018-00020, 2018 S.C.C. Ann. Rept. 358, Final Order (July 24, 2018).

[96] *Application of A&N Electric Cooperative, For a general increase in electric rates,* Case No. PUR-2018-00031, 2018 S.C.C. Ann. Rept. 373, Final Order (September 13, 2018).

[97] *Application of BARC Electric Cooperative, For a general increase in electric rates,* Case No. PUR-2022-00048, Doc. Con. Cen. No. 220430174, Order for Notice and Hearing (April 27, 2022).

[98] *Application of Craig-Botetourt Electric Cooperative, For a general increase in electric rates*, Case No. PUR-2020-00131, 2021 S.C.C. Ann. Rept. 240, Final Order (August 11, 2021).

4. Community Electric Cooperative

On April 1, 2020, Community Electric Cooperative administratively increased its rates by 5% and simultaneously rebalanced its revenues between its fixed and volumetric charges in accordance with § 56-585.3 A 2 and § 56-585.3 A 4 of the Code.

5. Central Virginia Electric Cooperative

On December 6, 2017, CVEC filed an application for approval of a community solar tariff pursuant to 56-585.1:3 C of the Code. The Commission approved CVEC's request for a community solar pilot program on May 8, 2018.[99] Subsequently, on August 4, 2022, CVEC filed to reopen the case and make its pilot program permanent. This case is currently pending before the Commission.

On August 6, 2018, CVEC sought Commission approval for a base rate increase in Case No. PUR-2018-00125. By Final Order dated June 11, 2019, the Commission approved a stipulation which provided for a base rate increase of approximately $5 million effective November 1, 2018.[100]

On September 8, 2021, CVEC filed an application for approval of a voluntary tariff for Electric Vehicle owners (Schedule A-TOU) pursuant to Code § 56-40, which was approved by the Commission on February 14, 2022, in Case No. PUR-2021-00216.[101]

6. Mecklenburg Electric Cooperative

On August 9, 2017, MEC filed an application for approval of a new proposed voluntary prepaid electric service tariff in Case No. PUR-2017-00108. On December 14, 2017, the Commission granted MEC's application subject to certain requirements.[102]

MEC has also submitted other filings to the Commission or through Staff. MEC administratively revised its Schedule SL – Street, Highway and Outdoor Lighting Service – to add light emitting diode bulbs effective April 1, 2018. In addition, MEC filed an application for approval of a community solar tariff pursuant to 56-585.1:3 C of the Code. The Commission

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[99] *Application of Central Virginia Electric Cooperative For approval of a community solar tariff*, Case No. PUR-2017-00165, 2018 S.C.C. Ann. Rept. 324, Final Order (May 8, 2018).

[100] *Application of Central Virginia Electric Cooperative, For general rate relief*, Case No. PUR-2018-00125, 2019 S.C.C. Ann. Rept. 253, Final Order (June 11, 2019).

[101] *Application of Central Virginia Electric Cooperative, For approval of a rate schedule effecting no increase*, Case No. PUR-2021-00216, Doc. Con. Cen. No. 220220216, Order (February 14, 2022).

[102] *Application of Mecklenburg Electric Cooperative, For approval of prepaid electric service tariff*, Case No. PUR-2017-00108, 2017 S.C.C. Ann. Rept. 554, Order on Application (December 14, 2017).

approved MEC's request for a community solar pilot program on July 24, 2018.[103] Lastly, MEC administratively increased its rates by 5%, effective January 1, 2020, pursuant to § 56-585.3 of the Code.

7. Northern Neck Electric Cooperative

Through an order dated May 11, 2018, the Commission authorized NNEC to increase base rates by $1.8 million.[104] Additionally, in Case No. PUR-2018-00022 the Commission approved NNEC's request for a community solar pilot program on July 24, 2018, pursuant to 56-585.1:3 C of the Code. [105]

On July 16, 2020, NNEC filed another application for approval of an increase to its base rates and a new demand charge for residential, prepaid, and small general service customers. On June 1, 2021, the Commission issued a Final Order adopting a stipulation that granted an increase of approximately $1.5 million in revenues.[106] Subsequently, NNEC exercised its authority pursuant to § 56-585.3 A 4 of the Code to increase administratively its demand charge in conjunction with a corresponding reduction in its distribution delivery charges effective on and after January 1, 2022.

8. Northern Virginia Electric Cooperative

On March 19, 2019, the Commission approved NOVEC request for approval to implement a large power dedicated facilities contract service schedule, HV-2, in Case No. PUR-2018-00165.[107]

9. Prince George Electric Cooperative

Prince George Electric Cooperative administratively increased its rates by 5% pursuant to § 56-585.3 A 2 of the Code effective January 1, 2020.

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[103] *Application of Mecklenburg Electric Cooperative*, *For approval of a community solar tariff*, Case No. PUR-2018-00021, 2018 S.C.C. Ann. Rept. 360, Final Order (July 24, 2018).

[104] *Application of Northern Neck Electric Cooperative*, *For a general increase in electric rates*, Case No. PUR-2017-00101, 2018 S.C.C. Ann. Rept. 249, Final Order (May 11, 2018).

[105] *Application of Northern Neck Electric Cooperative*, *For approval of a community solar tariff*, Case No. PUR-2018-00022, 2018 S.C.C. Ann. Rept. 362, Final Order (July 24, 2018).

[106] *Application of Northern Neck Electric Cooperative*, *For a general increase in electric rates*, Case No. PUR-2020-00083, 2021 S.C.C. Ann. Rept. 209, Final Order (June 1, 2021).

[107] *Application of Northern Virginia Electric Cooperative, For approval to implement a Large Power Dedicated Facilities Contract Service Schedule, HV-2*, Case No. PUR-2018-00165, 2019 S.C.C. Ann. Rept. 279, Order (March 19, 2019).

10. Rappahannock Electric Cooperative

On May 23, 2017, Rappahannock filed an application for, among other things, approval of an increase to its base rates and revised depreciation rates. On January 9, 2018, the Commission issued a Final Order adopting a stipulation that granted an increase of approximately $18 million in revenues and approved the depreciation rates, as modified by Staff.[108]

Rappahannock has submitted several other filings with Staff or the Commission since 2017. In Case No. PUR-2018-00019, the Commission approved Rappahannock's request for a community solar pilot program on July 24, 2018.[109] In addition, in Case No. PUR-2019-00217, the Commission approved Rappahannock's request to revise Schedule PTR Pilot, Peak Time Rebate on March 13, 2020.[110] Rappahannock also administratively increased its rates by 5% in accordance with Code § 56-585.3 A 2 effective January 1, 2021.

