FEASIBILITY STUDY FOR A POTENTIAL COMMUNITY CHOICE AGGREGATION IN ARLINGTON COUNTY

Research Paper

April 2020

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DISCLAIMER

Prepared by Virginia Clean Energy with support provided by the American Geophysical Union's Thriving Earth Exchange.

ACKNOWLEDGMENTS

This project was initiated by Virginia Clean Energy's board members Silvia Zinetti, Morris Meyer, and Mike Sandler as part of their effort to bring Community Choice Aggregation to the Commonwealth of Virginia. In December 2018, Virginia Clean Energy submitted the project proposal to the Thriving Earth Exchange program of the American Geophysical Union (AGU) and was selected to be included in the program along with other projects.

Virginia Clean Energy expresses its gratitude to AGU for supporting this undertaking and to AGU's volunteers and project team for sharing their valuable knowledge and helping with the implementation of this project.

Virginia Clean Energy also takes this opportunity to thank peer reviewers Jenny Heeter, National Renewable Energy Laboratory (NREL), and Eric O'Shaughnessy, Clean Kilowatts, for their comments and suggestions that helped improve and clarify this Study.

The project received no funding and was conducted entirely on a voluntary basis.

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EXECUTIVE SUMMARY

Virginia Code § 56-589 allows municipalities and other political subdivisions of the Commonwealth to establish Community Choice Aggregations (CCAs), also referred to as municipal aggregation, as an alternative electric power option to residents and businesses that are currently served by the incumbent utility.[1] The CCA program allows municipalities to choose their power mix with a preference for renewable energy sources while promoting local economic development as well as the community's energy and environmental goals.

The purpose of this research effort is to answer the question: *How can a CCA program for Arlington County support its 100% renewable energy goal, and provide other community co-benefits such as competitive rates, greenhouse gas (GHG) emissions reduction, renewable energy development, and energy efficiency programs?* Although not an official partner of this effort, Arlington County was chosen in part due to its transformative Community Energy Plan (CEP), which includes commitments to 100% electricity from renewable sources by 2035 and achieving carbon neutrality by 2050. This feasibility study (Study) is a project of Virginia Clean Energy (VCE)[2] with support provided by AGU's Thriving Earth Exchange.[3,4] The project aligns with VCE's mission to promote CCA as a tool for counties, cities, and municipalities seeking a faster transition toward a renewable energy future.

This Study evaluates the feasibility of a potential CCA program for residential and commercial customers for the county of Arlington. The electricity consumption of government buildings was ignored because government buildings are outside the scope of this project. To assess the viability of the CCA, several estimates and assumptions were made throughout the Study and are specifically mentioned in each section as they apply. General assumptions include the following: (1) The Arlington CCA would be established as an op-out program, where customers are automatically enrolled into the CCA service unless they choose to leave the CCA; (2) the service from the CCA program would be offered to all eligible customers in one phase at launch; and (3) the power will be procured through a Competitive Service Provider (CSP) selected via a Request for Proposal (RFP).

Because of the lack of some data and costs, this Study is limited in its scope and does not provide a full economic and financial analysis, but rather represents a starting point to access the feasibility of this type of undertaking.

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1. § 56-589. Municipal and State Aggregation. A. Subject to the provisions of subdivision A 3 of § 56-577, counties, cities, and towns (hereafter municipalities) and other political subdivisions of the Commonwealth may, at their election and upon authorization by majority votes of their governing bodies, aggregate electrical energy and demand requirements for the purpose of negotiating the purchase of electrical energy requirements from any licensed supplier within this Commonwealth, as follows: 1. Any municipality or other political subdivision of the Commonwealth may aggregate the electric energy load of residential, commercial, and industrial retail customers within its boundaries on an opt-in or opt-out basis.
2. Virginia Clean Energy is a nonprofit organization whose mission is to accelerate the development of clean and renewable energy via Community Choice Aggregation in the Commonwealth of Virginia. https://www.virginiacleanenergy.org/
3. AGU. https://sites.agu.org/, https://thrivingearthexchange.org/
4. The project was submitted to AGU's Thriving Earth Exchange program in October 2018, and in December 2018 Virginia Clean Energy was selected to participate in the program together with other communities.

ELECTRICITY USAGE AND LOAD FORECAST

Arlington County's historical electricity consumption and load data were used as the basis for the Study's customer and electricity load forecast.[5] The total numbers of accounts and aggregated residential and commercial electricity usage were provided by Arlington County employees.[6]

As Arlington County does not have actual hourly load readings from the incumbent utility, this Study examined two approaches with respect to characterizing the load curve hour by hour: (1) Dominion weather profiles and (2) calculation of a PJM-DOM to Arlington load ratio. The latter approach using hourly load data from the publicly available PJM Data Miner 2 database was used to generate the load profile for Arlington. The forecast electricity consumption (gigawatt hours (GWh)) for Arlington residential and commercial customers is then calculated for the years 2020 through 2030 for two scenarios: (1) CCA program with 100% customers and (2) CCA program with customer opt-out estimates.

The aggregated monthly electricity usage analyzed over 3 years follows the same general pattern and does not differ significantly from one year to another. Residential usage represents approximately 30% of total customer electricity usage, while commercial usage represents around 70%. Figure ES1 shows the aggregated yearly electricity usage for 2015–2018, and Figure ES2 shows the total aggregated monthly electricity usage for 2015–2017.

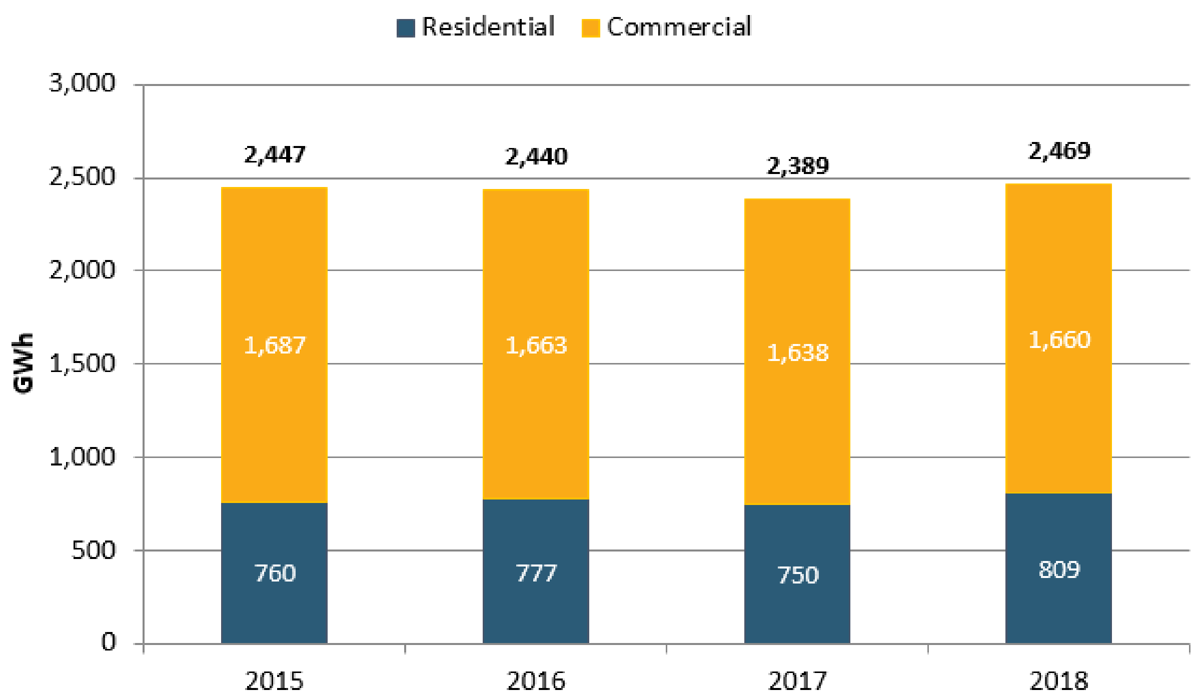

FIGURE ES1. Aggregated yearly electricity usage, 2015–2018.

5. Arlington customers currently purchase their electric power, transmission, and distribution services from Dominion Energy, which is the incumbent utility.
6. Historical data are available at https://data.arlingtonva.us/search/?category=Energy%20and%20Environment&resource=dt.

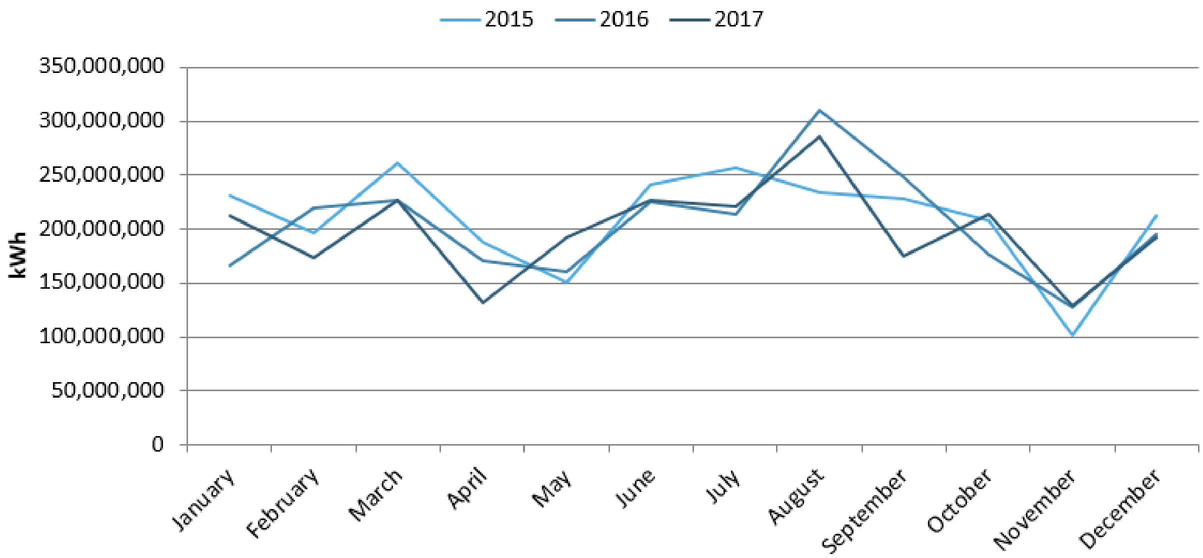

FIGURE ES2. Total aggregated monthly electricity usage, 2015–2017.

The load profile in Figure ES3 shows how Arlington load varies throughout the year. We notice higher load in the winter and summer months, most likely due to increased heating and cooling needs, respectively.[7]

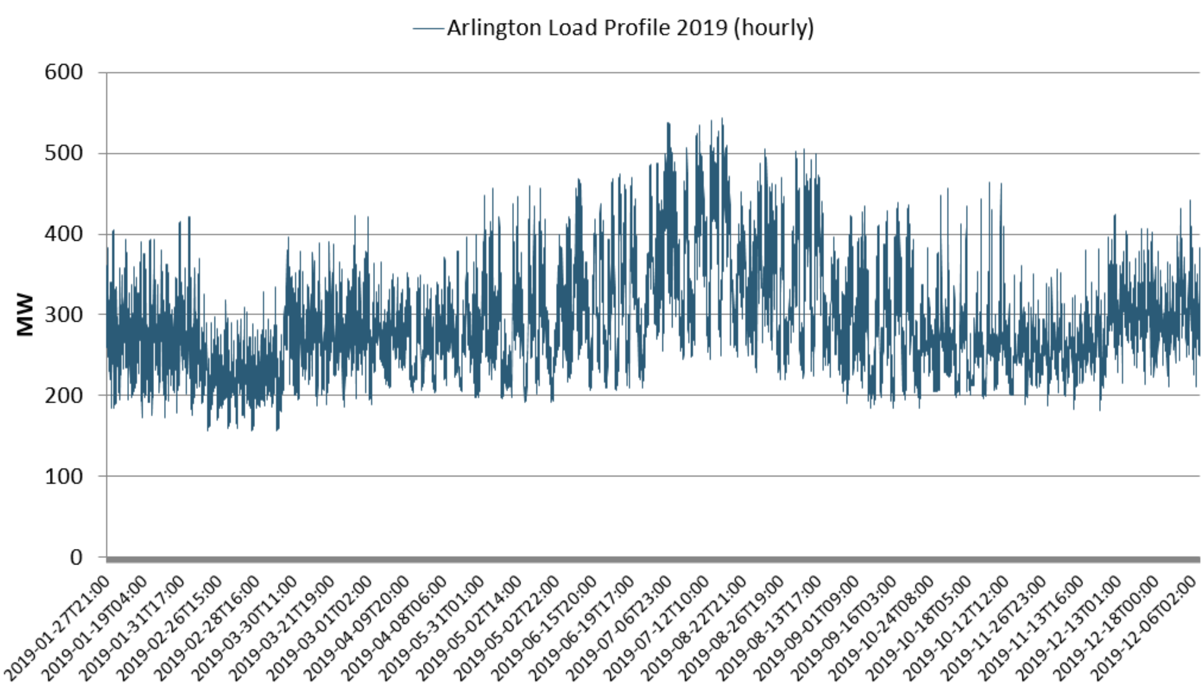

FIGURE ES3. Arlington hourly load profile, 2019.

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7. Compared with the U.S. average, a greater proportion of Virginia households heat with electricity (55%) and a smaller proportion uses natural gas (35%). https://www.eia.gov/consumption/residential/reports/2009/state_briefs/pdf/VA.pdf

The CCA program with a 100% customers scenario assumes an opt-out rate at zero, meaning all residential and commercial customers are assumed to stay in the CCA program once it is operational, while the CCA program with a customer opt-out scenario assumes some customers would return to the incumbent utility. The CCA program opt-out rate for this Study is assumed at 15% for residential customers, to be on the conservative side, and at 5% for commercial customers[8] and is calculated on the first year of the CCA program launch (in this Study, calculated for the year 2020). **As shown in Figure ES4, the total CCA retail sales for both residential and commercial in both scenarios are estimated to increase, with the latter more steadily. However, since energy efficiency measures and electrification were not taken into account, these projections may vary**.

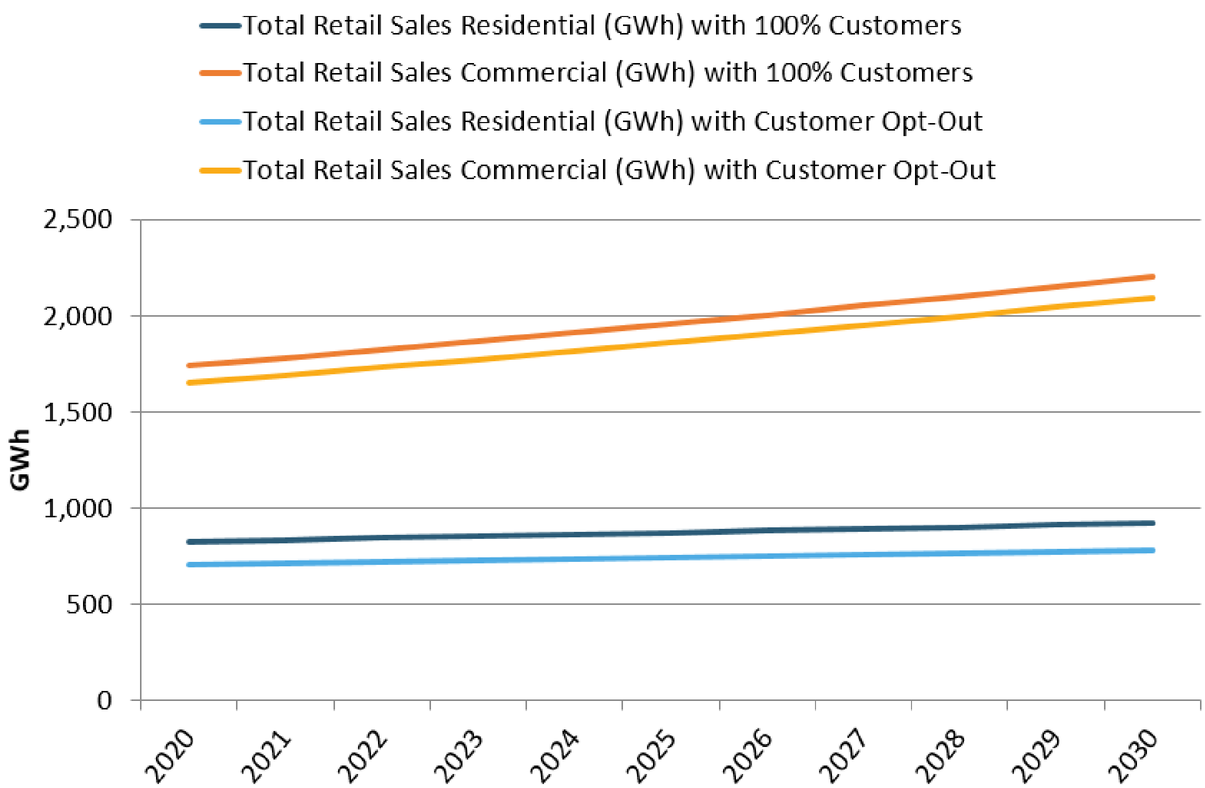

FIGURE ES4. Total retail sales for residential and commercial (GWh) by scenario.

8. On the basis of a recent survey, typical CCA opt-out rates are about 5%–15% on average. O'Shaughnessy, Eric, Jenny Heeter, Julien Gattaciecca, Jenny Sauer, Kelly Trumbull, and Emily Chen. 2019. *Community Choice Aggregation: Challenges, Opportunities, and Impacts on Renewable Energy Markets*. Golden, CO: National Renewable Energy Laboratory. NREL/TP-6A20-72195. https://www.nrel.gov/docs/fy19osti/72195.pdf

POWER PROCUREMENT STRATEGY AND COST ANALYSIS

The power procurement strategy strongly depends on state legislation and regulation. In Virginia, the current legislation allows a CCA program to purchase electricity from a Competitive Service Provider (CSP) licensed by the State Corporation Commission (SCC).[9] To select a CSP, the CCA writes a Request for Proposal (RFP).[10] Because of wholesale market price variability, a typical power procurement contract with a CSP is made for 12–24 months. At the time of this research, it is not clear whether the Power Purchase Agreement (PPA) option would be available to CCAs in Virginia, and further clarification with the SCC is needed.

The CSP will procure the power on behalf of the CCA on the PJM market, the regional transmission organization (RTO) that coordinates the movement of wholesale electricity in all or parts of the 13 Mid-Atlantic, South Atlantic, and Midwestern states under its jurisdiction, including Virginia.[11] PJM markets consist of the *Energy Market*, which includes the real-time and day-ahead markets,[12] the *Capacity Market*, which ensures the future availability of power supplies 3 years in advance,[13] and the *Ancillary Services Market*, which ensures system reliability and balance in frequency as electricity flows from generating resources to consumers.[14] Depending on which entity is responsible for collecting transmission charges, PJM then bills either a retail supplier or the utility directly.[15] In this regard, the transmission cost is a pass-through charge.

The municipality typically decides the CCA resource strategy based on its priorities and objectives. According to the 2019 CCA legal study,[16] "Virginia Code § 56-589 is silent as to whether a CCA may be authorized to offer multiple 'products' (e.g., portfolios with varying degrees of clean and/or renewable energy), or a single product (e.g., a 100 percent renewable energy option)." For the purpose of this Study and in line with Arlington objectives to power 100% of Arlington's electricity from renewable sources by 2035, the CCA explores the following options:

a. Voluntary Virginia Renewable Portfolio Standard (RPS) goal[17]
b. 50% renewable energy
c. 100% renewable energy

9. Further research is needed to clarify whether the CCA can also purchase its electricity needs on the wholesale market.
10. A CCA may be allowed to purchase power from multiple CSPs, but this issue needs to be clarified.
11. Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia. https://pjm.com/
12. The PJM Energy Market procures electricity to meet consumers' demands both in real time and in the near term. It includes the sale or purchase of energy in PJM's real-time energy market (5 minutes) and day-ahead market (1 day forward). https://pjm.com/markets-and-operations/energy.aspx
13. PJM's capacity market, called the Reliability Pricing Model, ensures long-term grid reliability by securing the appropriate amount of power supply resources needed to meet predicted energy demand in the future. https://pjm.com/markets-and-operations/rpm.aspx
14. Ancillary services help balance the transmission system as it moves electricity from generating sources to ultimate consumers. https://learn.pjm.com/three-priorities/buying-and-selling-energy/ancillary-services-market.aspx
15. https://blogs.constellation.com/energy-management/understanding-transmission-costs-in-your-power-bill-2/
16. Legal Options for Community Choice Aggregation in Virginia, December 2019. Prepared for Virginia Clean Energy by the Environmental and Regulatory Law Clinic at the University of Virginia School of Law.
17. The Virginia Clean Energy Act (VCEA), which passed on March 18, 2020, introduced mandatory RPS goals for utilities in the Commonwealth https://lis.virginia.gov/cgi-bin/legp604.exe?201+ful+HB1526ER

The following types of costs were considered in our case study and used to determine the historical market-based rates for 2019:

Power supply costs:

- **Wholesale electricity prices.** PJM wholesale electricity prices include energy market prices, capacity market prices, ancillary services costs, administrative charges, and transmission. For this research, we have analyzed the PJM locational marginal prices (LMPs) for the 3 years from 2017 to 2019 with the Ballston node as a stand-in for the price of electricity in Arlington County. PJM capacity market costs are derived from recent auction data in the PJM-DOM region. Ancillary services costs and administrative charges (both <1%) are calculated as a proportion of the PJM total wholesale cost. We assume that the entity responsible for collecting the transmission cost is Dominion.

Nonpower supply costs:

- **Competitive Service Provider (CSP) fee.** The CSP proposal to the CCA shall include all the costs associated with the procurement and delivery of electricity to the required delivery point, including its profit. For this Study, the CSP profit is estimated at 7%.[18]
- **CCA administration fee.** The CCA administration fee is a fee per kilowatt hour (kWh) that the CCA negotiates with the CSP to cover the organization’s expenses for managing the program, and implementing marketing and communications, customer service, and legal fees. For this Study, we assume a CCA administration fee at 0.1 cent/kWh, which is a common fee used among existing CCAs on the East Coast.

Pass-through charges from the incumbent utility:

- **Transmission and distribution charges.** Transmission charges are part of the Dominion generation charges as Rider T1, whereas distribution charges are set in the distribution component of the tariff.
- **Riders.** For every kWh, Dominion applies a variety of riders. For 2019, the total residential riders (Schedule 1) for generation, transmission, and distribution amount to 2.7895 cents/kWh, whereas the total commercial riders (Schedule GS1) amount to 2.1121 cents/kWh. **Dominion also has a fuel charge (Rider A), which is a pass-through cost for fuel used to produce electricity, including fuel shipment. We do not account for a Dominion fuel charge in our cost analysis, as fuel cost is already part of the wholesale electricity price.**

18. This percentage may vary according to the actual offer from the CSP.

CASE STUDY

The case study analyzes the bill for a residential customer in Arlington with 100% renewable energy certificates (RECs) assuming the CCA 100% customers scenario.[19] This section does not provide a full economic and financial analysis. Instead, it presents a case study for comparison purposes using only the publicly available data and costs. Thus, at this stage of the research, revenue requirements were not calculated as is typically done in other CCA feasibility studies.[20] The calculations of revenue requirements are deferred to a later stage when more information will be available concerning staffing requirements for the Arlington CCA. For comparison purposes only, this Study assumes that the rate design would initially mirror the structure of Dominion rates for the different components (generation, transmission, distribution, riders). However, **as detailed rate design was not part of this Study, the CCA rates in the case study follow the hourly PJM LMPs for 2019 and do not vary above 800-kWh thresholds as Dominion rates do. A CCA would typically establish fixed rates that would be stable across the year.**

The comparison between the CCA residential bill, procuring electricity via a third party on the wholesale market for 100% RECs, and a Dominion residential bill with the current power mix and tariffs indicates the CCA bill would be a price-competitive option for most months as shown in Figure ES5. Figure ES6 shows the yearly and monthly average residential retail prices.[21] From our investigation, an advantage of the CCA is the exclusion of the fuel cost in the rate setting, as it is already embedded in the wholesale market pricing.

The CCA yearly average residential retail electricity price over the 2019 period was 7% lower than Dominion, 11.57 and 12.40 cents/kWh, respectively. The CCA generation component is slightly higher, as it includes the cost of fuel. However, the total generation cost for the CCA, including the RECs, is lower than Dominion when the latter includes the fuel cost. **As shown in Figure ES7, the fuel rider has a substantial impact on Dominion's total retail price, accounting for around 19% of the total retail price.** The RECs account for around 12% of the generation cost and approximately 5% of the total retail rate. The CSP profit and CCA fee account for only a small percentage of the total retail price. Transmission, distribution, and riders are identical in both bills. Figure ES7 shows the CCA and Dominion residential retail price breakdowns in cents/kWh from the 2019 bill calculations.

The bill comparison was produced with our best knowledge of publicly available existing costs and existing available data. However, there may be additional hidden charges that we may not be aware of, and thus we recommend further vetting if using these estimates for comparison externally. In addition, to get a more precise cost breakdown, a complete study of all PJM costs, including a more detailed view of transmission costs, would be necessary.

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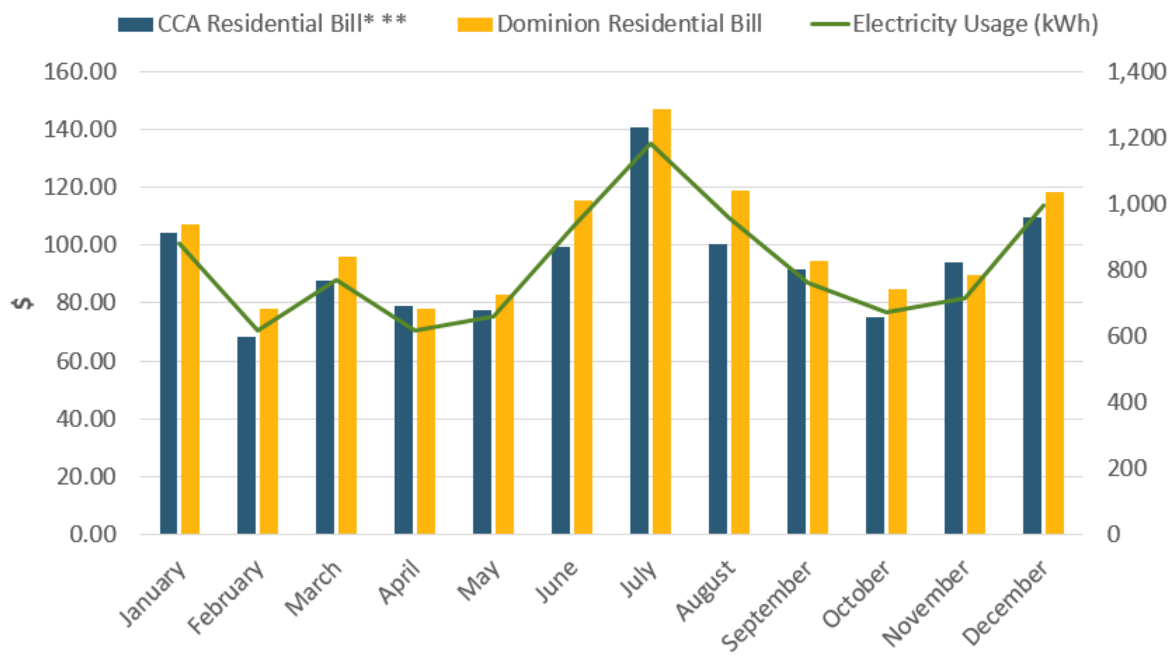
19. A case study for commercial customers is not provided in this Study because of a lack of clear indication of the ration of Arlington commercial customer rate structure—whether they are GS1 versus GS2 service.
20. See, for example, San Diego Feasibility Study for a Community Choice Aggregate, July 2017.
21. The monthly usage in kWh was derived as an average of total residential usage and existing accounts.



*For a more accurate comparison, we suggest using metered electricity usage figures from the utility. **The fuel mix includes 100% RECs from the PJM wholesale market.

FIGURE ES5. Case study: CCA bill versus Dominion bill.

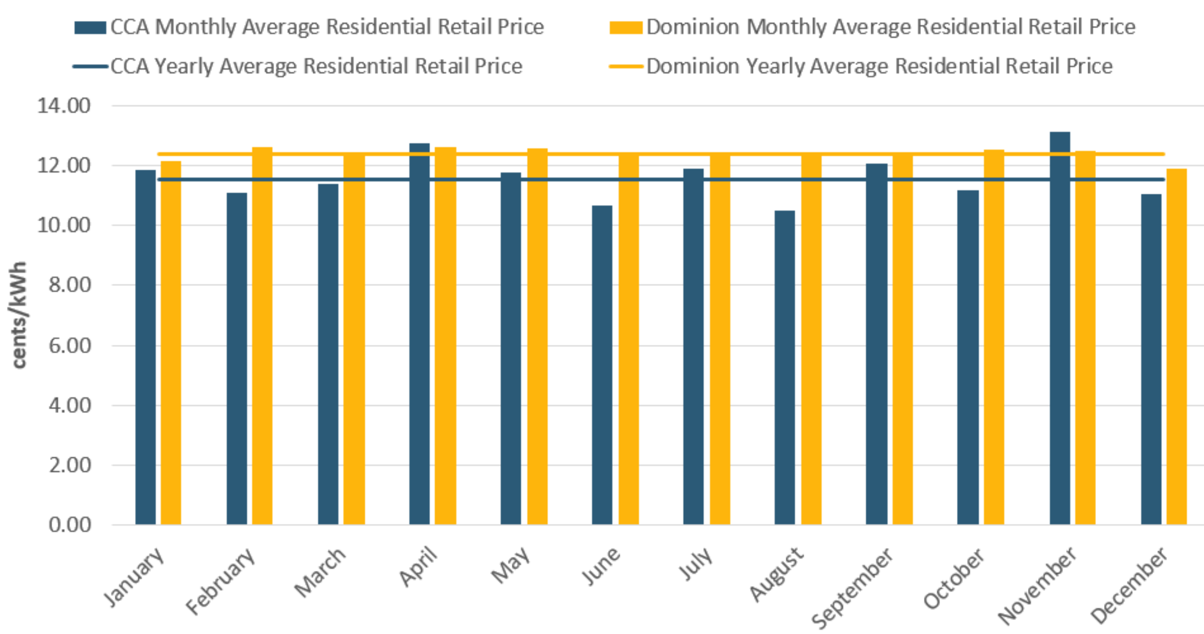


FIGURE ES6. CCA and Dominion monthly and yearly residential prices (cents/kWh).

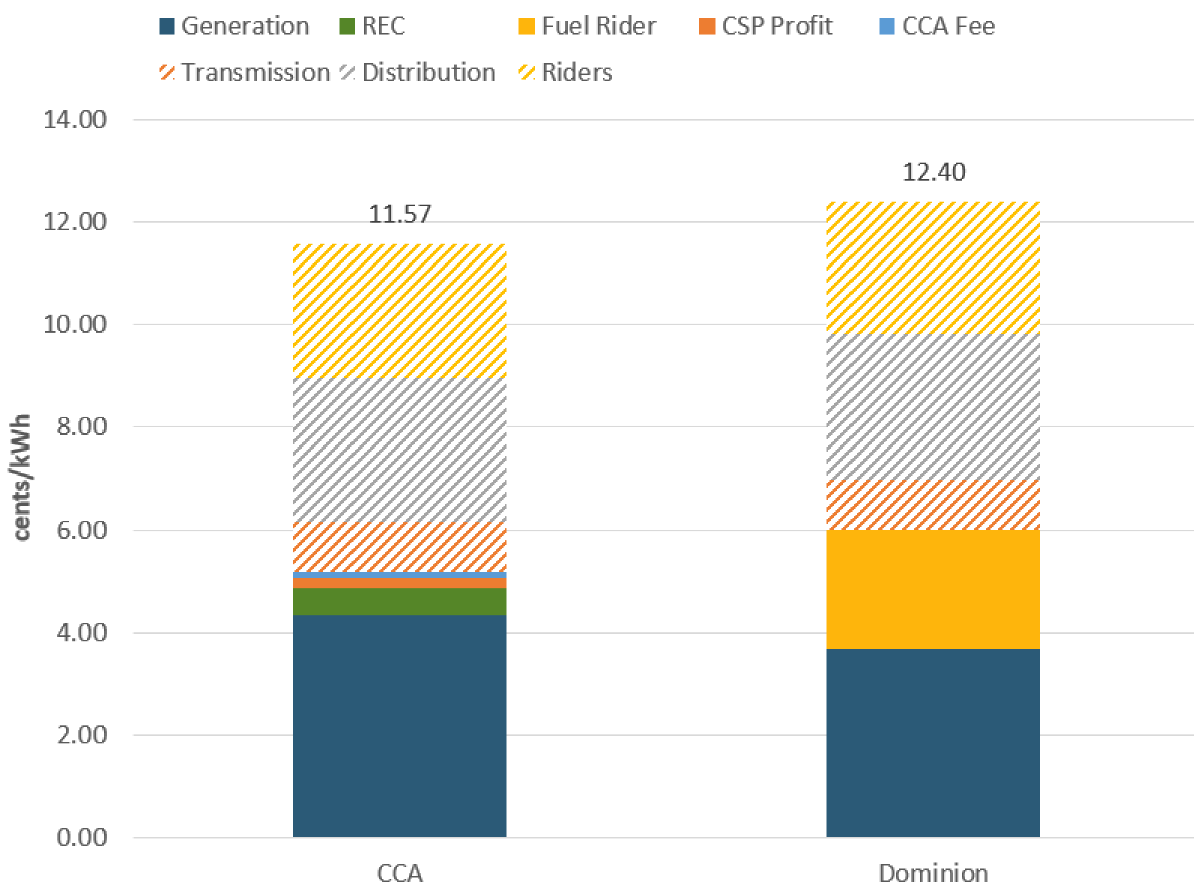


FIGURE ES7. Breakdown of CCA and Dominion electricity prices (cents/kWh).

SENSITIVITY ANALYSIS

The sensitivity analysis was carried out for different scenarios and rate modeling assumptions to better understand the impacts of one or more cost variations on the CCA and Dominion residential prices in the case study.

The sensitivity analysis suggests that the CCA residential case study would still be competitive under several cost increase/decrease assumptions. In all sensitivity scenarios analyzed, the CCA yearly residential average retail price remains competitive compared with Dominion. Likewise, in most sensitivity scenarios, the CCA monthly residential retail price ranges remain competitive with Dominion. We noted that the CCA yearly residential retail price and the CCA monthly residential retail price ranges were more sensitive to the load increase or decrease. As per our assumptions and methodology, the CCA rates in the case study follow the hourly PJM LMPs and do not differ above 800-kWh thresholds as Dominion rates do. However, we expect the Arlington CCA to establish fixed rates that would be stable across the year. The Dominion yearly residential retail price would be only slightly affected by an increase/decrease of both generation and fuel rider costs, respectively, while testing a combination of a ±5% increase/decrease of Dominion generation and fuel rider costs does show slightly more variation in the Dominion price. **Yet even in the extreme case where both the generation and the fuel rider decrease by 5%, the CCA residential retail price is still lower than the Dominion retail price by around 4.5%.**

Figure ES8 shows the results for the electricity load increase/decrease by ±5% and ±10%. Figure ES9 shows the results for Dominion generation and fuel rider costs increase/decrease by 2%, respectively, and Dominion generation and fuel rider costs increase/decrease ±5% simultaneously. Figure ES10 shows the monthly sensitivities for all scenarios analyzed.

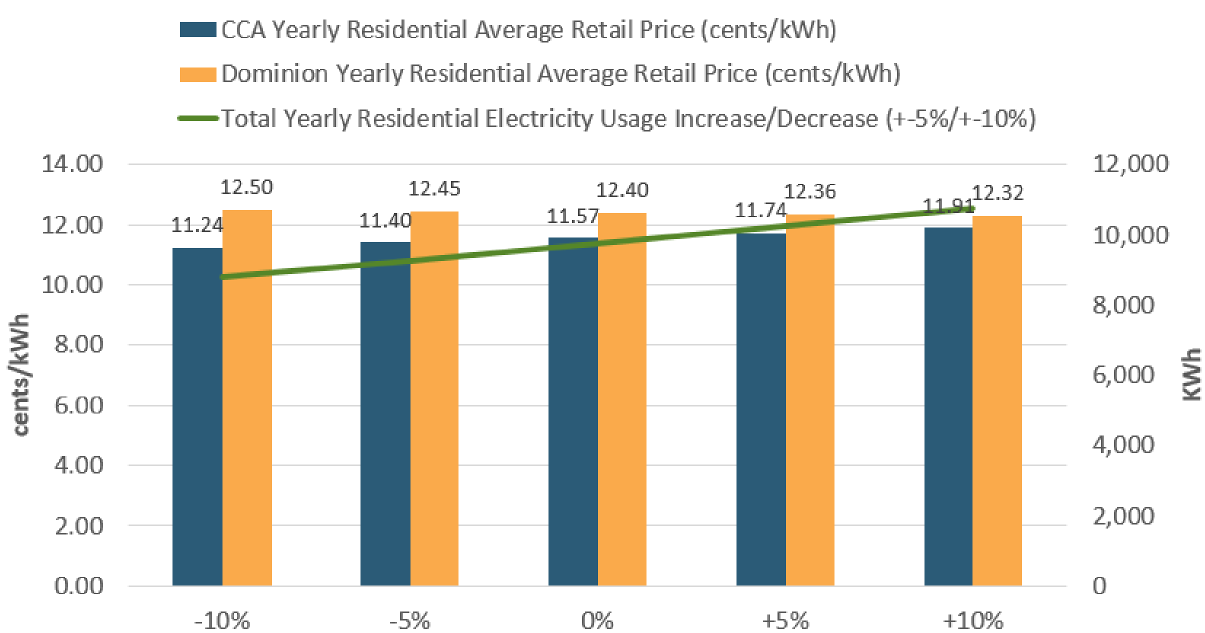


FIGURE ES8. Yearly residential average price comparison with CCA and Dominion sensitivity for load increase/decrease (±5%/±10%)

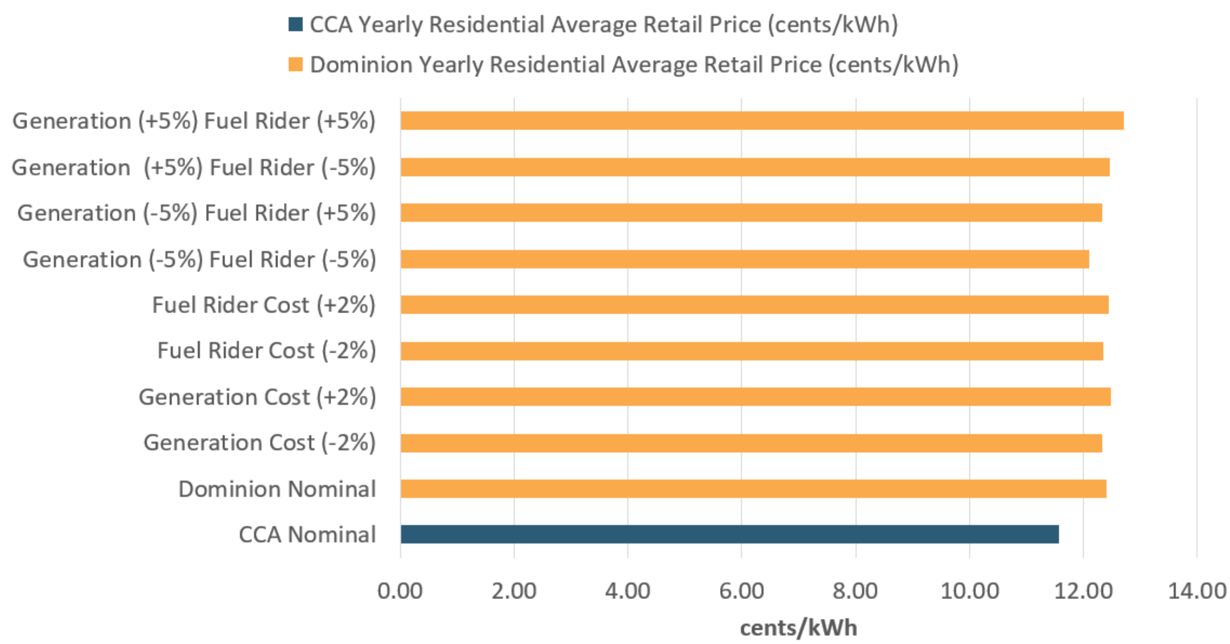


FIGURE ES9. Yearly residential average price comparison for all Dominion cost sensitivities.

