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June 23, 2020

VIA ELECTRONIC FILING

Mr. Joel H. Peck, Clerk
c/o Document Control Center
State Corporation Commission
Tyler Building – First Floor
1300 East Main Street
Richmond, Virginia 23219

RE: *Ex Parte*: Electrification of Motor Vehicles

Case No. PUR-2020-00051

Dear Mr. Peck:

Please find enclosed for filing in the above-referenced docket the Environmental Advocates' Comments as directed by the Commission's Order dated March 24, 2020.

If you should have any questions regarding this filing, please do not hesitate to contact me at (434) 977-4090.

Regards,

William C. Cleveland

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ENVIRONMENTAL ADVOCATES' COMMENTS

The Southern Environmental Law Center, along with the Piedmont Environmental Council, Clean Virginia, the Virginia Conservation Network, the Virginia League of Conservation Voters, Appalachian Voices, and the Chesapeake Climate Action Network, (collectively the "Environmental Advocates") are pleased to provide the following comments in response to the Commission's request in this case. Environmental Advocates agree with the Commission that electric vehicles ("EVs") "potentially could affect the affordability and reliability of electricity service delivered to consumers by regulated utilities."[1] Specifically, if coupled with the proper rate designs and incentives, EVs can play a critical role in helping electric utilities manage their loads while simultaneously reducing ratepayer costs.

EV deployment will occupy many spheres of Virginia's policy landscape in the coming years, but as far as the Commission is concerned, the central question regarding any utility-proposed EV project will be: looking at the system as a whole, over the long run, does the EV-related activity provide ratepayers a net benefit or a net cost?

[1] Order Establishing Proceeding Regarding Electric Vehicles, Va. State Corp. Comm'n, Docket No. PUR-2020-00051, at 1 (Mar. 24, 2020), https://scc.virginia.gov/docketsearch/DOCS/4m0q01!.PDF.

The necessary following issue, then, is to define the universe of costs and benefits the Commission will consider in that analysis. Although EVs offer intriguing grid-connected benefits (*e.g.*, vehicle-to-grid applications), can reduce grid system costs, and save owners money over the long-term, the primary driver – and therefore the primary benefit – behind increased EV deployment is to slash climate pollution and reduce other tailpipe pollutants as well. In recent years, the transportation sector has become the single largest carbon-emitting sector of the nation's economy.[2] In Virginia, the transportation sector's share of total carbon emissions is 48.2% and this share is likely to grow as Virginia continues to decarbonize its power sector.[3] While increased EV deployment is a critical component of the effort to reduce these emissions, it is only one part of the necessary policy work Virginia must do to address the intersection of climate and transportation issues. Electrifying the vehicle fleet will not be sufficient to eliminate transportation emissions in the foreseeable future. In fact, our analysis demonstrates that under even an aggressive EV growth scenario, by 2040, EVs reduce non-aviation transportation emissions by about 25%. Although this would bring substantial benefits, much more will be necessary in Virginia's transportation policy arena and elsewhere to address the remaining 75% of transportation emissions, including steps to reduce the amount of driving — and particularly, single-occupancy driving — through transportation demand management and accelerating use of cleaner alternatives to driving.

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[2] *Carbon Pollution from Transportation*, ENVTL. PROT. AGENCY, https://www.epa.gov/transportation-air-pollution-and-climate-change/carbon-pollution-transportation (last visited June 17, 2020) ("Greenhouse gas (GHG) emissions from transportation account for about 29 percent of total U.S. greenhouse gas emissions, making it the largest contributor of U.S. GHG emissions. Between 1990 and 2017, GHG emissions in the transportation sector increased more in absolute terms than any other sector.").

[3] Energy-Related CO2 Emission Data Tables, U.S. ENERGY INFO. ADMIN., https://www.eia.gov/environment/emissions/state/ (select "XLS" next to "Table 4: 2017 State energy-related carbon dioxide emissions by sector") (last visited June 17, 2020).

Given the various steps needed and industries involved (few of which are regulated utilities), many of those policy debates will happen outside of the Commission's purview. That being said, critical issues will come before the Commission, and it is imperative that we quickly and effectively respond to climate change in a thoughtful way that minimizes cost wherever possible, and the Commission should develop a comprehensive protocol for reviewing utility applications regarding EV infrastructure and rate designs.