On September 10, 2021, Rappahannock submitted its 100% Renewable Energy Attributes Electric Service Rider, designated as Schedule RE, pursuant to § 56-585.3 A 7 of the Code. Also, Rappahannock filed an application for approval of an electric vehicle smart charging pilot in Case No. PUR-2020-00001, which was approved by the Commission on December 17, 2021.[111] Most recently, on July 29, 2022, Rappahannock provided an informational filing of its On-Bill Tariff Program for energy efficiency measures in accordance with § 56-585.7 B of the Code.

11. Shenandoah Valley Electric Cooperative

SVEC administratively filed revisions to its Terms and Conditions of Service pursuant to § 56-585.3 A 3 of the Code effective July 26, 2018. Also, SVEC increased its rates by 5% and rebalanced customer charges in accordance with Code § 56-585.3 A 4 effective January 3, 2020. This change increased the single-phase residential customer's monthly basic consumer charge from $13.76 to $25.00.

On March 16, 2021, SVEC filed an application for a general rate increase, as well as a request to implement demand charges for its residential and church classes, in Case No. PUR-2021-00054. On March 11, 2022, the Commission issued its Final Order in that proceeding[112] and, subsequently, SVEC submitted a petition for reconsideration. On May 5, 2022, the

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[108] *Application of Rappahannock Electric Cooperative, For a general increase in electric rates,* Case No. PUR-2017-00044, 2018 S.C.C. Ann. Rept. 213, Final Order (June 9, 2018). *See* Ex. 1 (Stipulation) at 3-4.

[109] *Application of Rappahannock Electric Cooperative*, *For approval of a community solar tariff*, Case No. PUR-2018-00019, 2018 S.C.C. Ann. Rept. 357, Final Order (July 24, 2018).

[110] *Application of Rappahannock Electric Cooperative*, *For approval of a peak time rebate pilot program,* Case No. PUR-2019-00217, 2020 S.C.C. Ann. Rept. 397, Final Order (March 13, 2020).

[111] *Application of Rappahannock Electric Cooperative*, *For Approval of an Electric Vehicle Smart Charging Pilot Program*, Case No. PUR-2020-00001, 2021 S.C.C. Ann. Rept. 176, Final Order (December 17, 2021).

[112] *Application of Shenandoah Valley Electric Cooperative, For general increase in electric rates,* Case No. PUR-2021-00054, Doc. Con. Cen. No. 220320024, Final Order (March 11, 2022).

Commission issued its Order on Reconsideration, clarifying that the demand charges were denied for both residential and church service customers as SVEC does not have the existing capability to fully implement all aspects thereof.[113]

12. Southside Electric Cooperative

SEC administratively filed revisions to its Terms and Conditions of Service pursuant to § 56-585.3 A 3 of the Code effective August 16, 2018. In addition, on July 19, 2019, SEC applied for, among other things, approval to increase its base rates and implement demand charges for residential and general service customers. On April 22, 2020, the Commission issued its Final Order adopting a stipulation that granted an increase of approximately $8.019 million in revenues and approving the demand charges.[114]

[113] *Application of Shenandoah Valley Electric Cooperative, For general increase in electric rates,* Case No. PUR-2021-00054, Doc. Con. Cen. No. 220510062, Order on Reconsideration at 3 (May 5, 2022).

[114] *Application of Southside Electric Cooperative, For a general increase in electric rates,* Case No. PUR-2019-00090, 2020 S.C.C. Ann. Rept. 277, Final Order (April 22, 2020).

APPENDIX 2

DOMINION ENERGY VIRGINIA
Residential Bill Increases Since
July 1, 2007

Bill as of 7/1/07		$ 90.59
Increases Granted Per Code Section:		
2018 Senate Bill 966 Enactment Clauses 6 and 7 (Tax Reform)		$ (3.78)
56-585.1 A		
Base Rates (Triennial Review)		$ (0.89)
Rider VRR (Voluntary Rate Reduction)		$ (0.47)
56-585.1 A 4		
Base Rate Transmission (56-585.1 A 3)	$ 6.92	
Rider T1 (Transmission)	$ 6.90	
Total Transmission Rate Adjustment Clause		$ 13.82
56-585.1 A 5		
Base Rate Energy Efficiency (56-585.1 A 3)	$ 0.11	
Riders C1A, C2A, C3A, and C4A (DSM)	$ 1.31	
Rider E (Coal Ash)	$ 1.25	
Rider CCR (Coal Ash)	$ 2.95	
Rider RPS (RPS Compliance)	$ 0.18	
Total 56-585.1 A 5		$ 5.80
56-585.1 A 6		
Rider R (Bear Garden)	$ 1.14	
Rider S (Virginia City)	$ 3.70	
Rider W (Warren County)	$ 2.34	
Rider B (Biomass)	$ 0.30	
Rider BW (Brunswick County)	$ 2.10	
Rider GV (Greensville County)	$ 2.75	
Rider US-2 (Solar)	$ 0.17	
Rider US-3 (Solar)	$ 0.96	
Rider US-4 (Solar)	$ 0.30	
Rider CE (Owned Solar and Storage)	$ 1.32	
Rider U (Underground)	$ 2.50	
Rider GT (Grid Transformation)	$ 1.16	
Rider RBB (Rural Broadband)	$ 0.03	
Total 56-585.1 A 6		$ 18.77
56-585.6 PIPP Universal Service Fee		$ 0.03
56-249.6 Fuel Factor		$ 13.06
Bill as of 7/1/22		**$ 136.93**
Proposed Changes Per Code Section:		
56-585.1 A 4 (Rider T1)		$ (3.69)
56-585.1 A 5 (Riders RPS, PPA, C1A/C2A/C3A/C4A, E, and CCR)		$ 2.57
56-585.1 A 6 (Riders W, BW, B, US-2, CE, SNA, OSW, U, and RBB)		$ 5.02
Bill with Proposed Changes		**$ 140.83**