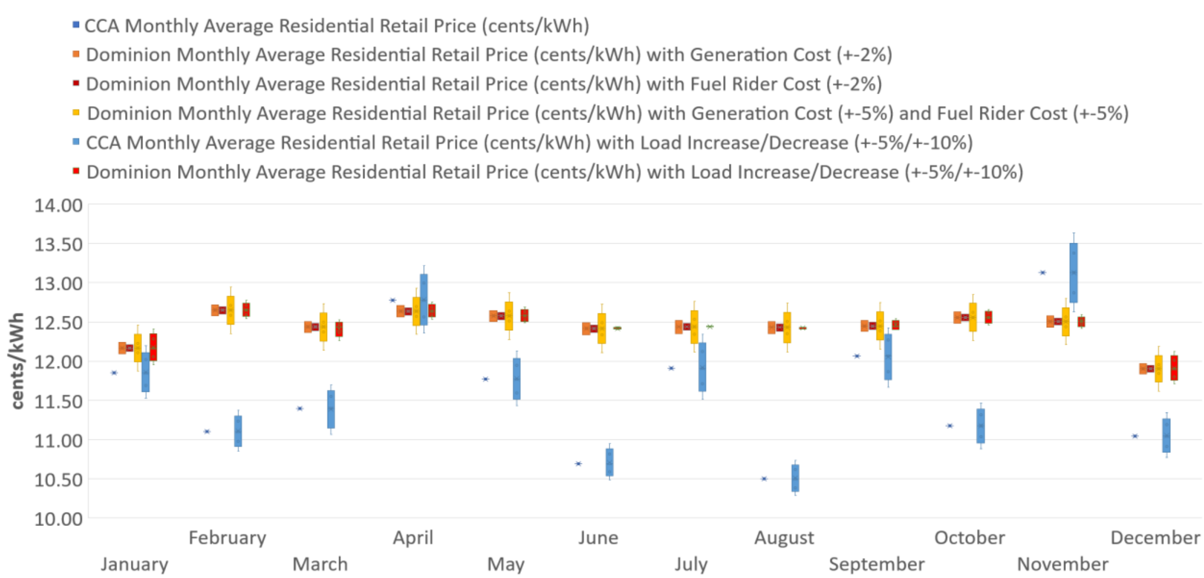


FIGURE ES10. Monthly residential average price range comparison for all sensitivities.

FINANCIAL BENEFITS

The Arlington CCA may be able to earn a profit from the sale of electricity. To be on the conservative side, this Study assumes the CCA would be collecting a small administrative fee in the amount of 0.1 cent/kWh to use for managing the program and other energy-related initiatives. This is a common practice among CCAs in several U.S. states on the East Coast. **As shown in Figure ES11, the Arlington CCA would be able to collect around $25–$30 million over 11 years of operation, depending on scenario.**

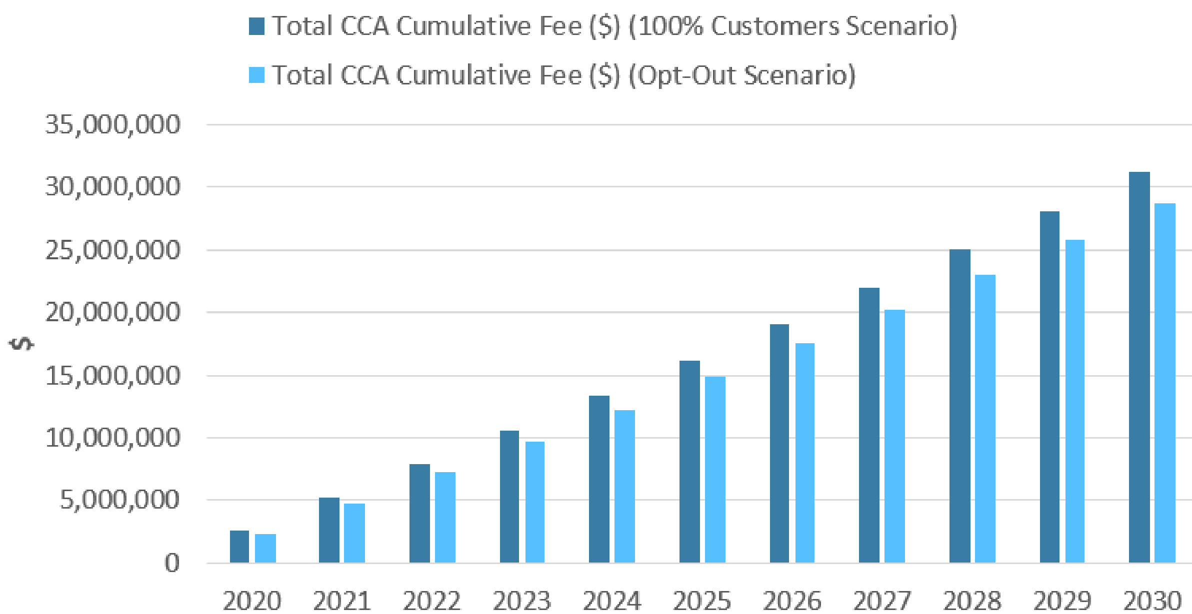


FIGURE ES11. Total CCA cumulative fee for the 100% customers scenario and the opt-out scenario.

ENVIRONMENTAL AND OTHER BENEFITS

One primary advantage of a CCA is greater local control over which resources are pursued in delivering electricity to customers. In line with Arlington's renewable energy and carbon-neutral goals, three scenarios were analyzed for the CCA: (1) voluntary RPS scenarios for the different years, (2) 50% renewable energy, and (3) 100% renewable energy. All three assume the CCA 100% customers scenario. The 2018 Dominion Energy Integrated Resource Plan (IRP)[22] and the U.S. Environmental Protection Agency (EPA) eGRID database[23] were used in modeling these scenarios. Specifically, historical emissions factors from the eGRID database and historical and projected emissions factors from the Dominion IRP were incorporated. These emissions factors apply to the combined fuel mix, rather than to each individual resource. For comparison with the CCA, we use Dominion non-RGGI (Regional Greenhouse Gas Initiative) projected emissions factors, which are part of their lowest emissions reduction scenario.[24]

All three CCA scenarios analyzed resulted in lower CO_2 emissions than the utility, as shown in Figure ES12. Significant CO_2 emission reductions occur in particular for the 50% and 100% renewable scenarios compared with the incumbent utility. In contrast, emissions under the incumbent utility are expected to increase in the future assuming rising Arlington electricity demand and minimal reduction in future carbon intensity, as projected by the 2018 Dominion Integrated Resource Plan (IRP).[25] **Arlington emissions reductions would initially be derived through the purchase of unbundled RECs on the wholesale market, rather than through the direct purchase of local renewables. As such, these emissions reductions represent a shift for Arlington's carbon accounting, namely, offsetting, rather than for net emissions.** However, a CCA would work toward directly purchasing local renewable energy in the future, and the purchase of unbundled RECs in the interim would still support further development of renewables.

These emissions reductions can be expressed as the number of cars off the road, as shown in Table ES1.[26] The annual carbon emissions reductions were averaged for 2020–2030 resulting from each CCA scenario in comparison with the existing utility emissions, rounded down to the nearest thousand. CO_2 emissions reductions for 2020–2030 were projected at 76,000 metric tons per year for the Virginia voluntary RPS scenario, 489,000 metric tons per year for the 50% renewable energy scenario, and 978,000 metric tons per year for the 100% renewable energy scenario. **This is equivalent to reducing the number of cars on the road by more than 200,000, on the same order as the population of Arlington County.**

Another benefit of the CCA is the possibility of fostering the uptake of energy efficiency measures within the community. Many CCAs in California directly offer or partner with programs offered by utilities, municipalities, and other organizations related to energy efficiency, distributed generation and

22. https://www.dominionenergy.com/library/domcom/media/about-us/making-energy/2018-irp.pdf
23. https://www.epa.gov/energy/emissions-generation-resource-integrated-database-egrid-questions-and-answers#egrid4b
24. To reduce Virginia emissions under RGGI implementation, Dominion projects higher imports of out-of-state energy, which would actually be more carbon-intensive than generation sourced in Virginia.
25. These results may vary, should Dominion change its power mix with less carbon intensity resources.
26. Assuming the EPA-estimated 4.6 metric tons of CO_2 per year emitted by passenger cars averaging 22 miles per gallon (mpg) and 11,500 miles per year https://nepis.epa.gov/Exe/ZyPDF.cgi?Dockey=P100U8YT.pdf

energy storage, and demand response. **The Arlington CCA could explore different alternatives on how to implement energy efficiency programs and measures similarly to CCAs in California.**[27]

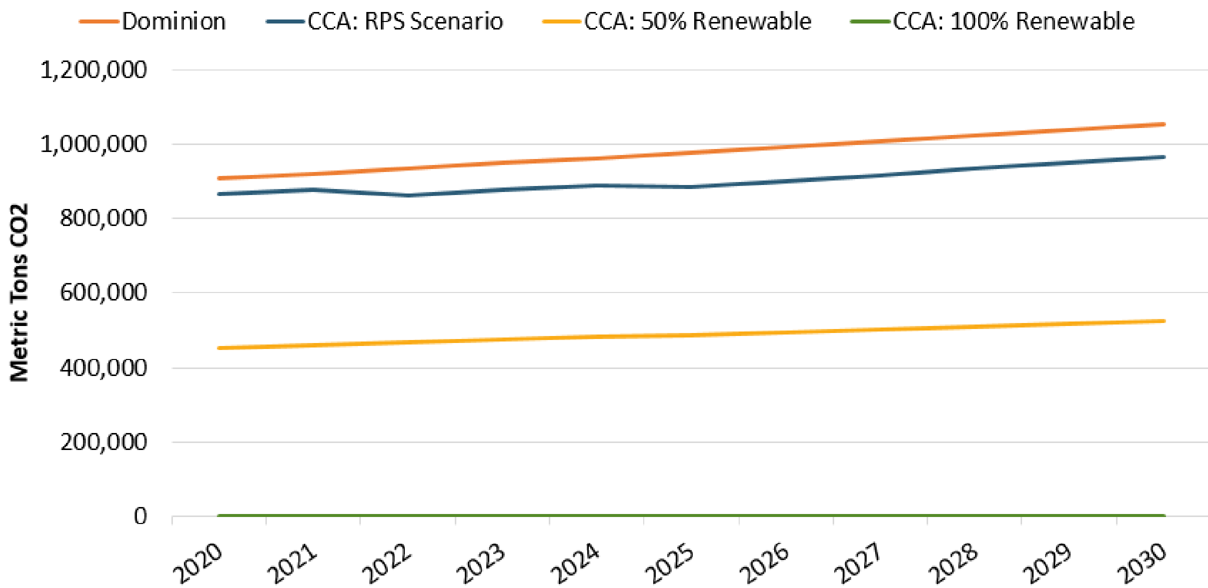


FIGURE ES12. Projected CO2 emissions from electricity for Arlington County for CCA scenarios and Dominion non-RGGI scenario.

TABLE ES1. Arlington CCA Annual Emissions Reductions, 2020–2030

CCA Scenario	RPS	50% Renewable	100% Renewable
Annual emissions reduction (metric tons CO_2)	76,000	489,000	978,000
Emissions reduction expressed as annual number of cars off the road **= 16,000 cars**	16,000	106,000	212,000

27. In this Study, we did not assess the legislation on energy efficiency in Virginia, and the implementation of energy efficiency programs and measures by the CCA would need further research.

PRELIMINARY FINDINGS AND CONCLUSION

Our investigation suggests that the CCA is a viable option for procurement of 100% renewable energy on the wholesale market at a competitive price, allowing Arlington to offset its carbon footprint. On the basis of the research, assumptions, and analyses conducted in this Study, preliminary findings and conclusion can be summarized as follows:

- **Support to the Arlington County CEP goals.** The formation of a CCA would support Arlington County's current CEP goals of achieving carbon neutrality by 2050 and 100% community-wide renewable electricity by 2035.
- **GHG emissions reduction through carbon offsetting.** Under the 100% renewable energy scenario, Arlington could already offset its carbon footprint by as much as 978,000 metric tons of CO_2/year, which is equivalent to reducing the number of cars on the road by more than 200,000, on the same order as the population of Arlington County.
- **Support for renewable energy development.** The purchase of unbundled RECs in the interim would still support the renewable energy market, as it encourages renewable electricity on a broader scale.
- **Economic benefits.** Economic benefits include electricity retail prices that are competitive with the incumbent utility**.** The case study analyzed with the CCA procuring 100% RECs resulted in an average retail electricity price 7% lower for a CCA residential customer compared with Dominion.
- **Exclusion of the fuel rider.** Our investigation suggests that an advantage of the CCA is the exclusion of the fuel cost in the rate settings, as this is already embedded in the wholesale market pricing. The fuel rider alone accounts for about 19% of Dominion residential retail price.
- **Sensitivity analysis.** The sensitivity analysis suggests that the CCA residential case study would still be competitive under several cost increase/decrease assumptions. In the extreme case where both the Dominion generation and the fuel rider decrease by 5%, the CCA residential retail price is still lower by around 4.5% compared with the Dominion retail price.
- **Financial benefits.** The CCA program would bring additional funds in an estimated amount of $25–$30 million from a cumulative administrative fee for 11 years of program operations. A portion of these funds will be used for managing the program, and the remainder could be reinvested in energy-related projects within the community, thus making the CCA a 100% self-supported program.
- **Risks.** The risks the CCA may encounter are typically related to the power supply procurement sector, which are well known and could be mitigated with the support of experienced power procurement companies. Another risk the CCA may encounter is an exit fee, which applies to CCAs in California but is not specifically addressed for CCAs in the Virginia code.

To conclude, the CCA is a tool that can help municipalities and counties achieve their goals of a full transition to 100% renewable energy. This Study provides many details and examples for the establishment of a CCA program in Arlington, with the hope that it would be helpful in pursuing this option. We believe that the establishment of a CCA program will allow Arlington flexibility in its power procurement options to match its long-term energy and climate goals. We also hope this Study is useful for any other municipality in the Commonwealth and for other states wishing to explore a CCA as a tool for their sustainable energy transition.

RECOMMENDATIONS

On the basis of the Study results, the following recommendations are provided:

- **The CCA is available to municipalities by right.** Arlington should embrace this opportunity and explore the CCA program as a tool to reach its renewable energy goals and drastically reduce its carbon footprint.
- **Tailor the CCA program to the local needs.** Arlington should investigate which operating structure option is best based on its needs and objectives. For the governance option, Arlington could explore the hybrid Joint Powers Authority (JPA) of the CCA option, which would lower its procurement costs and market risks.
- **Carefully review the data.** Results in this Study were produced with our best knowledge of publicly available existing data and costs. However, we would strongly recommend that stakeholders carefully review and analyze all raw data and costs from the PJM and the utility in drawing their own conclusions. In addition, we recommend that Arlington ask Dominion for hourly metered electricity usage data so as to perform more accurate and detailed calculations of the load requirements. A subscription to a wholesale market price forecasting service to estimate future energy pricing is also advised.
- **Include energy efficiency.** While energy efficiency was not factored into our calculations, CCAs have the potential to substantially accelerate the adoption of energy efficient technologies, as well as distributed generation, energy storage, electric vehicles, demand response, more advantageous rate structures, and other similar opportunities. CCAs in California have been particularly successful in implementing programs and taking advantage of these opportunities.
- **Clarify CCA open issues.** Finally, we encourage Arlington to clarify with the State Corporation Commission the following open questions for the CCA:
  - procurement of energy directly on the wholesale market
  - purchase of power from multiple CSPs
  - contracting PPAs with independent power producers
  - establishment of a multijurisdictional CCA
  - implementation of energy efficiency programs
- **Suggestions for future research.** Opportunities for future research include a detailed study on rates design for the CCA for both residential and commercial, a comprehensive review of costs for calculating the revenue requirements, and a full financial and economic analysis.

1. INTRODUCTION

The energy scene in the Commonwealth of Virginia is set to undergo a radical transformation in the coming years. On 17 September 2019, Gov. Ralph Northam signed Executive Order Forty-Three, which, although not enforceable, establishes ambitious goals to produce 30% of Virginia's electricity from renewable energy sources by 2030 and 100% from carbon-free sources by 2050. These goals reinforce the Commonwealth's commitments to reducing its environmental impact, mitigating the impact of climate change, and boosting the clean and renewable energy economy in Virginia.[28]

At the local level, municipalities and counties in Virginia are also setting 100% clean, renewable goals. In 2017, Floyd County was the first in Virginia to commit to achieving 100% renewable electricity,[29] followed by the town of Blacksburg, which established a community-wide target of powering its communities with 100% clean, renewable energy by 2050.[30] **On 21 September 2019, the Arlington County Board unanimously adopted the Community Energy Plan (CEP)**,[31] which was updated from the June 2013 version and sets ambitious targets to transform the County's energy sector, from buildings and electricity to transportation. Specific commitments include the following:

- Achieve carbon neutrality by 2050
- 100% of Arlington's electricity will be from renewable sources by 2035
- 100% of the County government operations will be from renewable sources by 2025[32]

The purpose of this research effort is to answer the question: How can a CCA program for Arlington County support its 100% renewable energy goal and provide other community co-benefits such as competitive rates, GHG emissions reduction, renewable energy development, and energy efficiency programs? Arlington was chosen in part due to its transformative CEP, although Arlington is not an official partner of this effort. This Study is a project of Virginia Clean Energy (VCE)[33] with support provided by AGU's[34] Thriving Earth Exchange program.[35,36] The project aligns with VCE's mission to promote CCA as a tool for counties, cities, and municipalities seeking a faster transition toward a renewable energy future. This Study may serve as a demonstration model for other communities in the Commonwealth and beyond.

28. https://www.governor.virginia.gov/newsroom/all-releases/2019/september/headline-846745-en.html
29. https://www.swvatoday.com/news/floyd/article_8ea734a6-b9bf-11e7-98d5-df6b46c2cc02.html
30. https://drive.google.com/file/d/1wDlhv8amV-fl-UKA9ThOviNGW0MwE2Cn/view
31. https://environment.arlingtonva.us/energy/community-energy-plan-cep/
32. On 28 January 2020, the Arlington County Board entered into a PPA for off-site solar energy with Dominion. https://newsroom.arlingtonva.us/release/arlington-county-partners-with-dominion-energy-to-help-achieve-energy-goals/
33. Virginia Clean Energy is a nonprofit organization whose mission is to accelerate the development of clean and renewable energy via Community Choice Aggregation in the Commonwealth of Virginia. https://www.virginiacleanenergy.org/
34. AGU. https://sites.agu.org/
35. https://thrivingearthexchange.org/
36. The project was submitted to AGU's Thriving Earth Exchange program in October 2018, and in December 2018 Virginia Clean Energy was selected to participate in the program together with other communities.

1.1. COMMUNITY CHOICE AGGREGATION

CCA, also known as municipal aggregation or governmental aggregation,[37] allows local governments to procure electricity on behalf of retail electricity customers within a municipality, county, or multiple ones combined, while the incumbent investor-owned utility (IOU) continues to provide transmission and distribution services, and billing (Figure 1). By gaining control over the power supply, the CCA can choose its power mix with a preference for renewable energy sources at the local, regional, and state levels, thus promoting local economic development as well as the energy and environmental community's goals.

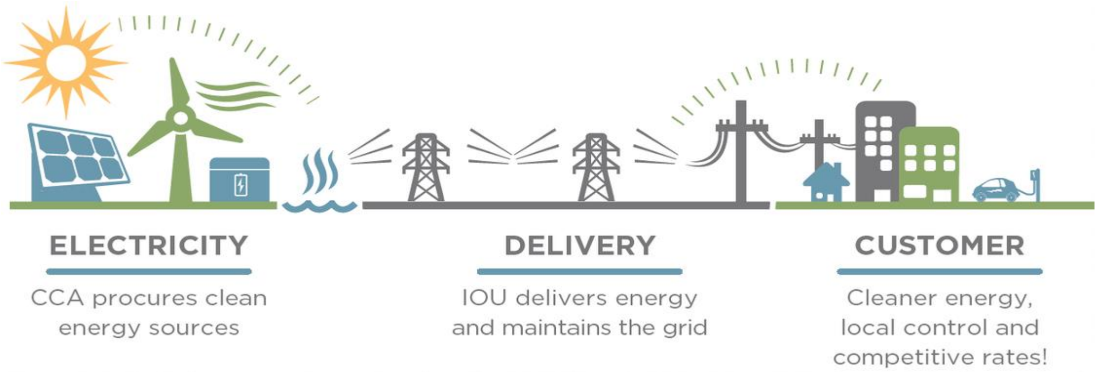


FIGURE 1. Community Choice Aggregation.

CCA is currently authorized in nine U.S. states, including California, Illinois, Massachusetts, New Hampshire, New Jersey, New York, Ohio, Rhode Island, and Virginia. Several other states are showing interest in discussing the CCA model as well. Figure 2 shows the states in which CCA is authorized (green), under consideration (blue), or in the inquiry phase (orange).

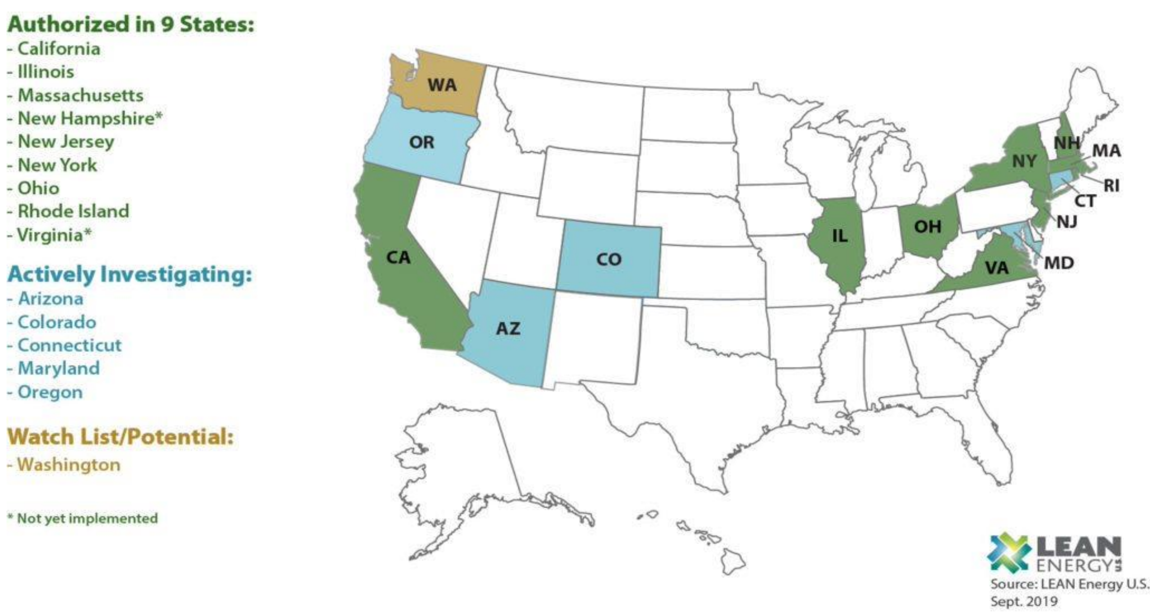


FIGURE 2. CCA across the United States. (Source: LEAN Energy U.S.)

37. In this report, the term Community Choice Aggregation is used to refer to municipal aggregation.

Virginia Code § 56-589 of the Virginia Electric Utility Restructuring Act of 1999 introduced CCA to the Commonwealth during the electricity deregulation effort to offer an alternative electric power option to residents and businesses that are currently served by the incumbent utility.[38] The code was reenacted in 2007, and although it allows for CCA formation, no CCA programs for residential and businesses exist in Virginia to date.

CCA offers a hybrid approach between the vertically integrated IOU and the municipal public utility, the first one being a for-profit organization and the second one being a nonprofit organization. Figure 3 shows the different business models of the IOU, CCA, and municipal public utility. With CCA, the generation and procurement of electricity are unbundled from the transmission, distribution, and billing services, which typically will remain the responsibility of the IOU or municipal public utility.

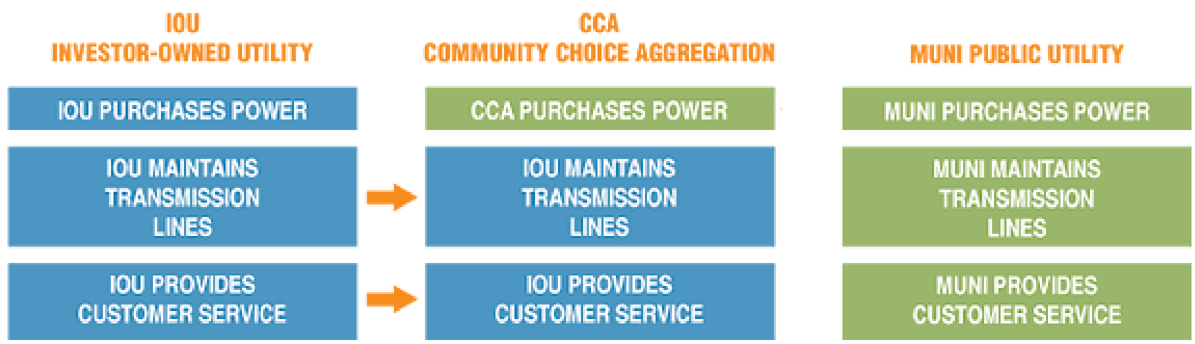


FIGURE 3. Energy model value chain. (Source: LEAN Energy U.S.)

Typical CCAs are formed as opt-out programs, where customers are automatically enrolled in the CCA service unless they choose to leave the CCA and return to the IOU. Alternatively, CCAs can be established as opt-in programs where customers choose to participate in the program. This report analyses an opt-out program.[39]

CCA programs are generally established by a single municipality or single county, or a multijurisdictional entity (e.g., Joint Powers Authority). On the basis of community preference, the program can be administered directly by the municipality or county or can be managed by a third party contracted by the CCA (see section 8, CCA GOVERNANCE AND OPERATIONAL OPTIONS).

38. § 56-589. Municipal and State Aggregation. A. Subject to the provisions of subdivision A 3 of § 56-577, counties, cities, and towns (hereafter municipalities) and other political subdivisions of the Commonwealth may, at their election and upon authorization by majority votes of their governing bodies, aggregate electrical energy and demand requirements for the purpose of negotiating the purchase of electrical energy requirements from any licensed supplier within this Commonwealth, as follows: 1. Any municipality or other political subdivision of the Commonwealth may aggregate the electric energy load of residential, commercial, and industrial retail customers within its boundaries on an opt-in or opt-out basis.

39. According to the 2019 NREL technical report on CCAs, "Findings from behavioral economics help explain why opt out is more effective than opt in in terms of renewable energy sales. Empirical data show that decision makers exhibit a bias toward the default option, meaning the option that will occur if the decisionmaker takes no action (Tversky and Kahneman 1991)." O'Shaughnessy, Eric, Jenny Heeter, Julien Gattaciecca, Jenny Sauer, Kelly Trumbull, and Emily Chen. 2019. *Community Choice Aggregation: Challenges, Opportunities, and Impacts on Renewable Energy Markets*. Golden, CO: National Renewable Energy Laboratory. NREL/TP-6A20-72195. https://www.nrel.gov/docs/fy19osti/72195.pdf on p. 12

Perhaps one of the most critical benefits relies on the fact that the CCA programs are revenue-based and thus self-supporting. Other important benefits in creating a CCA are as follows:

- Increase the renewable energy content in the power mix that exceeds the baseline power mix offered by the incumbent utility
- Decrease overall GHG emissions from electricity generation
- Provide stable and competitive rates
- Provide local control over power mix and rate setting
- Give residents and businesses a choice, other than the IOU
- Promote the expansion of renewable energy sources
- Promote energy efficiency programs and measures
- Stimulate the uptake of new technology, such as microgrids, EV, etc.

1.2. STUDY METHODOLOGY

This Study concentrates on electrical aggregation through Virginia Code 56-589 and attempts to characterize the load requirements for Arlington County's residential and commercial load as supplied by a potential CCA program for the county of Arlington. The electricity consumption of government buildings was ignored because government buildings are outside the scope of this project. Owing to the lack of some data and costs, including the hourly metered substation data, the Study uses estimates and assumptions to derive the County hourly load profile and to assess the viability of the CCA. Estimates and assumptions are specifically mentioned in each section as they apply. This Study provides the historic and projected load, estimated costs of power, and environmental benefits of three different load options of operating a CCA program. For environmental comparison only, the Study compares the current data and forecasts with the ones from Dominion, for the years 2020 through 2030. Historical aggregated electricity usage data in kilowatt-hours (kWh) for Arlington County was provided by the Arlington County staff, while metered load and locational marginal prices for the Dominion zone (DOM zone) were retrieved on the PJM Data Miner 2 and scaled to the Arlington load. This Study is limited in its scope and does not provide a full economic and financial analysis because of the lack of utility-metered hourly load profile data for the County and future wholesale market price forecasts from a subscription service. The cost analysis is divided by the following components:

- **Power Supply Costs**
    - Wholesale electricity market prices
    - Power Purchase Agreement (PPA) market prices for solar and wind
    - Levelized Cost of Energy (LCOE) prices for various technologies

- **Nonpower Supply Costs**
    - Competitive Service Provider (CSP) fee
    - CCA administration fee

- **Pass-Through Charges from Dominion**
    - Transmission and distribution charges
    - Riders

The above costs are used to determine the CCA's historical market-based rates for 2019 and to provide a bill comparison case study. The future market-based rates for power procurement estimates for 2020 through 2030 were calculated for the following cases:

- Voluntary RPS scenarios for the different years[40]
- 50% renewable energy
- 100% renewable energy

1.3. SECTION ORGANIZATION

This Study is organized into the following main sections. Section 1 provides an introduction of CCAs and Study methodology. Section 2 describes the electricity load requirements and the forecast for consumption for the period 2020 through 2030. Section 3 provides an outline of the power procurement strategy, including renewable energy in Virginia and the PJM territory. Section 4 provides the cost of power from the wholesale market, PPA market prices for solar and wind, LCOE prices for selected technologies, and nonpower costs, including transmission and distribution charges, CSP profit, and CCA administration fee. Section 5 provides a residential bill comparison case study for the CCA procuring 100% renewable energy on the wholesale market, and the utility's current power mix and tariff. This section also provides a sensitivity analysis for different scenarios and rate modeling assumptions. Future estimates for market-based rate for energy procurement for four scenarios and an estimation of the funds the CCA will be collecting are also provided. Section 6 provides an outlook of greenhouse gas emissions for three CCA power mix options and for the projected load from the incumbent utility. In addition, some future program options for energy efficiency, distributed generation, and energy storage are summarized. Section 7 provides a summary of the potential risk for the CCA program. Section 8 sets out the CCA governance options and the operating structure of the CCA. Section 9 provides conclusions and recommendations for Arlington County and any other municipality wishing to establish a CCA program in their territory.

40. The Virginia Clean Energy Act (VCEA), which passed on March 18, 2020, introduced mandatory RPS goals for utilities in the Commonwealth https://lis.virginia.gov/cgi-bin/legp604.exe?201+ful+HB1526ER

2. ELECTRICITY LOAD REQUIREMENTS

This section provides the historical electricity consumption aggregated by sector for Arlington County, and the load requirements, including on-peak and off-peak load. In addition, the projected electricity consumption for the years 2020 through 2030 is provided.

2.1. HISTORICAL ELECTRICITY CONSUMPTION

Arlington County's historical electricity consumption and load data were used as the basis for the Study's customer and electricity load forecast.[41] Electricity data include metered aggregated yearly usage from 2015 to 2018 and aggregated monthly electricity usage from 2015 to 2017.[42] The total numbers of accounts and electricity usage in kWh for both residents and businesses were provided by Arlington County employees.[43] In 2018, there were 92,711 customers for a total electricity consumption of 2,469 GWh.

2.1.1. AGGREGATED NUMBER OF ACCOUNTS

Figure 4 shows the aggregated number of accounts for residential and commercial[44] for 2015–2018.

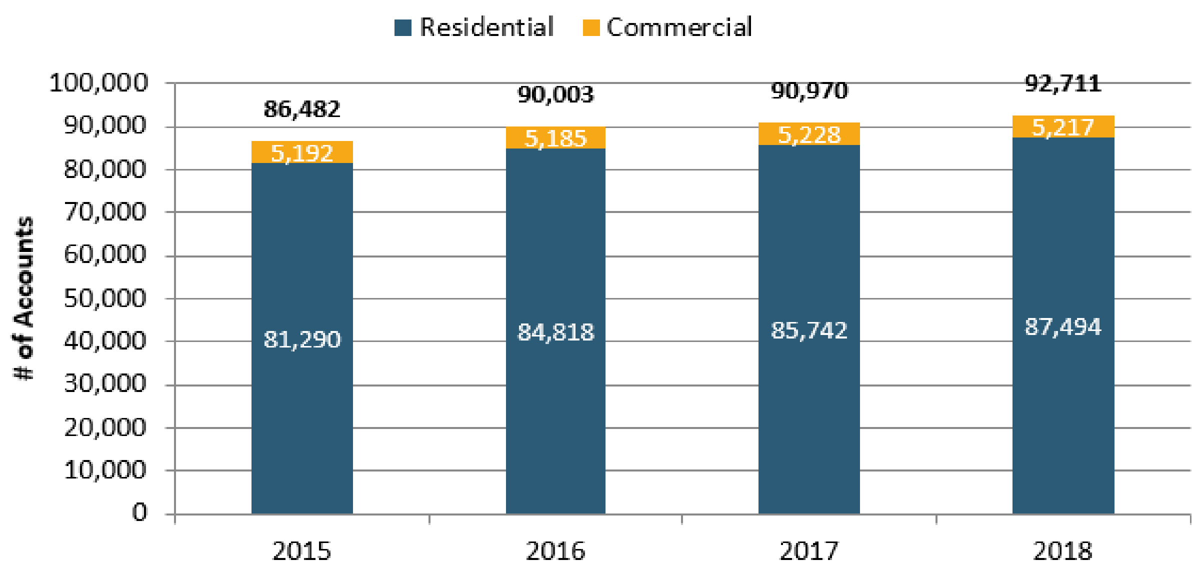


FIGURE 4. Aggregated number of accounts, 2015–2018.

41. Arlington customers currently purchase their electric power, transmission, and distribution services from Dominion Energy, which is the incumbent utility.
42. Note: Customers and annual kWh's shown reflect information obtained from end-of-year historic files and are representative for the years shown. They do not reflect nor should be used in lieu of actual (official) customers and kWh sales levels released by the company for use in public records. All kWh sales shown are unadjusted for weather fluctuations, and customer levels are reflective of connected premises that may or may not have been active at the time this report was created.
43. Historical data are available at https://data.arlingtonva.us/search/?category=Energy%20and%20Environment&resource=dt.
44. Because of the limited electricity consumption classified as industrial, 'industrial' sites were included in the commercial sector.

Residential accounts represent around 94% of total customer accounts, with commercial accounts making up the remaining 6%. Both accounts increased slightly from 2015 to 2018, with the residential averaging a 2.5% increase and the commercial less than a 1% increase.

2.1.2. AGGREGATED ELECTRICITY USAGE

Figure 5 shows the aggregated yearly electricity usage for 2015–2018.

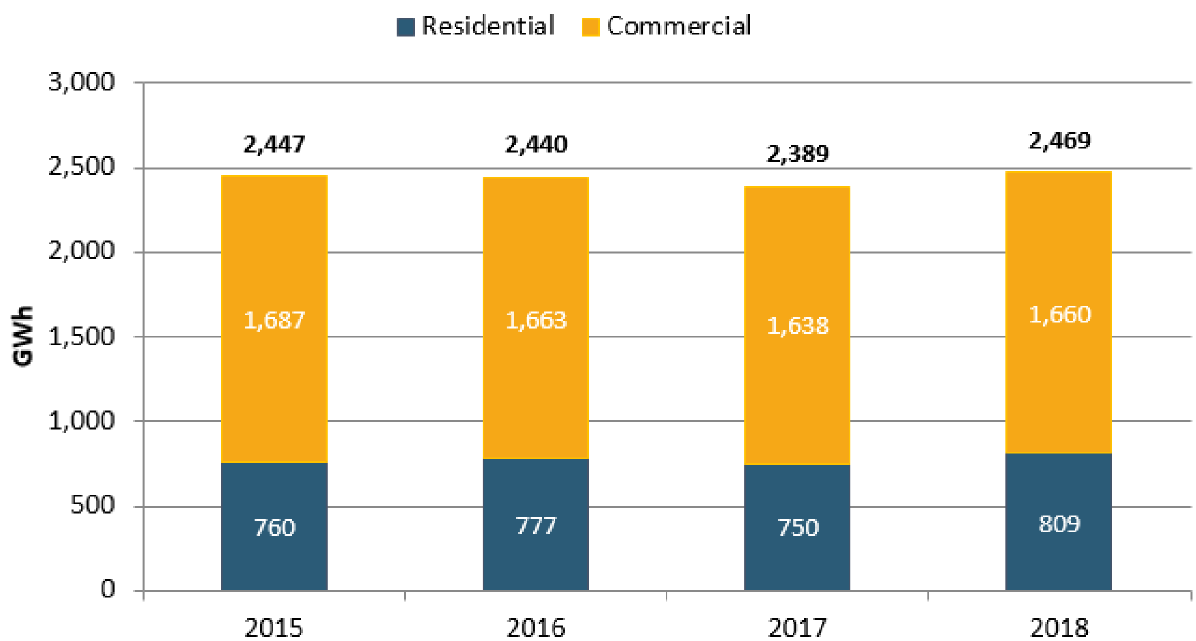


FIGURE 5. Aggregated yearly electricity usage, 2015–2018.

Residential usage represents approximately 30% of total customer electricity usage, whereas commercial usage represents around 70%. The total electricity usage experienced a slight decrease in 2016 and 2017 compared with 2015, and a small increase in 2018. Residential average electricity usage increase was around 2.2%, while the commercial average electricity usage decreased by less than 1%.

Although customer counts increased slightly from 2015 to 2018, yearly electricity usage has had minor variations (see also APPENDIX A: AGGREGATED MONTHLY ELECTRICITY USAGE BY SECTOR). Figure 6 shows the total aggregated monthly electricity usage for 2015–2017.

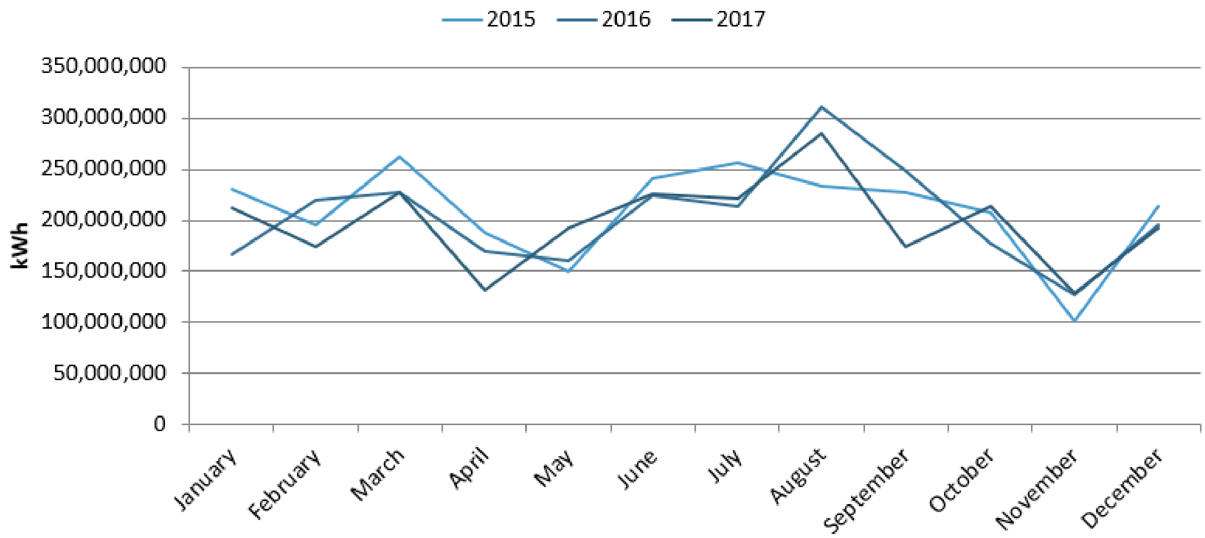


FIGURE 6. Total aggregated monthly electricity usage, 2015–2017.

As shown in Figure 6, **the aggregated monthly electricity usage analyzed over 3 years follows the same general pattern and does not differ significantly from one year to another.**

2.1.3. LOAD PROFILE

A load profile represents the pattern of electricity usage by day and by year. As Arlington County does not have actual hourly load readings from the incumbent utility, a process must be determined to characterize the load profile, including on-peak and off-peak load across the yearly load, and apply predictive certainty to calculations. **This Study examined two approaches with respect to characterizing the load curve hour by hour:[45] (1) Dominion weather profiles and (2) PJM-DOM to Arlington load ratio.** The latter approach uses hourly load data for the DOM zone from the publicly available PJM Data Miner 2 database,[46] which was then used to generate the load profile for Arlington (see APPENDIX B: LOAD PROFILE METHODOLOGY AND CALCULATIONS for details on methodology). With this method, the ratio of monthly DOM load to monthly Arlington load is used to proportionally allocate DOM hourly load as a stand-in for Arlington hourly load.

Figure 7 illustrates the aggregated Arlington hourly load profile for 2019.

45. Because of lack of data, only an aggregated hourly load from the entire load could be derived.
46. Hourly load metered data are available at https://dataminer2.pjm.com/feed/hrl_load_metered.

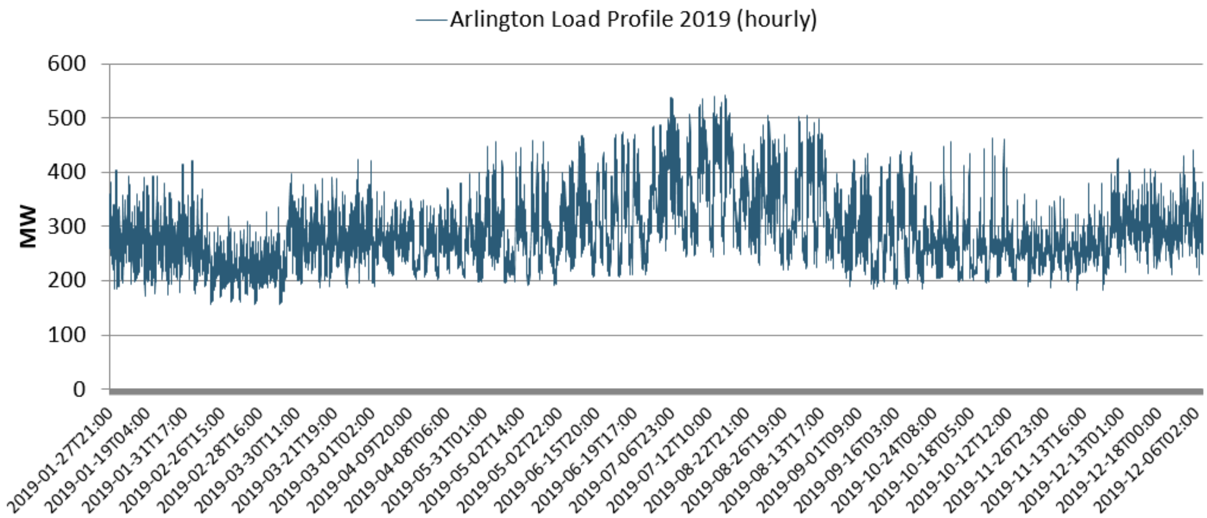


FIGURE 7. Arlington hourly load profile, 2019.