Against that backdrop, Environmental Advocates offer the following responses to the Commission's specific questions, supported by additional analysis provided by Greenlink Analytics and EQ Research Marketplace.[4]

I. Background Information on Electric Vehicles

Definition

The term "electric vehicle" or "EV" is generally used as shorthand for a "plug in electric vehicle" (PEV), referring to vehicles that are capable of charging from an external power source. A PEV may be an "all-electric vehicle" (AEV) or a "plug-in hybrid electric vehicle" (PHEV). In contrast to an AEV, a PHEV is also equipped with a supplemental source of power, typically an internal combustion engine (ICE). The term EV is used primarily to refer to on-road vehicles though it sometimes is also used in a way that encompasses off-road applications, such as forklifts and tractors. We use the term EV throughout these comments to refer to only on-road PEVs.

Like vehicles more generally, EVs and EV charging infrastructure are also frequently differentiated into classes that are based on vehicle weight. The classifications used by the Federal Highway Administration and the U.S. Census Bureau are shown in Figure 1 below.

[4] GREENLINK ANALYTICS, ALL CHARGED UP: IMPACTS OF VEHICLE ELECTRIFICATION IN VIRGINIA (June 2020) (included as Attachment A) (hereinafter GREENLINK ANALYTICS, ALL CHARGED UP).

Vehicle Weight Classes & Categories[5]

Gross Vehicle Weight Rating (lbs)	Federal Highway Administration		US Census Bureau
	Vehicle Class	GVWR Catagory	VIUS Classes
<6,000	Class 1: <6,000 lbs	Light Duty <10,000 lbs	Light Duty <10,000 lbs
10,000	Class 2: 6,001–10,000lbs		
14,000	Class 3: 10,001–14,000 lbs	Medium Duty 10,001–26,000 lbs	Medium Duty 10,001–19,500 lbs
16,000	Class 4: 14,001–16,000 lbs		
19,500	Class 5: 16,001–19,500 lbs		
26,000	Class 6: 19,501–26,000 lbs		Light Heavy Duty: 19,001–26,000 lbs
33,000	Class 7: 26,001–33,000 lbs	Heavy Duty >26,001 lbs	Heavy Duty >26,001 lbs
>33,000	Class 8: >33,001 lbs		

Generally speaking, vehicles used for personal transport fall within the light-duty category while the medium- and heavy-duty categories encompass a variety of commercial vehicles. Electrification of the medium- and heavy-duty vehicle segments is generally considered to be more challenging than for light-duty vehicles because heavier vehicles require greater battery capacity for an equivalent range, and that greater battery capacity directly translates to a need for higher-powered charging capacity in order to provide a charge sufficient to meet range needs in a reasonable amount of time.

Charging Applications

EV charging applications can be differentiated in several ways. The most basic differentiation is charger location, whether at a home (*i.e.*, residential) or in another setting (*i.e.*, non-residential). The distinction between residential and non-residential charging is relevant to the electric rate that is applied to charging use, either a residential rate or a non-residential rate.

The non-residential segment can be further broken down into public charging and restricted charging, where public charging refers to charging stations that are available to any

[5] *Vehicle Weight Classes & Categories*, U.S. DEP'T OF ENERGY, ALT. FUELS DATA CTR. (June 2012), https://afdc.energy.gov/data/10380.

user (similar to a gas station), while restricted charging refers to stations available only to a segment of EV users (*e.g.*, a commercial office building, patrons at business, residents at a multi-family building). Restricted charging also encompasses facilities that are fully dedicated to serving a private fleet of vehicles, such as delivery trucks or busses.

Finally, charging stations can be differentiated based on the metering configuration under which they pay for electric use, as standalone units or units installed in connection with existing non-EV energy uses (*i.e.*, building loads). The Table below depicts a generalized breakdown of EV charging use cases.