APPENDIX 3

APPALACHIAN POWER COMPANY
Residential Bill Increases Since
July 1, 2007

Bill as of 7/1/07		$ 66.61
Increases Granted Per Code Section:		
56-582 C (Base Rate Increase)		$ 13.12
56-585.1 A (Going-In and Biennial Rate Reviews)		$ 9.87
56-582 B (Reliability and Environmental Adjustment)		$ (1.84)
2018 Senate Bill 966 Enactment Clauses 6 and 7 (Tax Reform) - TRR Rider Credit		
Base Rates		$ (4.58)
TRR Rider Credit		$ (3.12)
56-585.1 A 4		
Base Rate Transmission	$ (4.66)	
T-RAC (Transmission)	$ 31.55	
Total Transmission Rate Adjustment Clause		$ 26.89
56-585.1 A 5		
DR-RAC (Demand Response)	$ 0.22	
EE-RAC (Energy Efficiency)	$ 1.12	
E-RAC (Coal Ash)	$ 2.11	
RPS-RAC (RPS Compliance)	$ (1.16)	
Total 56-585.1 A 5		$ 2.29
56-585.1 A 6		
G-RAC (Dresden Gas Combined Cycle)	$ 2.55	
BC-RAC (Rural Broadband)	$ 0.54	
Total 56-585.1 A 6		$ 3.09
56-585.6 PIPP Universal Service Fee		$ 0.04
56-249.6 Fuel Factor		$ 9.88
Bill as of 7/1/22		**$ 122.25**
Proposed Changes Per Code Section:		
56-585.1 A 4 (T-RAC)		$ 2.88
56-585.1 A 5 (EE-RAC, E-RAC, RPS-RAC)		$ 3.51
56-585.1 A 6 (BC-RAC)		$ (0.69)
Bill with Proposed Changes		**$ 127.95**

*On September 15, 2022, APCo filed an application proposing to increase its monthly fuel factor charge by $20.19 (to a total of $43.19 per month) effective November 1, 2022. This application is currently pending before the Commission.

PEER GROUP
Typical Bill Comparison
Residential Customers

Monthly Usage of 500 kWh:	July 2007 $	Jan 2017 $	Jan 2022 $	2007 to 2022 Change %	2007 Rank	2017 Rank	2022 Rank	2007 to 2022 Rank Change
Alabama Power	$ 58.25	$ 74.53	$ 79.97	37.29%	9	10	10	-1
Appalachian Power Company (Va)	$ 37.60	$ 61.35	$ 65.65	74.60%	1	7	4	-3
Dominion Virginia Power	$ 49.70	$ 60.28	$ 65.02	30.82%	5	5	3	2
DUKE Energy Carolinas (NC)	$ 45.78	$ 58.35	$ 60.14	31.37%	3	2	1	2
DUKE Energy Carolinas (SC)	$ 42.29	$ 60.15	$ 65.65	55.24%	2	4	4	-2
FP&L Company	$ 54.45	$ 51.77	$ 60.38	10.89%	8	1	2	6
Georgia Power	$ 47.84	$ 60.90	$ 68.20	42.56%	4	6	7	-3
Mississippi Power	$ 70.04	$ 76.13	$ 81.07	15.75%	11	11	11	0
Duke Energy Progress, Inc. (NC)	$ 51.16	$ 58.57	$ 70.05	36.92%	6	3	8	-2
Duke Energy Progress, Inc. (SC)	$ 52.08	$ 61.96	$ 67.32	29.26%	7	8	6	1
Duke Progress Energy Florida, Inc.	$ 59.29	$ 62.32	$ 72.04	21.50%	10	9	9	1
Average For East South Central	$ 51.06	$ 61.56	$ 78.28	53.31%				
Average For South Atlantic	$ 54.35	$ 65.38	$ 69.76	28.35%				
USA Average	$ 59.34	$ 71.46	$ 86.91	46.46%				

Monthly Usage of 750 kWh:	July 2007 $	Jan 2017 $	Jan 2022 $	2007 to 2022 Change %	2007 Rank	2017 Rank	2022 Rank	2007 to 2022 Rank Change
Alabama Power	$ 82.59	$ 104.34	$ 112.19	35.84%	9	11	11	-2
Appalachian Power Company (Va)	$ 52.16	$ 87.82	$ 94.74	81.63%	1	7	7	-6
Dominion Virginia Power	$ 71.04	$ 86.91	$ 94.23	32.64%	5	6	4	1
DUKE Energy Carolinas (NC)	$ 66.05	$ 81.17	$ 82.74	25.27%	3	2	1	2
DUKE Energy Carolinas (SC)	$ 60.35	$ 85.75	$ 92.16	52.71%	2	4	3	-1
FP&L Company	$ 78.95	$ 73.60	$ 86.12	9.08%	8	1	2	6
Georgia Power	$ 68.60	$ 85.96	$ 94.55	37.83%	4	5	5	-1
Mississippi Power	$ 92.48	$ 100.36	$ 107.79	16.55%	11	10	10	1
Duke Energy Progress, Inc. (NC)	$ 73.36	$ 81.63	$ 97.47	32.87%	6	3	8	-2
Duke Energy Progress, Inc. (SC)	$ 74.87	$ 88.24	$ 94.59	26.34%	7	8	6	1
Duke Progress Energy Florida, Inc.	$ 84.81	$ 88.98	$ 102.13	20.42%	10	9	9	1
Average For East South Central	$ 70.51	$ 84.86	$ 108.11	53.33%				
Average For South Atlantic	$ 78.09	$ 92.89	$ 98.62	26.29%				
USA Average	$ 85.68	$ 102.94	$ 124.70	45.54%				