The load profile shows how the load varies throughout the hours of the year. For instance, in the summer months of July and August, we can see a load increase, mostly because of the high usage of air conditioning. In winter we can notice some high load as well, most likely due to the usage of space heating.[47]

2.1.4. LOAD DURATION CURVE

The load duration curve (LDC) is a graphical representation of hourly electricity demand from highest to lowest over a certain time interval. The highest value shows the peak demand, while the lowest value represents the minimal load, also referred to as base load. The load duration curve is often used by electrical utilities to plan for their load and capacity requirements. Figure 8 shows the Arlington hourly load percentile duration curve for 2019.

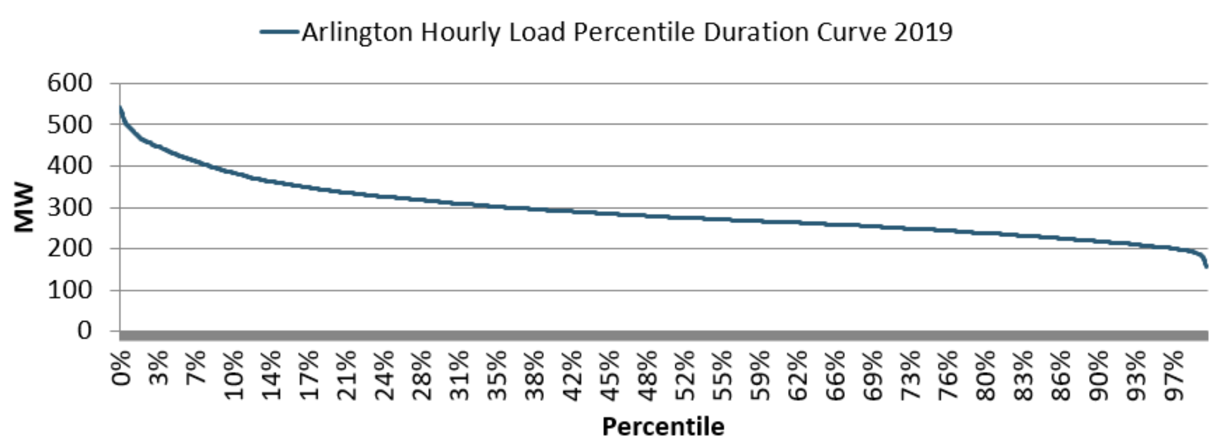


FIGURE 8. Arlington hourly load percentile duration curve, 2019.

47. Compared with the U.S. average, a greater proportion of Virginia households heat with electricity (55%) and a smaller proportion uses natural gas (35%). https://www.eia.gov/consumption/residential/reports/2009/state_briefs/pdf/VA.pdf

The peak load in 2019 was estimated at 543 megawatts (MW), while the minimum load observed was 156 MW. In 2019, the load above 500 MW occurred 0.66% of the time.[48]

BOX 1. Monthly On-Peak Load and Off-Peak Load

On the PJM, peak load hours are defined as from 7:00 a.m. to 11:00 p.m. weekdays excluding holidays, while off-peak period is from 11:00 p.m. to 7:00 a.m. This Study calculated the Arlington off-peak (52%) and on-peak (48%) load that characterizes the power factor of that aggregate load monthly over 2019, as shown in Figure 9.

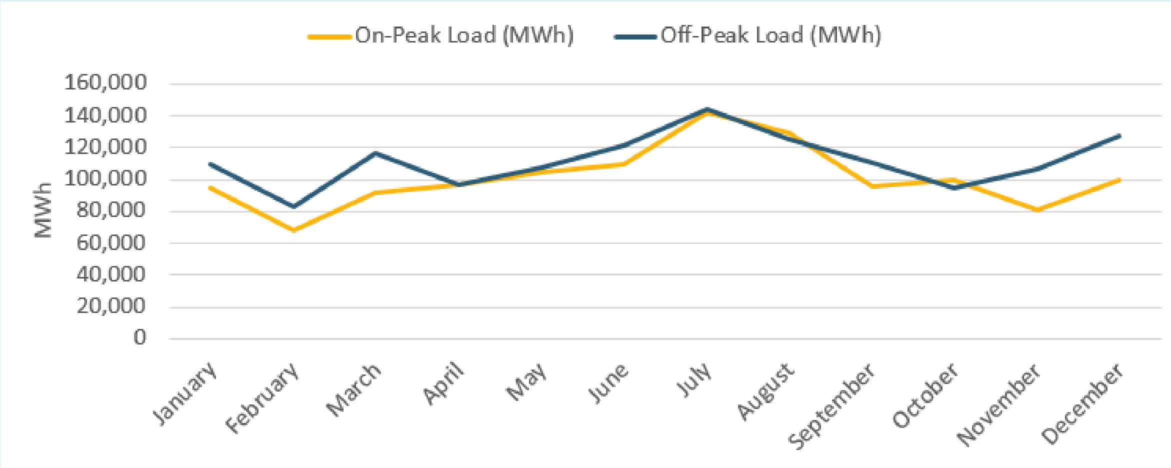


FIGURE 9. Arlington monthly on-peak and off-peak (MWh) load, 2019.

Peak, average, and minimum load in MW were also calculated monthly over 2019, as shown in Figure 10.

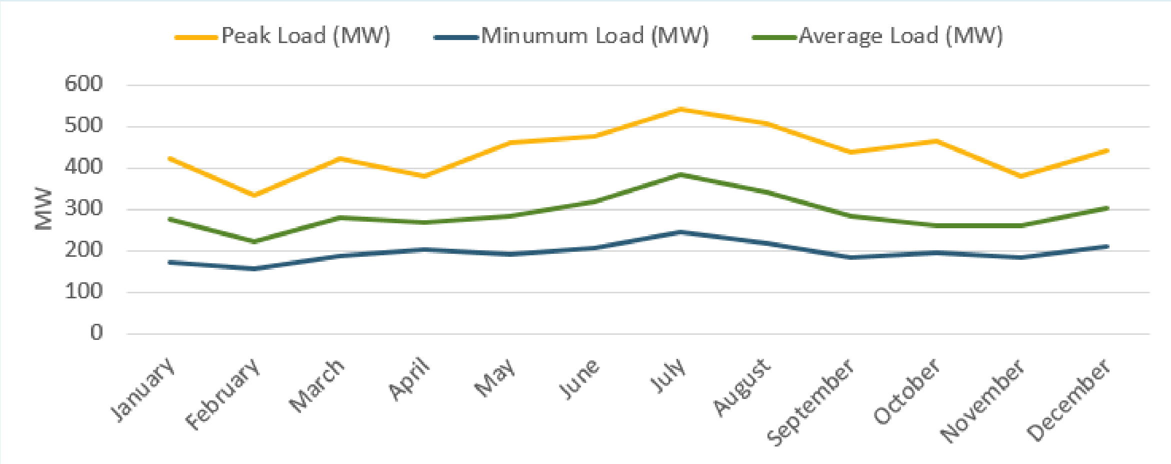


FIGURE 10. Arlington monthly peak, average, minimum load (MW), 2019.

48. These are estimated numbers, as we do not have Arlington hourly metered electricity usage for 2019.

2.2. FORECAST ELECTRICITY CONSUMPTION

The forecast electricity consumption (GWh) for Arlington residential and commercial customers is calculated for the years 2020 through 2030 for two scenarios:

1. CCA program with 100% customers
2. CCA program with customer opt-out estimates

Both scenarios assume that service from the CCA program would be offered to all eligible customers in one phase, at launch. This strategy enables the CCA to enroll all customers at the same time.

2.2.1. CCA PROGRAM WITH 100% CUSTOMERS

This scenario assumes an opt-out rate of zero, meaning all residential and commercial customers are assumed to stay in the CCA program once it is operational. Annual growth rate (%) for electricity demand[49] is estimated at 1.1% for residential and 2.4% for commercial (industry at -0.3%).[50] Transmission and distribution (T&D) losses are estimated at 5%.[51] Energy efficiency measures, as well as growth in demand due to electrification (e.g., Electric Vehicles (EVs)), are not factored in the assumptions, as this is out of scope for this Study. On the basis of the assumptions, the total retail electricity load, T&D losses, and the wholesale energy requirements in GWh are estimated in Table 1:

TABLE 1. Estimated Total Retail Sales and Total Wholesale Load (GWh), 2020–2030

Year	Total Retail Electricity Sales (GWh)	T&D Losses (GWh)	Total Wholesale Electricity Load (GWh)
2020	2,568	128	2,696
2021	2,619	131	2,750
2022	2,671	134	2,804
2023	2,724	136	2,860
2024	2,778	139	2,917
2025	2,834	142	2,975
2026	2,890	145	3,035
2027	2,948	147	3,096
2028	3,007	150	3,158
2029	3,068	153	3,221
2030	3,129	156	3,286

49. Dominion estimates are used as reference purposes only for this Study. For more accurate estimates, a more detailed analysis of future residential and customer growth and electrical consumption is needed.
50. Dominion Integrated Resource Plan 2018, p. 33.
51. The U.S. Energy Information Administration (EIA) estimates that electricity transmission and distribution (T&D) losses average about 5% of the electricity that is transmitted and distributed annually in the United States. https://www.eia.gov/tools/faqs/faq.php?id=105&t=3

Figure 11 shows the historical data and expected CCA electricity retail sales in GWh for both residential and commercial customers for the 100% customers scenario.

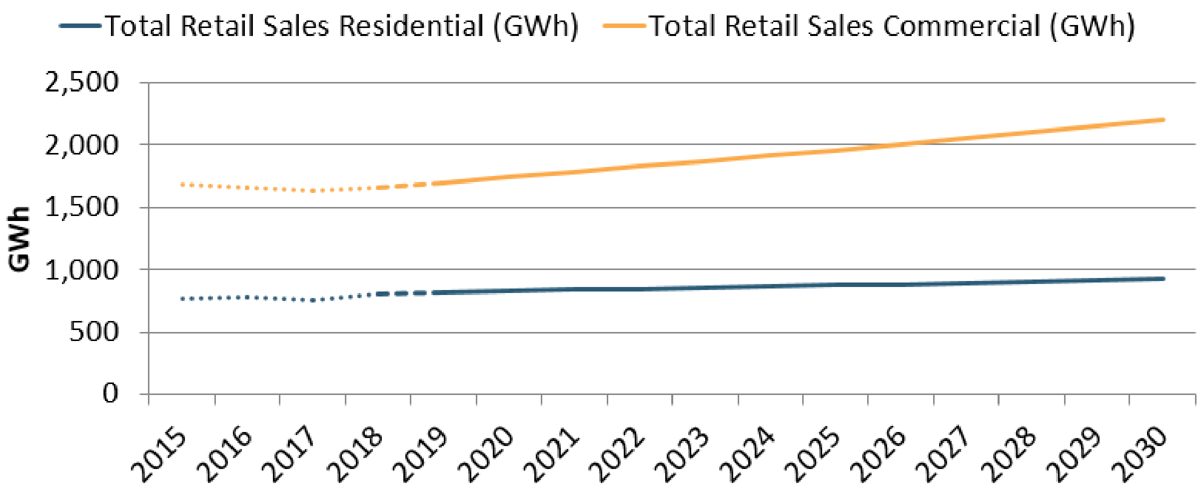


FIGURE 11. Total retail sales for residential and commercial (GWh) with 100% customers, historical data and forecasts.

As shown in Figure 11, the total CCA retail sales for both residential and commercial are estimated to increase, with the latter more steadily. However, because energy efficiency measures and electrification were not taken into account, these projections may vary.

2.2.2. CCA PROGRAM WITH OPT-OUT CUSTOMERS

This scenario assumes some customers would opt-out from the CCA program and return to the incumbent utility. The CCA program opt-out rate for this Study is assumed to be 15% for residential customers, to be on the conservative side, and 5% for commercial customers,[52] and is calculated on the first year of the CCA program launch (in this Study, calculated for the year 2020). The same estimates are used for the annual growth rate (%) for electricity demand and T&D losses. Energy efficiency measures, as well as growth in demand due to electrification (e.g., EVs), are not factored in the assumptions, as this is out of scope for this Study. On the basis of the assumptions, the total retail electricity sales, T&D losses, and wholesale energy requirements in GWh are estimated as follows:

52. On the basis of a recent survey, typical CCA opt-out rates are estimated to be 5%–15% on average. O'Shaughnessy, Eric, Jenny Heeter, Julien Gattaciecca, Jenny Sauer, Kelly Trumbull, and Emily Chen. 2019. *Community Choice Aggregation: Challenges, Opportunities, and Impacts on Renewable Energy Markets*. Golden, CO: National Renewable Energy Laboratory. NREL/TP-6A20-72195. https://www.nrel.gov/docs/fy19osti/72195.pdf

TABLE 2. Estimated Total Retail Sales and Total Wholesale Load (GWh), 2020–2030

Year	Total Retail Electricity Sales (GWh)	T&D Losses (GWh)	Total Wholesale Electricity Load (GWh)
2020	2,357	118	2,475
2021	2,404	120	2,524
2022	2,453	123	2,575
2023	2,502	125	2,627
2024	2,553	128	2,680
2025	2,605	130	2,735
2026	2,657	133	2,790
2027	2,711	136	2,847
2028	2,767	138	2,905
2029	2,823	141	2,964
2030	2,881	144	3,025

Figure 12 shows the historical data and expected electricity retail sales in GWh for both residential and commercial customers for the opt-out scenario.

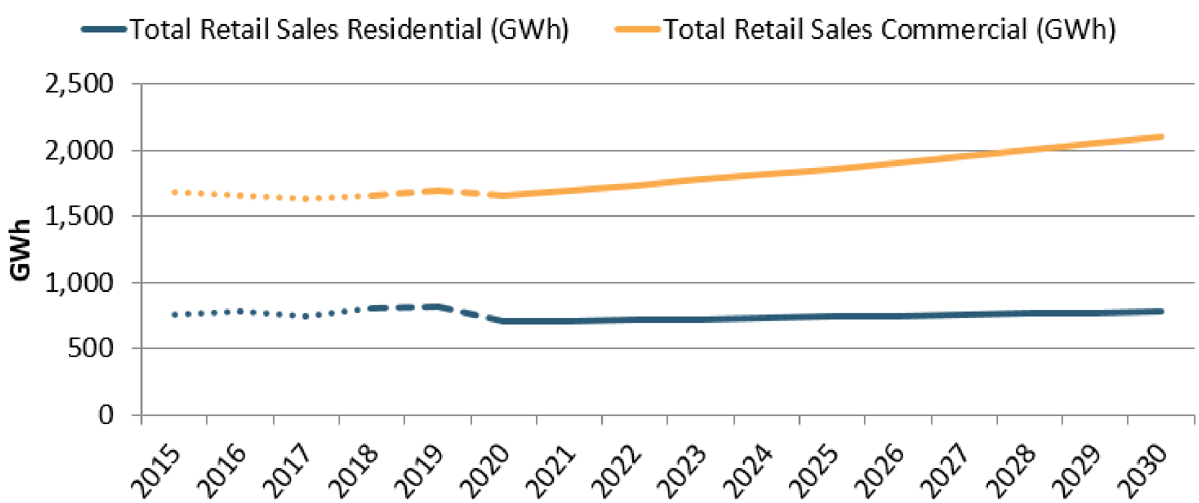


FIGURE 12. Total retail sales for residential and commercial (GWh) with customer opt-out, historical data and forecasts.

As shown in Figure 12, the total CCA retail sales for both residential and commercial will slightly decrease in the starting year of the CCA program (in this case, 2020) compared with the total Arlington electricity demand and due to the opt-out of customers, and then is projected to increase similar to the previous scenario.[53] As in the other scenario, because energy efficiency measures and electrification were not taken into account, these projections may vary.

53. Please note that the total retail sales in Arlington will not decrease; only the CCA retail sales will increase, due to the opt-out.

3. POWER SUPPLY PORTFOLIO STRATEGY

This section discusses the electricity procurement option and the CCA's potential power supply strategy.

3.1. ELECTRICITY GENERATION AND PROCUREMENT OUTLOOK

Electricity is generally procured through a variety of mechanisms, including bilateral agreements of varying term lengths and market purchase, which include day-ahead (DA), real-time (RT) markets. Figure 13 shows a typical power procurement strategy to serve the customer load. "Own Generation" refers to the power generation facility typically owned and operated by utilities but does not prevent CCAs from having some on its own in a future perspective. **However, in the beginning, a CCA program is more likely to procure the energy needed through a third-party provider, known as a Competitive Service Provider (CSP).** Once the CCA is well established, it can start procuring power through bilateral agreements (such as Power Purchase Agreements) or on the wholesale electricity market, as in the case of CCAs in California.

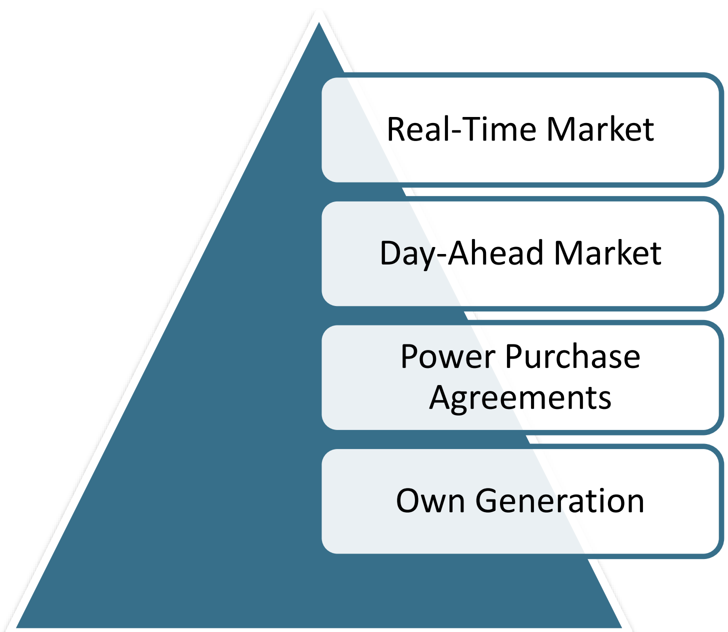


FIGURE 13. Hierarchy of power procurement.

The power procurement strategy strongly depends on state legislation and regulation. In Virginia, the current legislation allows a CCA program to purchase electricity from a CSP licensed by the State Corporation Commission (SCC)[54] (see APPENDIX E: LIST OF CSPs AND AGGREGATORS IN DEV TERRITORY).[55] To select a CSP, the CCA writes a Request for Proposal (RFP).[56] Because of the wholesale market price variability, a typical power procurement contract with a CSP is made for 12–24 months.

54. Further research is needed to clarify whether the CCA can also purchase its electricity needs on the wholesale market.
55. Full list is available at http://www.scc.virginia.gov/power/compsup.aspx.
56. A CCA may be allowed to purchase power from multiple CSPs, but this issue needs to be clarified.

3.1.1. POWER PURCHASE AGREEMENTS

Power Purchase Agreements (PPAs) are long-term bilateral contracts to purchase energy from independent power producers. According to NREL,[57] "third party PPAs are allowed in Virginia through pilot programs conducted by the IOUs. Dominion's program is limited to at most 50 MW, while Appalachian's program is limited to a total of 7 MW…. Solar projects between 50 kW and 1 MW are eligible for third party PPAs under the pilot programs."[58] It is not clear whether this option would be available to CCAs in Virginia, and further clarification with the SCC is needed.

BOX 2. Net Metering

Net metering allows customers to offset their electricity consumption and to send the excess electricity generated by the renewable generation system to the grid. In Virginia, net metering is available to customers of IOUs and electric cooperatives. The excess electricity is credited against future consumption (CCAs in California provide bill credits for excess electricity and annual cash-outs for excess generation). Net-metered solar photovoltaic (PV) systems >10 kW are subject to standby charges established by the utility (Dominion applies a standby charge to net metering customers served on Virginia Residential Schedule 1 with a generation system size in excess of 10 kW AC). Below is a summary of net metering rules for Virginia residential and commercial customers.

- **Maximum renewable generator size (AC capacity):** residential, 20 kW; nonresidential, 1 MW
- **Aggregate cap:** 1% of utility's adjusted Virginia peak-load forecast for the previous year
- **Payment/credit:** There is no direct cash payment for the energy produced. Net excess generation is credited at the retail rate.
- **RECs:** Customers retain ownership of RECs, with the option to sell to utility

Net metering rules are published in the Virginia Administrative Code under 20VAC5-315.

More information is at https://www.dominionenergy.com/large-business/renewable-energy-programs/traditional-net-metering/net-metering-faqs.

3.1.2. PJM MARKETS AND OPERATIONS

PJM is the regional transmission organization (RTO), also known as an Independent System Operator (ISO), that coordinates the movement of wholesale electricity in all or parts of 13 Mid-Atlantic, South Atlantic, and Midwestern states under its jurisdiction, including Virginia.[59] PJM manages all aspects of the wholesale market and the electric grid, from the purchase and sale of energy to transmission services to ancillary services, and provides regular invoices for each market participant for these services. With this respect, the total PJM wholesale electricity cost includes energy, capacity, transmission, ancillary

57. https://www.nrel.gov/solar/rps/va.html
58 .See also HB 2390 Renewable energy power purchase agreements; expands pilot program, sunset provision available at http://lis.virginia.gov/cgi-bin/legp604.exe?171+sum+HB2390=.
59. Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia. https://pjm.com/

services, and administrative charges. PJM also provides real-time information about the current load, current generation fuel mix, locational marginal pricing, ancillary services, reserve pricing, and wind power.

PJM Markets

PJM markets consist of the Energy Market, which include the real-time and day-ahead markets,[60] **the Capacity Market, which ensures the future availability of power supplies 3 years in advance,**[61] **and the Ancillary Services Market, which ensures system reliability and balance in frequency as electricity flows from generating resources to consumers.**[62] In 2018, the energy market accounted for 63% of wholesale electricity cost, the capacity market accounted for 20% of wholesale electricity cost, and ancillary services accounted for less than 1% of wholesale electricity cost.[63] Transmission charges accounted for most of the remaining costs. Figure 14 illustrates a typical purchase and sale of electricity to resellers in the wholesale market and purchase and sale of electricity to consumers in the retail market.

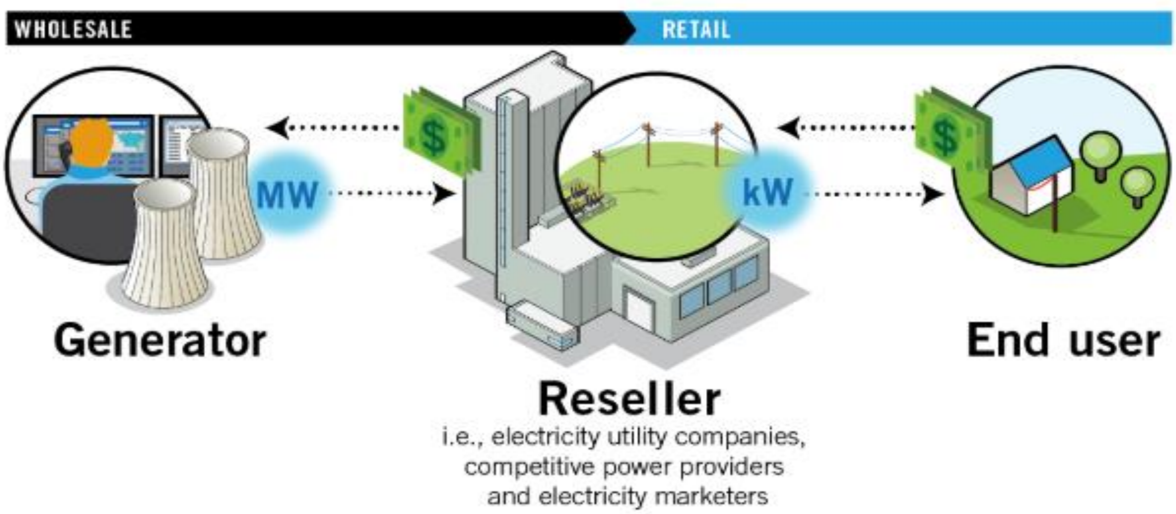


FIGURE 14. Wholesale market and retail market. (Source: PJM)

The wholesale market involves the buying and selling of power between the generators and the resellers (electricity utility companies, competitive power providers, electricity marketers). The electricity is bought by the resellers in the wholesale market and sold to end users in the retail market.[64] In the case of a regulated utility, the electricity retail rates are set by state regulators.

60. The PJM Energy Market procures electricity to meet consumers' demands both in real time and in the near term. It includes the sale or purchase of energy in PJM's real-time energy market (5 minutes) and the day-ahead market (1 day forward). https://pjm.com/markets-and-operations/energy.aspx
61. PJM's capacity market, called the Reliability Pricing Model, ensures long-term grid reliability by securing the appropriate amount of power supply resources needed to meet predicted energy demand in the future. https://pjm.com/markets-and-operations/rpm.aspx
62. Ancillary services help balance the transmission system as it moves electricity from generating sources to ultimate consumers. https://learn.pjm.com/three-priorities/buying-and-selling-energy/ancillary-services-market.aspx
63. https://learn.pjm.com/-/media/about-pjm/newsroom/fact-sheets/understanding-the-difference-between-pjms-markets-fact-sheet.ashx?la=en
64. https://learn.pjm.com/electricity-basics/market-for-electricity.aspx

BOX 3. Day-Ahead Market and Real-Time Market

"The **Real-Time Market** serves electricity needs in real time (which will always differ at least a little from the day-ahead forecast). The Real-Time Market is a spot market, meaning electricity is procured for immediate delivery. Supply and demand are paired and prices are calculated every five minutes for more than 10,000 different pricing points based on actual grid operating conditions.... Suppliers are paid the day-ahead price for whatever they were scheduled for, and the real time price for any generation that exceeds the scheduled amount."

"The **Day-Ahead Market** is a "forward" market, which means prices are set for energy that will be delivered in the future—in this case, the next day. Hourly prices are calculated based on generator offers, bids from power consumers such as utility companies and market-related financial transactions. PJM matches offers from the lowest- to highest-priced seller until it meets the bid-in demand for electricity, plus some reserves.... Any deviations from cleared quantities in the Day-Ahead Market are settled in the Real-Time Market."

More information is at https://learn.pjm.com/-/media/about-pjm/newsroom/fact-sheets/understanding-the-difference-between-pjms-markets-fact-sheet.ashx?la=en

Transmission

Transmission is the transfer of bulk electricity from the generation power plants, over long distances and at a high voltage, to the substations closer to the area of demand for electricity. Transmission is different from distribution, which delivers the electricity from the substation to the end consumers. Transmission infrastructure may be owned, operated, and maintained either by electric utilities or by independent transmission owners. PJM has Network Integration Transmission Services (NITS) rates, which cover the transmission owners' annual costs and revenue requirements, and the transmission enhancement charges, which are set to compensate the transmission owners for the necessary system upgrades and enhancements.[65,66] The Federal Energy Regulatory Commission (FERC) approves the transmission rates.

Depending on which entity is responsible for collecting those charges, PJM then bills either a retail supplier or the utility directly.[67] In this regard, the transmission cost is a pass-through charge. In 2018, PJM transmission charges accounted for 15% of the total wholesale electricity cost.[68]

65. https://pjm.com/markets-and-operations/billing-settlements-and-credit/guide-to-billing.aspx
66. PJM Open Access Transmission Tariff is available at https://pjm.com/directory/merged-tariffs/oatt.pdf.
67. https://blogs.constellation.com/energy-management/understanding-transmission-costs-in-your-power-bill-2/
68. https://learn.pjm.com/-/media/about-pjm/newsroom/fact-sheets/understanding-the-difference-between-pjms-markets-fact-sheet.ashx?la=en

3.1.3. PJM POWER MIX

In 2018, the PJM power mix was predominantly from nuclear, coal, and natural gas, with a small percentage of renewable energy, as shown in Figure 15.[69]

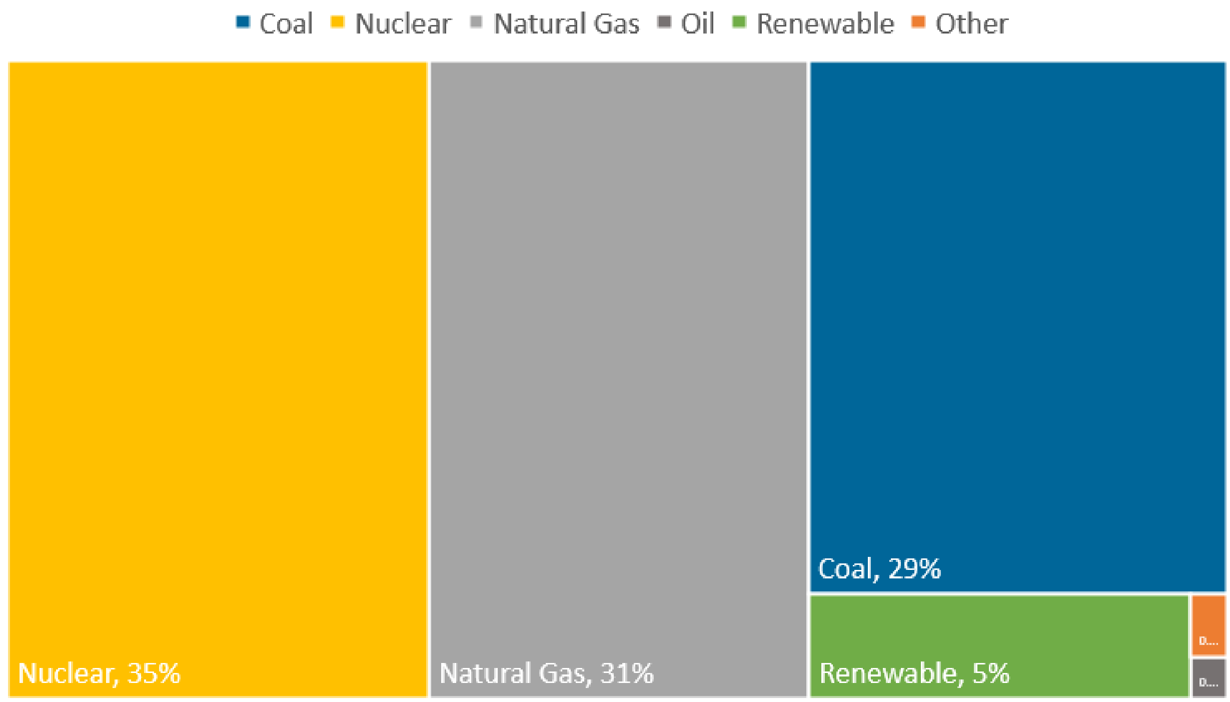


FIGURE 15. PJM Energy's power mix, 2018.

3.1.4. DOMINION ENERGY POWER MIX

Dominion Energy is the incumbent utility for Arlington customers. The company, with headquarters in Richmond, Va., is one of the nation's largest producers and transporters of energy and is the largest electricity provider in the Commonwealth. Dominion serves approximately 2.5 million electricity customers in Virginia and North Carolina. The company plans to achieve the Commonwealth voluntary[70] renewable energy goal of 15% by 2025 in Virginia (see section 3.2.1, Renewable Portfolio Standard in Virginia) through existing renewable resources, developing new renewable energy, and purchasing renewable energy certificates (RECs).[71, 72]

Figure 16 shows Dominion's power content mix for the historical year 2017.[73]

69. PJM Power mix hourly content is available at https://dataminer2.pjm.com/feed/gen_by_fuel.
70. The goal is not enforceable and has no penalty for utilities.
71. https://www.dominionenergy.com/company/making-energy/renewable-generation
72 The recently approved VCEA requires Dominion Energy to deliver electricity from 100% renewable sources by 2045. https://lis.virginia.gov/cgi-bin/legp604.exe?201+sum+HB1526
73. Dominion IRP 2017, p. 33, and IRP 2018, p. 27.

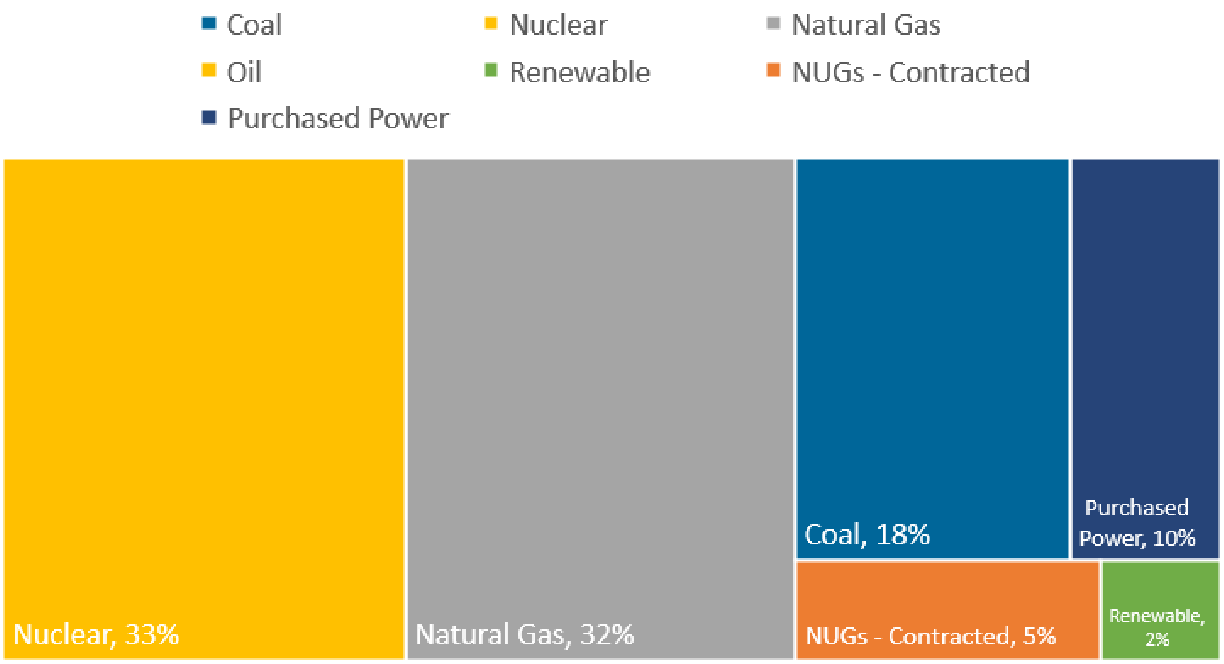


FIGURE 16. Dominion actual energy mix, 2017.

Similar to the PJM power mix, the Dominion energy mix in 2017 is predominantly from nuclear, natural gas, and coal, with a small percentage of renewable energy.

3.2. RENEWABLE ENERGY IN VIRGINIA AND PJM MARKET

The definition of renewable energy is set as follows in Virginia Code § 56-576:[74, 75]

> "Renewable energy" means energy derived from sunlight, wind, falling water, biomass, sustainable or otherwise, (the definitions of which shall be liberally construed), energy from waste, landfill gas, municipal solid waste, wave motion, tides, and geothermal power, and does not include energy derived from coal, oil, natural gas, or nuclear power. Renewable energy shall also include the proportion of the thermal or electric energy from a facility that results from the co-firing of biomass.

Renewable energy must be generated or purchased in Virginia or in the PJM service territory.[76] Tier I alternative energy[77] sources include

- Solar
- Wind power
- Geothermal energy
- Hydropower

74. https://law.lis.virginia.gov/vacode/title56/chapter23/section56-576/
75 Note: The "renewable energy" definition was recently updated in the VCEA https://lis.virginia.gov/cgi-bin/legp604.exe?201+ful+HB1526ER
76. https://www.pjm-eis.com/program-information/virginia.aspx?p=1
77. "Renewable energy" shall not include electricity generated from pumped storage, but shall include run-of-river generation from a combined pumped-storage and run-of-river facility.

- Wave
- Tidal
- Biomass energy
- Research and development expenses related to renewable energy can meet up to 20% of the renewable energy goal, as of the effective date of SB413 (2012).

BOX 4. Renewable Energy Certificates: Bundled and Unbundled

As per the EPA definition, “renewable energy certificates (RECs) are tradable, market-based instruments that represent the legal property rights to the "renewable-ness" (i.e. environmental attributes) of one megawatt-hour (MWh) of renewable electricity generation…. RECs play an important role in accounting, tracking, and assigning ownership to renewable electricity generation and use.”

Bundled RECs: The electricity and the RECs are sold together. These must come from the regional grid and are normally more expensive.

Unbundled RECs: The electricity is sold separately from the RECs. Unbundled RECs can come from anywhere in the United States, and they are normally cheaper than the bundled RECs. Unbundled RECs allow for a simple way to offset the carbon footprint of an entity and support clean energy.

While buying bundled RECs promotes the development of renewable energy in the area, buying unbundled RECs also supports the renewable energy market, as it encourages renewable electricity on a broader scale. The more RECs are in demand, the more renewable energy must be generated.

More information is at https://www.epa.gov/greenpower/renewable-energy-certificates-recs.

For renewable generation resources available in Virginia and the PJM, see APPENDIX F: RENEWABLE GENERATION RESOURCES IN VIRGINIA AND PJM.

3.2.1. RENEWABLE PORTFOLIO STANDARD IN VIRGINIA

The Commonwealth of Virginia has a voluntary[78] Renewable Portfolio Standard (RPS) goal[79] as follows:

- **RPS Goal III:** For calendar years 2017 through 2021, inclusive, an average of 7% of total electric energy sold in the base year,[80] and in the calendar year 2022, 12% of total electric energy sold in the base year.

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78. The Virginia Clean Energy Act (VCEA), which passed on March 18, 2020, introduced mandatory RPS goals for utilities in the Commonwealth. https://lis.virginia.gov/cgi-bin/legp604.exe?201+ful+HB1526ER
79. § 56-585.2. Sale of electricity from renewable sources through a renewable energy portfolio standard program. https://law.lis.virginia.gov/vacode/title56/chapter23/section56-585.2/
80. “Total electric energy sold in the base year” means total electric energy sold to Virginia jurisdictional retail customers by a participating utility in calendar year 2007, excluding an amount equivalent to the average of the annual percentages of the electric energy that was supplied to such customers from nuclear generating plants for the calendar years 2004 through 2006. § 56-585.2. A.

- **RPS Goal IV:** For calendar years 2023 and 2024, inclusive, an average of 12% of total electric energy sold in the base year, and in the calendar year 2025, 15% of total electric energy sold in the base year.

Table 3 shows the RPS percentages in Virginia from 2020 to 2025.

TABLE 3. RPS Percentages in Virginia, 2020–2025

Reporting Year	Target (% of the base year)	Renewable Energy (MWh)
2020	7%	122,915
2021	7%	122,915
2022	12%	210,711
2023	12%	210,711
2024	12%	210,711
2025	15%	263,388

Virginia also allows multipliers for certain types of technology: Two credits are received for each MWh of electricity generated from solar, onshore wind, or from facilities in the Commonwealth fueled primarily by animal waste, and three credits are received for each MWh of electricity generated from an offshore wind farm.[81] **Electricity must be generated or purchased in Virginia or in the PJM service territory,** as previously mentioned.[82]

3.3. RESOURCE STRATEGY FOR THE ARLINGTON CCA

The municipality typically decides the CCA resource strategy based on its priorities and objectives. According to the 2019 CCA legal study,[83] "Virginia Code § 56-589 is silent as to whether a CCA may be authorized to offer multiple 'products' (e.g., portfolios with varying degrees of clean and/or renewable energy), or a single product (e.g., a 100 percent renewable energy option)." **For the purpose of this Study and in line with Arlington objectives to power 100% of Arlington's electricity from renewable sources by 2035, the CCA explores three options as follows:**

a. Voluntary Virginia RPS goal (see Table 3)
b. 50% renewable energy
c. 100% renewable energy

81. https://www.pjm-eis.com/program-information/virginia.aspx
82. https://www.pjm-eis.com/~/media/pjm-eis/documents/rps-comparison.ashx
83. Legal Options for Community Choice Aggregation in Virginia, December 2019. Prepared for Virginia Clean Energy by the Environmental and Regulatory Law Clinic at the University of Virginia School of Law.

4. COST OF SERVICE

This section describes the cost of service for the CCA, which includes power supply costs, non–power supply costs, and pass-through charges from Dominion. The power supply costs are provided for the wholesale electricity prices (historical, current, forecast), PPA prices for solar and wind, and LCOE of selected technologies, while non–power supply costs are provided for the CSP fee and the CCA administration fee. Pass-through charges include transmission and distribution charges and riders.