Table 1: EV Charging Use Cases & Characteristics

Host Site Rate	Accessibility	Vehicle Type	Configuration	Examples
Residential	Private	Personal light-duty	Existing load site	Vehicle used for daily commute
Non-Residential	Public	All types potentially, but generally personal light-duty	Standalone or existing load site	Public parking lots, retail stores, on-street (multi-unit buildings)
	Restricted	All types potentially, but generally personal light-duty	Standalone or existing load site	Motels, commercial office buildings, multi-unit buildings
	Private Fleet	Commercial, from light-duty to heavy-duty	Standalone or existing load site	Goods distribution center, public transport garage.

Charger Types

Table 2 below depicts the basic characteristics of the commonly recognized categories of EV charging stations. The table uses ranges to reflect these characteristics because product characteristics differ among EV supply equipment vendors. Level 1 charging, also known as trickle charging, uses any standard electric outlet, and only provides a meaningful amount of range over long durations, such as an overnight period or longer. Residential chargers are often either Level 1 or Level 2 chargers, although Level 2 chargers, which use a 240V outlet (*i.e.*, a dryer outlet), charge an EV at a significantly faster rate. Non-residential charging applications generally fall within the faster-charging Level 2 or Level 3 categories.

Table 2 – Types of EV Chargers[6]

Type	Voltage (V)	Capacity (kW)	Minutes to Supply 80 Miles of Range
Level 1	120 V	1.4 - 1.9	630 - 860
Level 2	240 V	3.4 - 20	60 - 350
Level 3 (DCFC)	480 V	50 - 400	3 - 24

II. Commission Questions Regarding Existing Development and Projected Growth

1. How many electric vehicles are currently deployed in Virginia and what is the expected growth over the next five, ten and twenty years? What is the current level of demand being put on the electric grid by electric vehicle charging and how is that expected to grow over those time periods?

According to Greenlink Analytics and the various forecasts Greenlink reviewed, EV deployment in Virginia, now and in the future, is as follows:

Table 3 – EVs Deployed in Virginia[7]

Year	Number of EVs
2019	14,000
2025	74,000 – 120,000
2030	176,000 – 524,000
2035	353,000 – 1,070,000
2040	600,000 – 1,680,000

For additional details on EV sales growth rates, both in isolation and as a portion of total new vehicle sales, please see Attachment A.[8] Currently, EV-related electricity demand is small in proportion to Virginia's total load, but that will grow over time as EV sales grow.[9]

Table 4 – EV Demand and Share of Total Load

Year	Demand (million MWh)	Portion of Total Load (%)
2020	196,000 – 285,000	0.2%
2025	707,000 – 1,220,000	0.6% – 1%
2030	1,740,000 – 5,180,000	1.4% – 3.8%
2035	3,600,000 – 10,900,000	2.9% – 7.6%
2040	6,290,000 – 17,700,000	5.1% – 11.6%

[6] GARRETT FITZGERALD & CHRIS NELDER, Rocky Mountain Inst., FROM GAS TO GRID: BUILDING CHARGING INFRASTRUCTURE TO POWER ELECTRIC VEHICLE DEMAND. 33 tbl.2 (2017), https://rmi.org/wp-content/uploads/2017/10/RMI-From-Gas-To-Grid.pdf.

[7] GREENLINK ANALYTICS, ALL CHARGED UP, *supra* note 4, at 8.

[8] *Id.* at 5-6.

[9] *Id.* at 9-10.

2. ***What is the current level of public charging infrastructure in Virginia and how is that expected to grow?***

Environmental Advocates interpret "public charging infrastructure" to mean that the charging is not restricted to specific private users through physical or legal means (charging in homes or reserved specifically for one company's commercial fleet would not qualify as publicly accessible). In that light, Greenlink Analytics estimates that Virginia currently has 626 publicly-accessible EV charging stations.[10] Growth of publicly-available charging infrastructure obviously depends in part upon whether and how the General Assembly, the Governor's administration, regional and local authorities, and this Commission create policies to encourage deployment. Since those policies are not currently in place and have yet to be developed, it is difficult to estimate the growth rates. That being said, Greenlink Analytics compiled several studies of the estimated deployment rates:

Table 5 - Publicly-Available EV Charging Stations in Virginia[11]

Year	Number of Charging Stations
2019	626
2025	1,300 – 3,200
2030	2,900 – 8,200
2035	6,300 – 16,000
2040	9,400 – 23,700

3. ***Whether and how rate designs should be structured to incentivize the use of electric vehicles?***

<u>*Rate designs should be structured to incentivize the use of electric vehicles*</u>.