PEER GROUP
Typical Bill Comparison
Residential Customers

Monthly Usage of 1000 kWh:	July 2007 $	Jan 2017 $	Jan 2022 $	2007 to 2022 Change %	2007 Rank	2017 Rank	2022 Rank	2007 to 2022 Rank Change
Alabama Power	$ 104.94	$ 132.10	$ 142.37	35.67%	9	11	11	-2
Appalachian Power Company (Va)	$ 66.72	$ 114.29	$ 123.83	85.60%	1	8	7	-6
Dominion Virginia Power	$ 90.59	$ 111.76	$ 121.80	34.45%	5	5	5	0
DUKE Energy Carolinas (NC)	$ 86.33	$ 103.98	$ 105.34	22.02%	3	2	1	2
DUKE Energy Carolinas (SC)	$ 78.42	$ 111.34	$ 118.68	51.34%	2	4	3	-1
FP&L Company	$ 103.46	$ 95.43	$ 111.85	8.10%	8	1	2	6
Georgia Power	$ 90.23	$ 112.36	$ 122.27	35.51%	4	6	6	-2
Mississippi Power	$ 114.76	$ 124.42	$ 134.25	16.98%	11	10	10	1
Duke Energy Progress, Inc. (NC)	$ 95.56	$ 104.70	$ 124.89	30.69%	6	3	8	-2
Duke Energy Progress, Inc. (SC)	$ 96.33	$ 113.17	$ 120.53	25.12%	7	7	4	3
Duke Progress Energy Florida, Inc.	$ 110.34	$ 115.65	$ 132.24	19.84%	10	9	9	1
Average For East South Central	$ 89.60	$ 107.87	$ 137.49	53.45%				
Average For South Atlantic	$ 101.70	$ 120.34	$ 127.40	25.27%				
USA Average	$ 111.68	$ 133.99	$ 162.33	45.35%				

PEER Group
Typical Bill Comparison
Commercial Customers

Usage of 375 kWh:	July 2007 $	Jan 2017 $	Jan 2022 $	2007 to 2022 Change %	2007 Rank	2017 Rank	2022 Rank	2007 to 2022 Rank Change
Alabama Power	$ 53.00	$ 88.13	$ 97.29	83.57%	9	11	11	-2
Appalachian Power Company (Va)	$ 30.00	$ 46.00	$ 48.12	60.40%	1	2	1	0
Dominion Virginia Power	$ 45.00	$ 50.44	$ 53.35	18.56%	2	3	3	-1
DUKE Energy Carolinas (NC)	$ 49.00	$ 67.06	$ 67.27	37.29%	5	8	7	-2
DUKE Energy Carolinas (SC)	$ 46.00	$ 59.20	$ 62.68	36.26%	3	6	4	-1
FP&L Company	$ 49.00	$ 44.00	$ 51.34	4.78%	5	1	2	3
Georgia Power	$ 58.00	$ 78.00	$ 92.72	59.85%	10	9	10	0
Mississippi Power	$ 69.00	$ 78.00	$ 84.00	21.74%	11	9	9	2
Duke Energy Progress, Inc. (NC)	$ 50.00	$ 64.00	$ 71.00	42.00%	7	7	8	-1
Duke Energy Progress, Inc. (SC)	$ 48.00	$ 55.00	$ 64.00	33.33%	4	5	6	-2
Duke Progress Energy Florida, Inc.	$ 51.00	$ 53.00	$ 63.64	24.79%	8	4	5	3
Average For East South Central	$ 48.00	$ 65.00	$ 76.00	58.33%				
Average For South Atlantic	$ 50.00	$ 59.00	$ 64.00	28.00%				
USA Average	$ 55.00	$ 65.00	$ 78.00	41.82%				

Usage of 1,500 kWh:	2022 $	2022 Rank
Alabama Power	$ 307.09	11
Appalachian Power Company (Va)	$ 165.03	1
Dominion Virginia Power	$ 168.61	2
DUKE Energy Carolinas (NC)	$ 195.48	5
DUKE Energy Carolinas (SC)	$ 207.69	8
FP&L Company	$ 170.71	3
Georgia Power	$ 243.10	10
Mississippi Power	$ 196.00	6
Duke Energy Progress, Inc. (NC)	$ 193.00	4
Duke Energy Progress, Inc. (SC)	$ 209.00	9
Duke Progress Energy Florida, Inc.	$ 207.60	7
Average For East South Central	$ 225.00	
Average For South Atlantic	$ 194.00	
USA Average	$ 238.00	

Demand of 40 kW and Usage of 10,000 kWH:	July 2007 $	Jan 2017 $	Jan 2022 $	2007 to 2022 Change %	2007 Rank	2017 Rank	2022 Rank	2007 to 2022 Rank Change
Alabama Power	$ 1,094.00	$ 1,432.02	$ 1,540.49	40.81%	11	11	11	0
Appalachian Power Company (Va)	$ 619.00	$ 1,042.00	$ 1,104.18	78.38%	1	8	7	-6
Dominion Virginia Power	$ 836.00	$ 987.32	$ 1,100.22	31.61%	5	6	5	0
DUKE Energy Carolinas (NC)	$ 757.00	$ 867.62	$ 837.70	10.66%	3	2	1	2
DUKE Energy Carolinas (SC)	$ 733.00	$ 887.64	$ 911.84	24.40%	2	3	2	0
FP&L Company	$ 1,055.00	$ 962.00	$ 1,101.12	4.37%	9	5	6	3
Georgia Power	$ 1,089.00	$ 1,387.26	$ 1,515.23	39.14%	10	10	10	0
Mississippi Power	$ 1,009.00	$ 1,029.00	$ 1,108.00	9.81%	8	7	8	0
Duke Energy Progress, Inc. (NC)	$ 803.00	$ 866.00	$ 1,016.00	26.53%	4	1	3	1
Duke Energy Progress, Inc. (SC)	$ 839.00	$ 960.00	$ 1,048.00	24.91%	6	4	4	2
Duke Progress Energy Florida, Inc.	$ 971.00	$ 1,053.00	$ 1,186.21	22.16%	7	9	9	-2
Average For East South Central	$ 929.00	$ 1,116.00	$ 1,416.00	52.42%				
Average For South Atlantic	$ 992.00	$ 1,101.00	$ 1,260.00	27.02%				
USA Average	$ 1,081.00	$ 1,234.00	$ 1,505.00	39.22%				