4.1. POWER SUPPLY COSTS

4.1.1. WHOLESALE ELECTRICITY PRICES

PJM wholesale electricity prices include (1) energy market prices, (2) capacity market prices, (3) ancillary services costs, (4) administrative cost, and (4) transmission. For this research, we assume that the entity responsible for collecting the transmission cost is Dominion (see section 4.3.1, Transmission and Distribution Charges). The PJM "Markets at a Glance" summary provides useful background surrounding these components.[84]

PJM Wholesale Market Prices

Energy market prices account for just under two thirds of wholesale price and are divided between real-time (RT) and day-ahead (DA) markets, which reflect the price of electricity in $/MWh, known as locational marginal prices (LMPs). LMPs are composed of system energy, congestion, and marginal loss costs for a given location within the PJM Interconnection (for details, see APPENDIX C: PJM WHOLESALE MARKET PRICES). For this **research, we have analyzed the LMP for 3 years from 2017 to 2019. Note that we did not attempt to forecast the next decade of natural gas prices or other energy-pricing unknowns** and are aware that the 3-year look is not fully encompassing of all energy pricing outcomes. However, **we believe that this look provides a useful representative sample for discussion surrounding electricity pricing in the PJM and Arlington County.**

In this Study, we use the Ballston node as a stand-in for the price of electricity in Arlington County (for the full list of Arlington nodes, see APPENDIX D: ZIP CODE AND CLOSEST CORRESPONDING PNODE MAPPING). In 2019, the day-ahead and real-time LMP duration curve show that the RT LMP price at Ballston node varies between -$54 and $913, while the DA price varies between $10 and $200, with an average of $28 and median of $26 (Figure 17). The 10th percentile cutoff for DA LMP at Ballston is $19, while the 90th percentile is $40, meaning that the middle 80% of prices are within this range.

84. https://www.pjm.com/-/media/about-pjm/newsroom/fact-sheets/understanding-the-difference-between-pjms-markets-fact-sheet.ashx?la=en

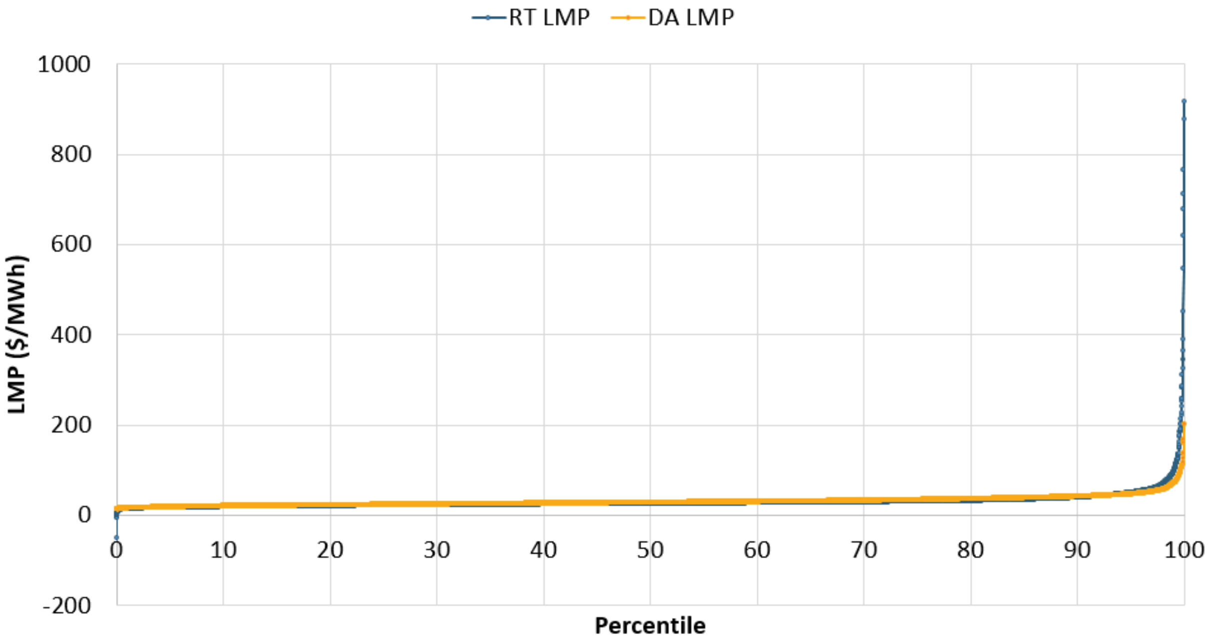

FIGURE 17. RT and DA LMP duration curve at Ballston, 2019.

Electricity prices in Arlington vary based on a variety of factors including load, the hour of the day, fuel mix, and other grid factors. From the 3 years analyzed, from 2017 to 2019, we can see that there is variability in the cost of energy for each year (see APPENDIX C: PJM WHOLESALE MARKET PRICES). While this 3-year lookback does capture some of the variability in real-time and day-ahead pricing, it does not show the full extent in possible outcomes. For example, Figure 18, from the Energy Information Administration (EIA), shows how **variable natural gas prices can correlate with electricity prices**.[85] In the winter of 2008–2009, this increase in natural gas prices led to increased energy prices in the PJM.

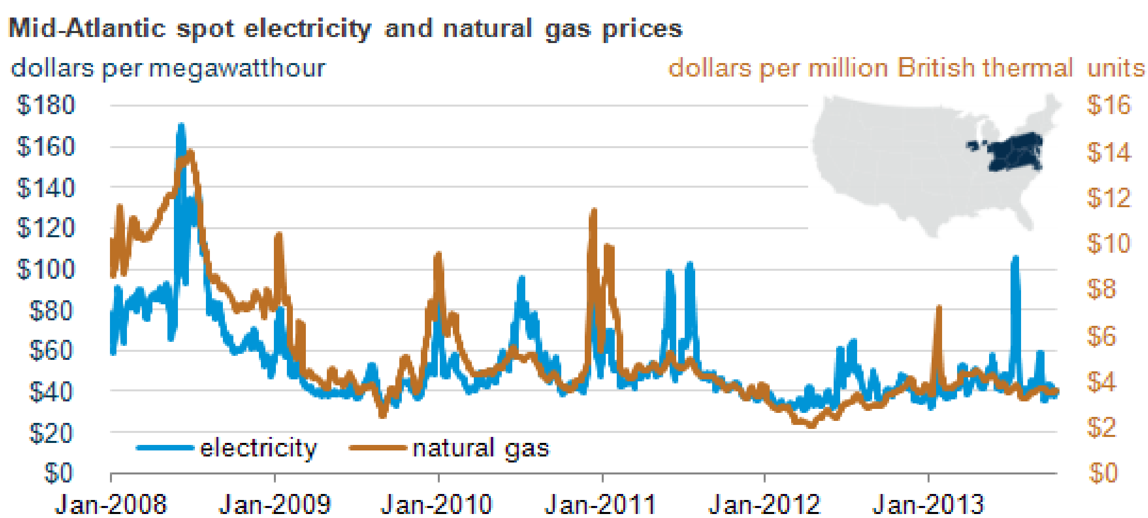

FIGURE 18. Mid-Atlantic spot electricity and natural gas prices. (Source: EIA)

85. https://www.eia.gov/todayinenergy/images/2013.11.18/chart2.png

PJM Wholesale Capacity Prices

According to 2018 Dominion IRP,[86]

> PJM conducts an annual reserve requirement Study to determine an adequate level of capacity in its footprint to meet the target level of reliability measured with a loss of load expectation (" LOLE") equivalent to one day of outage in 10 years. PJM's 2017 Reserve Requirement Study for delivery year 2021/2022, recommended using an installed reserve margin (" IRM") of 15.9% to satisfy the NERC/Reliability First Corporation (" RFC") Adequacy Standard BAL-502-RFC-02, Planning Resource Adequacy Analysis, Assessment, and Documentation.

The LOLE margin is combined with the PJM capacity market settled second incremental action. The auction price for energy capacity in the PJM-DOM region for 2019–2020 is $98.07 per megawatt-day. This figure is from the PJM 2019–2020 Final Zonal Scaling Factors, UCAP Obligations, Zonal Capacity Prices, and Zonal CTR Credit Rates.[87]

PJM Ancillary Services

PJM hourly ancillary service market results include MW quantities and prices.[88] For this Study, we use a proportion of the PJM total wholesale cost, which accounted for less than 1% in 2018.[89]

PJM Administrative Cost

PJM recovers its administrative costs under Schedules 9-1 through 9-6 in the PJM Open Access Transmission Tariff.[90] For this Study, we use a proportion of the PJM total wholesale cost, which accounted for around 1% in 2018.[91]

Power Prices Forecast

To estimate future rates, a subscription to a wholesale market price forecasting service[92] is needed. **VCE does not currently have a subscription to wholesale market price forecasting services, thus this Study uses ICF[93] market forecast estimates provided in the 2018 Dominion IRP for information purposes only.[94]**

Figure 19 shows the ICF Power Price Forecast for PJM-DOM On-Peak, Off-Peak, PJM Tier 1 REC Prices ($/MWh), and RTO Capacity prices ($/kW-yr) fall 2017 forecast.[95]

86. See 2018 Dominion IRP on p. 53.
87. https://pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2019-2020/2019-2020-third-incremental-auction-results.ashx?la=en
88. https://dataminer2.pjm.com/feed/reserve_market_results/definition
89. https://learn.pjm.com/-/media/about-pjm/newsroom/fact-sheets/understanding-the-difference-between-pjms-markets-fact-sheet.ashx?la=en
90. https://pjm.com/committees-and-groups/committees/fc/pjm-admin-cost-rates.aspx
91. https://learn.pjm.com/-/media/about-pjm/newsroom/fact-sheets/understanding-the-difference-between-pjms-markets-fact-sheet.ashx?la=en
92. See, for example, Intercontinental Exchange (ICE) at https://www.theice.com/market-data/view-only-quotes.
93. ICF is a global consulting services company, specializing in power markets among other things.
94. See 2018 Dominion IRP, Appendix 4A, p. 191.
95. The 2018 through 2020 prices are a blend of futures/forwards and forecast prices for all commodities except capacity prices; 2021 and beyond are forecast prices. Capacity prices reflect PJM RPM auction clearing prices through delivery year 2020–2021, forecast thereafter. See 2018 Dominion IRP, Appendix 4A, p. 191.

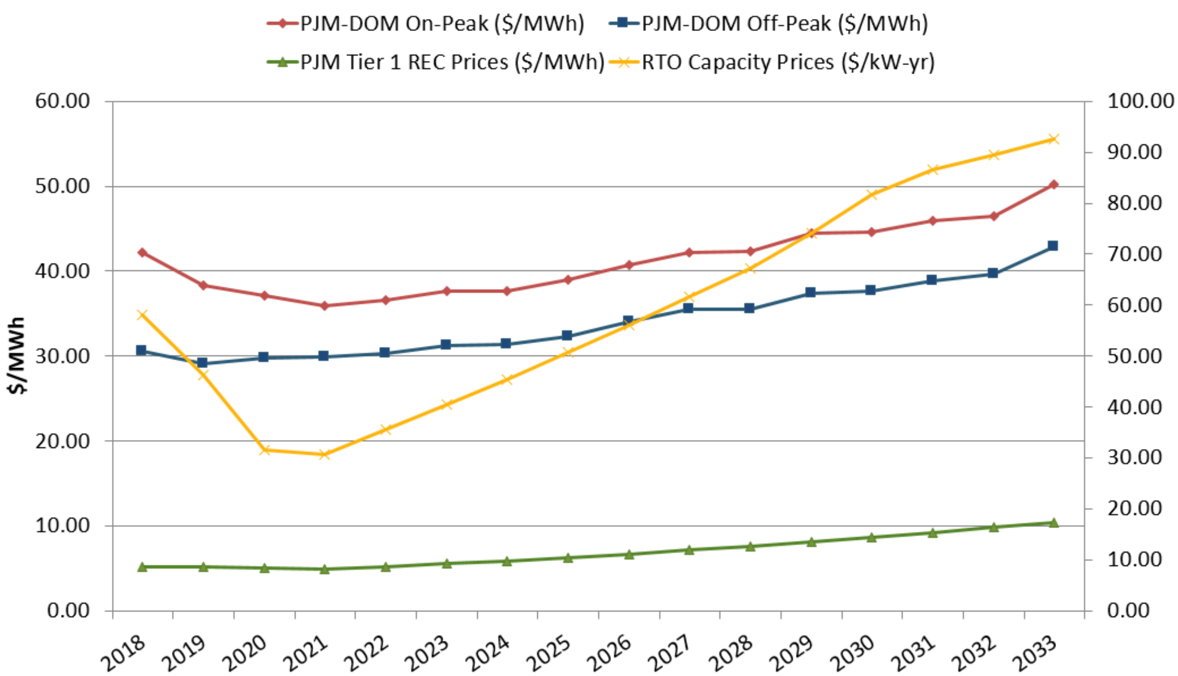

FIGURE 19. ICF federal CO_2 power and REC prices forecast, nominal $. (Source: Dominion)

4.1.2. PPA MARKET PRICES FOR SOLAR AND WIND

LevelTen[96] publishes a quarterly PPA Price Index for wind and solar projects in five ISO regions, including PJM. All prices are hub-settled for a virtual PPA[97] contract structure. Below are the prices provided for Q3 2019:[98]

- **Solar:** The 10th percentile market price for Q3 2019 solar PPAs in the PJM region was $32.3/MWh.
- **Wind:** The 10th percentile market price for Q3 2019 wind PPAs in the PJM region was $27.1/MWh.

The Arlington County recent price agreement for a virtual solar PPA with Dominion is $33.5/MWh. According to the County's energy manager, "the county government would have to cover any differential between that price and what the hourly wholesale power price is."[99]

96. LevelTen Energy Inc. (LevelTen) is a commodity-trading advisor (CTA) registered with the Commodity Futures Trading Commission (CFTC) and is a member of the National Futures Association (NFA). https://leveltenenergy.com/
97. CCAs in California normally sign a physical PPA. For more information on physical versus virtual PPA, see https://leveltenenergy.com/blog/energy-procurement/physical-power-purchase-agreement-or-virtual-ppa/.
98. https://leveltenenergy.com/blog/ppa-price-index/q3-2019/
99. https://www.washingtonpost.com/local/virginia-politics/amazon-arlington-solar-farm/2020/01/28/c44baf76-41e2-11ea-b503-2b077c436617_story.html

4.1.3. LCOE PRICES FOR VARIOUS TECHNOLOGIES

Lazard's Levelized Cost of Energy (LCOE) analysis[100] provides a comparative LCOE analysis for various generation technologies on a $/MWh basis, as shown in Figure 20.

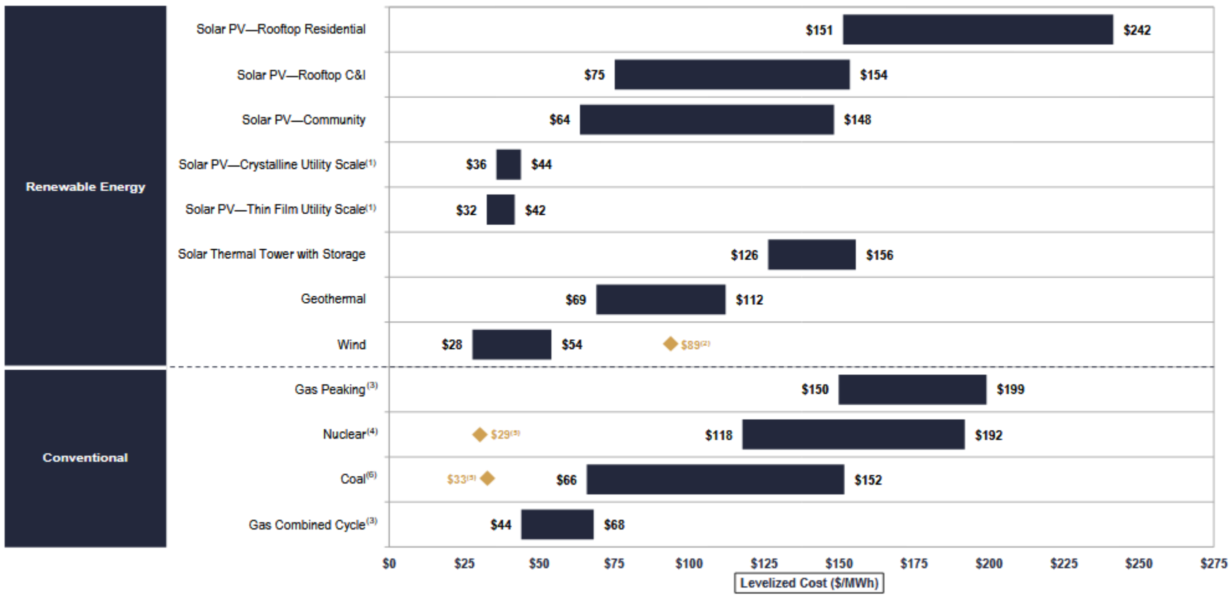

FIGURE 20. Levelized Cost of Energy comparison—unsubsidized analysis.[101]

According to Lazard's analysis, "selected renewable energy generation technologies are cost-competitive with conventional generation technologies under certain circumstances."

4.2. NONPOWER COSTS

4.2.1. COMPETITIVE SERVICE PROVIDER PROFIT

The CSP proposal to the CCA shall include all the costs associated with the procurement and delivery of electricity to the required delivery point, including its profit. For this Study, the CSP profit is estimated at 7%.[102]

4.2.2. CCA ADMINISTRATION FEE

The CCA administration fee is a fee per kWh that the CCA negotiates with the CSP to cover the organization's expenses for managing the program, implement marketing and communications, customer service, and legal fees (see section 8, CCA GOVERNANCE AND OPERATIONAL OPTIONS). For this Study, we assume a CCA administration fee at 0.1 cent/kWh, which is a common fee used among existing

100. https://www.lazard.com/media/451086/lazards-levelized-cost-of-energy-version-130-vf.pdf

101. Reprinted with permission from Lazard's Levelized Cost of Energy Analysis—Version 13.0. Copyright 2019 Lazard. https://www.lazard.com/media/451086/lazards-levelized-cost-of-energy-version-130-vf.pdf

102. This percentage may vary according to the actual offer from the CSP.

CCAs on the East Coast (see examples in BOX 8 and BOX 10). However, this fee could be negotiated differently with the CSP and adjusted based on local needs[103] and power prices.

4.3. PASS-THROUGH CHARGES FROM DOMINION

4.3.1. TRANSMISSION AND DISTRIBUTION CHARGES

Transmission charges are part of the Dominion generation charges as Rider T1 (see section 4.3.2, Riders), while distribution charges are set in the distribution component of the tariff. The monthly distribution kWh charges for residential and commercial customers for the year 2019 are summarized in Table 4.

TABLE 4. Dominion Monthly Distribution kWh Charge, 2019

Billing Months	Schedule 1 Basic Residential	GS1 Small General Service (Under 30 kW)
Basic Customer Charge	$6.58 per billing month	For single-phase service, $10.78 per billing month For three-phase service, $14.54 per billing month
June–September	First 800 kWh @ 2.1086¢ per kWh Over 800 kWh @ 1.1943¢ per kWh	First 1,400 kWh @ 1.7045¢ per kWh Over 1,400 kWh @ 1.0251¢ per kWh
October–May	First 800 kWh @ 2.1086¢ per kWh Over 800 kWh @ 1.1943¢ per kWh	First 1,400 kWh @ 1.7045¢ per kWh Over 1,400 kWh @ 1.0251¢ per kWh

4.3.2. RIDERS

For every kWh, Dominion applies a variety of riders, including

1. **Generation riders**, which cover the cost for the production of electricity from Dominion's power plants
2. **Transmission charge** (Rider T1), which is the cost of moving electricity from Dominion Energy's power plants to the substations
3. **Distribution riders,** which include Demand-Side Management (DSM) riders

For 2019, the total residential riders (Schedule 1) for generation, transmission, and distribution amount to 2.7895 cents/kWh, while the total commercial riders (Schedule GS1) amount to 2.1121 cents/kWh (see APPENDIX G: DOMINION BILL COST BREAKDOWN for rider charges details). **Dominion also has a fuel charge (Rider A), which is the cost for fuel used to produce electricity, including fuel shipment. We do not account for the Dominion fuel charge in our cost analysis, as fuel cost is already part of the wholesale electricity price.**

103. A detailed staffing requirements analysis for the management of the CCA program should be carried out for staffing cost estimates. These estimates will vary depending on the choice of the operating structure options for the amount of internal staff, external consultants, or third-party management.

5. RATE COMPARISON

This section provides a case study for a residential bill comparison between the latest 2019 Dominion residential tariff and riders for the current power mix and a potential CCA power purchase on the wholesale market for 100% renewable energy certificates (RECs). This section also provides future market-based rate estimates for power procurement for three different scenarios, and the funds the CCA would collect for managing its program and operations. All prices are expressed before taxes. **This section does not provide a full economic and financial analysis. Instead, it presents a case study for comparison purposes using only the publicly available costs and data.** Thus, at this stage of the research, we do not attempt to calculate the revenue requirements as is typically done in other CCA feasibility studies.[104] Calculation of these revenue requirements will be deferred to a later stage when more information will be available concerning staffing requirements for the Arlington CCA.

5.1. RESIDENTIAL BILL COMPARISON

A residential bill comparison between the latest 2019 Dominion tariff and riders for the current power mix and a potential CCA power purchase on the open market for 100% renewable energy certificates (RECs) was calculated as a case study for comparison purposes.[105] **The bill comparison was produced with our best knowledge of publicly available existing costs and existing available data.** However, there may be additional hidden charges that we may not be aware of, and thus we recommend further vetting if using these estimates for comparison externally. In addition, to get a more precise cost breakdown, a complete study of all PJM costs, including a more detailed view of transmission costs, would be necessary.

5.1.1. KEY ASSUMPTIONS AND METHODOLOGY

The key assumptions and methodology used to calculate the bill and retail price are summarized as follows:

- For comparison purposes only, this Study assumes that the rate design would initially mirror the structure of Dominion rates for the different components (i.e., generation, transmission, distribution, riders). (see APPENDIX G: DOMINION BILL COST BREAKDOWN). Detailed rate design was not part of this Study, therefore, the CCA rates in the case study follow the hourly PJM LMPs and do not differ above 800-kWh thresholds as Dominion rates do.[106] A CCA would typically establish fixed rates that would be stable across the year.

104. See, for example, San Diego Feasibility Study for a Community Choice Aggregate, July 2017.
105. A case study for commercial customers is not provided in this Study because of a lack of clear indication of the ration of Arlington commercial customer rate structure—whether they are GS1 versus GS2 service.
106. The utility also has time-of-use (TOU) rates, which the CCA could potentially offer. This Study does not account for Dominion TOU rates.

- As Dominion audited meter readings across Arlington are not publicly available, we calculated Arlington's 2019 hourly load profile as a proportion of the PJM-DOM load zone, using the methodology described in section 2.1.3 (Load Profile).[107]
- The set of applicable riders for generation and distribution is identical between the CCA and the Dominion bill (see section 4.3.1, Transmission and Distribution Charges), with the exception that the CCA bill does not include the Rider A fuel charge, as fuel is bundled into the PJM day-ahead LMP prices.[108]

Key assumptions and methodology to calculate the CCA bill are as follows:

- Monthly load by the number of residential subscribers in Arlington is used to derive the monthly electricity usage in kWh.
- The 100% customers scenario is assumed (see section 2.2.1).
- 2019 pricing data from the PJM for day-ahead LMP delivery to the Arlington Ballston substation is used as the pricing reference node for all of Arlington County (see section 4.1.1).[109]
- To generate the CCA bill, the model uses the 2019 hourly load data with the corresponding hourly day-ahead pricing.
- To this figure is then added the REC Tier 1 price from the ICF estimate for 2019 (see section 4.1.1).
- The capacity cost was calculated using the 15.9% extra capacity as described in PJM Wholesale Capacity Prices.
- Transmission charges from Dominion Schedule 1 and the applicable Rider T1 for electricity supply transmission were used.[110]
- PJM capacity, ancillary services, and administrative fees are considered pass-through charges. The PJM ancillary services and administrative fee is considered as a proportion of the total wholesale cost (see PJM Ancillary Services).
- The CSP profit and the CCA administration fee are calculated on the market LMP cost (see section 4.2, Nonpower Costs).

Key assumptions and methodology to calculate the Dominion bill are as follows:

- The Dominion bill was generated using the Schedule 1 tariff[111] for residential for the year 2019 to create a pricing model for the hour-by-hour load across the year.
- Modeling for Arlington load uses the 2019 Dominion residential tariffs with the residential load to determine residential rates.
- The Dominion residential tariff has a price increase point of usage over 800 kilowatt-hours during the summer cooling season and price decreases over 800 kilowatt-hours during nonsummer months.

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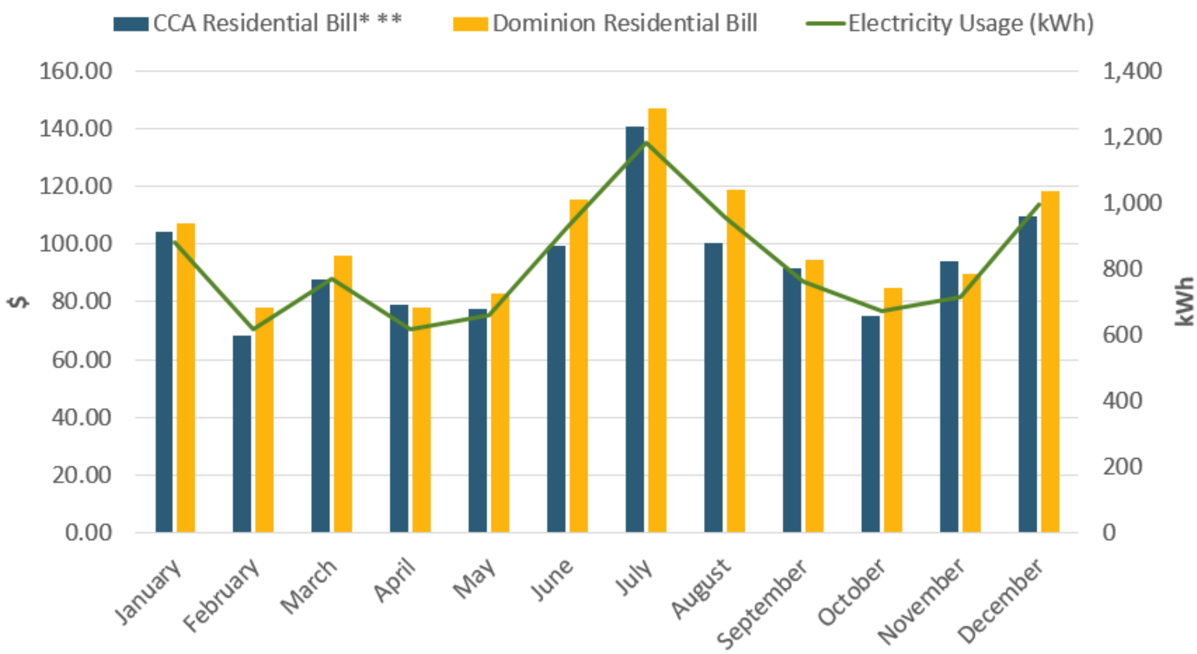
107. The most accurate load characterization for a municipality is drawn from the investor-owned utility from audited meters across the municipality. The load over different substations in combination with the LMP for each substation is necessary to determine an accurate pricing aggregate for the municipality.
108. To our knowledge and understanding, the fuel rider is a pass-through charge for Dominion to recover the cost for fuel used to generate electricity. Because the CCA will procure the electricity on the wholesale market, the fuel is already calculated into the PJM LMP prices and we do not include it in the CCA tariff.
109. Pricing considerations between different Arlington County substations' LMP delivery are minimal (see section 4.1).
110. PJM transmission pricing utilizes the Network Service Peak Load to determine pricing cost as explained in Transmission, and PJM transmission modeling is outside of scope for this Study.
111. https://www.dominionenergy.com/home-and-small-business/rates-and-regulation/residential-rates

5.1.2. CASE STUDY RESULTS

A bill comparison for residential customer between a potential CCA with 100% renewable energy (RECs) procured on the wholesale market, versus Dominion with current power mix, was derived as a case study for the 12 months of the year (Figure 21).



*For more accurate comparison, we suggest using metered electricity usage figures from the utility. **The fuel mix includes 100% RECs from the PJM wholesale market.

FIGURE 21. Case study: CCA bill versus Dominion bill.

The comparison between the CCA bill, procuring electricity via a third party on the wholesale market for 100% renewable energy (RECs), and the Dominion bill with the current power mix shows the CCA bill would be a price-competitive option for most months. From our investigation, an advantage for the CCA is the exclusion of the fuel cost in the rate-setting (see APPENDIX G: DOMINION BILL COST BREAKDOWN). As previously explained, the fuel cost is already embedded in the wholesale market pricing.

Figure 22 shows the monthly and yearly average for residential retail prices for both Dominion and the CCA. As mentioned earlier, the CCA rates in this case study follow the PJM hourly LMPs, but a typical CCA would establish fixed rates so the rates would be stable across the year.

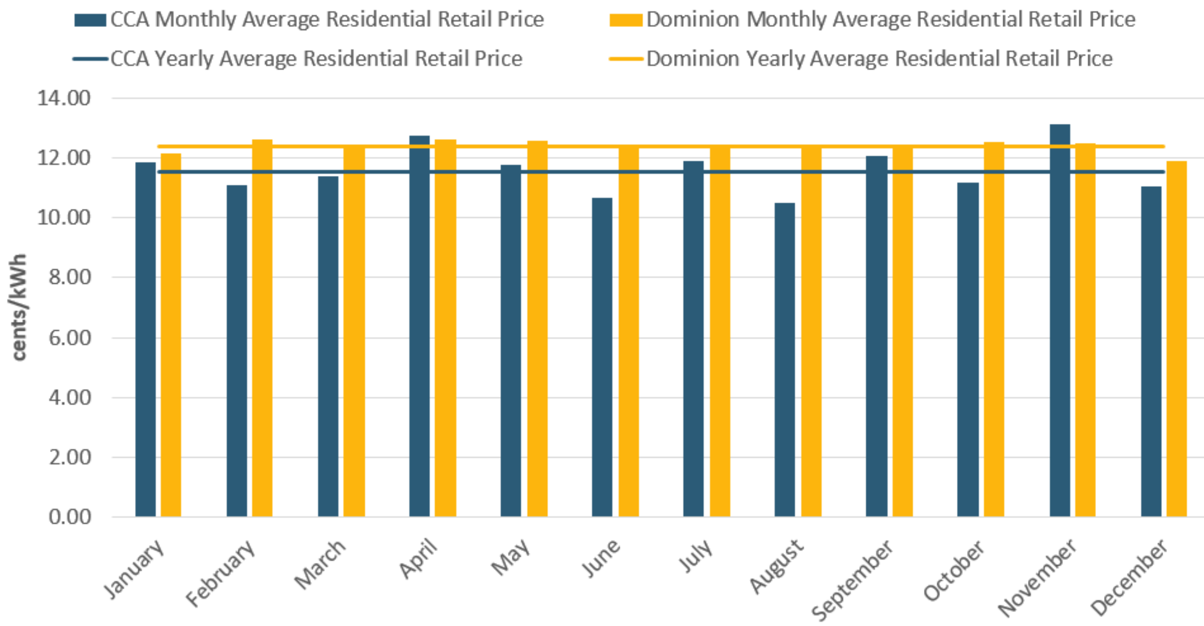


FIGURE 22. CCA and Dominion monthly and yearly residential electricity retail prices (cents/kWh).

Figure 23 shows the CCA and Dominion electricity price breakdown in cents/kWh from the 2019 bill calculations.

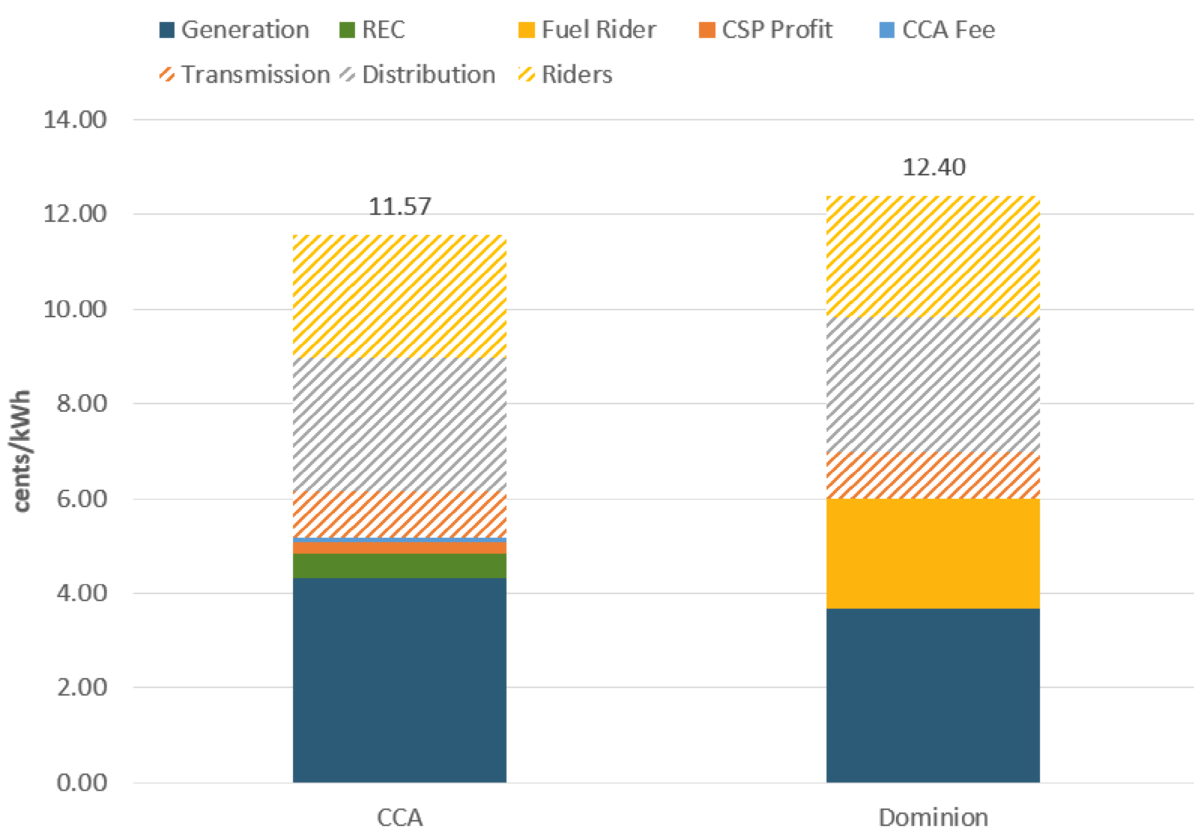


FIGURE 23. CCA and Dominion electricity price breakdown (cents/kWh).

The CCA yearly average residential retail electricity price over the 2019 period was 7% lower than Dominion, 11.57 cents/kWh and 12.40 cents/kWh, respectively. The CCA generation component is slightly higher, as it includes the cost of fuel. However, the total generation cost for the CCA, including the RECs, is projected to be lower than Dominion when the latter includes the fuel cost. **As shown in Figure 23, the fuel rider has a substantial impact on Dominion's total retail price, accounting for around 19% of the total retail price.** The RECs account for around 12% of the generation cost and approximately 5% of the total retail rate. The CSP profit and the CCA fee account for only a small percentage of the total retail price (see **FIGURE 24**). Transmission, distribution, and riders are identical in both bills.

CCA Bill Breakdown

To better understand the CCA bill, we also provide a detailed breakdown of every component as follows:

- Generation includes energy, capacity, and others (ancillary services and administrative costs)
- Renewable energy certificates (RECs)
- Distribution includes distribution charges and basic customer charge
- Transmission
- Dominion riders
- CSP profit
- CCA administrative fee

The following pie chart (Figure 24) shows the breakdown of the components of the CCA bill.

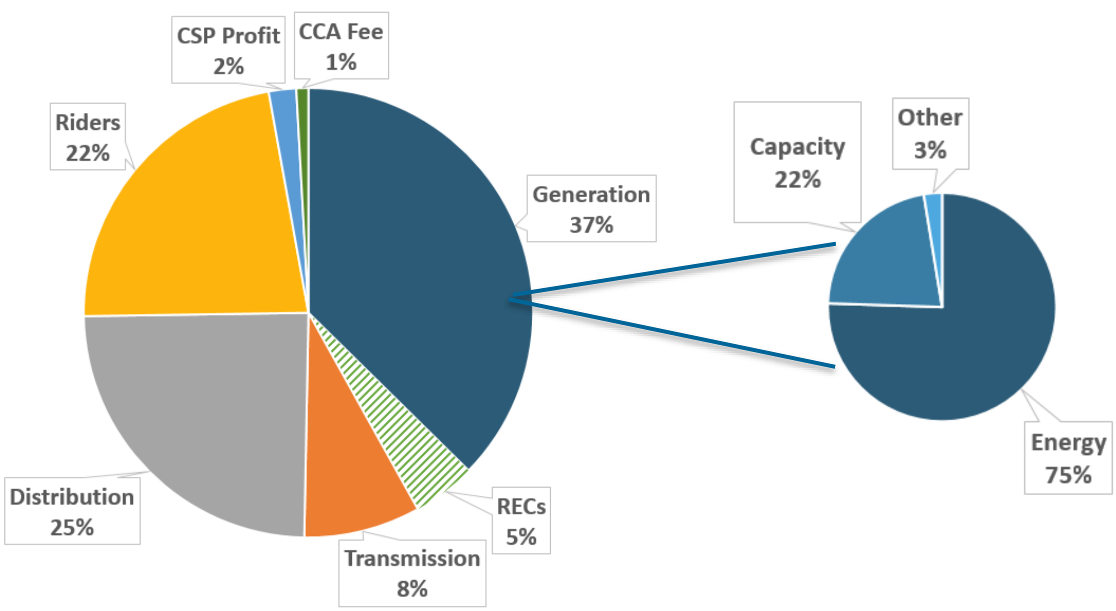


FIGURE 24. CCA bill breakdown.

As we can see from the pie chart above, the CCA retail price includes all but the fuel charge. The major expense is the generation, around 42% of the total retail price. The Dominion riders are quite significant, accounting for 22% of the bill. From the generation breakdown, we can see that the energy component accounts for the most (75%), followed by capacity (22%).

5.1.3. SENSITIVITY ANALYSIS

This section presents several sensitivity analyses carried out for different scenarios and modeling assumptions. Understanding the impacts of one or more cost variations allows for better comprehension surrounding possible CCA and Dominion residential price.

The sensitivity analysis was made for the case study presented in section 5.1.2 and performed for the follow sensitivities:

a) Electricity load increase/decrease
b) Dominion generation cost increase/decrease
c) Dominion fuel rider cost increase/decrease
d) Dominion generation and fuel rider cost increase/decrease simultaneously.

In this analysis, we assumed modest increases or decreases in load, generation cost, and fuel rider cost to represent a range of plausible outcomes. We understand that actual values for these variables could fall outside the range bounded by historic metrics and that this sensitivity analysis does not cover the full extent of possible outcomes. Still, this case study is intended to provide an idea of possible variability in pricing outcomes.

Residential Electricity Load Increase/Decrease

Figure 25 shows the yearly residential price sensitivity for the average residential prices assuming a load increase and decrease by +5%/10% and -5%/10%, respectively.

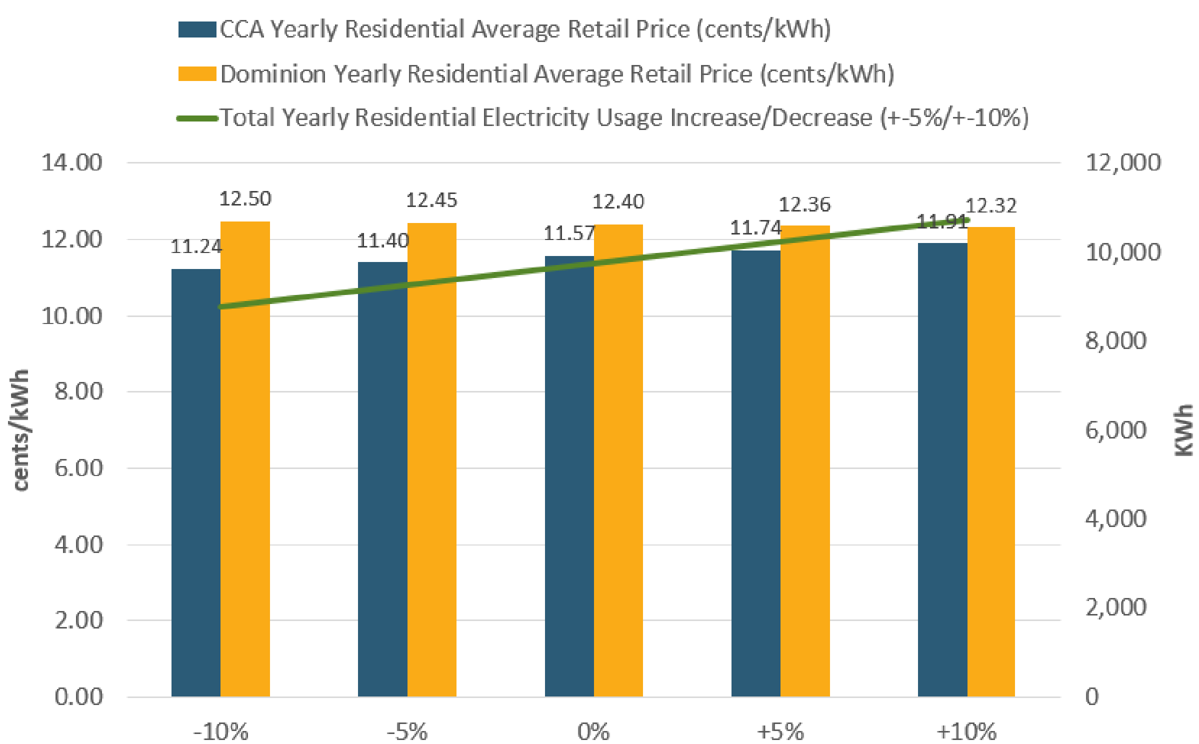


FIGURE 25. Yearly residential average price comparison for load sensitivity (±5%/±10%).