Environmental Advocates support transportation electrification, and encourage Virginia to implement policies to harness the growth in EV adoption to take advantage of the EV charging load's unique characteristics and flexibility. However, rate structures should do more than simply

[10] *Id.* at 7-8.

[11] *Id.* at 8.

incentivize the use of EVs. Rate structures should incentivize the use of EVs in a manner that produces benefits for *all* ratepayers and distributes those benefits to EV operators and non-EV ratepayers alike in an equitable manner (*i.e.*, beneficial electrification). It is also necessary to ensure that the growth of EVs does not become a burden to non-EV ratepayers, who are (at least in the near term) likely to be less affluent on average than EV operators.

Rate designs should incentivize off-peak charging.

With respect to the specific design of rate structures, we believe the characteristics of beneficial electrification as defined by the Regulatory Assistance Project (RAP) provide an excellent starting point. RAP describes three conditions of beneficial electrification generally, which can be applied to transportation electrification as well as other forms of electrification, such as buildings.[12] Electrification is beneficial if it meets at least one of the following criteria and does not adversely affect the other two:

- Saves consumers money over the long run.
- Enables better grid management.
- Reduces negative environmental impacts.[13]

Well-designed time-varying EV charging rates are capable of advancing all three of these outcomes. First, well-designed EV rates produce cost savings for EV owners relative to what they might otherwise pay under a standard rate, which could be seen as a generally fairer outcome if a large portion of EV charging is expected to occur during off-peak hours when energy is cheaper.

[12] DAVID FARNSWORTH AT AL., REGULATORY ASSISTANCE PROJECT, BENEFICIAL ELECTRIFICATION OF TRANSPORTATION 9 (January 2019), https://www.raponline.org/wp-content/uploads/2019/01/rap-farnsworth-shipley-sliger-lazar-beneficial-electrification-transportation-2019-january-final.pdf.

[13] *Id.*

Second, encouraging off-peak charging saves non-EV ratepayers money and enables better grid management by mitigating the very real potential that growing, unmanaged EV load could exacerbate peak demands and create additional system costs. In fact, additional load concentrated in off-peak times improves system utilization rates (*i.e.*, load factor), allowing embedded costs to be spread across a greater volume of sales and producing cost-savings benefits for non-EV ratepayers. In other words, a well-designed EV charging rate can reduce general system costs.

Third, in areas with high penetration of solar, EV rates can potentially enable better grid management by helping to mitigate "duck curve" issues arising from a combination of low loads and high solar generation during some parts of the year. For instance, in order to address "duck curve" issues in California, where utility-scale solar generation accounts for almost 40% of net grid power produced during certain midday hours,[14] utilities have adopted time-varying rates featuring an off-peak or super off-peak period during the midday period.[15] Likewise, Arizona Public Service (APS) has begun piloting a managed EV charging program for fleets, workplaces, and multi-family buildings that provides for the development of charging plans that reduce charging power during peak periods (3 – 8 PM) and provides incentives via reduced fees for charging during off-peak hours (10 AM – 3 PM), which increasingly show negative wholesale

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[14] Chris Namovicz, *Rising Solar Generation in California Coincides with Negative Wholesale Electricity Prices*, U.S. ENERGY INFO. ADMIN. (Apr. 7, 2017), https://www.eia.gov/todayinenergy/detail.php?id=30692; *see also Today's Outlook: Supply*, CAL. INDEP. SYS. OPERATOR, http://www.caiso.com/about/Pages/default.aspx (next to "Supply Trend," select "06/17/2020," and then next to "Renewables Trend," select "06/17/2020") (last visited June 18, 2020).