PEER Group
Typical Bill Comparison
Commercial Customers

Demand of 40 kW and Usage of 14,000 kWh:	July 2007 $	Jan 2017 $	Jan 2022 $	2007 to 2022 Change %	2007 Rank	2017 Rank	2022 Rank	2007 to 2022 Rank Change
Alabama Power	$ 1,378.00	$ 1,818.57	$ 1,978.30	43.56%	11	11	11	0
Appalachian Power Company (Va)	$ 775.00	$ 1,260.00	$ 1,350.59	74.27%	1	7	7	-6
Dominion Virginia Power	$ 786.00	$ 1,181.12	$ 1,332.29	69.50%	2	5	5	-3
DUKE Energy Carolinas (NC)	$ 985.00	$ 1,054.74	$ 1,039.00	5.48%	5	2	1	4
DUKE Energy Carolinas (SC)	$ 951.00	$ 1,106.97	$ 1,136.16	19.47%	3	3	2	1
FP&L Company	$ 1,355.00	$ 1,166.00	$ 1,339.68	-1.13%	10	4	6	4
Georgia Power	$ 1,263.00	$ 1,547.51	$ 1,687.14	33.58%	8	10	10	-2
Mississippi Power	$ 1,262.00	$ 1,265.00	$ 1,369.00	8.48%	7	8	8	-1
Duke Energy Progress, Inc. (NC)	$ 982.00	$ 1,054.00	$ 1,212.00	23.42%	4	1	3	1
Duke Energy Progress, Inc. (SC)	$ 1,030.00	$ 1,187.00	$ 1,281.00	24.37%	6	6	4	2
Duke Progress Energy Florida, Inc.	$ 1,299.00	$ 1,311.00	$ 1,462.10	12.56%	9	9	9	0
Average For East South Central	1,160.00	1,443.00	1808	55.86%				
Average For South Atlantic	1,287.00	1,395.00	1594	23.85%				
USA Average	1,387.00	1,570.00	1926	38.86%				

Demand of 500 kW and Usage of 150,000 kWh:	July 2007 $	Jan 2017 $	Jan 2022 $	2007 to 2022 Change %	2007 Rank	2017 Rank	2022 Rank	2007 to 2022 Rank Change
Alabama Power	$ 15,449.00	$ 19,779.53	$ 21,385.32	38.43%	11	11	11	0
Appalachian Power Company (Va)	$ 8,967.00	$ 14,534.00	$ 15,549.73	73.41%	1	9	8	-7
Dominion Virginia Power	$ 10,371.00	$ 12,991.34	$ 14,205.88	36.98%	4	6	5	-1
DUKE Energy Carolinas (NC)	$ 10,306.00	$ 11,463.04	$ 11,170.17	8.39%	3	2	1	2
DUKE Energy Carolinas (SC)	$ 9,852.00	$ 12,381.90	$ 12,871.05	30.64%	2	4	3	-1
FP&L Company	$ 14,829.00	$ 12,875.00	$ 15,448.89	4.18%	10	5	6	4
Georgia Power	$ 13,175.00	$ 16,037.30	$ 16,118.46	22.34%	7	10	10	-3
Mississippi Power	$ 13,570.00	$ 14,043.00	$ 15,547.00	14.57%	8	7	7	1
Duke Energy Progress, Inc. (NC)	$ 10,913.00	$ 10,556.00	$ 13,439.00	23.15%	5	1	4	1
Duke Energy Progress, Inc. (SC)	$ 11,451.00	$ 11,656.00	$ 12,504.00	9.20%	6	3	2	4
Duke Progress Energy Florida, Inc.	$ 13,914.00	$ 14,425.00	$ 15,788.67	13.47%	9	8	9	0
Average For East South Central	$ 11,908.00	$ 14,941.00	$ 19,590.00	64.51%				
Average For South Atlantic	$ 13,854.00	$ 15,128.00	$ 18,510.00	33.61%				
USA Average	$ 14,480.00	$ 16,310.00	$ 21,019.00	45.16%				

Demand of 500 kW and Usage of 180,000 kWh:	July 2007 $	Jan 2017 $	Jan 2022 $	2007 to 2022 Change %	2007 Rank	2017 Rank	2022 Rank	2007 to 2022 Rank Change
Alabama Power	$ 17,580.00	$ 22,742.23	$ 24,668.87	40.32%	11	11	11	0
Appalachian Power Company (Va)	$ 9,707.00	$ 15,871.00	$ 17,035.70	75.50%	1	8	6	-5
Dominion Virginia Power	$ 11,146.00	$ 13,697.50	$ 15,089.75	35.38%	2	5	5	-3
DUKE Energy Carolinas (NC)	$ 12,010.00	$ 12,968.18	$ 12,745.73	6.13%	4	2	1	3
DUKE Energy Carolinas (SC)	$ 11,380.00	$ 13,613.96	$ 14,074.20	23.67%	3	4	3	0
FP&L Company	$ 16,986.00	$ 14,599.00	$ 17,085.55	0.59%	10	6	7	3
Georgia Power	$ 14,486.00	$ 17,239.13	$ 17,407.83	20.17%	7	10	8	-1
Mississippi Power	$ 15,310.00	$ 15,609.00	$ 17,412.00	13.73%	8	7	9	-1
Duke Energy Progress, Inc. (NC)	$ 12,257.00	$ 11,767.00	$ 14,908.00	21.63%	5	1	4	1
Duke Energy Progress, Inc. (SC)	$ 12,884.00	$ 13,068.00	$ 13,911.00	7.97%	6	3	2	4
Duke Progress Energy Florida, Inc.	$ 16,346.00	$ 16,335.00	$ 17,837.36	9.12%	9	9	10	-1
Average For East South Central	$ 13,516.00	$ 16,691.00	$ 22,231.00	64.48%				
Average For South Atlantic	$ 15,838.00	$ 16,937.00	$ 20,836.00	31.56%				
USA Average	$ 16,506.00	$ 18,363.00	$ 42,443.00	157.14%				