This sensitivity analysis shows that if the load increases by 5%/10%, or decreases by 5%/10%, the CCA yearly residential retail price remains competitive compared with Dominion. We can, however, note that the CCA yearly residential retail price is more sensitive to the load increase or decrease (see TABLE 5). In the 5% load increase scenario, the CCA yearly residential average retail price would increase/decrease by 1.4%, while Dominion's yearly residential average retail price would be affected only with an increase/decrease by 0.7%. In the 10% load increase scenario, the CCA yearly residential average retail price would increase/decrease by 2.8%, while Dominion's yearly residential average retail price would be slightly affected with an increase/decrease by 0.4%.

Variability in load may be relevant, as the Dominion residential tariff has a price increase point of usage over 800 kWh during the summer cooling season and price decreases over 800 kWh during nonsummer months that allows Dominion to shift the higher summer LMP over 4 months to lower LMP costs during the 8 nonsummer months. Following our methodology, CCA rates follow the hourly PJM LMPs and do not differ above 800-kWh thresholds as Dominion rates do. We expect the Arlington CCA to establish fixed rates so the rates would be stable across the year.

TABLE 5. CCA and Dominion Yearly Residential Average Price Range (%) for Load Sensitivity

Percentage Increase/Decrease	CCA Yearly Residential Average Retail Price Range (%)	Dominion Yearly Residential Average Retail Price Range (%)
±5%	±1.4%	±0.7%
±10%	±2.8%	±0.4%

Dominion Generation Cost Increase/Decrease

FIGURE 26 shows the yearly residential retail price sensitivity for the average residential retail prices assuming the Dominion generation cost would increase and decrease by ±2%, respectively. The CCA residential retail price is assumed to be the same, as well as total electricity usage.

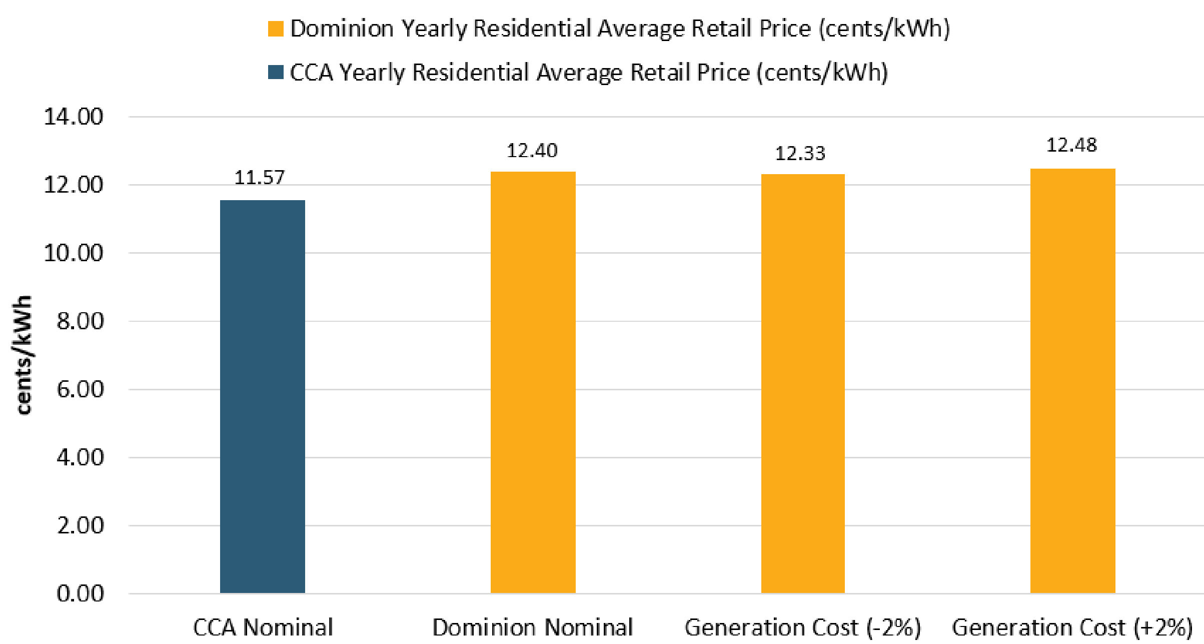


FIGURE 26. Yearly residential average price comparison with Dominion generation cost sensitivity (±2).

This sensitivity analysis shows that if Dominion generation cost increases or decreases by 2%, the CCA yearly residential retail price remains competitive compared with Dominion. Dominion yearly residential average retail price would be slightly affected with an increase/decrease by 0.6% as shown in Table 6.

TABLE 6. CCA and Dominion Yearly Residential Average Price Range (%) for Generation Cost Sensitivity

Percentage Increase/Decrease	Dominion Yearly Residential Average Retail Price Range (%)
±2%	±0.6%

Dominion Fuel Rider Cost Increase/Decrease

Figure 27 shows the yearly residential retail price sensitivity for the average residential retail prices assuming the Dominion fuel rider cost would increase and decrease by ±2%, respectively. The CCA residential retail price is assumed to be the same, as well as total electricity usage.

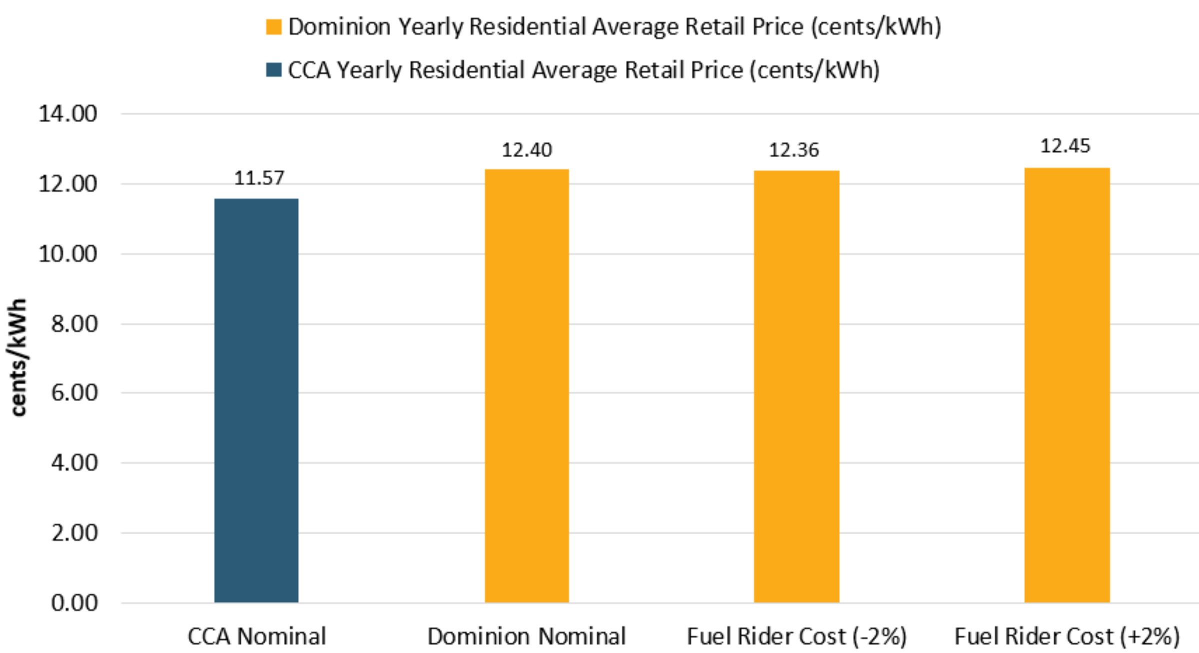


FIGURE 27. Yearly residential average price comparison with Dominion fuel rider cost (±2%).

This sensitivity analysis also suggests that if the Dominion fuel rider cost increases or decreases by 2%, the CCA yearly residential retail price remains competitive compared with Dominion. The Dominion yearly residential average retail price would be marginally affected with an increase/decrease by 0.4% as shown in Table 7.

TABLE 7. CCA and Dominion Yearly Residential Average Price Range (%) for Fuel Rider Cost Sensitivity

Percentage Increase/Decrease	Dominion Yearly Residential Average Retail Price Range (%)
±2%	±0.4%

Dominion Generation and Fuel Rider Costs Increase/Decrease

Figure 28 shows the yearly residential retail price sensitivity for the average residential retail prices assuming that various combinations of Dominion generation costs and fuel rider costs would increase and decrease by +5% and -5% simultaneously. The CCA residential retail price is assumed to be the same, as well as total electricity usage.

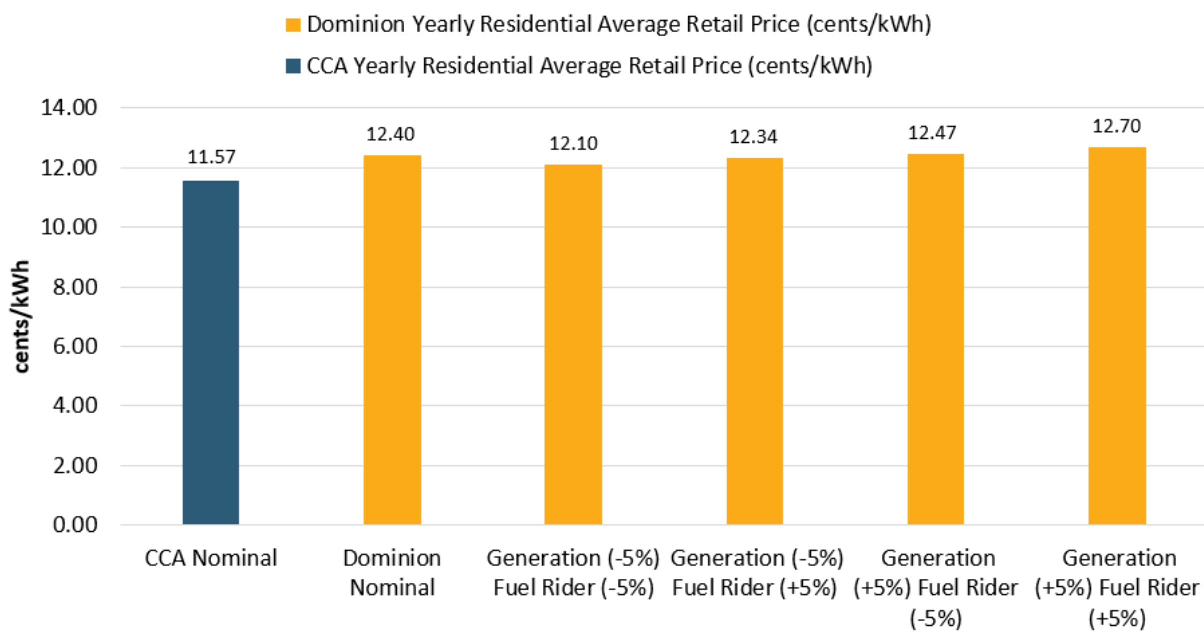


FIGURE 28. Yearly residential average price comparison with Dominion generation cost (±5%) and fuel rider cost (±5%).

This sensitivity analysis shows that if Dominion generation and fuel rider costs increase or decrease by 5% simultaneously, the CCA yearly residential retail price still remains competitive compared with Dominion. In particular, in the extreme case where both the generation and the fuel rider decrease by 5%, the CCA residential retail price is still lower by around 4.5% compared with Dominion. In the other extreme case where both the generation and the fuel rider increase by 5%, the CCA would have a 10% advantage over the retail prices. The Dominion yearly residential average retail price would be affected with an increase/decrease by 0.5% and 2.4% under the various scenarios considered as shown in Table 8.

TABLE 8. CCA and Dominion Yearly Residential Average Price Range (%) for Generation and Fuel Rider Cost Sensitivity

Percentage Increase/Decrease	Dominion Yearly Residential Average Retail Price Range (%)
±5%	±0.5%
±±5%	±2.4%

Monthly Residential Retail Rate Ranges for all Sensitivities

Figure 29 shows the monthly average residential retail price ranges according to all the sensitivity analyses performed for each case.

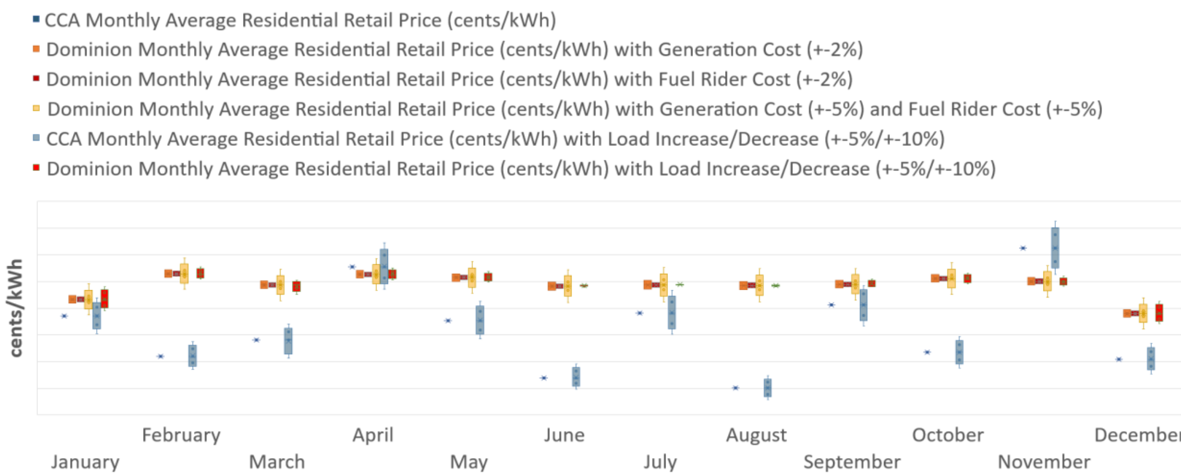


FIGURE 29. Monthly residential average price range comparison for all sensitivities.

Figure 29 shows that in most all sensitivity scenarios in most months, the CCA residential retail price remains competitive compared with Dominion. We can also note that the CCA monthly residential retail price ranges are more sensitive than Dominion to the load increase or decrease, similarly to the yearly prices.

5.1.4. CONCLUSION

The sensitivity analysis suggests that the CCA residential case study would still be competitive under several cost increase or decrease assumptions. In all sensitivity scenarios analyzed, the CCA yearly residential average retail price remains competitive compared with Dominion. Likewise, in most sensitivity scenarios, the CCA monthly residential retail price ranges remain competitive with Dominion. The CCA yearly residential retail price is more sensitive to the load increase or decrease compared with Dominion. However, we expect the Arlington CCA to establish fixed rates that would be stable across the year. Dominion yearly residential retail price would be only slightly affected by an increase/decrease of both generation and fuel rider costs, respectively, while testing a combination of ±5% of Dominion generation and fuel rider costs does show slightly more variation in the Dominion price. **Still, even in the extreme case where both the generation and the fuel rider decrease by 5%, the CCA residential retail price is still lower than the Dominion retail price by around 4.5%.**

5.2. FUTURE MARKET-BASED RATE ESTIMATES FOR POWER PROCUREMENT

Future market-based rate estimates for power procurement, which include the wholesale cost of energy, capacity, ancillary services, administrative services, along with the CSP cost and CCA administrative fee, were calculated for 2020–2030 for informational purposes only. The following scenarios for different power mix were analyzed:

- Base case scenario with current power mix
- Voluntary Virginia RPS goals (see Table 3)
- 50% renewable energy
- 100% renewable energy

5.2.1. KEY ASSUMPTIONS AND METHODOLOGY FOR FUTURE RATE ESTIMATES

The key assumptions and methodology for the calculation of the future rates are as follows:

- For these calculations, the CCA Program with 100% Customers scenario was used.
- The on-peak load and off-peak load were calculated using the ratio of the yearly on-peak load (48%) and off-peak load (52%) from the 2019 monthly data (see BOX1).
- The cost of energy was calculated using the ICF Power Price Forecast for Dominion for the PJM-DOM zone (see Power Prices Forecast), as VCE does not currently have a subscription to wholesale market price forecasting services.
- The capacity, ancillary services, and administrative services were calculated as a percentage of the total market cost as a fraction of the total wholesale cost (see PJM Wholesale Capacity Prices, PJM Ancillary Services, PJM Administrative Cost).
- The PJM Tier 1 REC price was added to the PJM-DOM zone weighted average price (from the on-peak and off-peak price).
- Rates include a CSP profit of 7% and a CCA administrative fee of 0.1 cent/kWh.

5.2.2. RESULTS

Figure 30 shows a comparison of future market-based rates estimates for power procurement (cents/kWh) for the period 2020–2030 for the four scenarios.

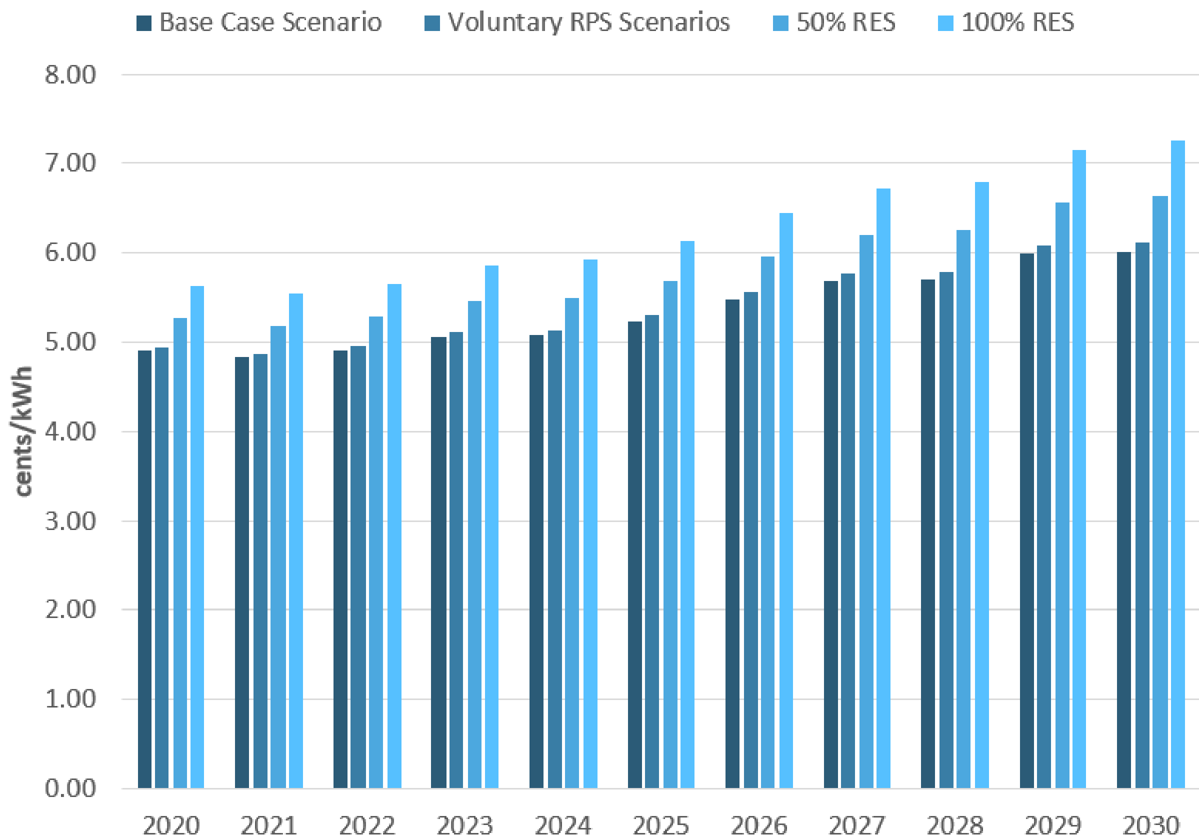


FIGURE 30. Future market-based rate estimates for power procurement for the four scenarios, 2020–2030.

Results show a minimal difference from the RPS scenarios versus the base case (1%–2% difference), around 6%–9% rate difference for the 50% RES versus RPS scenarios and base case. The 100% rate would have a difference of around 12%–16% versus RPS scenarios and base case, and around 6%–8% with the 50% RES scenario.

It is worth noting that the ICF Federal Commodity Price Forecast (nominal $) has predicted a federal price on CO_2 ($/ton) from 2026 onward. The CO_2 cost was not factored into our calculations. However, the cost of renewable energy will further decrease and be more competitive with the cost of electricity from fossil fuel should the CO_2 cost be applied. Table 9 shows the ICF Federal Commodity Price Forecast (nominal $) for the period 2026–2033.

TABLE 9. ICF Federal Commodity Price Forecast (Nominal $), 2026–2033

Year	2026	2027	2028	2029	2030	2031	2032	2033
CO_2 ($/ton)	0.35	0.56	1.83	2.16	5.04	6.53	6.53	8.20

In addition, should the CCA be able to procure renewable energy through PPAs directly with independent power producers, the cost of renewable energy could decrease due to the favorable and competitive prices for these technologies as described in section 4.1.2, PPA Market Prices for Solar and Wind, and section 4.1.3, LCOE Prices for Various Technologies.

5.3. ESTIMATED FUNDS FOR THE ARLINGTON CCA

Estimated funds for the Arlington CCA were calculated assuming an administration fee of 0.1 cent/kWh (see section 4.2.2, CCA Administration Fee). Figure 31 shows the cumulative amount of the fee for both the 100% customers scenario and the opt-out scenario.

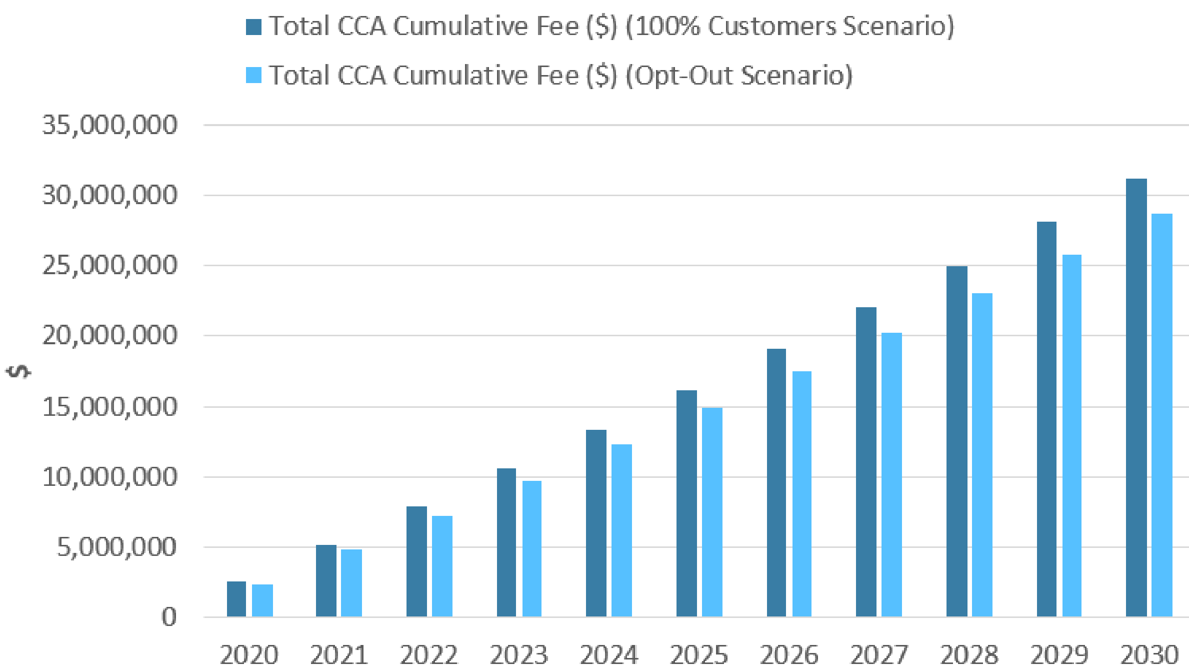


FIGURE 31. Total CCA cumulative fee for the 100% customers scenario and the opt-out scenario.

Depending on scenario, the Arlington CCA would be able to collect around $25–$30 million over around 11 years of operation, which would be used toward the administration of the program and other energy-related initiatives.

5.4. CONCLUSIONS

Our calculations show that the CCA is a viable option for procurement of 100% renewable energy on the wholesale market at a competitive price. Future market-based estimate for power procurement, including CSP profit and CCA fee, varies according to the percentage of renewable energy in the power mix. It is important to highlight that the cost of renewable energy could decrease should the federal price on CO_2 be applied from 2025 onward. **The CCA is a self-sufficient program and would use the administrative fee funds for its administration and other energy-related initiatives.**

6. ENVIRONMENTAL AND OTHER BENEFITS

This section provides an overview of the potential environmental impacts, notably, greenhouse gas emissions reduction, for the implementation of a CCA for residents and businesses in Arlington County for three different scenarios. In addition, a brief summary is provided of potential future energy efficiency programs, and other programs, that could be offered by the CCA.

6.1. EMISSIONS OUTLOOK

6.1.1. BACKGROUND

One primary advantage of a CCA is greater local control over which resources are pursued in delivering electricity to customers. Several CCAs have successfully created multiple options for low-carbon and renewable energy power for their customers, compared with incumbent utilities. For example, Sonoma Clean Power[112] offers the California counties of Sonoma and Mendocino a "CleanStart" option of 91% carbon-free electricity[113] and an EverGreen option of 100% locally produced renewable energy. In addition, in California, CCAs can pursue PPAs with renewable energy resources developers, including solar PV and wind energy, to meet climate action requirements. Such resources have been decreasing in cost due to innovations in technology and greater economies of scale. As illustrated in section 4.1.3, the cost of solar PV and wind has declined significantly since 2009, making these renewable energy technologies less expensive than conventional fossil fuel resources.

In line with Arlington's goals of carbon neutrality by 2050, renewable energy resources reduce greenhouse gas emissions and air pollution when compared with fossil fuel resources. This section outlines the greenhouse gas emissions outlooks for different resource procurement scenarios under the CCA, in comparison with projections under the existing utility, Dominion Energy. These scenarios are also in line with the Virginia Clean Economy Act, which was introduced in December 2019 and establishes a goal of 100% carbon-free electricity with zero utility emissions by 2050 by scaling up demand-side management, energy efficiency programs, and enacting a statewide clean energy standard (CES).[114] This builds on the foundation set by previous statewide goals including those in the 2018 Virginia Energy Plan, which calls for grid modernization, greater uptake of both utility-scale and rooftop solar PV and onshore wind, and more options for corporate procurement of renewable energy sources.[115]

112. https://sonomacleanpower.org/
113. CleanStart includes 49% from renewables including solar, wind, and geothermal and 42% from hydropower. CleanStart's percentage of renewables is 11% higher than that of the incumbent utility, Pacific Gas & Electric Company.
114. The Virginia Clean Energy Act (VCEA) was passed on March 18, 2020 https://lis.virginia.gov/cgi-bin/legp604.exe?201+ful+HB1526ER
115. https://www.governor.virginia.gov/media/governorvirginiagov/secretary-of-commerce-and-trade/2018-Virginia-Energy-Plan.pdf

6.1.2. METHODOLOGY

The 2018 Dominion Energy Integrated Resource Plan (IRP)[116] **and the U.S. Environmental Protection Agency (EPA) eGRID database**[117] **were used in modeling these scenarios.** Specifically, historical emissions factors from the eGRID database and historical and projected emissions factors from the IRP were incorporated. **Note that these emissions factors apply to the combined fuel mix, rather than to each individual resource.** Historical annual electricity usage provided by Arlington County for 2000–2018[118] was extended to 2030 using compound annual growth rates from the IRP. In this analysis and for comparison purposes, the CCA Program with 100% Customers was applied to each scenario. Total emissions were then calculated as the product of emissions factors and electricity usage.

Figure 32 compares historical emissions factors (lbs CO_2/MWh electricity generated) from the 2018 Dominion IRP (p. 30, Figure 3.1.3.1) with EPA eGRID data for Virginia and the broader Virginia/Carolina region (SRVC). **As the IRP emissions factors provide a continuous record from 2000 to 2017 and compare well with EPA eGRID data, these IRP emissions factors are used in further analysis.**

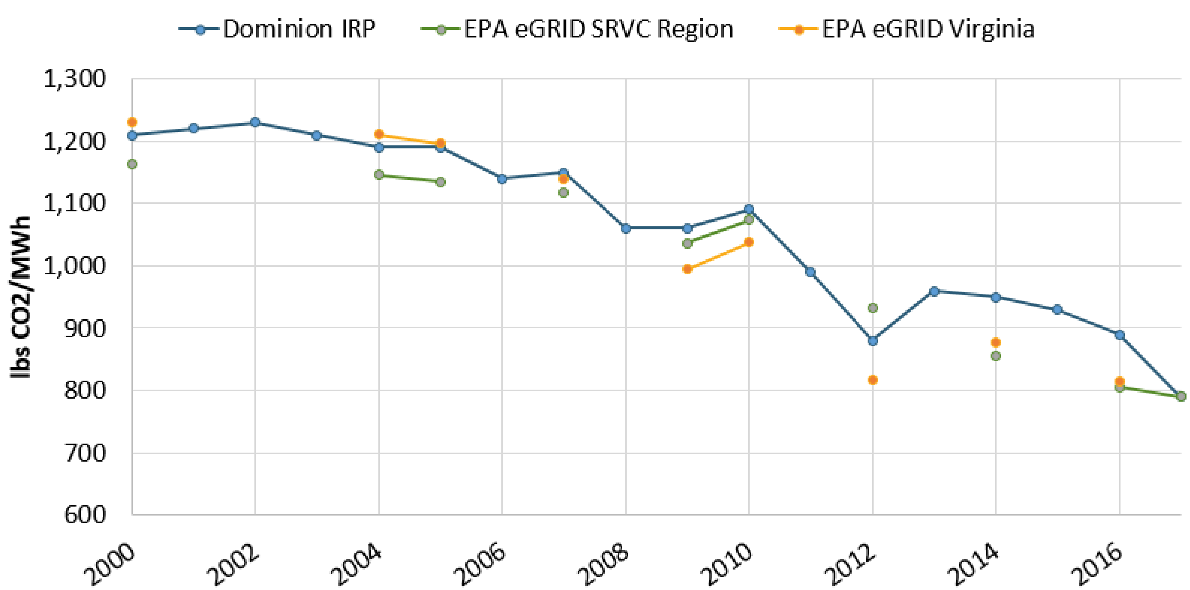


FIGURE 32. Historical emissions factors from the Dominion IRP, EPA eGRID SRVC region, and EPA eGRID Virginia region.

6.1.3. BASELINE EMISSIONS WITH INCUMBENT UTILITY

The CCA scenarios are compared to a baseline of Arlington County power provided entirely by the incumbent utility, Dominion Energy. As shown in Figure 33, historical emissions factors from 2000 to 2017 are extended to 2030 using estimates provided by the Dominion IRP (p. 41), with **projections for emissions factors with and without the implementation of the Regional Greenhouse Gas Initiative**

116. https://www.dominionenergy.com/library/domcom/media/about-us/making-energy/2018-irp.pdf
117. https://www.epa.gov/energy/emissions-generation-resource-integrated-database-egrid-questions-and-answers#egrid4b
118. https://data.arlingtonva.us/dataviews/231353/utility-accounts-usage/ for 2000–2014; personal communication for 2015–2018

(RGGI). Established in 2009, RGGI is a cooperative effort to cap and reduce greenhouse gas emissions among nine New England and Mid-Atlantic U.S. states.[119] It is the first mandatory, market-based program of its kind related to carbon emissions in the United States. Under RGGI, an annual, regional budget for power sector emissions in all states is established by issuing carbon allowances via regional auctions. Power plants can trade these allowances. Revenue collected from the auctions is dedicated to reinvestment in strategic energy and customer programs, including energy efficiency programs and direct bill assistance. In 2017, RGGI reported lifetime savings of 13.9 million MWh of avoided electricity use and 7.5 million MT CO_2.[120]

Decreasing historical carbon intensity is largely driven by an increase in natural gas and renewable generation as well as energy efficiency programs. To reduce Virginia emissions under RGGI implementation, Dominion projects higher imports of out-of-state energy, which would actually be more carbon-intensive than generation sourced in Virginia. Therefore, Dominion projects higher emissions under RGGI implementation compared with non-RGGI implementation as shown in Figure 33.

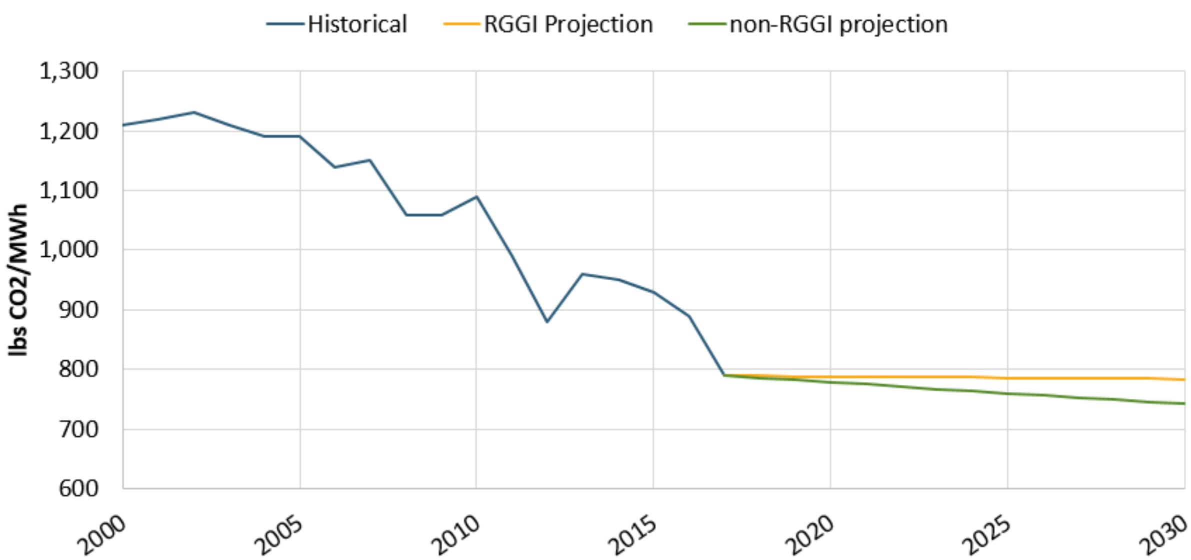


FIGURE 33. Dominion emissions factor, 2000–2030. (Source: 2018 Dominion IRP)

These emissions factors are multiplied by Arlington's electricity usage (Figure 34) to obtain total CO_2 emissions for Arlington County (Figure 35). Historical Arlington electricity usage from 2000 to 2018 is extended through 2030 based on 2.4% commercial and 1.1% residential Virginia compound annual growth rates from the Dominion IRP (see section 2.2). We use the non-RGGI projected emissions factors here to estimate the lowest potential incumbent utility emissions, for a conservative estimate of CCA emission reductions.

While Arlington emissions have decreased historically due to declining emissions factors, a weaker decline in future emissions factors combined with a projected increase in electricity demand would promote a rise in projected emissions with Dominion.[121]

119. Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island, and Vermont.
120. https://www.rggi.org/investments/proceeds-investments
121. These results may vary should Dominion change its power mix with less carbon intensity resources.

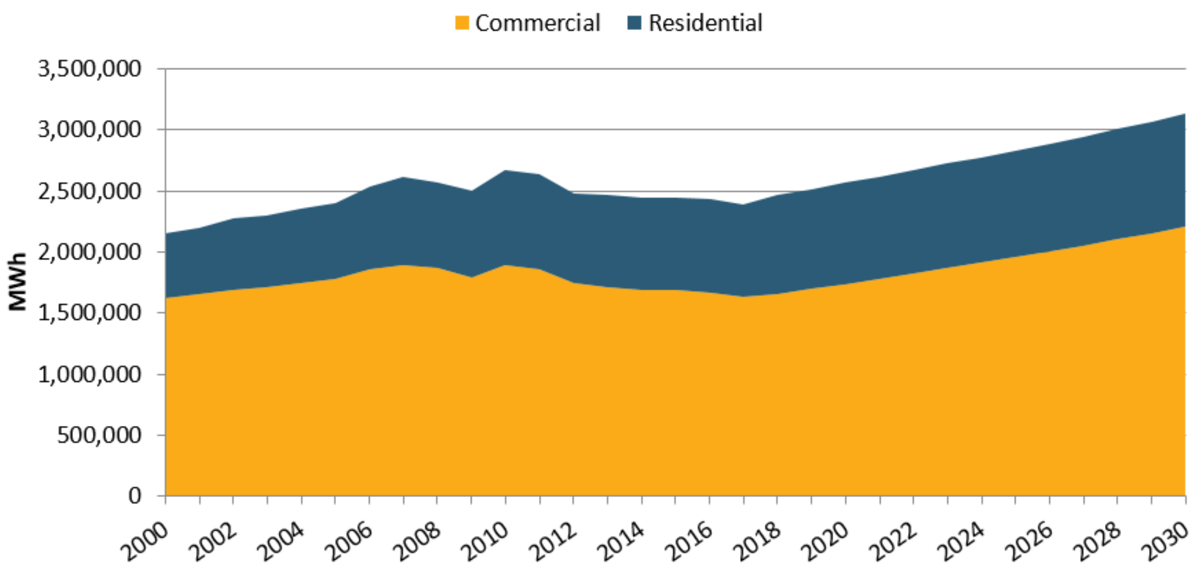


FIGURE 34. Arlington electricity usage for historical, 2000–2018, and IRP-projected, 2019–2030.

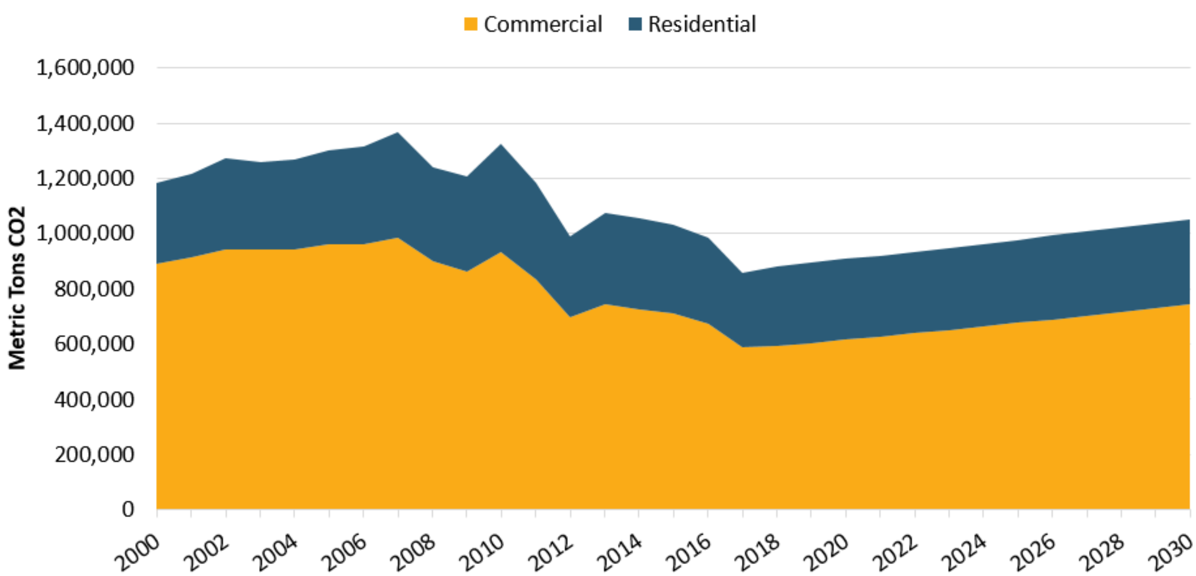


FIGURE 35. Arlington CO_2 emissions for electricity usage for historical, 2000–2018, and IRP-projected non-RGGI, 2019–2030.[122]

However, as energy efficiency measures are not taken into consideration, results may vary.

122. Figure 4 depicts carbon emissions in metric tons. One metric ton is equivalent to 2204.62 lb.

6.1.4. EMISSIONS FOR CCA SCENARIOS

The following sections present three CCA scenarios for power procurement and their respective greenhouse gas emissions footprints, modeled through 2030, as follows:

a. Voluntary RPS scenario: by 2025, renewable energy will comprise 15% of the total electric energy sold in 2007
b. 50% renewable energy scenario
c. 100% renewable energy scenario

Arlington emissions reductions presented here would initially be derived through the purchase of unbundled RECs on the wholesale market, rather than through the direct purchase of local renewables (see BOX 4. Renewable Energy Certificates: Bundled and Unbundled). As such, these emissions reductions represent a shift for Arlington's carbon accounting, namely, offsetting, rather than for net emissions. However, a CCA would work toward directly purchasing local renewable energy in the future, and the purchase of unbundled RECs in the interim would support further development of renewables.

100% Renewable Energy

To calculate emissions for CCA scenarios, we assume emissions factors equal to zero for renewable energy resources (defined as solar, wind, and hydropower), as done in previous CCA feasibility studies. The 100% renewable energy scenario is therefore assumed to account for zero emissions.

50% CCA Renewable Energy

To estimate emissions for the 50% CCA renewable energy scenario, we assume zero emissions for 50% of the total Arlington electricity usage and multiply the remaining 50% of the total Arlington electricity usage by the Dominion IRP projected emissions factors. This assumes that the nonrenewable portion of the CCA fuel mix will have emissions factors equivalent to the Dominion fuel mix as a first estimate.