[15] *See* Pac. Gas & Elec. Co., Electric Schedule BEV, Cal. Pub. Utils. Comm'n, Docket No. 5661-E-B, Sheet No. 46493-E, at 2 (Apr. 28, 2020), https://www.pge.com/tariffs/assets/pdf/tariffbook/ELEC_SCHEDS_BEV.pdf (outlining rates for separately metered commercial EV charging); Pac. Gas & Elec. Co., Electric Schedule EV2, Cal. Pub. Utils. Comm'n, Docket No. 5661-E-B, Sheet No. 4566-E, at 2 (Apr. 28, 2020), https://www.pge.com/tariffs/assets/pdf/tariffbook/ELEC_SCHEDS_EV2%20(Sch).pdf (outlining rates for residential EV owners).

energy pricing during some months of the year.[16] These EV rates are intended to concentrate load at times of low marginal greenhouse gas emissions and avoid renewables curtailment. In other words, at low solar and EV penetration levels, time-varying rates will likely encourage EV charging at night and during other off-peak hours to reduce total system costs. On the other hand, with high penetration of solar and EVs, it may be best to incorporate features into time-varying rates that encourage EV charging during the mid- to late afternoon when solar is producing at its maximum and driving energy prices down. Virginia is not anywhere near that scenario yet, but it may become real for Virginia in the future. Finally, transportation electrification generally is a critical component of decarbonizing Virginia's economy and reducing negative environmental impacts. Cost-effective charging is a critical element to transportation electrification because it will help to offset the up-front costs of EVs and related charging infrastructure. The design elements of EV rates that effectively encourage off-peak charging are discussed in more detail in the response to question 4, below.

4. ***Whether and how rate designs should be structured to incentivize charging of electric vehicles during off-peak times?***

As discussed in response to question 3, we recommend that the Commission focus its attention on rates structures that incentivize off-peak charging. Below we discuss several important design characteristics for achieving this outcome. Implicit within this discussion is the assumption that all rate structures will feature time variation.[17] We generally focus on "time of use" (TOU) rates because they provide predictability for customers. However, other varieties of

[16] Ariz. Pub. Serv. Co., Application for Approval of Amended 2018 DSM Implementation Plan, Ariz. Corp. Comm'n, Docket No. E-01345A-17-0134, Exhibit A, at 6 (Nov. 14, 2017), https://images.edocket.azcc.gov/docketpdf/0000183906.pdf.

[17] We refer to time variation in a manner that encompasses all possible rate structures that incentivize charging during certain time periods, which could include rates that offer a lower effective rate via a credit model.

time-varying rates, such as critical peak pricing, variable peak pricing, and real-time pricing could also play a role in EV rate formulation. We define these general terms as follows.

- *TOU Rate*: A rate that relies on preset pricing windows and rates that are known in advance to customers.

- *Critical Peak Pricing*: A rate that typically features a high on-peak rate that is known in advance, but for which the timing is not pre-established. Certain days and hours are designated as critical peak periods based on expected system conditions.

- *Variable Peak Pricing*: A rate that features preset on-peak pricing periods, but allows the price charged during those periods to fluctuate according to system costs.

- *Real-Time Pricing*: A rate for which prices fluctuate in line with energy costs, such as on any hourly basis.

Regardless of the specific structure or features of any individual rate design, we emphasize that the overall objective should be minimizing net costs to ratepayers.

<u>Rates Should Permit Separately Measured EV Charging</u>

EV charging loads are generally more controllable and flexible than whole building loads. Part of the reason for this is that since EV charging is a single end use, it is inherently easier to manage than the collection of numerous end uses that make up a whole building load. In addition, many EV supply equipment products have programmability and control features that allow charging to be managed without any ongoing attention from the consumer.

Rates that allow for separate measurement of EV charging load take advantage of this relatively greater flexibility, enabling more precise rate designs than may be appropriate for whole building use. Furthermore, they avoid forcing consumers to enroll in a whole building time-varying rate if they wish to benefit from managed charging. Offering a time-varying rate that does not distinguish between the whole building and the EV charging load is likely to discourage some customers from enrolling due to the greater complexity inherent in effectively managing whole building use.

To be clear, separately metering EV load should be an option, not a requirement, for EV operators. Some EV customers seeking to undertake managed charging may prefer to take service under a whole building TOU rate and should be allowed to do so. A rate that allows separate measurement of EV load simply expands the potential managed charging customer base by providing an option that may be a better fit for some customers despite any additional costs associated with the separate metering infrastructure. This is true in both residential and non-residential charging applications.