PEER GROUP
Typical Bill Comparison
Industrial Customers

Demand of 75 kW and Usage of 15,000 kWh:	July 2007 $	Jan 2017 $	Jan 2022 $	2007 to 2022 Change %	2007 Rank	2017 Rank	2022 Rank	2007 to 2022 Rank Change
Alabama Power	$ 1,646.00	$ 2,135.73	$ 2,298.17	39.62%	9	10	10	-1
Appalachian Power Company (Va)	$ 945.00	$ 1,623.00	$ 1,719.37	81.94%	1	6	5	-4
Dominion Virginia Power	$ 1,368.00	$ 1,702.33	$ 1,950.54	42.58%	6	7	7	-1
DUKE Energy Carolinas (NC)	$ 1,140.00	$ 1,363.28	$ 1,306.94	14.64%	3	1	1	2
DUKE Energy Carolinas (SC)	$ 1,112.00	$ 1,493.87	$ 1,508.16	35.63%	2	4	2	0
FP&L Company	$ 1,668.00	$ 1,594.00	$ 1,816.42	8.90%	10	5	6	4
Georgia Power	$ 1,814.00	$ 2,271.00	$ 2,395.64	32.06%	11	11	11	0
Mississippi Power	$ 1,598.00	$ 1,869.00	$ 2,069.00	29.47%	8	9	9	-1
Duke Energy Progress, Inc. (NC)	$ 1,317.00	$ 1,382.00	$ 1,581.00	20.05%	4	2	3	1
Duke Energy Progress, Inc. (SC)	$ 1,354.00	$ 1,466.00	$ 1,631.00	20.46%	5	3	4	1
Duke Progress Energy Florida, Inc.	$ 1,505.00	$ 1,723.00	$ 1,951.79	29.69%	7	8	8	-1
Average For East South Central	$ 1,444.00	$ 1,860.00	$ 2,356.00	63.16%				
Average For South Atlantic	$ 1,531.00	$ 1,748.00	$ 2,088.00	36.38%				
USA Average	$ 1,699.00	$ 1,956.00	$ 2,392.00	40.79%				

Demand of 75 kW and Usage of 30,000 kWh:	July 2007 $	Jan 2017 $	Jan 2022 $	2007 to 2022 Change %	2007 Rank	2017 Rank	2022 Rank	2007 to 2022 Rank Change
Alabama Power	$ 2,758.00	$ 3,674.32	$ 3,997.66	44.95%	10	11	11	-1
Appalachian Power Company (Va)	$ 1,534.00	$ 2,519.00	$ 2,707.98	76.53%	1	7	6	-5
Dominion Virginia Power	$ 1,981.00	$ 2,321.09	$ 2,627.59	32.64%	4	4	5	-1
DUKE Energy Carolinas (NC)	$ 1,943.00	$ 2,217.55	$ 2,092.87	7.71%	3	3	1	2
DUKE Energy Carolinas (SC)	$ 1,914.00	$ 2,495.79	$ 2,366.95	23.67%	2	6	4	-2
FP&L Company	$ 2,792.00	$ 2,356.00	$ 2,711.00	-2.90%	11	5	7	4
Georgia Power	$ 2,473.00	$ 2,867.67	$ 3,034.30	22.70%	7	10	9	-2
Mississippi Power	$ 2,548.00	$ 2,756.00	$ 3,096.00	21.51%	8	9	10	-2
Duke Energy Progress, Inc. (NC)	$ 1,991.00	$ 1,993.00	$ 2,242.00	12.61%	5	1	2	3
Duke Energy Progress, Inc. (SC)	$ 2,093.00	$ 2,184.00	$ 2,350.00	12.28%	6	2	3	3
Duke Progress Energy Florida, Inc.	$ 2,733.00	$ 2,688.00	$ 2,986.41	9.27%	9	8	8	1
Average For East South Central	$ 2,302.00	$ 2,824.00	$ 5,092.00	121.20%				
Average For South Atlantic	$ 2,553.00	$ 2,749.00	$ 4,781.00	87.27%				
USA Average	$ 2,760.00	$ 3,090.00	$ 5,531.00	100.40%				

PEER GROUP
Typical Bill Comparison
Industrial Customers

Demand of 75 kW and Usage of 50,000 kWh:	July 2007 $	Jan 2017 $	Jan 2022 $	2007 to 2022 Change %	2007 Rank	2017 Rank	2022 Rank	2007 to 2022 Rank Change
Alabama Power	$ 4,144.00	$ 5,625.69	$ 6,163.57	48.73%	10	11	11	-1
Appalachian Power Company (Va)	$ 2,027.00	$ 3,411.00	$ 3,698.64	82.47%	1	7	6	-5
Dominion Virginia Power	$ 2,513.00	$ 2,815.41	$ 3,246.04	29.17%	2	2	5	-3
DUKE Energy Carolinas (NC)	$ 2,738.00	$ 2,993.86	$ 2,982.36	8.92%	4	3	1	3
DUKE Energy Carolinas (SC)	$ 2,548.00	$ 3,081.41	$ 3,178.30	24.74%	3	5	3	0
FP&L Company	$ 4,291.00	$ 3,371.00	$ 3,903.79	-9.02%	11	6	8	3
Georgia Power	$ 3,298.00	$ 3,586.12	$ 3,812.25	15.59%	7	8	7	0
Mississippi Power	$ 3,815.00	$ 3,652.00	$ 4,100.00	7.47%	8	9	9	-1
Duke Energy Progress, Inc. (NC)	$ 2,838.00	$ 2,754.00	$ 3,022.00	6.48%	5	1	2	3
Duke Energy Progress, Inc. (SC)	$ 2,999.00	$ 3,072.00	$ 3,231.00	7.74%	6	4	4	2
Duke Progress Energy Florida, Inc.	$ 4,117.00	$ 3,847.00	$ 4,160.54	1.06%	9	10	10	-1
Average For East South Central	$ 3,409.00	$ 4,040.00	$ 5,092.00	49.37%				
Average For South Atlantic	$ 3,747.00	$ 3,898.00	$ 4,781.00	27.60%				
USA Average	$ 4,079.00	$ 4,518.00	$ 5,531.00	35.60%				