Virginia Voluntary RPS Goal

The Virginia voluntary RPS goal is relative to the total electricity sold in 2007, excluding the percentage of nuclear energy averaged from 2004 to 2006.[123] According to Dominion's 2014 Annual Report to the SCC on Renewable Energy,[124] the 2004–2006 average nuclear energy generation constitutes 33% of the 2007 Virginia electricity sold. We therefore use 67% of the 2007 Arlington County electricity usage, or 1,755,923 MWh, as the RPS Target Baseline for Arlington County. The RPS goals for Arlington County for 2020 through 2025 are estimated below, with no additional growth of renewable energy sources assumed after 2025. RPS scenario emissions are estimated by subtracting renewable sources from the total Arlington electricity usage and calculating the product of this nonrenewable electricity usage with projected emissions factors.

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123. https://law.lis.virginia.gov/vacode/title56/chapter23/section56-585.2/
124. https://www.scc.virginia.gov/pur/renew/dvp_renew_14.pdf at p. 6

TABLE 10. Arlington RPS Targets Assuming RPS Target Baseline

Year	2020–2021	2022	2023–2024	2025
Renewable sources (%)	7% average	12%	12% average	15%
Renewable sources (MWh)	122,915	210,711	210,711	263,388

Results

All three CCA scenarios analyzed resulted in lower CO_2 emissions than those of the utility. As mentioned earlier, the non-RGGI projected emissions factors are used here to estimate the lowest potential incumbent utility emissions, for a conservative estimate of CCA emission reductions. The CCA RPS and 50% renewable scenarios project rising emissions over time due to anticipated increased electricity usage, with the exception of the 100% renewable scenario. Significant CO_2 emission reductions occur in particular for the 50% and 100% renewable scenarios compared with the incumbent utility. Projected carbon dioxide emissions for Arlington under the incumbent utility as well as under these three CCA scenarios are shown in Figure 36.

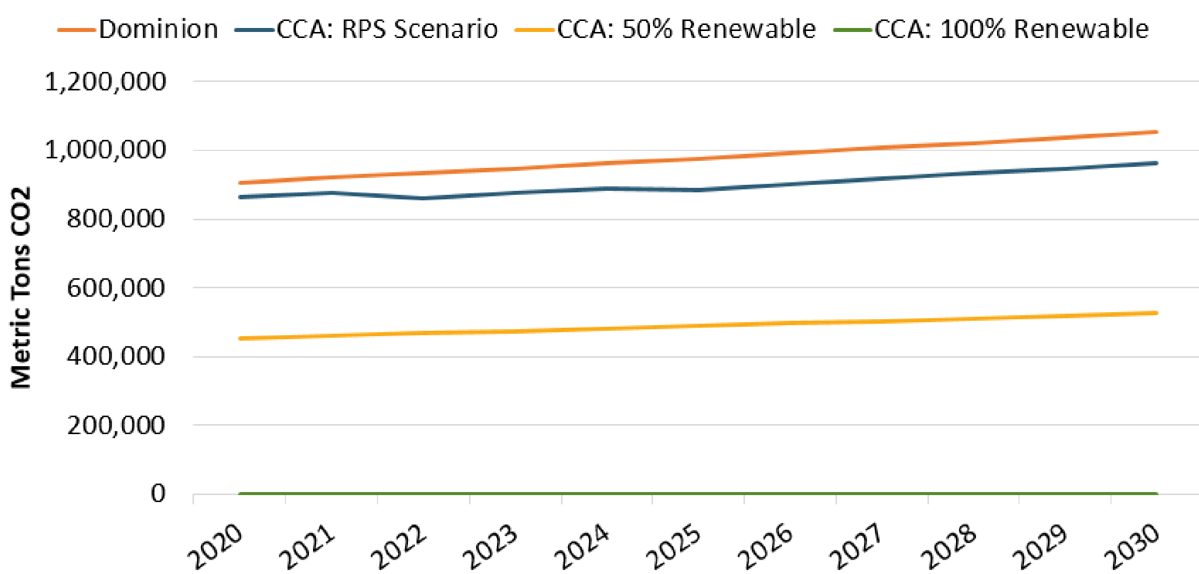


FIGURE 36. Projected CO_2 emissions from electricity for Arlington CCA scenarios and Dominion non-RGGI scenario.

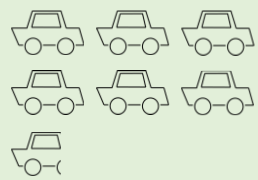
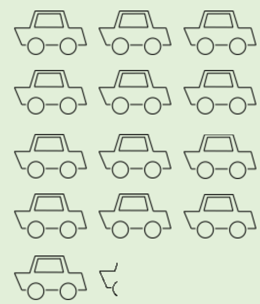
6.1.5. CCA ANNUAL EMISSIONS REDUCTIONS COMPARED WITH EXISTING UTILITY

Below are the annual carbon emissions reductions averaged for 2020–2030 resulting from each CCA scenario in comparison with the existing utility emissions, rounded down to the nearest thousand. **These emissions reductions can be expressed as the number of cars off the road, assuming the EPA-estimated 4.6 metric tons of CO_2 per year emitted by passenger cars averaging 22 mpg and 11,500 miles per year.**[125] As previously explained, these emissions reductions would initially be derived through the

125. https://nepis.epa.gov/Exe/ZyPDF.cgi?Dockey=P100U8YT.pdf

purchase of RECs on the wholesale market, rather than through the direct purchase of local renewables. As such, these emissions reductions represent a shift for Arlington's carbon accounting rather than for net emissions.

TABLE 11. Arlington CCA Annual Emissions Reductions, 2020–2030

CCA Scenario	RPS	50% Renewable	100% Renewable
Annual emissions reduction (metric tons CO_2)	76,000	489,000	978,000
Emissions reduction expressed as annual number of cars off the road  **= 16,000 cars**	16,000 	106,000 	212,000 

6.1.6. CONCLUSIONS

The analysis projects significant reductions in greenhouse gas emissions for the Arlington CCA in comparison with the incumbent utility, particularly for the 100% renewable energy scenario. The potential emissions reductions associated with the implementation of a CCA align with Arlington County's long-term energy and climate action goals. Arlington County's current CEP sets goals of achieving carbon neutrality by 2050, and 100% government- and community-wide renewable electricity by 2025 and 2035, respectively. However, projected emissions under the incumbent utility would instead increase over time with rising Arlington electricity demand and minimal reduction in future carbon intensity according to the 2018 Dominion IRP. **Arlington emissions reductions would initially be derived through the purchase of unbundled RECs on the wholesale market, while the CCA would work toward directly purchasing local renewable energy in the future.** The purchase of unbundled RECs in the interim would still support the renewable energy market, as it encourages renewable electricity on a broader scale. The establishment of a CCA will ensure that the County has the agency to tailor its power procurement to its long-term goal of a significantly reduced carbon footprint.

6.2. CCA IMPLEMENTATION OF ENERGY EFFICIENCY AND OTHER PROGRAMS

Many CCAs in California directly offer or partner with programs offered by utilities, municipalities, and other organizations related to energy efficiency, distributed generation and energy storage, and demand response. In some cases, Property-Assessed Clean Energy (PACE) financing[126] is available, in which case the property owner can implement the upgrades with little to no upfront cost in exchange for an increase in property taxes. Figure 37 shows the programs implemented, in development, or pilot by CCA in California as of 2019.[127]

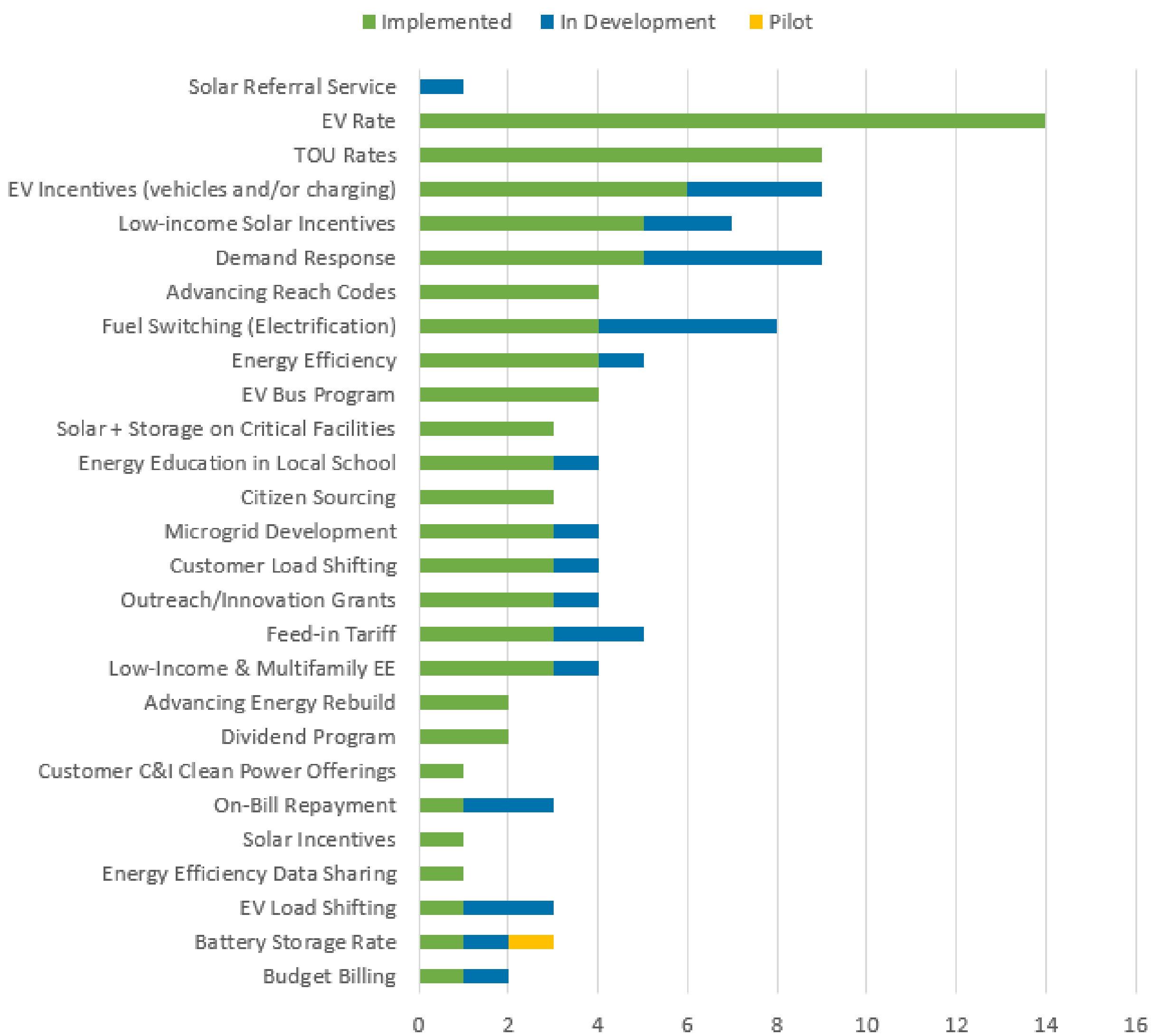


FIGURE 37. Summary of programs implemented, in development, and pilot by CCAs in California, 2019. (Source: CalCCA)

126. https://pacenation.org/pace-programs/
127. For more information, visit https://cal-cca.org/cca-programs/.

Among the variety of programs, EV rate, TOU rate, and EV incentives (vehicles and/or charging) are among the ones most offered. A growing interest is for demand response and fuel switching with several programs in development.

6.2.1. ENERGY EFFICIENCY

Energy efficiency programs incentivize customers to replace their lighting, appliances, HVAC systems, or even more complex equipment like motors or to implement energy management systems. For CCAs in California, most programs focus on residential and small businesses with simple incentives with quick paybacks like LED lighting, appliances, HVAC, and refrigeration. These programs are less common with CCAs in other states.

6.2.2. DISTRIBUTED GENERATION

Distributed generation (DG) is a generator that is sited in the same location as the consumer. Some CCAs also offer programs to incentivize DG, primarily rooftop solar, though incentives for energy storage systems like batteries are sometimes available, as well, as exemplified by an agreement between SunRun and East Bay Community Energy (EBCE). The way their agreement works, SunRun will install solar and battery systems on over 500 low-income houses to replace the capacity lost from a gas plant that was shut down in Oakland.[128]

6.2.3. ENERGY STORAGE

Energy storage (primarily battery systems) technologies have a wide range of uses from reducing peak demand and incorporating to keeping the grid balanced and integrating renewable generation. Some CCAs including EBCE provide incentives for those systems.

6.2.4. DEMAND RESPONSE

Demand response (DR) is a change in consumption by customers either by adjusting their demand and/or by adjusting the amount of electricity generated on-site. Some CCAs offer their own DR programs, as well, incentivizing their customers to reduce their usage during peak demand hours to reduce congestion on the grid and avoid high wholesale real-time energy prices. This is also accomplished through time-of-use (TOU) rates, in which the customers are charged less for energy used during off-peak hours (e.g., nights, weekends) and more during peak hours (primarily weekday evenings). TOU rates are rather common for nonresidential customers throughout the country but are only common for residential customers in certain states, including California.

128. https://www.solarpowerworldonline.com/2019/07/sunrun-home-solarstorage-installs-contracted-to-replace-oakland-jet-fuel-power-plant/

BOX 5. Marin Clean Energy

Marin Clean Energy was the first CCA established in California and has some of the best examples of programs that could be implemented under the CCA model.

It provides a $3,500 rebate for electric vehicles to customers below certain income thresholds that depend on household size. It also provides rebates for charging stations in addition to having its own network of public charging stations. Furthermore, the charging stations operate with time-of-use (TOU) rates so that they're cheapest when demand is lowest and/or renewable generation is highest.

Rebates of $900 are available for residential solar projects, as well as to customers below certain income thresholds that depend on household size.

Energy efficiency incentives include free smart thermostats, free energy assessments, and subsidized upgrades for low-income homes. Rebates and financing are also available for commercial projects. There are also incentives for commercial and industrial customers for lighting, variable frequency drives, heat and steam recovery systems, and control systems.

Overall, the CCA has eliminated 340,000 metric tons of GHGs through 2018, saved their customers over $50 million, created 5,000 jobs in California, committed $1.5 billion to build new renewable generation projects in California, has had 31 MW of new renewable generation projects built in their service territory, and their generation profile has been over 60% renewable since 2017 and will be 99% carbon-free by 2022.

More at https://www.mcecleanenergy.org/

6.2.5. STATUS QUO: PROGRAMS OFFERED BY DOMINION

Like most utilities, Dominion offers incentives for various energy efficiency projects along with some other programs. These would still be available to CCA customers.

On the residential level, these include $20 rebates for recycled appliances, rebates on new lighting and appliances, $40 for participating in a direct load control program (where the utility installs a control on their AC units), energy audits, and energy efficiency improvements for low-income homes.

On the small commercial level, these include energy audits to assess potential upgrades for lighting, drives, heat pumps, AC systems, and retrocommissioning energy management systems, for which there are incentives.

On the large commercial level, there are incentives for lighting systems and controls, HVAC systems, windows, refrigeration, kitchen equipment, and distributed generation.

All customers also have access to their renewable energy programs, which include a community solar program, PPAs for customer-owned renewable generation, and the ability to sell RECs back to Dominion.

The American Council for an Energy-Efficient Economy (ACEEE) policy scorecards rank Virginia 29th in energy efficiency policy with a particularly low rating for its utilities.[129]

6.2.6. ENERGY EFFICIENCY FOR THE ARLINGTON CCA

The Arlington CCA could explore different alternatives on how to implement energy efficiency programs and measures similarly to CCAs in California, which directly offer or partner with programs offered by utilities, municipalities, and other organizations related to energy efficiency, distributed generation and energy storage, and demand response.[130] However, in this Study, we did not assess the legislation on energy efficiency in Virginia, and the implementation of energy efficiency programs and measures by the Arlington CCA would need further research.[131]

Since 2007, Arlington's Initiative to Rethink Energy[132] has reduced emissions by 24%, energy consumption in buildings by 11%, energy consumption by transportation by 13%; has had 13 million square feet of buildings certified by LEED; and is the first community in the country to be certified as LEED Platinum. **With the new energy efficiency goals of reducing energy consumption in buildings by 38% by 2050, and decreasing transportation emissions by 88% by 2050, energy efficiency would be instrumental for Arlington to reach those objectives.**

6.3. EXAMPLE OF BENEFITS WITH CCA IN CALIFORNIA

CCA in California has already gained great benefits from the start of CCAs in their municipality and counties. The next sections summarize some of these benefits.

6.3.1. RENEWABLE ENERGY DEVELOPMENT

According to CalCCA, CCAs in California have contracted over 3 GW of renewable capacity, including 2,269 MW of solar, 915 MW of wind, 11.5 MW of biogas, and 240 MW/788 MWh of energy storage. Furthermore, each of the CCAs in California offers a baseline energy mix of at least 31% renewable with Marin Clean Energy's being the highest baseline at 60%. Most of the CCAs offer 100% renewable energy for a premium as well, but the 100% rate should eventually become the cheapest option. In 2019, California CCAs were responsible for 44.4 TWh of energy with a peak load of 10.76 GW.[133]

6.3.2. ENERGY EFFICIENCY

California CCAs offer a wide range of programs that are traditionally offered directly through utilities, energy services companies (ESCOs), and/or retail energy suppliers, including demand response, time-of-use rates, development of microgrids and solar + storage systems, energy efficiency rebates, electrification incentives, and special rates and charging infrastructure for EVs.[134]

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129. https://database.aceee.org/state/virginia
130. See subsection 6.2. CCA Implementation of Energy Efficiency and Other Programs
131. This issue should be further clarified with the SCC.
132. https://environment.arlingtonva.us/energy/
133. https://cal-cca.org/cca-impact/
134. https://cal-cca.org/cca-programs

6.3.3. GHG EMISSIONS REDUCTION

A 2017 report for the Center for Climate Protection estimates that CCAs in California have resulted in the reduction of annual GHG emissions by nearly 1.5 million metric tons by 2019 compared to hypothetical emissions if all CCA customers were still customers of the legacy utilities.[135]

Table 12 summarizes MCE benefits gained within the years of the CCA operation.

TABLE 12. Summary of MCE Benefits[136]

Metric	Description
340,000 metric tons	Cumulative GHG reductions through 2018
$50,000,000	MCE customer savings since 2010
$1,500,000,000	Investment in new renewable energy capacity by MCE in California
60%	Renewable energy for standard service since 2017
99%	Clean energy goal for standard service by 2022
31 MW	Renewable energy capacity built in MCE service territory
5,000	Jobs in California supported by MCE

135. https://cleanpowerexchange.org/wp-content/uploads/2017/06/Forecast-of-CCA-Impacts-in-CA-2016-2020-June-2-2017.pdf
136. https://www.mcecleanenergy.org/

7. RISK ANALYSIS

CCAs may run into certain risks, some of which are specific to the power supply procurement sector. This section provides a short description of some primary risks that a CCA may encounter that could affect the economic and financial feasibility of the CCA program, along with some risk mitigation strategies. **This is not intended to be a comprehensive risk assessment and does not attempt to quantify the risks; they are beyond the scope of the Study.** General risks include political, legislative and regulatory, financial and credit, while CCA and power supply procurement related risks include power procurement, customer opt-out, and exit fee.

7.1. POLITICAL RISK

One primary risk when investigating a CCA program is political. The incumbent utility, in this case, Dominion, may oppose the program, directly or indirectly, and delay or prevent its formation. The utility may criticize the technical Study methods and assumptions and suggest that the program bears greater risks than benefits. Furthermore, the utility may advocate for new legislation that would make the CCA less competitive or oppose the program. To mitigate this risk, Arlington should (1) anticipate a certain degree of opposition from the incumbent utility and (2) communicate the benefits of the CCA program to its residents and businesses.

7.2. POWER PROCUREMENT RISK

Power prices may increase, resulting in higher electricity rates for residents and businesses. To mitigate this risk, the CCA should (1) work with experienced power procurement companies, if outsourced, or have in-house experts that understand market dynamics and market rules, power risk management, scheduling and coordination, and demand forecasting, (2) have a robust power supply plan and diverse supply portfolio, and (3) establish a reserve fund to use for stabilizing rates through price increases.

7.3. OPT-OUT RISK

Several customers may decide to opt out of the CCA program and return to the incumbent utility, or choose another retail supplier (in deregulated markets),[137] thus reducing the CCA market share and potential cost increase. To mitigate this risk the CCA should (1) strengthen customer relationships to increase program trust and loyalty, (2) have effective communication channels, thus ensuring a properly communicated value proposition, and (3) start early in communicating the benefits of a CCA program and engage residents and businesses in the process.[138]

137. Virginia is a regulated electricity market. There is a current effort to decouple power generation activities from transmission and distribution. Should this happen, it would create additional competition in the market, which could increase the customer's opt-out from the CCA program.

138. S. Zinetti (2016), Sustainable energy for cities and local governments. An integrated assessment of Community Choice Energy business models in California. Master's Thesis. Chapter 7, Conclusion and Recommendations on p. 69.

7.4. LEGISLATIVE AND REGULATORY RISK

New legislation or regulatory decisions may undermine CCA competitiveness or prevent the CCA program from being continued. The SCC may, for instance, deny the license to form a CCA (this seems unlikely; see BOX 6) or require higher electricity tariffs. The CCA should continuously monitor the legislative and regulatory environment to protect and advocate for the CCA benefit.

BOX 6. Main Findings from the 2019 CCA Legal Study

The *Legal Options for Community Choice Aggregation in Virginia* study, prepared for Virginia Clean Energy by the Environmental and Regulatory Law Clinic at the University of Virginia School of Law (December 2019), has investigated the legality of CCA under Virginia law. The main findings are summarized and reported as follows:

- **"Community choice aggregation is generally available to municipalities by right."**
- "The most relevant provisions are Va. Code § 56-577 (A)(3) and § 56-589."
- "Va. Code § 56- 577 (A)(3) requires a demand of at least 5 megawatts in the previous calendar year to qualify.… For large municipalities like Arlington County or the City of Alexandria, this 5 megawatt threshold might be easy to meet."
- § 56-577 (A)(3) requires that a customer cannot have had a peak demand exceeding one percent of the incumbent utility's peak load during the previous calendar year unless "such customer had noncoincident peak demand in excess of 90 megawatts in calendar year 2006 or any year thereafter." The noncoincident peak demand is a generally accepted industry term referring to that customer's peak demand during the stated timeframe. That stands in contrast to 'coincident peak' which would be the utility's peak load during the same timeframe. Again, the 90 megawatt requirement might be fairly easy to clear for municipalities the size of Alexandria and Arlington, which would then eliminate the one percent cap imposed by subdivision (A)(3)."
- "§ 56-577 (A)(3)(c) requires a five year written notice period before the customer may return to the incumbent utility for any reason. This requirement may be waived by the Commission by a finding that it would not adversely impact the incumbent utility or its customers, including a consideration of the cumulative impact of previous waivers."
- "The Clinic's view is that Va. Code § 56-577 subdivisions (A)(4) and (A)(5) are inapplicable in the CCA context under Va. Code § 56-589.… Thus, the requirement for a public interest finding in subdivision (A)(4) is not part of the approval process for any community choice aggregation proposal under Va. Code § 56-589."
- "A cursory review did not identify any particular barrier to CCA formation. Still, it will be important to do more research when more is known about an individual proposed CCA project."

7.5. FINANCIAL AND CREDIT RISK

CCAs may be unable to acquire the desired financing or credit, which would delay the program launch. Because Arlington would procure electricity via a third-party CSP, this risk should be minimal. To mitigate this risk, however, the CCA could (1) partner with a financially strong organization in its start-up phase to build enough credit to work independently, (2) minimize overhead costs, or (3) use a lockbox structure.[139] Another risk of CCA is that its electricity rates could be higher than those from the utility. This may cause customers to opt out of the CCA program and return to the incumbent utility. CCA should build separate reserves that may be used when the price of power spikes and mitigate the risk of opt-out.

7.6. EXIT FEE RISK

Another risk CCAs may encounter is the exit fee, or Power Charge Indifference Adjustment (PCIA).[140] The exit fee is a cost that a utility may ask for each kWh to repay for their previously made long-term financial obligations that would increase the electricity rates and affect the CCA competitiveness. **To our knowledge, the exit fee is applied only to CCAs in California, and while it does not constitute a risk in the other states where CCA programs are being implemented, it is not specifically addressed for CCAs in the Virginia code.** Because the exit fee is a cost that a utility may ask for each kWh to repay for their previously made long-term financial obligations, we include all the riders that are Dominion long-term obligations, except the fuel rider, in our calculations estimating the exit fee. However, Arlington should closely monitor the regulatory process for implementing the CCA and actively participate in the fee evaluation should this become an actual risk.

139. Some CCAs in California use a "lockbox" financial structure to give confidence and reduce risk to partners that are concerned about the creditworthiness of a new CCA. Revenues from the sale of electricity are directly deposited into a separate trust account and are used to pay an energy supplier each month. The lockbox gives priority to pay those invoices first before the CCA pays its operating expenses, thus creating more trust with its partners. Source: https://cal-cca.org/

140. The California Public Utility Commission defines the PCIA as the mechanism to ensure that the customers who remain with the utility do not end up taking on the long-term financial obligations the utility incurred on behalf of now-departed customers. Examples of such financial obligations include utility expenditures to build power plants and, more commonly, long-term power purchase contracts with independent power producers. https://www.cpuc.ca.gov/PCIA/

8. CCA GOVERNANCE AND OPERATIONAL OPTIONS

8.1. CCA GOVERNANCE OPTIONS

The governance structure defines what entity would be responsible for the policy direction and reporting requirements of the CCA. This differs from the operating structure, which defines the operational management of the CCA. The basic governance options to form a CCA include a single-jurisdiction CCA, where a jurisdiction can form a CCA program as its own program, or a multijurisdiction CCA, where neighboring cities and counties enter into an intergovernmental agreement (IGA), often establishing a separate entity as a Joint Powers Authority (JPA). These options are not mutually exclusive, as a jurisdiction can opt to start its own CCA program at first and allow other jurisdictions to join the program later. The following are existing models of the governance structure.[141]

8.1.1. SINGLE-JURISDICTION CCA

The single-jurisdiction model allows each city to establish and operate its own CCA program, benefiting from taking all policy decisions on revenues, power content mix, and local programs. However, all the risks and liabilities associated with the CCA fall on the single jurisdiction. Usually, the jurisdiction develops contractual language to protect the general fund. The creation of an enterprise fund provides a legal structure to report revenues and expenses in a separate fund. A lockbox[142] option is normally used as a guarantee for power procurement. Examples of single-jurisdiction governance models are Lancaster Choice Energy,[143] CleanPower,[144] and SolanaEnergyAlliance[145] in California; Swampscott Community Power[146] in Massachusetts; Village of Glen Ellyn Electric Aggregation Program[147] in Illinois; and the City of Cleveland Municipal Aggregation Program[148] in Ohio.

141. Governance options availability may differ by state legislation.
142. With a lockbox option, the income stream is pledged to first pay the power provider.
143. https://www.lancasterchoiceenergy.com/
144. https://www.cleanpowersf.org/
145. https://solanaenergyalliance.org/
146. https://masspowerchoice.com/swampscott
147. http://www.glenellyn.org/584/Electric-Aggregation
148. http://www.city.cleveland.oh.us/CityofCleveland/Home/Government/CityAgencies/OfficeOfSustainability/AdvancedAndRenewableEnergy

BOX 7. Solana Energy Alliance (SEA)

The City of Solana Beach's CCA, Solana Energy Alliance (SEA), in California, was established by the city council in December 2017 and began serving customers in June 2018. **The Solana Beach city council governs the program, with the operation of the program administered by Solana Beach city staff and consultants.** The city council is responsible for establishing program policies and objectives and overseeing SBCCA's operation. The Solana Beach city manager serves as the SBCCA executive director to manage the operations of SBCCA (administration and finance, marketing and public affairs, power procurement, etc.) in accordance with policies adopted by the city council. The Energy Authority (TEA), a nonprofit organization, is the energy services provider to SEA, while Calpine Energy Solutions provides data management and customer services.

To protect the general fund, the city created a lockbox with a $200,000 minimum reserve and a separate operating reserve, which is built every month up to a required $550,000. The majority of the monthly expenses related to SEA operations for power supply, TEA services, and data management are paid directly out of the lockbox account, while other expenses, such as city staff time, professional consulting services, and notice mailing, are paid out of the SEA budget, with city funds. These expenses are being reimbursed to the city out of the SEA lockbox each month.

More information is at https://solanaenergyalliance.org/..

BOX 8. Swampscott Community Power's 100% Renewable Energy Default Option

The town of Swampscott launched the Swampscott Community Power CCA program in January 2016 to bring the benefits of renewable energy and electricity choice to its residents and businesses. **The town has a long-standing commitment to reducing its carbon footprint, and a centerpiece of the aggregation program is support for renewable energy.** On the basis of data from the first year of the program, Swampscott was able to reduce its carbon footprint by more than 9,700 tons of carbon dioxide. That's equivalent to removing more than 2,000 passenger vehicles from the road for 1 year. (Source: EPA)

Swampscott Community Power offers participants three options:

- **Standard Green:** This is the default option. All new program participants are automatically enrolled in Standard Green unless another option is chosen. Standard Green gives customers 100% renewable electricity from a mix of sources and includes 5% additional renewable electricity from renewable energy projects in New England above the 14% minimum amount required by the state.
- **New England Green** is an option that is available upon request. New England Green provides 100% renewable electricity, all from renewable energy projects in New England.
- **Basic** is an option that is available upon request. This option meets minimum state requirements for renewable energy (14% in 2019).

An important benefit of the program is price stability. Under the contract with Direct Energy, the program prices for all three program options are fixed until November 2021. This price stability makes the program different from National Grid's basic service, where the price used to calculate the supply services portion of the electricity bill changes every 6 months for residential and commercial accounts or 3 months for industrial accounts. Note: **Price includes a 0.1¢/kWh administration fee**.

More information is at https://masspowerchoice.com/swampscott..

8.1.2. MULTIJURISDICTION CCA: JOINT POWERS AUTHORITY

The Joint Powers Authority (JPA) is a traditional legal structure that allows multijurisdictions to form an independent public agency to implement a CCA. The JPA operates on behalf of its member jurisdictions with shared decision-making authority.[149] This model allows for increased administrative efficiency and program cost savings through economies of scale, and minimizes the associated risks. Some of the disadvantages of a JPA include reduced autonomy for each participant jurisdiction, a longer decision-making process, and less control over rate setting and local programs. The JPA has sole responsibility for the energy procurement liability and any cost associated with running the CCA. Other forms of intergovernmental agreement (IGA) between multiple jurisdictions can be used based on state law. Examples of CCAs operating under JPAs, or other intergovernmental agreement, include Marin Clean Energy,[150] Sonoma Clean Power,[151] and Peninsula Clean Energy[152] in California;[153] Cape Light Compact[154] in Massachusetts; Sustainable Westchester[155] in New York; the Northeast Ohio Public Energy Council;[156] and the Rhode Island Energy Aggregation Program.[157]

8.1.3. HYBRID JPA OF CCAS

The hybrid JPA of CCAs is a relatively new governance model that allows members to take advantage of the economies of scale for power procurement while maintaining a certain level of local control (see example in BOX 9). Costs are shared among members for the technical operation of the CCA, such as power procurement, scheduling, forecasting, technical analysis, etc. Each member has local control over rate structure, power content, local program development, and operational revenues. The board of the hybrid JPA is responsible for budgeting and contracting for third-party vendors. Member cities in this option do not obtain a seat at the board of the JPA, which is the responsibility of the entity that governs the hybrid JPA.

8.1.4. GOVERNANCE STRUCTURE OF THE CCA IN ARLINGTON

Virginia Code § 56-589 does not appear to allow for multiple-municipality CCAs unless aggregating governmental services/buildings (option 3 under the CCA statute). Thus, it appears it would not be possible to have one CCA that aggregates two or more municipalities and counties, such as Arlington and Alexandria, in the form of a JPA for all electricity customers (residential, commercial, industrial) in those jurisdictions. **However, Arlington could explore the hybrid JPA of CCAs option as mentioned above**.[158]

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149. In Virginia, "§ 15.2-1300. Joint exercise of powers by political subdivisions" regulates the formation of Joint Power multijurisdictional agreement. More information is at https://law.lis.virginia.gov/vacode/title15.2/chapter13/section15.2-1300/.
150. https://www.mcecleanenergy.org/
151. https://sonomacleanpower.org/
152. https://www.peninsulacleanenergy.com/
153. Most CCAs in California are launched through JPAs
154. https://www.capelightcompact.org/about-us/
155. https://sustainablewestchester.org/#
156. https://www.nopec.org/who-is-nopec/
157. http://www.rileague.org/163/Rhode-Island-Energy-Aggregation-Program
158. This issue would need to be further researched.

BOX 9. California Choice Energy Authority

California Choice Energy Authority (CalChoice) is a hybrid CCA structure governed by the city of Lancaster (in California) with each city joining as an associate member of the JPA. Associate member CCAs include the cities of Lancaster, San Jacinto, Pico Rivera, and Rancho Mirage. **Each associate city's council sets rates for its city, purchases its energy, and contracts its CCA services through existing CalChoice contracts, which help keep costs low and maximize revenues for each associate member**. It provides members the ability to leverage CalChoice's knowledge and staff to benefit from lower energy procurement costs, regulatory matters, accounting, and compliance functions, which are crucial to the success of a CCA. **A member city is able to take advantage of these economies of scale without having to sacrifice key control often associated with JPAs or taking on the significant liability of a single-entity CCA.** CalChoice then contracts with the city of Lancaster and other qualified third-party consultants to perform an agreed-upon scope of work.

This model allows each member agency the following benefits:

- Use of existing contracts and costs
- Access to trained and experienced staff
- Transparent procurement costs
- Transparent operational costs
- Control over local energy rates and operations
- Control of operational revenues for local program development tailored to each community
- Cost savings and efficiency

More information is at https://californiachoiceenergyauthority.com/cca-history/.

8.2. CCA OPERATING STRUCTURE OPTIONS

The operating structure delineates the level of control of the CCA operational functions, which can be fully retained in-house with direct staffing, be fully outsourced to third-party vendors, or be a mix of the two. The choice of the operating structure is usually at the discretion of the governing board of the CCA and thus applies to both JPA and a single-jurisdiction governing structure.

The day-to-day functions of a CCA include: power procurement, scheduling, finance, budgeting, accounting, billing and customer service, marketing, communication, and outreach, managing specific renewable energy and energy efficiency programs, regulatory compliance, SCC filing, monitoring regulatory and legislative energy policy. **In general, and especially during the start-up phase, some functions where specific expertise is required, such as power procurement and scheduling, are outsourced to specialized organizations.** With time, the CCA can train in-house staff and create expertise to deal with such functions.

8.2.1. FULL IN-HOUSE ADMINISTRATION

All the operational functions of the CCA are fully managed by internal staff.

8.2.2. THIRD-PARTY ADMINISTRATION: COMMERCIAL MANAGED SERVICE

A third-party entity—either nonprofit or for-profit—contracted by the CCA manages the program and assist in all aspects, from start-up to full implementation, including power procurement, scheduling coordinator, and technical analysis. The managing organization retains a percentage of the profits, thus reducing the funds available to be reinvested locally.

BOX 10. Sustainable Westchester and Westchester Power

Westchester Power is a CCA in New York State launched in May 2016. The program is managed by Sustainable Westchester, a nonprofit 501(c)(3) consortium of Westchester County local governments that has been authorized by the New York State Public Service Commission to act as the manager and administrator of Westchester Power on behalf of its member municipalities. The participating Westchester County municipalities passed the required local legislation and then chose to participate in the program. **Westchester Power contracted with a competitive supplier for its energy procurement and scheduling activities through the launch of an RFP.** All power-related activities are managed by the selected competitive supplier, which also retains most of the benefits from the power sales. **Westchester Power negotiates with the energy service provider an administration fee per kWh (currently at 0.1¢/kWh) to cover the organization's expenses for communications and outreach assistance, customer service, support to municipalities, and legal fees associated with managing the program.**

More information is at https://www.westchesterpower.org/.

8.2.3. OPERATING STRUCTURE OPTIONS FOR THE CCA IN ARLINGTON

Virginia Code § 56-589 allows the CCAs to purchase electricity from any Competitive Service Provider licensed within the Commonwealth[159] (see APPENDIX E: LIST OF CSPs AND AGGREGATORS IN DEV TERRITORY).[160] With this regard, the CCA in Arlington will have the choice to administer the program either internally, as part of the county program, or via a third-party organization, as in the case of Westchester Power described above. In both cases, the power will be procured through a CSP selected via an RFP. To summarize, the Arlington CCA will have two options:

- **Option A:** The CCA program is administered by Arlington County, which negotiates the purchase of electrical energy requirements from any licensed supplier within this Commonwealth via an RFP.
- **Option B:** The CCA program is administered by a third-party organization contracted by Arlington County, which negotiates the purchase of electrical energy requirements from any licensed supplier within this Commonwealth via an RFP.

Arlington should explore which option is best based on its needs and objectives. In addition, Arlington could explore the hybrid JPA of CCAs option that would lower their procurement costs and market risks.

159. Further research is needed to verify whether the CCA can also purchase its electricity needs on the wholesale market.
160. See also the complete list of licensed suppliers available at https://www.scc.virginia.gov/power/compsup.aspx.

9. CONCLUSION AND RECOMMENDATIONS

This Study aimed at determining the economic and technical feasibility of a potential CCA program in Arlington, Va. The overall objective is to inform policy makers and ratepayers about how Arlington County can procure higher percentages of renewable energy in its power mix with a CCA program, along with other community co-benefits such as competitive rates, reduction of GHG emissions, renewable energy project development, and energy efficiency programs. **Our investigation suggests that the CCA is a viable option for Arlington to procure 100% renewable energy on the wholesale market at a competitive price and offset its carbon footprint.** The key preliminary results and conclusions from the research and assumptions are summarized as follows:

- **The formation of a CCA would support Arlington County's current CEP goals of achieving carbon neutrality by 2050 and 100% community-wide renewable electricity by 2035.** A CCA program would allow Arlington to decide to procure a higher percentage of renewable energy in its power mix. The current power mix from Dominion and the PJM is predominantly nuclear, coal, and natural gas, with a small percentage of renewable energy.
- **The analysis projects significant reductions in greenhouse gas emissions for the Arlington CCA in comparison with the incumbent utility, particularly for the 100% renewable energy scenario.** Projected emissions under the incumbent utility would instead increase over time with rising Arlington electricity demand and minimal reduction in future carbon intensity according to the 2018 Dominion IRP. Under the 100% renewable energy scenario, Arlington could already offset its carbon footprint by as much as 978,000 metric tons of CO_2/year, which is equivalent to reducing the number of cars on the road by more than 200,000, on the same order as the population of Arlington County.
- **Arlington emissions reductions would initially be derived through the purchase of unbundled RECs on the wholesale market, while the CCA would work toward directly purchasing local renewable energy in the future.** The purchase of unbundled RECs in the interim would still support the renewable energy market as it encourages renewable electricity on a broader scale.
- **Economic benefits include electric retail prices that may be competitive with the incumbent utility.** The case study analyzed between the CCA residential bill, procuring 100% renewable energy via a third party on the wholesale market, and Dominion residential bill, assuming the current power mix, using 2019 data, resulted in an average retail electricity price for a residential customer over the 2019 period 7% lower compared with Dominion, 11.57 cents/kWh and 12.40 cents/kWh, respectively. Our investigation suggests that an advantage of the CCA is the exclusion of the fuel cost in the rate settings, as this is already embedded in the wholesale market pricing. The fuel rider alone accounts for about 19% of Dominion residential retail price.
- **The sensitivity analysis suggests that the CCA residential case study would still be competitive under several cost increase/decrease assumptions.** Even in the extreme case where both the Dominion generation and the fuel rider decrease by 5%, the CCA residential retail price is still lower by around 4.5% compared with the Dominion retail price. The CCA yearly residential retail price is more sensitive to the load increase or decrease than Dominion. However, we expect the Arlington CCA to establish fixed rates so that consumer rates would be stable across the year.

- **Financial benefits include additional funds for the County.** The CCA program would bring additional funds in an estimated amount of around $25–$30 million from cumulative fees for 11 years of program operations. A portion of these funds will be used for managing the program, and the remainder could be reinvested in energy-related projects within the community, thus making the CCA a 100% self-supported program.
- **The risks the CCA may encounter are typically related to the power supply procurement sector.** These risks are well known and could be mitigated with the support of experienced power procurement companies. Another risk the CCA may encounter is an exit fee. To our knowledge, the exit fee is applied only to CCAs in California; it is not specifically addressed for CCAs in the Virginia code.

On the basis of the Study results, we provide the following recommendations:

- **A CCA is available to municipalities by right.** Arlington should embrace this opportunity and explore the CCA program as a tool to reach its renewable energy goals and drastically reduce its carbon footprint.
- **Tailor the CCA program to the local needs.** Arlington should investigate which operating structure option is best based on its needs and objectives. For the governance option, Arlington could explore the hybrid JPA of CCAs option, which would lower its procurement costs and market risks.
- **Carefully review the data.** Results in this Study were produced with our best knowledge of publicly available existing data and costs. However, we would strongly recommend that stakeholders carefully review and analyze all raw data and costs from the PJM and the utility in drawing their own conclusions. In addition, we recommend that Arlington ask Dominion for hourly metered electricity usage data to perform more accurate and detailed calculations on the load requirements. A subscription to a wholesale market price forecasting service to estimate future energy pricing is also advised.
- **Include energy efficiency.** While energy efficiency was not factored into our calculations, CCAs have the potential to substantially accelerate the adoption of energy efficient technologies, as well as distributed generation, energy storage, electric vehicles, demand response, more advantageous rate structures, and other similar opportunities. CCAs in California have been particularly successful in implementing programs and taking advantage of these opportunities.
- **Clarify CCA open issues.** Finally, we encourage Arlington to clarify with the State Corporation Commission the following open questions for the CCA:
    - procurement of energy directly on the wholesale market
    - purchase of power from multiple CSPs
    - contracting PPAs with independent power producers
    - establishment of a multijurisdiction CCA
    - implementation of energy efficiency programs.
- **Suggestions for future research.** Opportunities for future research include a detailed study on rate design for the CCA for both residential and commercial customers, a comprehensive review of costs for calculating the revenue requirements, and a full financial and economic analysis.