Non-Residential EV Rates Should Rarely, if Ever, Include Demand Charges

Many utilities include demand charges in non-residential rate designs for all but the smallest sized non-residential customers. As a result, non-home EV charging stations are often subject to demand charges. For example, an EV charging station installed behind an existing customer meter may be subject to a demand rate (*e.g.*, a commercial office building) or a standalone charging station by itself may have a maximum demand that causes it to fall within a demand rate class (*e.g.*, a public charging station).[18] Demand charges, particularly non-coincident demand charges, often make high capacity EV charging stations, such as DC fast chargers (DCFCs), too costly to operate. Demand charges have been repeatedly shown to be one of largest barriers (if not the single largest), to public EV charging, especially DCFC charging.[19]

[18] Incremental EV charging load could also cause a customer on a non-demand rate to become subject to a demand rate.

[19] *See, e.g.*, Farnsworth et al., *supra* note 12, at 13; Garrett Fitzgerald & Chris Nelder, Rocky Mountain Inst., DCFC Rate Design Study for the Colorado Energy Office 5 (Feb. 2020) [hereinafter DCFC Rate Design Study], https://rmi.org/wp-content/uploads/2019/09/DCFC_Rate_Design_Study.pdf; Garrett Fitzgerald & Chris Nelder, Rocky Mountain Inst., EVgo Fleet and Tariff Analysis, Phase 1: California 1 (2017) [hereinafter EVgo Fleet and Tariff Analysis], https://rmi.org/wp-content/uploads/2017/04/eLab_EVgo_Fleet_and_Tariff_Analysis_2017.pdf; Dane McFarlane et al., Great Plains Inst., Analytical White Paper: Overcoming Barriers to Expanding Fast Charging Infrastructure in the Midcontinent Region 2 (July 2019), https://scripts.betterenergy.org/reports/GPI_DCFC_Analysis_July_2019.pdf.

The cost issues presented by demand rate designs tend to be particularly pronounced for public EV charging stations because public charging stations typically have relatively low utilization rates due to the modest adoption of EVs to date. Because EV charging stations often have a fixed demand based on the type of charger installed, a single instance of on-peak charging during a billing period sets the demand charge a station owner pays. When utilization rates are low, that effective fixed charge is spread across only a small number of charging sessions, resulting in extraordinarily high rates for charging. For example, a study by the Rocky Mountain Institute found that demand charges can be responsible for more than 90% of a DCFC ratepayer's electric bill under existing typical utilization rates.[20] In practice, the punitive effects of demand rates are not limited to public charging stations. The basic math remains the same for all non-residential EV charging applications that are subjected to demand rates.

It is difficult to mitigate the punitive impacts of demand charges for DCFC chargers as well as other non-residential customers because while EV charging load is more flexible than whole building load, it is not infinitely flexible and typically cannot completely avoid on-peak periods. This is particularly true when an on-peak period lasts for a large portion of day time hours and fails to differentiate true peak periods from periods of time with more moderate demand.

The practical failing of demand charges is that they provide an unbalanced and inconsistent price signal. One instance of on-peak charging under a rate design with a high on-peak demand rate can largely eliminate a customer's incentive to engage in off-peak charging during the remainder of a billing period. Volumetric time-varying rates solve this problem by ensuring that each instance of charging is subject to the same price signal.

[20] Garrett Fitzgerald and Chris Nelder. "EVgo Fleet and Tariff Analysis." Rocky Mountain Institute, 2017.

However, exceptions exist and in cases where the utilization rate of a charging station is sufficiently high, a customer may prefer demand-based rates to volumetric rates. This may be the case with applications such as fleet charging, where charging needs are reasonably predictable and it is logistically possible to consistently cycle vehicles in and out. It could also be the case for other charging applications, including public charging, as EVs become more prevalent. Customers should retain access to the rates that best fit their circumstances.

Rates Should Have a Basis in Marginal Costs

Charging rates that reflect the cost of providing service (*i.e.*, cost causation) is one of the most important principles of good rate design. Marginal costs, or the time windows associated with higher or lower marginal costs, form the basic foundation of time-varying rate design.[21] EV load is unique in that it is dominantly new load, the incremental cost of which is defined by the marginal costs incurred to service it.[22] Rates based on marginal costs during different time periods ensure that EV operators and charging station owners pay for service in a way that is consistent with the costs they cause. Rates set at or above[23] marginal costs ensure that other ratepayers are, at a minimum, held harmless with respect to the incremental costs of EV load. Setting rates for EV charging at the level of marginal costs is also equitable to EV operators because off-peak marginal costs by their nature are lower than the average costs that the customer would otherwise pay under flat rates, providing them with savings if they are able to consistently charge an EV during off-peak periods.