Demand of 1,000 kW and Usage of 200,000 kWh:	July 2007 $	Jan 2017 $	Jan 2022 $	2007 to 2022 Change %	2007 Rank	2017 Rank	2022 Rank	2007 to 2022 Rank Change
Alabama Power	$ 17,040.00	$ 18,123.21	$ 18,978.18	11.37%	4	3	3	1
Appalachian Power Company (Va)	$ 12,080.00	$ 19,865.00	$ 21,149.34	75.08%	1	4	4	-3
Dominion Virginia Power	$ 18,032.00	$ 23,501.37	$ 25,345.76	40.56%	5	10	9	-4
DUKE Energy Carolinas (NC)	$ 14,138.00	$ 17,372.02	$ 16,519.01	16.84%	3	1	1	2
DUKE Energy Carolinas (SC)	$ 13,569.00	$ 17,703.17	$ 17,637.01	29.98%	2	2	2	0
FP&L Company	$ 22,428.00	$ 21,795.00	$ 25,358.78	13.07%	10	8	10	0
Georgia Power	$ 24,315.00	$ 30,841.51	$ 32,364.44	33.10%	11	11	11	0
Mississippi Power	$ 20,366.00	$ 21,635.00	$ 23,653.00	16.14%	7	7	6	1
Duke Energy Progress, Inc. (NC)	$ 21,238.00	$ 21,126.00	$ 24,357.00	14.69%	9	6	7	2
Duke Energy Progress, Inc. (SC)	$ 20,473.00	$ 20,947.00	$ 23,314.00	13.88%	8	5	5	3
Duke Progress Energy Florida, Inc.	$ 19,582.00	$ 22,333.00	$ 24,550.59	25.37%	6	9	8	-2
Average For East South Central	$ 17,445.00	$ 21,646.00	$ 28,379.00	62.68%				
Average For South Atlantic	$ 19,365.00	$ 23,078.00	$ 24,017.00	24.02%				
USA Average	$ 21,543.00	$ 24,837.00	$ 31,557.00	46.48%				

PEER GROUP
Typical Bill Comparison
Industrial Customers

Demand of 1,000 kW and Usage of 400,000 kWh:	**July 2007 $**	**Jan 2017 $**	**Jan 2022 $**	**2007 to 2022 Change %**	**2007 Rank**	**2017 Rank**	**2022 Rank**	**2007 to 2022 Rank Change**
Alabama Power	$ 27,526.00	$ 29,476.36	$ 31,184.85	13.29%	5	4	3	2
Appalachian Power Company (Va)	$ 18,905.00	$ 30,959.00	$ 33,583.24	77.64%	1	7	7	-6
Dominion Virginia Power	$ 23,198.00	$ 28,209.09	$ 31,238.23	34.66%	2	2	4	-2
DUKE Energy Carolinas (NC)	$ 24,195.00	$ 27,826.73	$ 26,752.31	10.57%	4	1	1	3
DUKE Energy Carolinas (SC)	$ 23,465.00	$ 28,739.95	$ 29,904.60	27.44%	3	3	2	1
FP&L Company	$ 36,809.00	$ 30,961.00	$ 36,269.82	-1.46%	11	8	9	2
Georgia Power	$ 33,422.00	$ 39,339.79	$ 41,624.78	24.54%	9	11	11	-2
Mississippi Power	$ 32,072.00	$ 32,232.00	$ 36,224.00	12.95%	8	9	8	0
Duke Energy Progress, Inc. (NC)	$ 30,726.00	$ 30,104.00	$ 33,445.00	8.85%	7	6	6	1
Duke Energy Progress, Inc. (SC)	$ 29,721.00	$ 29,833.00	$ 32,256.00	8.53%	6	5	5	1
Duke Progress Energy Florida, Inc.	$ 35,797.00	$ 35,066.00	$ 38,208.56	6.74%	10	10	10	0
Average For East South Central	$ 26,473.00	$ 30,165.00	$ 40,836.00	54.26%				
Average For South Atlantic	$ 31,333.00	$ 35,158.00	$ 36,884.00	17.72%				
USA Average	$ 34,242.00	$ 37,688.00	$ 47,921.00	39.95%				

Demand of 1,000 kW and Usage of 650,000 kWh:	**July 2007 $**	**Jan 2017 $**	**Jan 2022 $**	**2007 to 2022 Change %**	**2007 Rank**	**2017 Rank**	**2022 Rank**	**2007 to 2022 Rank Change**
Alabama Power	$ 39,160.00	$ 42,156.70	$ 44,932.10	14.74%	5	8	7	-2
Appalachian Power Company (Va)	$ 24,996.00	$ 40,107.00	$ 43,249.55	73.03%	1	5	4	-3
Dominion Virginia Power	$ 29,656.00	$ 34,093.74	$ 38,603.81	30.17%	2	1	2	0
DUKE Energy Carolinas (NC)	$ 35,566.00	$ 38,183.75	$ 38,334.71	7.78%	4	2	1	3
DUKE Energy Carolinas (SC)	$ 33,147.00	$ 38,895.32	$ 40,148.34	21.12%	3	3	3	0
FP&L Company	$ 53,718.00	$ 42,017.00	$ 49,467.82	-7.91%	11	7	9	2
Georgia Power	$ 44,083.00	$ 48,765.30	$ 51,943.35	17.83%	8	11	11	-3
Mississippi Power	$ 45,315.00	$ 43,007.00	$ 49,276.00	8.74%	9	9	8	1
Duke Energy Progress, Inc. (NC)	$ 41,331.00	$ 39,847.00	$ 44,630.00	7.98%	7	4	6	1
Duke Energy Progress, Inc. (SC)	$ 40,703.00	$ 40,747.00	$ 43,434.00	6.71%	6	6	5	1
Duke Progress Energy Florida, Inc.	$ 52,713.00	$ 47,954.00	$ 51,644.64	-2.03%	10	10	10	0
Average For East South Central	$ 36,856.00	$ 40,320.00	$ 55,572.00	50.78%				
Average For South Atlantic	$ 45,106.00	$ 48,773.00	$ 51,382.00	13.91%				
USA Average	$ 49,130.00	$ 52,955.00	$ 67,256.00	36.89%				