To fully transition to 100% renewable energy requires long-term vision and planning. The CCA is a tool that can help municipalities and counties to elaborate on a successful strategy for reaching this goal. We believe that the establishment of a CCA program will allow Arlington flexibility in its power procurement options to match its long-term energy and climate goals. Though Arlington emissions reductions would initially be obtained through purchasing RECs on the wholesale market, thus representing a shift for Arlington's carbon accounting rather than a net emissions decrease, this option in the interim would still support the renewable energy market while the CCA would work toward directly purchasing local renewable energy in the future. Furthermore, the PPA market prices and LCOE costs for solar and wind are already cost-competitive with conventional generation technologies. **This Study provides many details and examples for the establishment of a CCA program in Arlington, with the hope that it would be helpful in pursuing this option. We also hope this Study is useful for any other municipality in the Commonwealth and for other states wishing to explore a CCA as a tool for their sustainable energy transition.**

APPENDIX A: AGGREGATED MONTHLY ELECTRICITY USAGE BY SECTOR

Figures A1, A2, and A3 illustrate the aggregated monthly electricity usage for 2017, 2016, and 2015, respectively.

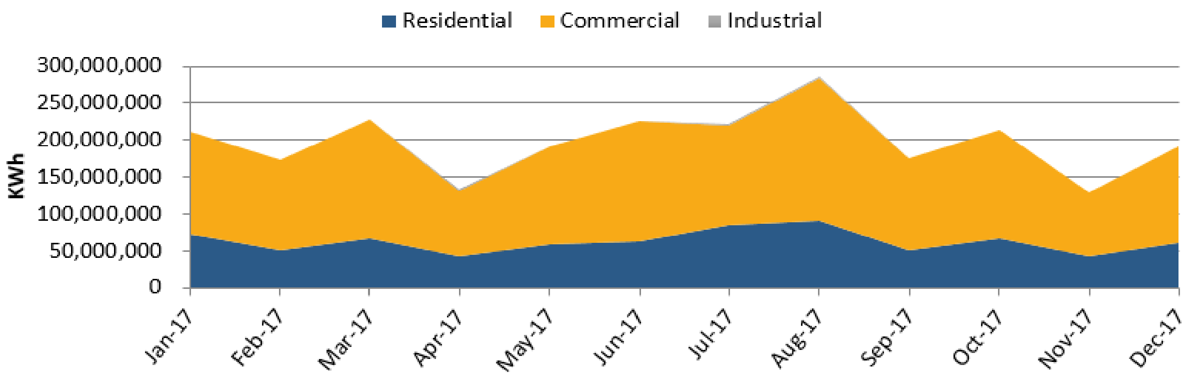

FIGURE A1. Aggregated monthly electricity usage, 2017.

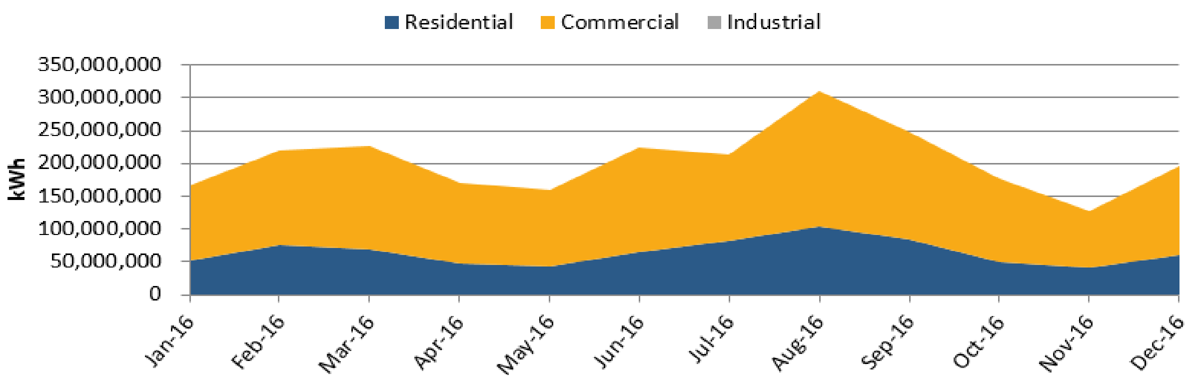

FIGURE A2. Aggregated monthly electricity usage, 2016.

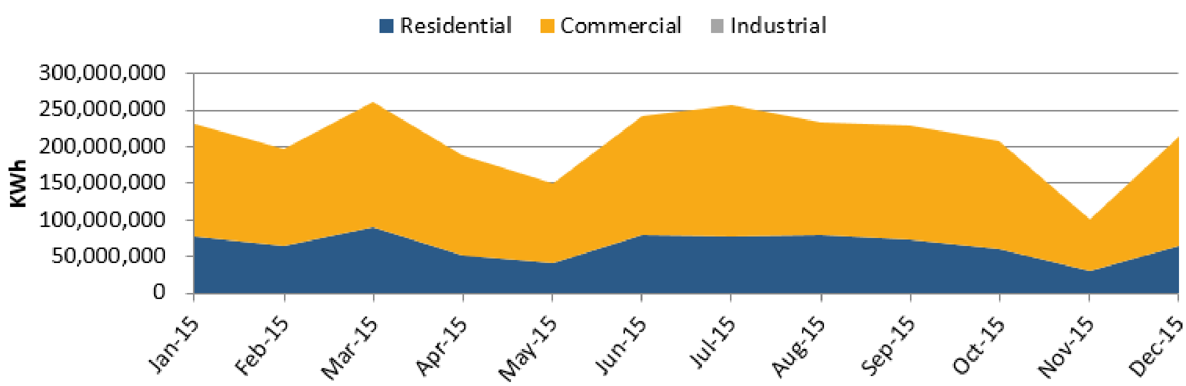

FIGURE A3. Aggregated monthly electricity usage, 2015.

APPENDIX B: LOAD PROFILE METHODOLOGY AND CALCULATIONS

B1. Approach 1: Dominion Weather Profiles

The first approach was to look at the Dominion weather sensitive profiles[161] for each customer class (residential[162] and commercial, i.e., Schedule GS1, Schedule GS2)[163] and use this information to programmatically determine hourly load output. The Dominion profiles were developed based on 2000–2003 weather conditions and the residential and commercial loads from that time frame. Weather data were downloaded from the National Oceanic and Atmospheric Administration (NOAA) Climate Extremes Index (CEI) database[164] for the nearest weather station at Ronald Reagan Washington National Airport from 1999 through 2017. Figure B1 shows the average yearly weather at this location.

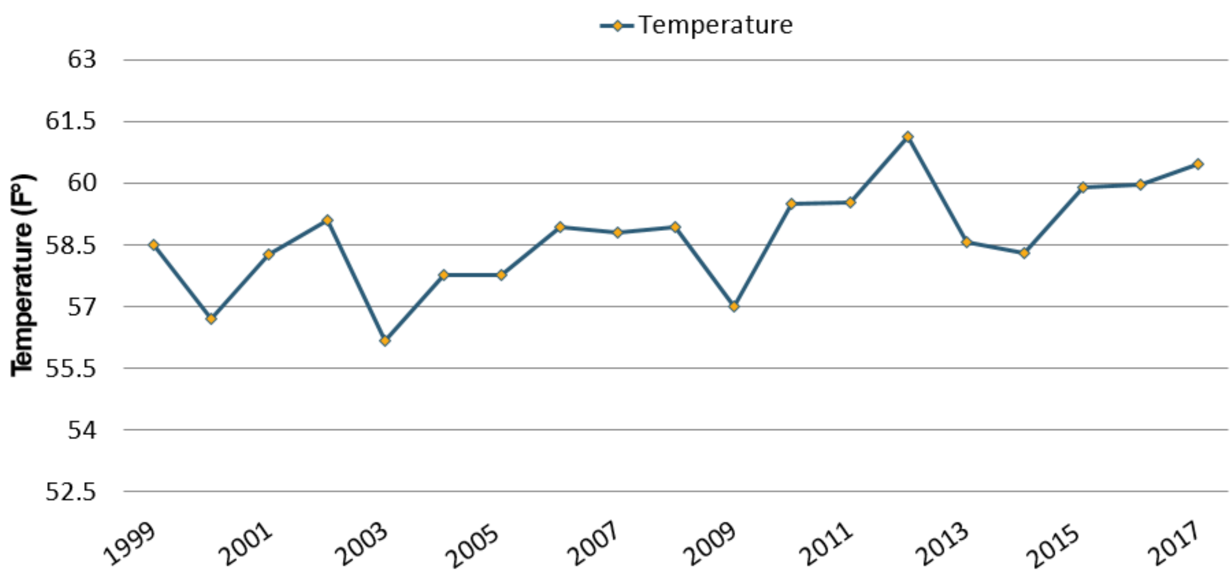

FIGURE B1. Average yearly weather at Ronald Reagan Washington National Airport. (Source: NOAA)

The weather data in Figure B1 show a marked variance in recent years from the aggregate load calculations that determine the Dominion weather profiles from 2000 to 2003.[165] **Temperature changes**

161. https://www.dominionenergy.com/suppliers/energy-suppliers/instructions-for-using-weather-sensitive-profiles
162. https://www.dominionenergy.com/home-and-small-business/rates-and-regulation/residential-rates
163. https://www.dominionenergy.com/home-and-small-business/rates-and-regulation/business-rates
164. https://www.ncdc.noaa.gov/cdo-web/datatools/lcd
165. The increase in temperature from the NOAA data indicates a serious shift in terms of heating and cooling parameters for the residential and commercial load. Further investigation should be considered in terms of aggregate energy efficiency improvements and the increased density of housing in Arlington County.

impact load and translate to greater cooling and heating requirements at temperature extremes. However, this Study does not analyze these impacts, as they are out of its scope.

Using the metered load data from Arlington County and the load audited from their load serving entity allowed for verification of the Dominion weather sensitive profiles from their 2000–2003 baseline through to the current day. However, increases in temperature, relative humidity, and efficiency adjustments add variables to the Dominion weather profile parameters. A multivariate linear equation solver was considered to apply these parameter differences to the Dominion load profile, but having multiple optimal solutions across a month's worth of load added error to the Dominion weather profile. This limited its predictive capability and usefulness in characterizing load for the Arlington supply.

B2. Approach 2: PJM-DOM to Arlington Load Ratio

An alternative approach to characterize the load generation was used that allows for an hour-by-hour load profile from the publicly available PJM Data Miner 2 database.[166] The generation for Arlington County was determined by comparing the hourly data from the PJM Data Miner 2 database for the Dominion zone (DOM zone) as a basis for the hour-by-hour load for the Commonwealth of Virginia and for Arlington County. To derive the 2019 Arlington load profile, an aggregate value over 3 years of PJM-DOM zone load was downloaded from the Data Miner 2 portal and aggregated month by month to create an average ratio between an Arlington month over the historic period 2015–2017 and the Dominion month during those years. The calculations resulted in an average variance of around 2.5%, as shown in Figure B2.

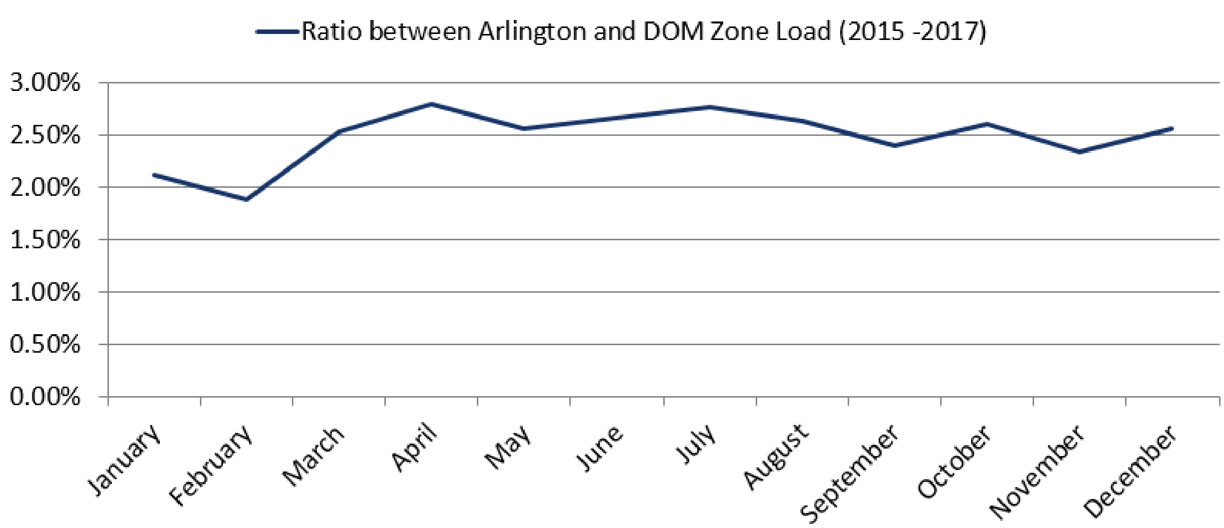

FIGURE B2. Ratio between Arlington and DOM zone load, 2015–2017.

The load proportion between Arlington and DOM zone load was then applied to the Dominion load reported from the PJM Data Miner 2 service for the PJM-DOM calendar year 2019, and as described above, to generate the 2019 load profile for Arlington.

166. https://dataminer2.pjm.com/feed/hrl_load_metered.

B3. Load Profile

Figure B3 illustrates the aggregated Arlington electricity hourly load profile for 2019.

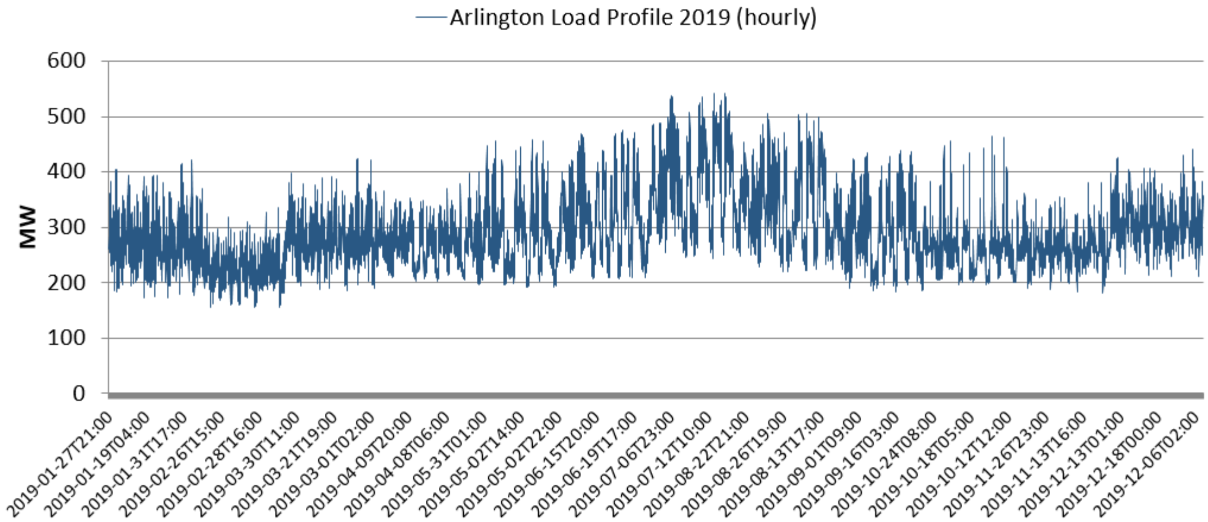

FIGURE B3. Arlington hourly load profile, 2019.

B4. Load Duration Curve

Figure B4 provides the Arlington hourly load duration curve for 2019, using the same data as explained above.

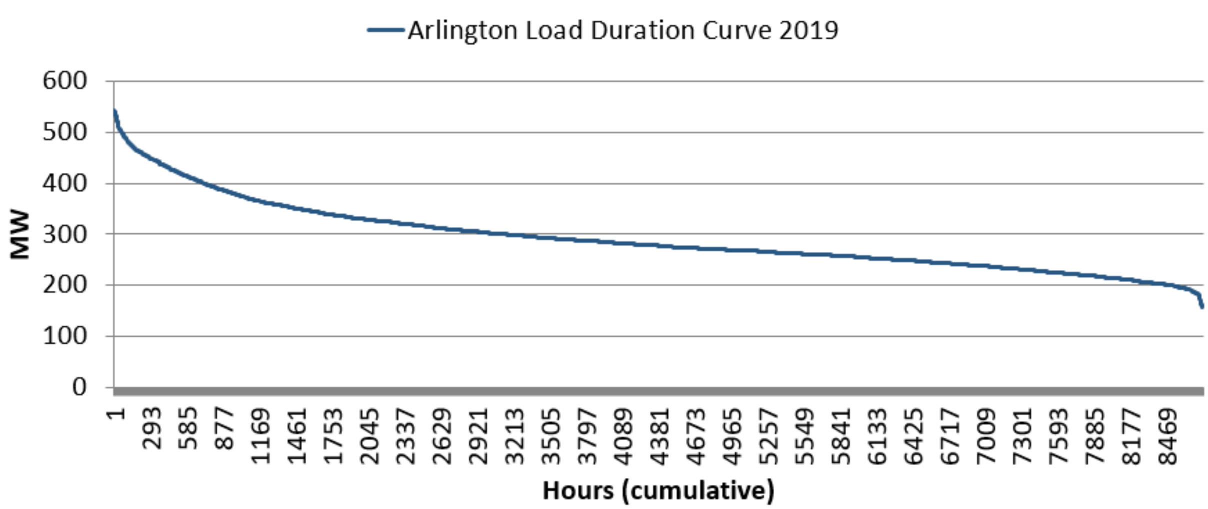

FIGURE B4. Arlington load duration curve, 2019 (cumulative hours).

Figure B5 provides the Arlington hourly load percentile duration curve for 2019 in percentage.

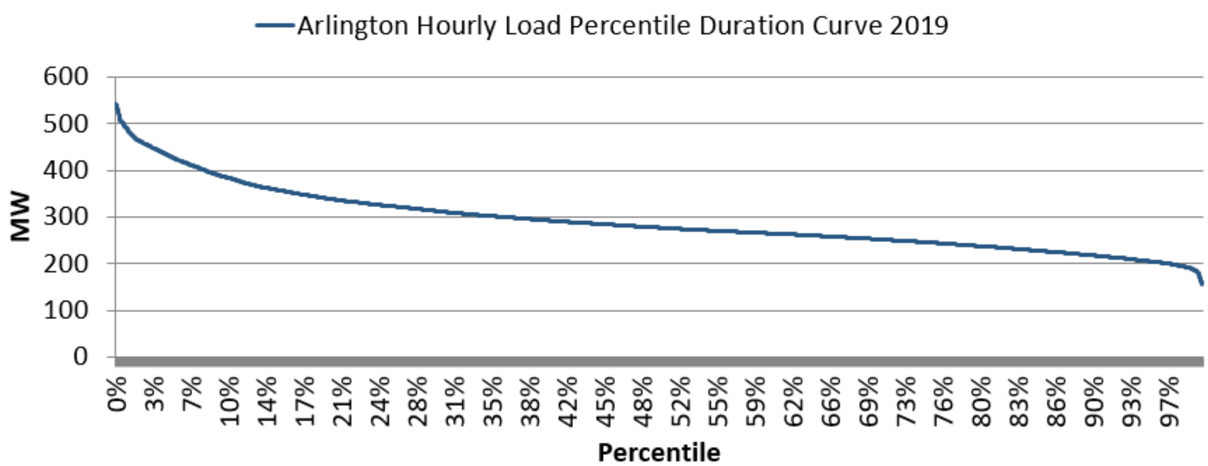

FIGURE B5. Arlington hourly load percentile duration curve, 2019.

The peak load in 2019 was 543 MW, while the base load was 156 MW. In 2019, the peak load capacity above 500 MW occurred 0.66% of the time.[167]

B5. Load Factor

The load factor is used to characterize the peakiness or flatness of the aggregate load. A higher load factor reflects a flatter and more efficient monthly load. A low load factor indicates that peak load is predominant and that peak shaving mechanisms could be used to lower aggregate prices for delivered electricity. Figure B6 shows the load factor for 2019.

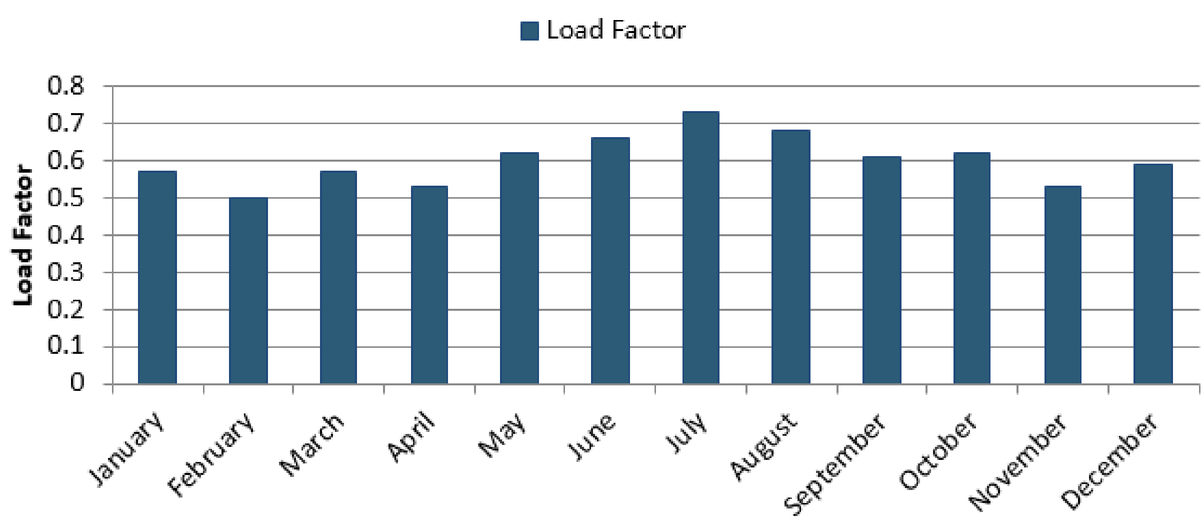

FIGURE B6. Arlington load factor, 2019.

167. These are estimated numbers because we don't have hourly metered electricity usage for 2019.

APPENDIX C: PJM WHOLESALE MARKET PRICES

C1. Locational Marginal Pricing

Locational Marginal Pricing (LMP) is the system that PJM Interconnection uses to establish the price of energy purchases and sales in the PJM wholesale electricity market. LMP reflects the value of the energy at the specific location and time it is delivered. If congestion occurs, the LMP prices of the additional electricity are higher in those locations. LMP prices include system energy price, congestion price, and marginal loss price. The map in Figure C1 shows the LMP for each transmission zone in the region PJM serves.

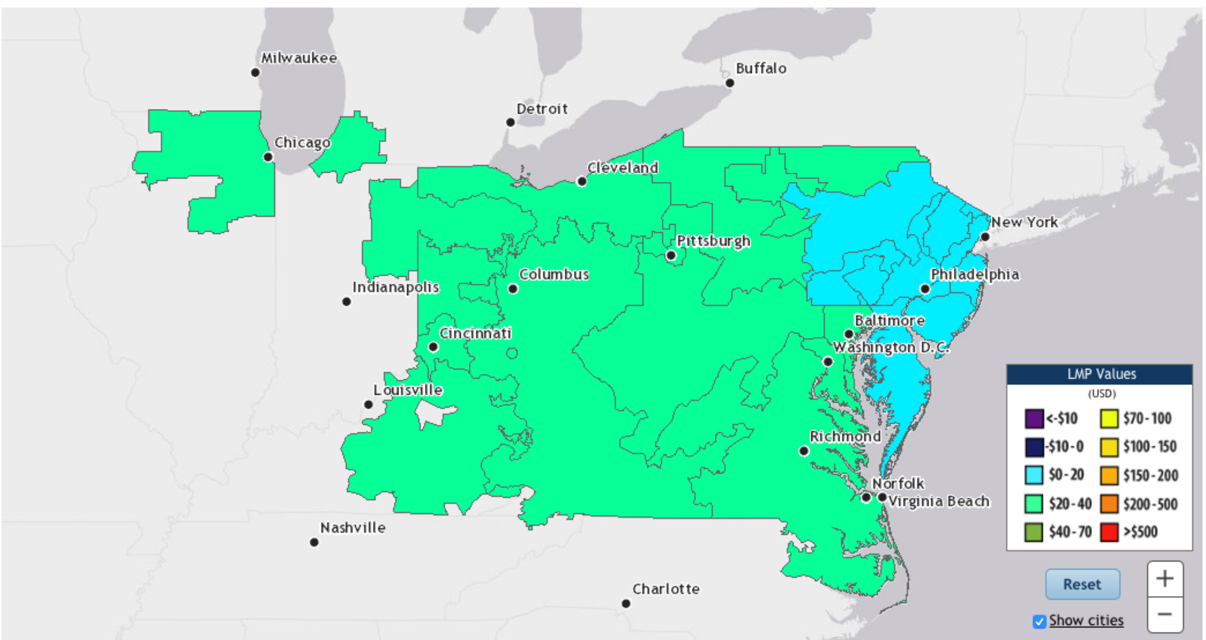

FIGURE C1. Screenshot of Locational Marginal Pricing map. (Source: PJM)[168]

The PJM Now app allows users to track wholesale power prices in real time throughout the PJM region, and the current fuel mix as shown in Figure C2.

168. The legend at bottom right shows color-coded values for LMP; these values are reflected on the map. https://www.pjm.com/library/maps/lmp-map.aspx

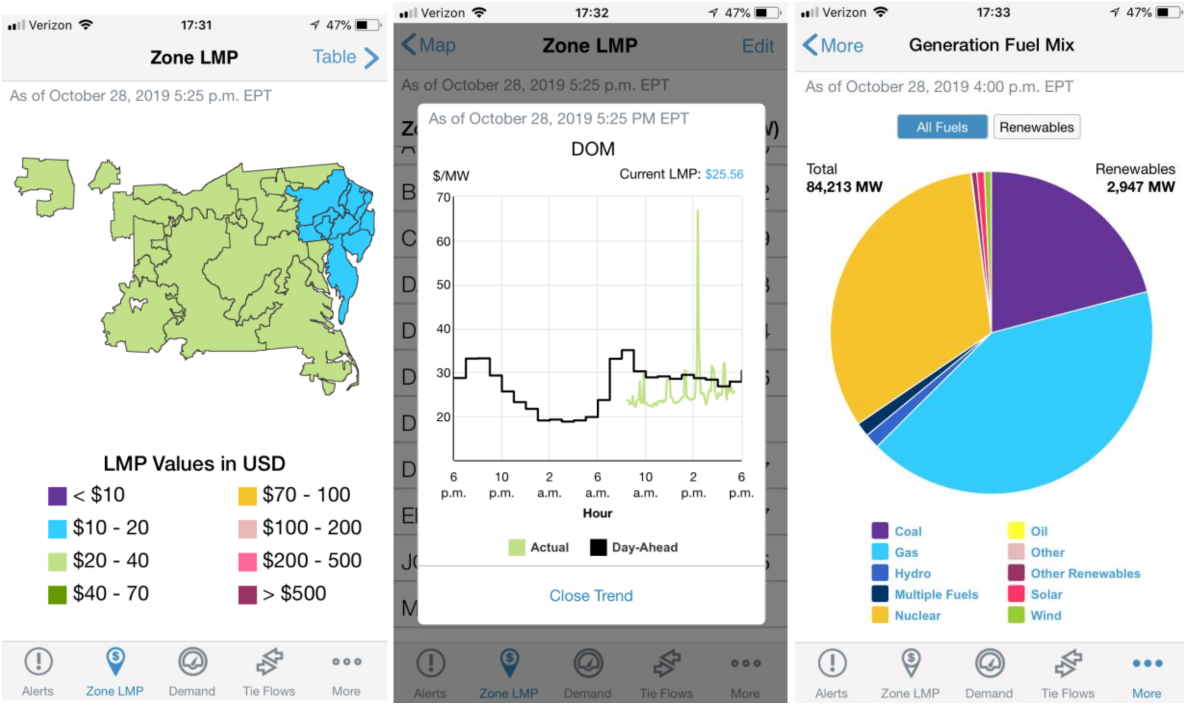

FIGURE C2. Locational Marginal Pricing map and power mix. (Source: PJM Now app, 28 October 2019 at 17:30)

Section C2 provides the wholesale market prices that have been extrapolated for one Arlington node.

C2. Arlington Node Selection

PJM provides publicly available data through the Data Miner 2 service, which we used to fetch PJM Arlington area nodes real-time[169] and day-ahead[170] locational marginal prices (LMPs). This resource provides a useful archive of hourly data back to at least 2015, which we are able to sort by respective node and download for the relevant time span as a .csv file.

Electricity prices in Arlington vary based on a variety of factors including load, the hour of the day, fuel mix, and other grid factors. Despite occasional deviations across node prices in Arlington, prices at the representative nodes of Ballston (63381281), Crystal City (34886201), and Rosslyn (34886401) show little standard deviation during 2018 (Figure C3).[171] In this Study, we use the Ballston node as a stand-in for the price of electricity in Arlington County (for the full list of Arlington nodes, see APPENDIX D: ZIP CODE AND CLOSEST CORRESPONDING PNODE MAPPING).

169. https://dataminer2.pjm.com/feed/rt_hrl_lmps
170. https://dataminer2.pjm.com/feed/da_hrl_lmps
171. A comparison of the LMP between the 35-kilovolt Ballston and Crystal 4 Arlington substations is 3.33 cents/MWh (minuscule). Pricing variance between substations can be attributed to power delivery at higher-voltage substations flowing radially to lower-voltage substations. Lower-voltage substations that are farther from the main voltage substation have a bit more transmission loss for substation electricity delivery.

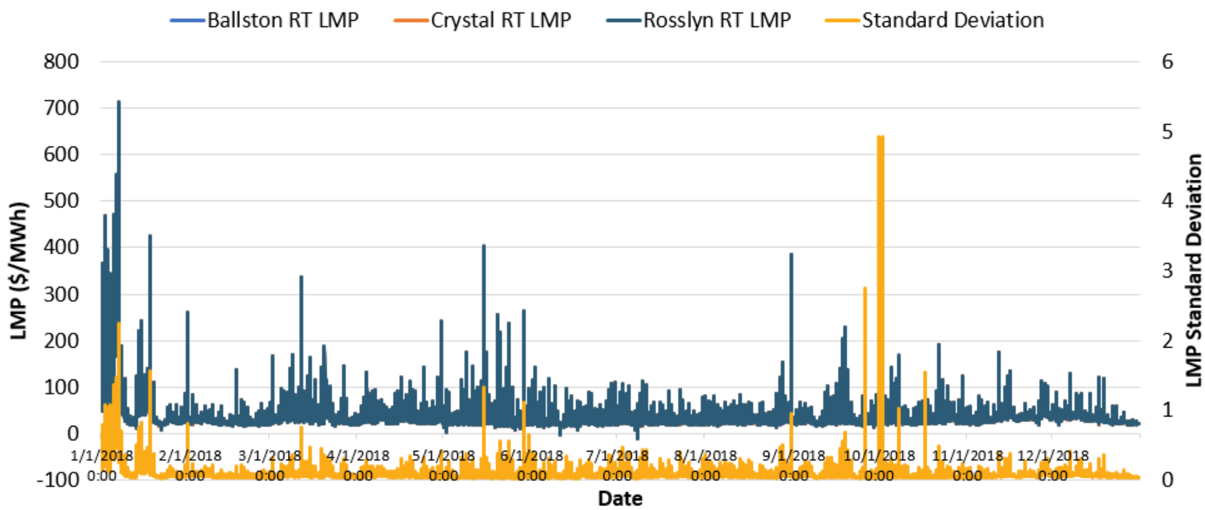

FIGURE C3. Arlington nodes RT LMP comparison, 2018.

We see that there is some deviation between the three selected Arlington nodes; however, in comparison with overall LMP prices, this variation is minimal. In this time series, we see only the gray Ballston LMP, as the Crystal and Rosslyn nodes are similar enough to appear overlapping.

C3. Day-Ahead And Real-Time Lmp Duration Curves

In 2019, we see that the RT LMP price at Ballston node varies between -$54 and $913, while the DA price varies between $10 and $200, with an average of $28 and a median of $26 (Figure C4). The 10th percentile cutoff for DA LMP at Ballston is $19, while the 90th percentile is $40, meaning that the middle 80% of prices are within this range.

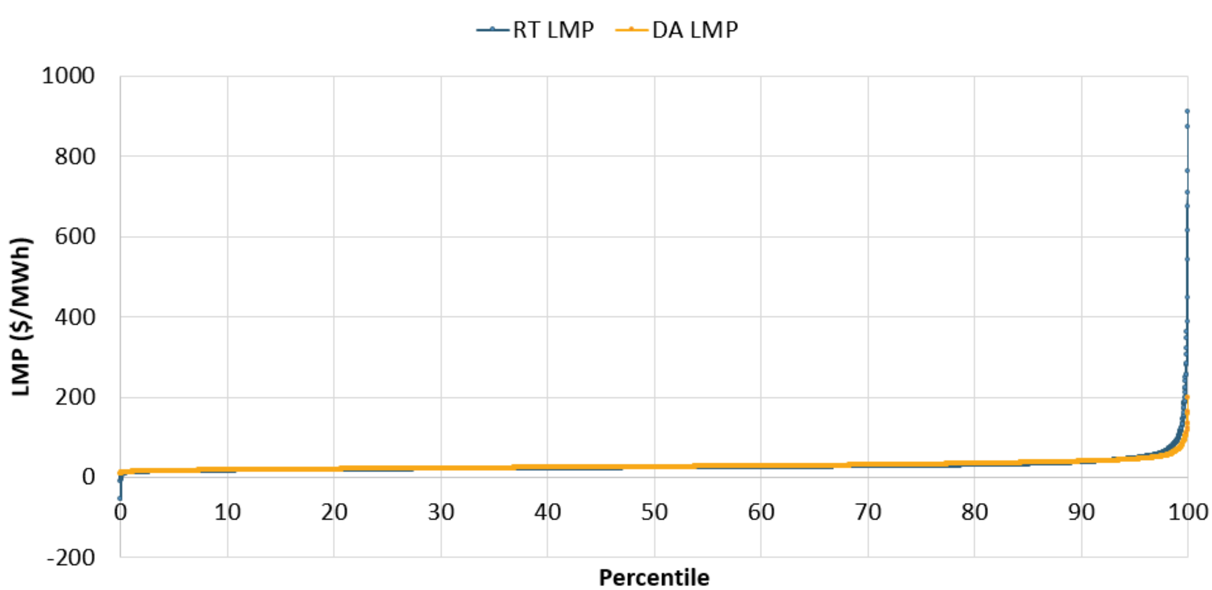

FIGURE C4. RT and DA LMP duration curve at Ballston, 2019.

In 2018, we see that the RT LMP price at Ballston varies between -$11 and $709, while the DA price varies between $13 and $400, with an average of $40 and a median of $33 (Figure C5). The 10th percentile cutoff for DA LMP at Ballston is $21, while the 90th percentile is $56.

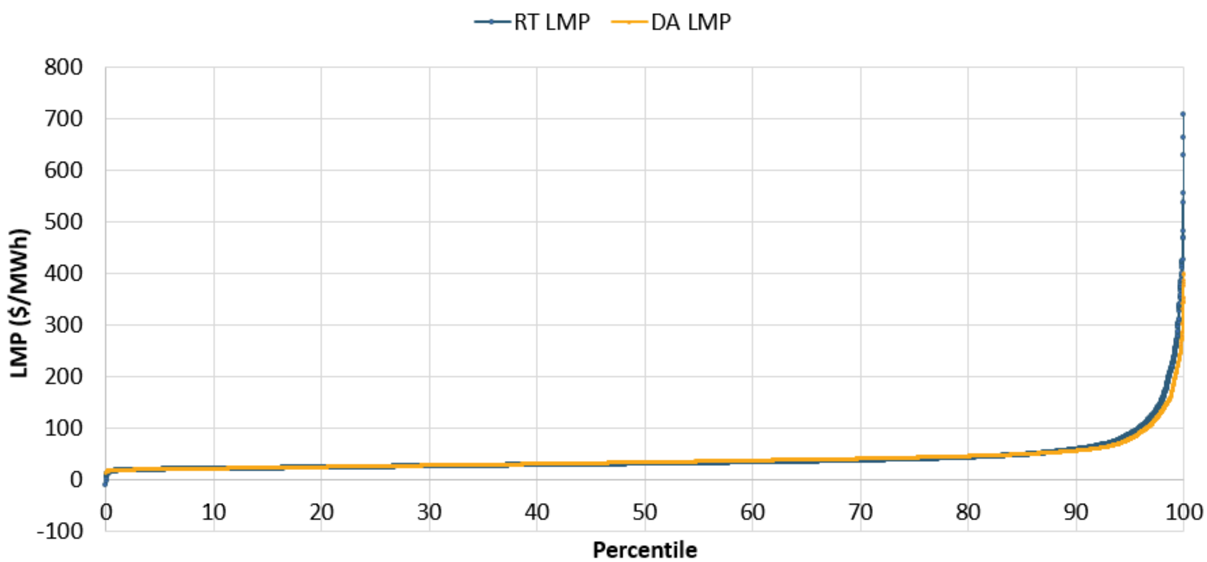

FIGURE C5. RT and DA LMP duration curve at Ballston, 2018.

In 2017, we see that the RT LMP price at Ballston varies between -$36 and $730, while the DA price varies between $10 and $237, with an average of $32 and a median of $29 (Figure C6). The 10th percentile cutoff for DA LMP at Ballston is $10, while the 90th percentile is $45.

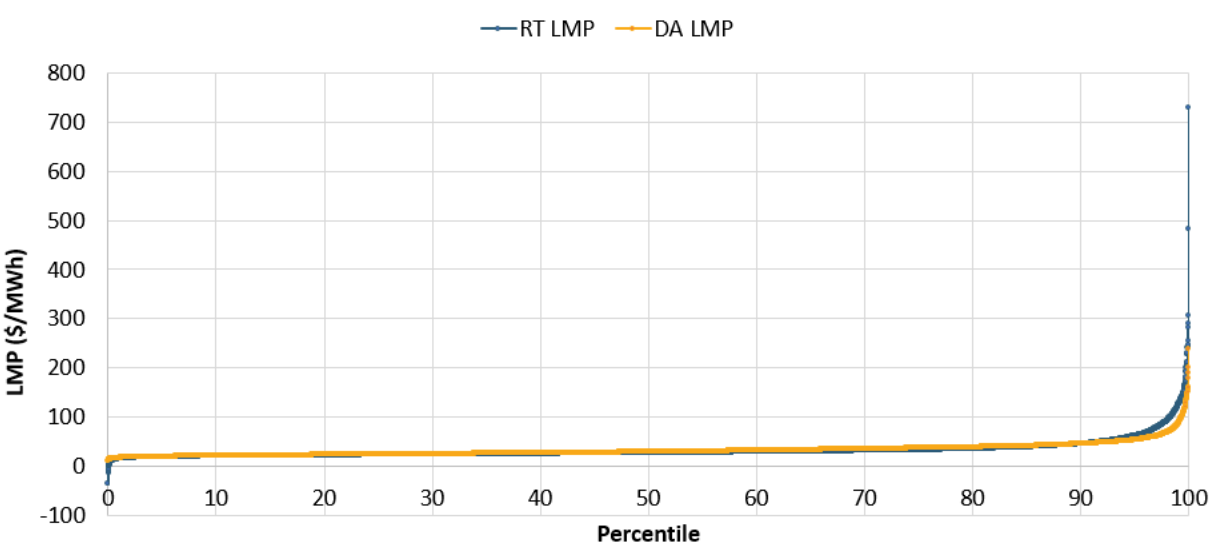

FIGURE C6. RT and DA LMP duration curve at Ballston, 2017.

From these 3 years, we can see that is there is variability in the cost of energy. While this 3-year lookback does capture some of the variability in real-time and day-ahead pricing, it does not show the full extent in possible outcomes. For example, Figure C7, taken from the Energy Information

Administration (EIA), shows how variable natural gas prices can correlate with electricity prices.[172] In the winter of 2008–2009, this increase in natural gas prices led to increasing energy prices in the PJM.