Demand of 50,000 kW and Usage of 15,000,000 kWh:	**July 2007 $**	**Jan 2017 $**	**Jan 2022 $**	**2007 to 2022 Change %**	**2007 Rank**	**2017 Rank**	**2022 Rank**	**2007 to 2022 Rank Change**
Alabama Power	$ 1,096,080.00	$ 1,173,306.42	$ 1,237,525.85	12.90%	5	4	4	1
Appalachian Power Company (Va)	$ 696,139.00	$ 1,267,520.00	$ 1,413,052.92	102.98%	1	8	9	-8
Dominion Virginia Power	$ 1,013,942.00	$ 1,272,789.35	$ 1,393,653.90	37.45%	4	9	8	-4
DUKE Energy Carolinas (NC)	$ 862,988.00	$ 1,030,105.16	$ 1,015,726.30	17.70%	3	2	2	1
DUKE Energy Carolinas (SC)	$ 801,751.00	$ 1,034,906.17	$ 1,055,552.85	31.66%	2	3	3	-1
FP&L Company	$ 1,216,104.00	$ 789,127.00	$ 921,018.07	-24.26%	7	1	1	6
Georgia Power	$ 1,228,754.00	$ 1,448,319.20	$ 1,524,740.44	24.09%	9	11	10	-1
Mississippi Power	$ 1,224,279.00	$ 1,248,338.00	$ 1,374,009.00	12.23%	8	7	7	1
Duke Energy Progress, Inc. (NC)	$ 1,259,600.00	$ 1,186,638.00	$ 1,347,849.00	7.01%	10	6	6	4
Duke Energy Progress, Inc. (SC)	$ 1,149,025.00	$ 1,177,511.00	$ 1,289,942.00	12.26%	6	5	5	1
Duke Progress Energy Florida, Inc.	$ 1,377,733.00	$ 1,427,623.00	$ 1,559,289.00	13.18%	11	10	11	0
Average For East South Central	$ 995,348.00	$ 1,150,679.00	$ 1,512,956.00	52.00%				
Average For South Atlantic	$ 1,194,536.00	$ 1,355,019.00	$ 1,387,337.00	16.14%				
USA Average	$ 1,305,418.00	$ 1,447,943.00	$ 1,831,595.00	40.31%				

PEER GROUP
Typical Bill Comparison
Industrial Customers

Demand of 50,000 kW and Usage of 25,000,000 kWh:	July 2007 $	Jan 2017 $	Jan 2022 $	2007 to 2022 Change %	2007 Rank	2017 Rank	2022 Rank	2007 to 2022 Rank Change
Alabama Power	$ 1,553,774.00	$ 1,675,396.23	$ 1,782,427.65	14.72%	5	8	7	-2
Appalachian Power Company (Va)	$ 936,782.00	$ 1,559,920.00	$ 1,724,589.20	84.10%	1	5	5	-4
Dominion Virginia Power	$ 1,272,262.00	$ 1,503,285.35	$ 1,682,337.30	32.23%	3	4	4	-1
DUKE Energy Carolinas (NC)	$ 1,340,713.00	$ 1,444,386.04	$ 1,426,674.82	6.41%	4	3	2	2
DUKE Energy Carolinas (SC)	$ 1,242,936.00	$ 1,443,974.90	$ 1,483,971.43	19.39%	2	2	3	-1
FP&L Company	$ 1,868,045.00	$ 1,155,401.00	$ 1,371,405.48	-26.59%	10	1	1	9
Georgia Power	$ 1,662,124.00	$ 1,848,071.36	$ 1,960,484.64	17.95%	7	10	9	-2
Mississippi Power	$ 1,788,838.00	$ 1,744,324.00	$ 1,968,279.00	10.03%	9	9	10	-1
Duke Energy Progress, Inc. (NC)	$ 1,734,000.00	$ 1,635,538.00	$ 1,802,249.00	3.94%	8	7	8	0
Duke Energy Progress, Inc. (SC)	$ 1,611,425.00	$ 1,621,811.00	$ 1,737,042.00	7.80%	6	6	6	0
Duke Progress Energy Florida, Inc.	$ 2,058,918.00	$ 1,946,817.00	$ 2,101,247.74	2.06%	11	11	11	0
Average For East South Central	$ 1,389,359.00	$ 1,526,487.00	$ 2,098,811.00	51.06%				
Average For South Atlantic	$ 1,747,675.00	$ 1,892,884.00	$ 1,941,920.00	11.11%				
USA Average	$ 1,885,249.00	$ 2,036,463.00	$ 2,591,104.00	37.44%				

Demand of 50,000 kW and Usage of 32,500,000 kWh:	July 2007 $	Jan 2017 $	Jan 2022 $	2007 to 2022 Change %	2007 Rank	2017 Rank	2022 Rank	2007 to 2022 Rank Change
Alabama Power	$ 1,897,045.00	$ 2,051,963.59	$ 2,191,104.00	15.50%	5	9	8	-3
Appalachian Power Company (Va)	$ 1,117,264.00	$ 1,779,220.00	$ 1,958,241.41	75.27%	1	5	5	-4
Dominion Virginia Power	$ 1,466,002.00	$ 1,676,157.35	$ 1,898,849.85	29.53%	2	2	4	-2
DUKE Energy Carolinas (NC)	$ 1,674,698.00	$ 1,755,096.71	$ 1,734,886.20	3.59%	4	4	2	2
DUKE Energy Carolinas (SC)	$ 1,482,015.00	$ 1,749,492.28	$ 1,788,228.72	20.66%	3	3	3	0
FP&L Company	$ 2,357,002.00	$ 1,430,107.00	$ 1,709,196.04	-27.48%	10	1	1	9
Georgia Power	$ 1,971,914.00	$ 2,124,363.22	$ 2,261,326.64	14.68%	7	10	9	-2
Mississippi Power	$ 2,171,316.00	$ 2,036,157.00	$ 2,328,706.00	7.25%	9	8	10	-1
Duke Energy Progress, Inc. (NC)	$ 2,027,025.00	$ 1,898,483.00	$ 2,134,293.00	5.29%	8	6	7	1
Duke Energy Progress, Inc. (SC)	$ 1,929,308.00	$ 1,944,444.00	$ 2,072,367.00	7.42%	6	7	6	0
Duke Progress Energy Florida, Inc.	$ 2,628,573.00	$ 2,389,984.00	$ 2,572,050.50	-2.15%	11	11	11	0
Average For East South Central	$ 1,679,017.00	$ 1,798,324.00	$ 2,521,147.00	50.16%				
Average For South Atlantic	$ 2,145,019.00	$ 2,285,199.00	$ 2,358,565.00	9.96%				
USA Average	$ 2,302,376.00	$ 2,467,094.00	$ 3,152,664.00	36.93%				