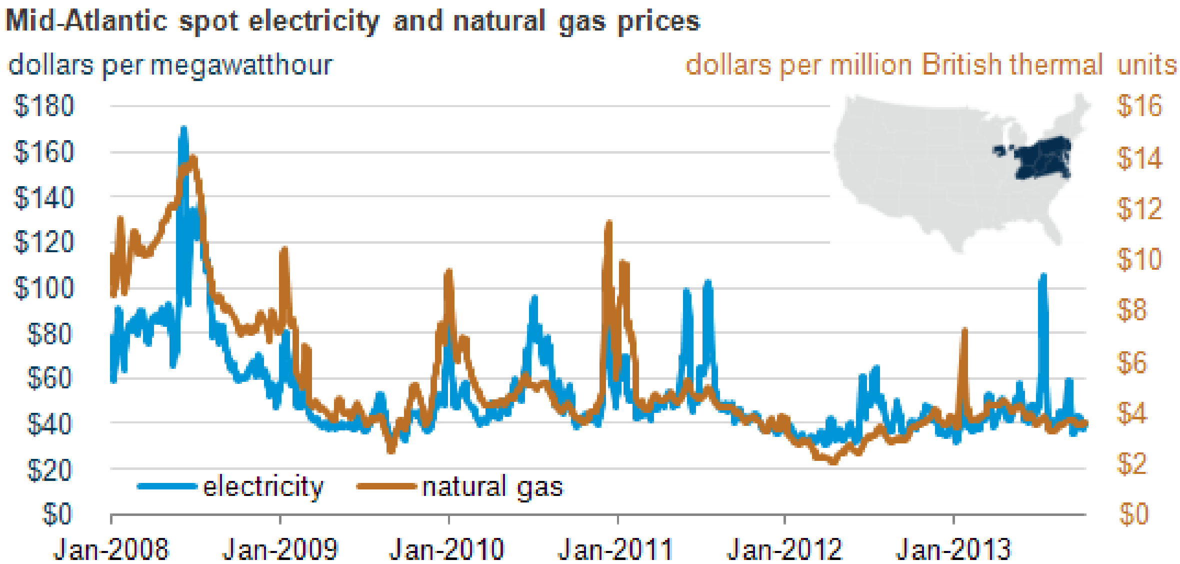

FIGURE C7. Mid-Atlantic spot electricity and natural gas prices. (Source: EIA)

In this Study, we have not attempted to forecast the next decade of natural gas prices or other energy-pricing unknowns and are aware that this 3-year look does not fully encompass all energy pricing outcomes. However, **we believe that this look provides a useful representative sample for discussion surrounding electricity pricing in the PJM and Arlington County.**

C4. Summer 2017 LMP + Load

Figure C8 shows the summer (June–September) hourly DA LMP averages at the Ballston node in 2017. We see that the evening peak, when the load is highest, is coincident with higher prices. Here we view the middle band as the 25th–75th percentile, which represents the middle 50% of outcomes for a given hour. The middle cross represents the mean, and the middle line represents the median. In overnight off-peak hours, we see lower prices, whereas during the afternoon and evening, peak hour prices are higher and generally with a wider range in possible outcomes.

172. https://www.eia.gov/todayinenergy/images/2013.11.18/chart2.png

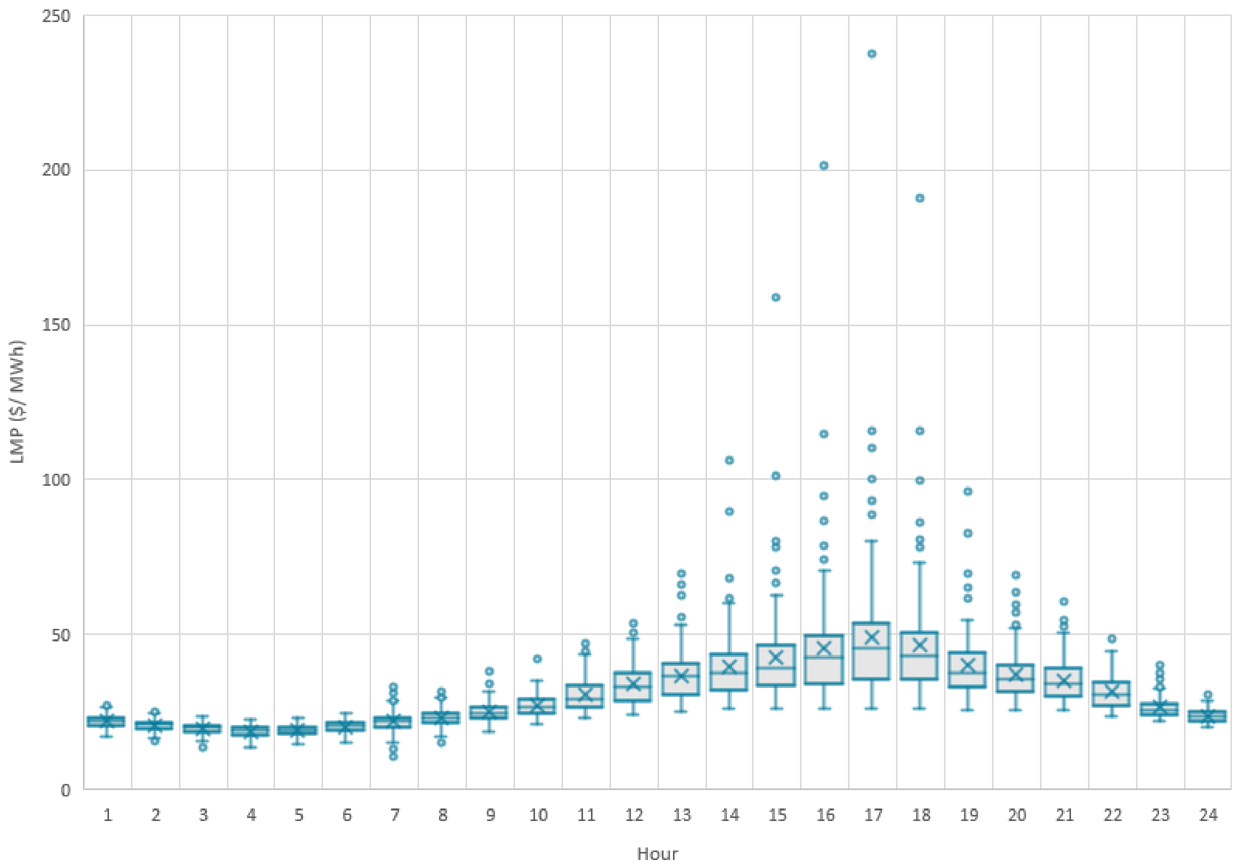

FIGURE C8. Summer (June–September) average pricing at Ballston, 2017.

APPENDIX D: ZIP CODE AND CLOSEST CORRESPONDING PNODE MAPPING

TABLE D1. ZIP Code and Closest Corresponding PNODE Mapping (8 January 2014)

Zip Code	City	State	PNODE ID	PNODE NAME
22201	Arlington	VA	63381281	BALSTON 35 KV TX2
22201	Arlington	VA	63381281	BALSTON 35 KV TX2
22201	Arlington	VA	63381281	BALSTON 35 KV TX2
22202	Arlington	VA	34886201	CRYSTAL435 KV TX1
22202	Arlington	VA	34886201	CRYSTAL435 KV TX1
22202	Arlington	VA	34886201	CRYSTAL435 KV TX1
22202	Arlington	VA	34886201	CRYSTAL435 KV TX1
22202	Arlington	VA	34886201	CRYSTAL435 KV TX1
22202	Arlington	VA	34886201	CRYSTAL435 KV TX1
22202	Arlington	VA	34886201	CRYSTAL435 KV TX1
22202	Arlington	VA	34886203	CRYSTAL435 KV TX2
22202	Arlington	VA	34886203	CRYSTAL435 KV TX2
22202	Arlington	VA	34886203	CRYSTAL435 KV TX2
22202	Arlington	VA	34886203	CRYSTAL435 KV TX2
22202	Arlington	VA	34886203	CRYSTAL435 KV TX2
22202	Arlington	VA	34886203	CRYSTAL435 KV TX2
22202	Arlington	VA	34886203	CRYSTAL435 KV TX2
22202	Arlington	VA	34886205	CRYSTAL435 KV TX3
22202	Arlington	VA	34886205	CRYSTAL435 KV TX3
22202	Arlington	VA	34886205	CRYSTAL435 KV TX3
22202	Arlington	VA	34886205	CRYSTAL435 KV TX3
22202	Arlington	VA	34886205	CRYSTAL435 KV TX3
22202	Arlington	VA	34886205	CRYSTAL435 KV TX3
22202	Arlington	VA	34886205	CRYSTAL435 KV TX3
22202	Arlington	VA	34886207	CRYSTAL435 KV TX4
22202	Arlington	VA	34886207	CRYSTAL435 KV TX4
22202	Arlington	VA	34886207	CRYSTAL435 KV TX4
22202	Arlington	VA	34886207	CRYSTAL435 KV TX4
22202	Arlington	VA	34886207	CRYSTAL435 KV TX4
22202	Arlington	VA	34886207	CRYSTAL435 KV TX4
22202	Arlington	VA	34886207	CRYSTAL435 KV TX4
22203	Arlington	VA	34886261	GLCARLYN35 KV TX1
22203	Arlington	VA	34886263	GLCARLYN35 KV TX3
22203	Arlington	VA	34886265	GLCARLYN35 KV TX4
22204	Arlington	VA	34886267	GLEBE 35 KV TX1
22204	Arlington	VA	34886267	GLEBE 35 KV TX1
22204	Arlington	VA	34886269	GLEBE 35 KV TX2
22204	Arlington	VA	34886269	GLEBE 35 KV TX2

22205	Arlington	VA	34886261	GLCARLYN35 KV TX1
22205	Arlington	VA	34886261	GLCARLYN35 KV TX1
22205	Arlington	VA	34886261	GLCARLYN35 KV TX1
22205	Arlington	VA	34886261	GLCARLYN35 KV TX1
22205	Arlington	VA	34886261	GLCARLYN35 KV TX1
22205	Arlington	VA	34886263	GLCARLYN35 KV TX3
22205	Arlington	VA	34886263	GLCARLYN35 KV TX3
22205	Arlington	VA	34886263	GLCARLYN35 KV TX3
22205	Arlington	VA	34886263	GLCARLYN35 KV TX3
22205	Arlington	VA	34886263	GLCARLYN35 KV TX3
22205	Arlington	VA	34886265	GLCARLYN35 KV TX4
22205	Arlington	VA	34886265	GLCARLYN35 KV TX4
22205	Arlington	VA	34886265	GLCARLYN35 KV TX4
22205	Arlington	VA	34886265	GLCARLYN35 KV TX4
22205	Arlington	VA	34886265	GLCARLYN35 KV TX4
22206	Arlington	VA	34886267	GLEBE 35 KV TX1
22206	Arlington	VA	34886267	GLEBE 35 KV TX1
22206	Arlington	VA	34886267	GLEBE 35 KV TX1
22206	Arlington	VA	34886267	GLEBE 35 KV TX1
22206	Arlington	VA	34886269	GLEBE 35 KV TX2
22206	Arlington	VA	34886269	GLEBE 35 KV TX2
22206	Arlington	VA	34886269	GLEBE 35 KV TX2
22206	Arlington	VA	34886269	GLEBE 35 KV TX2
22207	Arlington	VA	34886183	CLARENDN35 KV TX1
22207	Arlington	VA	34886185	CLARENDN35 KV TX2
22209	Arlington	VA	34886397	ROSLYN 13 KV TX1
22209	Arlington	VA	34886397	ROSLYN 13 KV TX1
22209	Arlington	VA	34886397	ROSLYN 13 KV TX1
22209	Arlington	VA	34886397	ROSLYN 13 KV TX1
22209	Arlington	VA	34886399	ROSLYN 13 KV TX2
22209	Arlington	VA	34886399	ROSLYN 13 KV TX2
22209	Arlington	VA	34886399	ROSLYN 13 KV TX2
22209	Arlington	VA	34886399	ROSLYN 13 KV TX2
22209	Arlington	VA	34886401	ROSLYN 13 KV TX3
22209	Arlington	VA	34886401	ROSLYN 13 KV TX3
22209	Arlington	VA	34886401	ROSLYN 13 KV TX3
22209	Arlington	VA	34886401	ROSLYN 13 KV TX3
22209	Arlington	VA	34886403	ROSLYN 13 KV TX4
22209	Arlington	VA	34886403	ROSLYN 13 KV TX4
22209	Arlington	VA	34886403	ROSLYN 13 KV TX4
22209	Arlington	VA	34886403	ROSLYN 13 KV TX4
22213	Arlington	VA	34886237	FLSCHURC35 KV TX3
22213	Arlington	VA	34886239	FLSCHURC35 KV TX4

Source: PJM (https://www.pjm.com/-/media/markets-ops/energy/lmp-model-info/zip-code-mapping.ashx?la=en)

"This listing shows ZIP codes in the PJM footprint and the closest load PNODE to that ZIP code. This mapping is done strictly by geographical distance and has no correlation to actual power flows or the transmission or distribution systems. This mapping has been created based on the best data available to PJM, however missing data may impact the mapping for certain locations. In many cases, multiple load busses at the same location mean the ZIP code is equal distances from two or more load PNODES and in such cases, all relevant load PNODES are listed."

APPENDIX E: LIST OF CSPS AND AGGREGATORS IN DEV TERRITORY

See the full list at the SCC website: https://scc.virginia.gov/power/compsup.aspx.

TABLE E1. List of CSPs and Aggregators in DEV Territory

COMPANY NAME/CONTACT INFORMATION	SERVICES AUTHORIZED	CUSTOMER TYPE	REGISTERED IN LDC SERVICE TERRITORIES
Alternative Utility Services Inc.	Aggregator	C,I	DEV
American PowerNet Management LP	CSP, Aggregator	C,I	DEV
Collegiate Clean Energy LLC	CSP, Aggregation	C,I	DEV, APCO
Constellation NewEnergy	Aggregator	R,C,I	DEV
CSD Advisors LLC	Aggregator	C,I	DEV
DirectEnergy Business	CSP	C,I,G	APCO, DEV
EA Power Solutions	Aggregator	C,I	DEV
Energy-Tel LLC	Aggregator	R,C,I	DEV, APCO
GPC Green Energy LLC	CSP	C,I	DEV
Independent Energy Consultants Inc.	Aggregator	R,C,I	DEV
Integrity Energy Ltd. LLC	Aggregator	C,I,G	DEV, APCo
Liberty Power Holdings LLC	CSP	C,I	DEV
Massie Power LLC	CSP, Aggregator	R,C,I	DEV
Stand Energy	Aggregator	C,I,G,ED	APCO, DEV

C, commercial; ED, educational; I, industrial; G, governmental; R, residential.

APPENDIX F: RENEWABLE GENERATION RESOURCES IN VIRGINIA AND PJM

F1. Solar Energy

Solar energy within the area served by PJM is growing, with a total of approximately 7,003 MW (nameplate capacity) in 2019.[173] New Jersey (2,859 MW), North Carolina (1,359 MW), and Maryland (1,159 MW) are the top three states, followed by Virginia, Pennsylvania, Ohio, Delaware, Illinois, Washington, D.C., Kentucky, Indiana, Michigan, West Virginia, and Tennessee.[174] Figure F1 shows solar energy by state in the PJM service area.

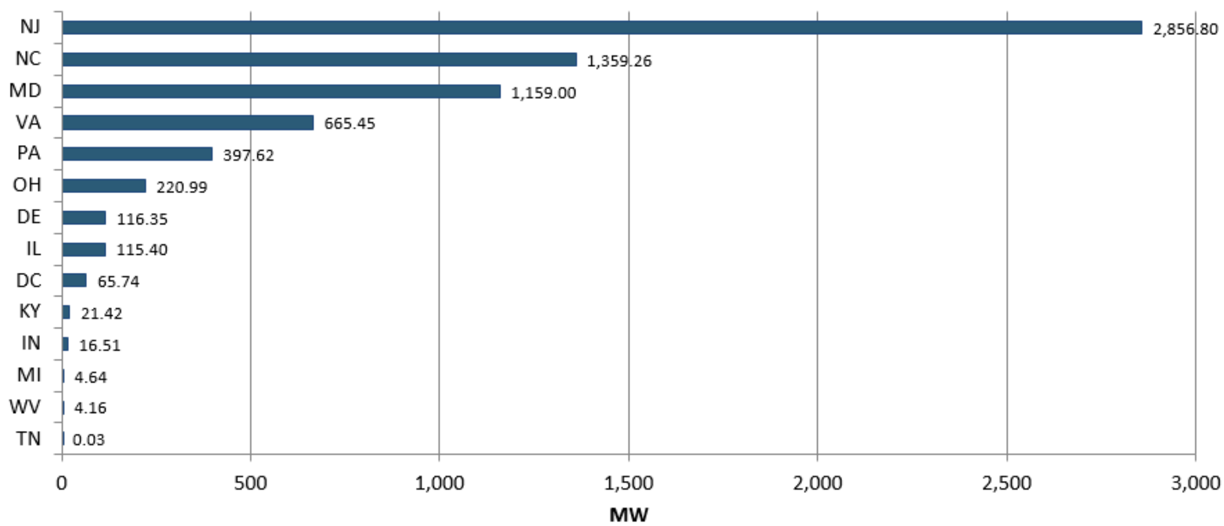

FIGURE F1. Solar energy by state in the PJM service area in 2019. (Source: PJM)

F2. Generation Attribute Tracking System (GATS)

The Generation Attribute Tracking System (GATS), owned by PJM subsidiary Environmental Information Services, is a web-based generation registry and tracking service that allows the states in the PJM area to chart emissions data and renewable energy certificates.[175, 176]

173. https://insidelines.pjm.com/use-pjms-interactive-tools-to-track-renewables/
174. PJM serves only a portion of Illinois, Indiana, Kentucky, Michigan, North Carolina, and Tennessee.
175. https://learn.pjm.com/-/media/about-pjm/newsroom/fact-sheets/gats-fact-sheet.ashx
176. https://gats.pjm-eis.com/gats2/PublicReports/RenewableGeneratorsRegisteredinGATS

F3. Renewable Generation Resources in Virginia

According to the 2018 IRP, Dominion currently owns and operates 533 MW of renewable resources, including three solar units for a total of 56 MW (nameplate) in Virginia, approximately 8 MW (nameplate) of solar generation facilities through the Solar Partnership Program, approximately 153 MW of biomass generating facilities, and three hydro facilities for a total of 316 MW.[177, 178]

F4. Renewable Energy Projects Queue

PJM publishes a live map of renewable resources under study for possible interconnection to the grid (Figure F2). Colored dots denote projects involving biomass, hydro, methane (generated by landfills, etc.), solar, wind, wood, and other fuels.[179]

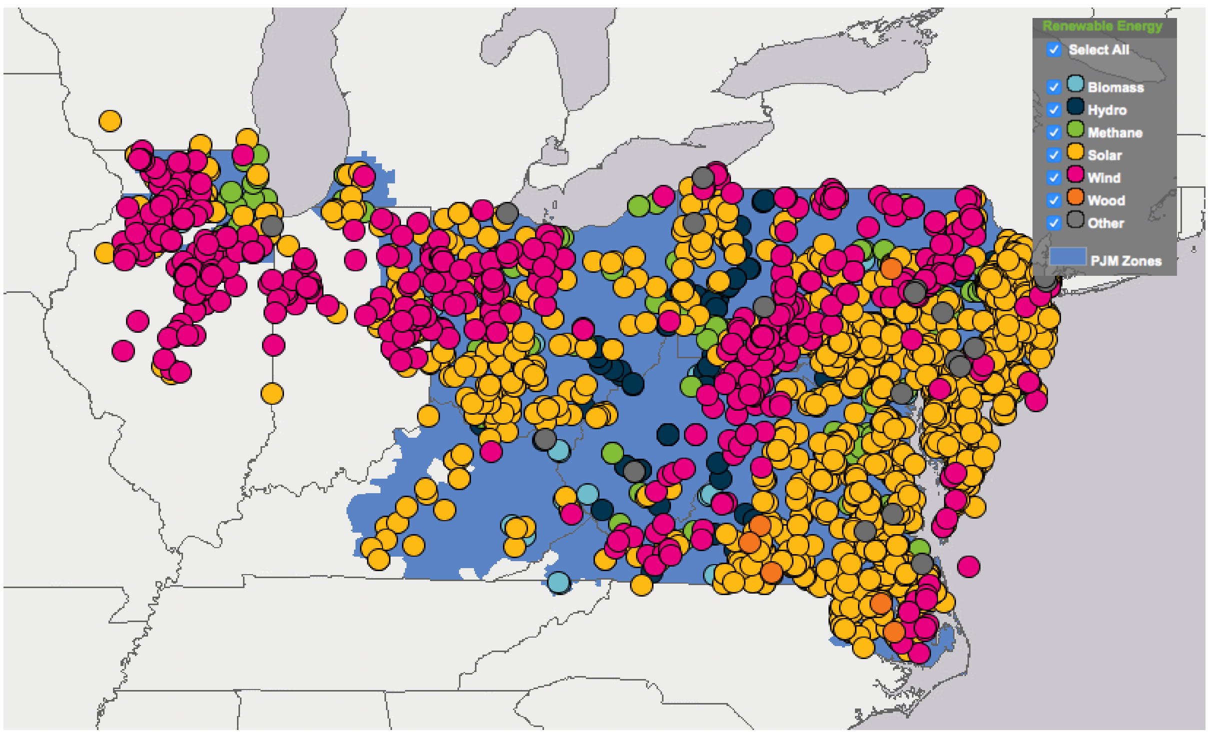

FIGURE F2. Renewable energy (queue) map. (Source: PJM)[180]

177. For more information about Dominion energy generation by type, please refer to the 2018 IRP on p. 173.
178. See Dominion map of renewable generation resources in Virginia and North Carolina at https://www.dominionenergy.com/company/making-energy/renewable-generation
179. Not all of these projects will be built; only about 15% of all proposed new capacity comes online. See https://www.pjm.com/planning/services-requests/interconnection-queues.aspx.
180. https://mapservices.pjm.com/renewables/

APPENDIX G: DOMINION BILL COST BREAKDOWN

The Dominion bill includes electric supply service (generation), transmission, and distribution charges for the electric service provided to residential, commercial, and industrial customers.

BOX 11. Understanding Dominion Residential Billing

A typical Dominion residential bill is divided into (1) distribution service, (2) electricity supply service, (3) sales and use surcharge, and (4) state and local taxes. The electricity supply component includes generation + transmission + fuel charges. **The CCA bill would be identical in points 1, 3, and 4.** For point 2, the CCA would not include fuel charges, as fuel is already embedded in the wholesale market prices. Below is an example of a Dominion bill for a residential customer.

Billing and Payment Summary

[redacted]

Total Draft Amount:	**$**	**46.77**

Previous Amount Due:	$	42.31
Payments as of Dec 30:	$	42.31CR

For service emergencies and power outages please call
***1-866-DOM-HELP** (1-866-366-4357). Visit us at www.dominionenergy.com.*

Meter and Usage

Current Billing Days: 32

Billable Usage		
Schedule 1	*11/25-12/27*	
Total kWh		310
Measured Usage		
***Meter:** 0259799651*	*11/25-12/27*	
Current Reading		18358
Previous Reading		18048
Total kWh		310
Current Reading		2.73
Demand		2.73

Usage History

Mo	Yr	kWh
Dec	18	311
Jan	19	152
Feb	19	304
Mar	19	266
Apr	19	185
May	19	189
Jun	19	210
Jul	19	333
Aug	19	245
Sep	19	262
Oct	19	248
Nov	19	274
Dec	19	310

Explanation of Bill Detail

Customer Service **1-866-DOM-HELP** *(1-866-366-4357)*

Previous Balance	42.31	
Payment Received	42.31CR	
Balance Forward		**0.00**
Residential Service (Schedule 1)	*11/25-12/27*	
Distribution Service		14.04
Electricity Supply Svc (ESS)		
Generation		15.75
Transmission		6.12
Fuel		7.21
Sales and Use Surcharge		0.17
State/Local Consumption Tax		0.48
ARLINGTON Utility Tax		3.00
Total Current Charges		**46.77**
Total Account Balance		**46.77**

To better understand how your bill is calculated, visit www.dominionenergy.com/yourbill.

More at https://www.dominionenergy.com/home-and-small-business/billing-options/understanding-your-bill.

Figure G1 shows the breakdown of the major components of a Dominion residential bill.[181] Generation represents the major expense (43%), followed by distribution and fuel charges (23% each), transmission (10%), consumption tax (1%), and sales and use surcharge (0.38%).

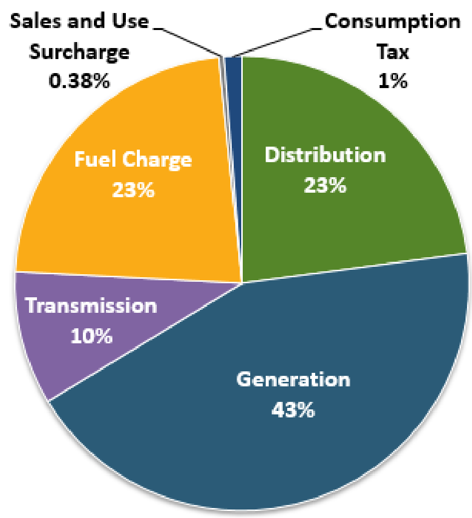

FIGURE G1. Breakdown of Dominion residential bill by major components (%).

Figure G2 shows a more detailed breakdown of the components of a Dominion residential bill with riders (also known as Rate Adjustment Clauses, or RACs). The detailed breakdown shows that generation costs still account for the majority of the total bill (33%), followed by fuel charge (23%), distribution charge (22%), and transmission (10%). The generation rider accounts for 10% of the total bill, while distribution riders account for 1%.

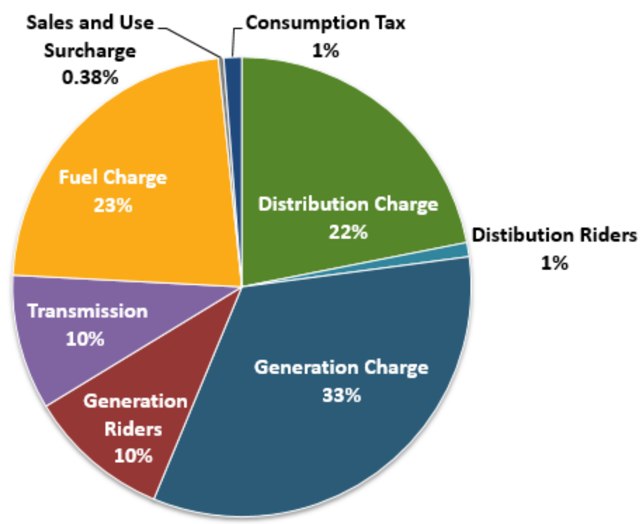

FIGURE G2. Breakdown of Dominion residential bill by single components (%).

181. Percentages calculated from the Bill Calculator Worksheet for the period June–September, billing days 30, total kWh 1,000. Available at https://www.dominionenergy.com/home-and-small-business/billing-options/understanding-your-bill.

G1. Dominion Return on Equity

The Dominion Return on Equity (ROE) combined for generation and distributions approved by the Commission for DEV's RACs is 9.20%.[182] The utility sought approval of an ROE increase to 10.75% to be applicable to RACs (before any adders) and to measure earnings in its first triennial review (filed 29 March 2019).[183]

G2. Electricity Supply Service Charges and Riders

Dominion has different rate schedules for different classes of customers. In this section, we analyze Schedule 1–Basic Residential Rate, and GS1 Small General Service (under 30 kW).[184]

The electricity supply service includes the cost of generation and transmission of electricity. For every kWh, Dominion applies a variety of riders including

1. **Fuel charge** (Rider A) is the cost for fuel used to produce electricity, including fuel shipment.
2. **Generation riders**, which cover the cost for the production of electricity from Dominion's power plants: Rider S, Virginia City Hybrid Energy Center; Rider GV, Greensville County Power Station charges; Rider BW, Brunswick County Power Station; Rider W, Warren County Power Station; Rider E, Environmental Rider; Rider R, Bear Garden Generating Station; Rider B, Biomass Conversions; Rider US-2, 2016 Solar Projects; Rider US-3; Solar Projects.
3. **Transmission charge** (Rider T1), which is the cost of moving electricity from Dominion Energy's power plants to the substations.

The Dominion monthly generation kWh charges for residential and commercial customers for 2019 are summarized in Table G1.

TABLE G1. Dominion Monthly Generation kWh Charge, 2019

Billing Months	Schedule 1 Basic Residential	GS1 Small General Service (Under 30 kW)
June–September	First 800 kWh @ 3.5826¢ per kWh Over 800 kWh @ 5.4500¢ per kWh	First 1,400 kWh @ 3.5138¢ per kWh Over 1,400 kWh @ 4.7155¢ per kWh
October–May	First 800 kWh @ 3.5826¢ per kWh Over 800 kWh @ 2.7632¢ per kWh	First 1,400 kWh @ 3.5138¢ per kWh Over 1,400 kWh @ 2.2657¢ per kWh

Figure G3 shows the applicable riders for the electricity supply service (cents/kWh) for Schedule 1–Basic Residential Rate for 2019.

182. *Application of Virginia Electric and Power Company, For the determination of the fair rate of return on common equity to be applied to its rate adjustment clauses*, Case No. PUR-2017-00038, 2017 S.C.C. Ann. Rept. 475, Final Order (29 November 2017).
183. SCC Status Report: Implementation of the Virginia Electric Utility Regulation Act Pursuant to § 56-596 B of the Code of Virginia. 29 August *2019*
184. Each such utility shall make a triennial filing by 31 March of every third year, with such filings commencing for a Phase I Utility in 2020, and *such* filings commencing for a Phase II Utility in 2021, consisting of the schedules contained in the Commission's rules governing utility rate increase applications. See paragraph 3 of § 56-585.1.https://law.lis.virginia.gov/vacode/title56/chapter23/section56-585.1/

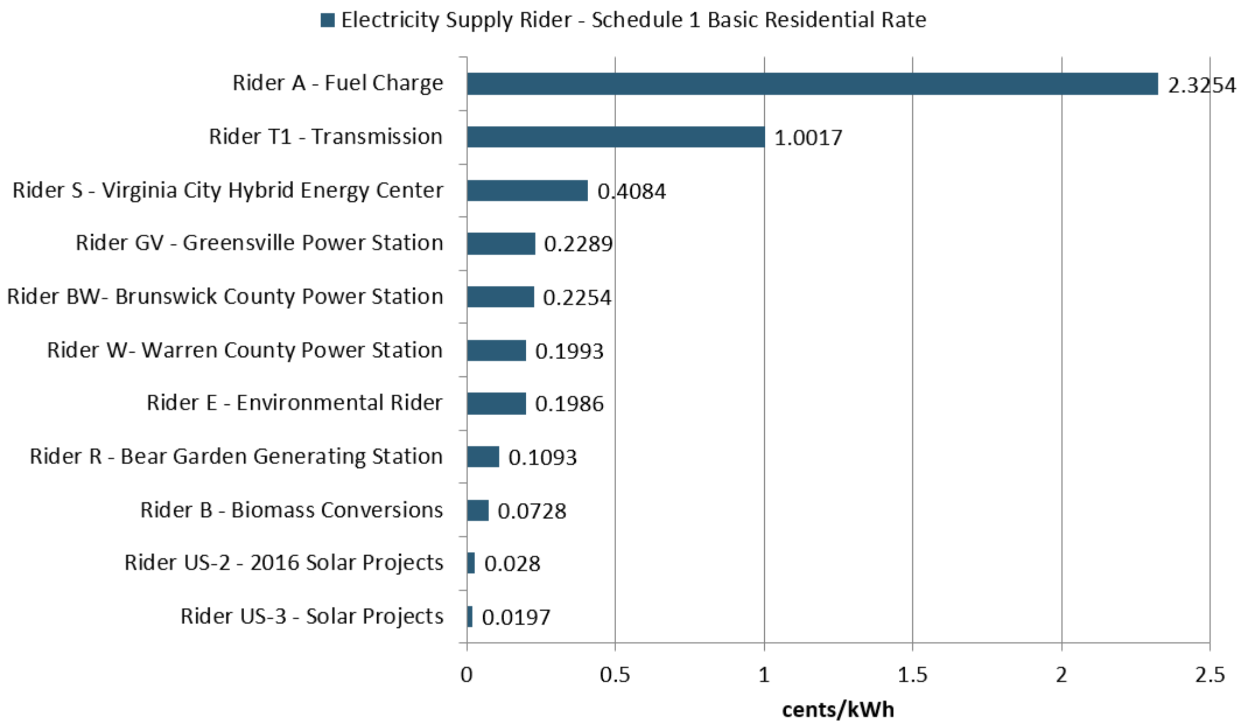

FIGURE G3. Electricity supply riders, Schedule 1–Basic Residential Rate, 2019.

Figure G4 shows the applicable riders for the electricity supply service (cents/kWh) for GS1 Small General Service (under 30 kW) riders for 2019.

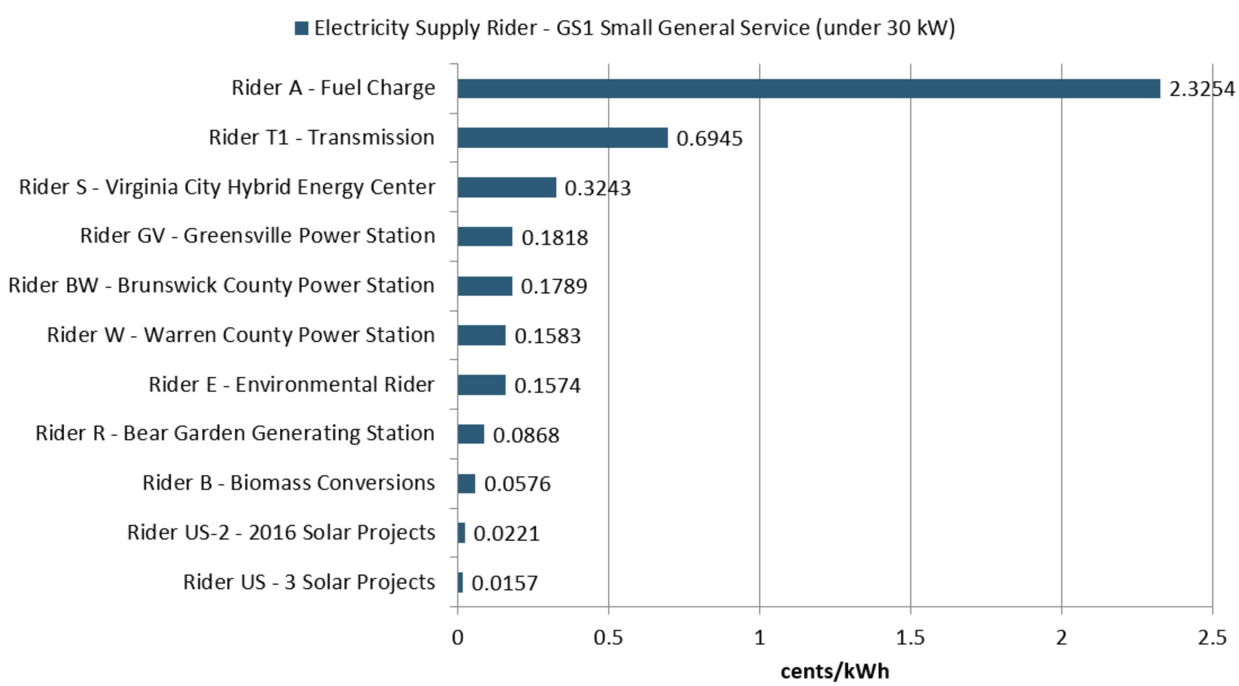

FIGURE G4. Electricity supply rider—GS1 Small General Service (under 30 kW), 2019.

G3. Distribution Charges and Riders

The distribution service is the cost for the use of local wires, transformers, substations, and other equipment used to deliver electricity to homes or businesses, including Demand-Side Management (DSM) riders: Rider C1A (Peak Shaving), DSM Riders C2A and C3A (Energy Efficiency), and Demand-Side Management (DSM) Rider U, Strategic Underground Program. The monthly distribution kWh charges for residential and commercial customers for 2019 are summarized in Table G2.

TABLE G2. Dominion Monthly Distribution kWh Charge, 2019

Billing Months	Schedule 1 Basic Residential	GS1 Small General Service (Under 30 kW)
Basic customer charge	$6.58 per billing month	For single-phase service $10.78 per billing month For three-phase service $14.54 per billing month
June–September	First 800 kWh @ 2.1086¢ per kWh Over 800 kWh @ 1.1943¢ per kWh	First 1,400 kWh @ 1.7045¢ per kWh Over 1,400 kWh @ 1.0251¢ per kWh
October–May	First 800 kWh @ 2.1086¢ per kWh Over 800 kWh @ 1.1943¢ per kWh	First 1,400 kWh @ 1.7045¢ per kWh Over 1,400 kWh @ 1.0251¢ per kWh

FIGURE G5. shows the applicable riders for the distribution charges (cents/kWh) for Schedule 1–Basic Residential Rate for 2019.

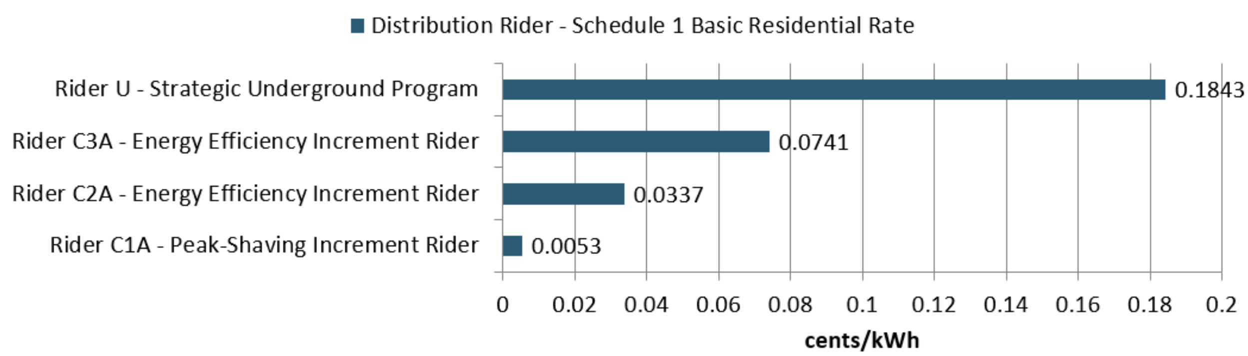

FIGURE G5. Distribution rider—Schedule 1–Basic Residential Rate, 2019.

Figure G6 shows the applicable riders for the distribution charges (cents/kWh) for GS1 Small General Service (under 30 kW) for 2019.

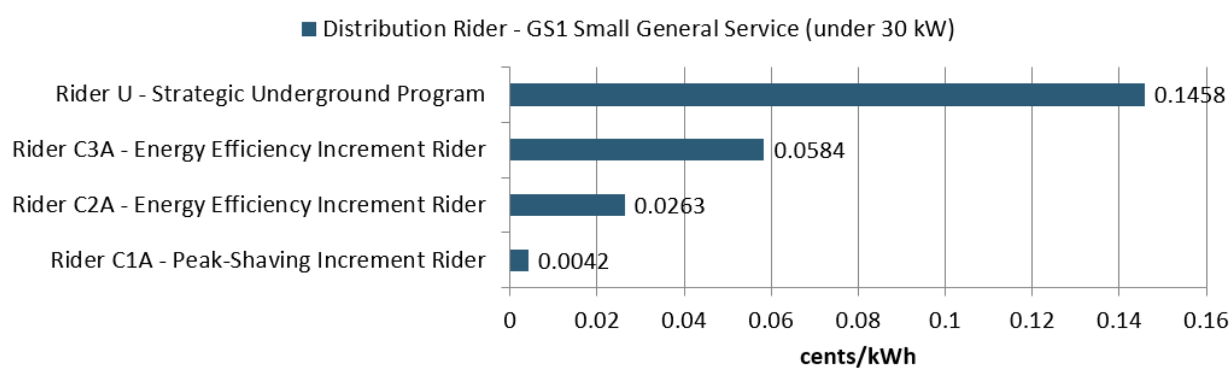

FIGURE G6. Distribution rider—GS2 Intermediate General Service 30–500 KW, 2019.

G4. Sales and Use Tax Surcharge

The sales and use surcharge includes the recovery of the sales tax on certain Dominion Energy Virginia purchases and leases. The sales and use tax surcharges for residential and commercial customers for 2019 are summarized in Table G3.

TABLE G3. Dominion Monthly Sales and Use kWh Charge, 2019

Billing Months	Schedule 1 Basic Residential	GS2 Intermediate General Service 30–500 kW
All months	0.031¢ per kWh	0.024¢ per kWh

G5. Consumption Tax

A consumption tax is applied to all kilowatt-hours consumed, in accordance with the Code of Virginia §58.1-2900. Dominion collects and remits the consumption tax.[185]

G6. Arlington Electric Utility Consumer Tax

Arlington charges a utility tax on residential and commercial users of electricity based on kilowatt-hours (kWh) usage delivered monthly. Rates are limited in the state code: Residential rates are limited to a $3/month maximum per utility, and rates must be based on usage and commercial is not to exceed 20% of "the monthly amount charged to consumers."[186] The tax is collected by the service provider from the consumer and is paid to the service provider for the use of Arlington County at the time of the purchase price. Table G4 summarizes the monthly tax on each purchase of electricity delivered to consumers by a service provider.

TABLE G4. Arlington Monthly Electric Utility Consumer Tax

Consumers Class	Description
Residential consumers	For electricity consumption in excess of four hundred (400) kWh such tax shall be $0.00341 on each kWh delivered monthly to residential consumers not to exceed three dollars ($3.00) per month; provided, however, in the case of any multi-family dwelling served by a master meter or meters, such tax shall be $0.00341 on each kWh delivered monthly in excess of the number of units times four hundred (400) kWh with the tax not to exceed three dollars ($3.00) multiplied by the number of individual dwelling units served by the master meter or meters.
Commercial consumers	Such tax shall be one dollar and fifteen cents ($1.15) plus the rate of $0.00649 on each kWh delivered monthly to commercial consumers.
Industrial consumers	Such tax shall be one dollar and fifteen cents ($1.15) plus the rate of $0.01043 on each kWh delivered monthly to industrial consumers

185. https://www.dominionenergy.com/home-and-small-business/rates-and-regulation/residential-rates
186. Arlington County Code, Chapter 63, Utility Tax, in accordance with Virginia Code § 58.1-3814

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