[21] Due to the nature of embedded cost ratemaking and the need to reflect embedded costs in rates, the actual rates charged under a time-varying rate typically do not exactly match marginal costs. However, they still have a basis in marginal costs insofar as they reflect higher and lower marginal cost time periods and the relative cost differentials between those time periods.

[22] This entire concept is problematic to implement in Dominion's territory where current base rates have no connection to Dominion's actual costs of service since those base rates have not been adjusted since 1992, meaning current actual rates may already be *higher* than the marginal cost of the actual system.

[23] Setting rates exactly at marginal cost might hold non EV customers harmless, but it does not necessarily drive EV benefits to those non EV customers, which is why it may be appropriate to set rates above marginal cost.

The changing nature of the electric system, including changes attributable to the growth in EV load, has the potential to affect marginal costs. For instance, increasing zero-marginal cost resources such as solar and wind may shift the timing of low and high marginal energy cost hours. Likewise, evolving consumer load patterns due to transportation and building electrification may shift the timing of peak system demands. Pricing must adapt to reflect evolving system conditions in order to send the proper price signals to consumers.

Time Variation Should Use Relatively Granular Pricing Periods

Because EV load is inherently more controllable and flexible than whole building loads, EV-specific rate designs should take advantage of this flexibility and use more granular pricing periods that more closely tether time varying system costs to rates for service. This can be achieved in a variety of ways, but a typical approach is to confine recovery of costs that are based on coincident peak demand, such as generation capacity, to only those hours when those coincident peaks are likely to occur.

For instance, on a system that experiences peak demands on hot summer afternoons, the utility could exclusively recover the costs of peaking generation capacity during those peak hours (*e.g.*, 2 – 6 PM from June – September). The same utility could recover distribution costs, however, through time-varying rates over a different set of time periods (*e.g.*, year-round from 7 AM – 7 PM). The resulting rate design could have an off-peak period when no system peaks occur, a mid-peak period with higher rates to recover distribution costs, and a narrow critical-peak period with the highest rates to recover generation capacity costs. Generally, the on-peak period with the highest rates should be of a limited duration and as narrow as possible to allow customers to easily shift load to off-peak periods; it should not exceed five hours.

Rates Should Provide the Opportunity for Meaningful Cost Savings

EVs carry a higher sticker price on average than internal combustion vehicles. However, in many cases, home charging under a typical residential retail rate is generally cheaper on a cost-per-mile of range basis than gasoline.[24] Although generalized fuel cost savings for home charging may offset the incremental up-front costs of an EV relative to an internal combustion engine, the same is not necessarily true for charging under non-residential rate structures due to the extraordinary costs that demand rates create for charging station owners, which are passed through to customers. In addition, Level 2 and 3 charging units are expensive. Buying and installing a moderate capacity Level 2 charging station, the type that a typical homeowner would install, is likely to cost at least $1,000.[25] Depending on the characteristics of the installation, the cost could be much higher. Furthermore, the added controllability and greater speed of Level 2 chargers may be necessary to consistently charge during off-peak times. EV rates should provide an opportunity for meaningful savings to EV operators in order to both stimulate the desired response, and to help offset the incremental costs associated with an EV and charging equipment.

In developing the rate, the utility should consider the spread between the on-peak and off-peak rates to provide a strong price signal and opportunity for meaningful savings. The on-peak to off-peak energy price ratio should be at least 2:1, and ideally 3:1 or higher.

In addition, the utility should also consider any incremental costs that may be associated with participation in the rate. For instance, while it is generally reasonable for participants enrolled in an EV rate for home charging to pay for any additional metering costs, rates should ensure those costs do not become a barrier to enrollment. We urge the Commission to explore

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[24] *See* FARNSWORTH ET AL., *supra* note 12, at 30.

[25] *See* MICHAEL SULLIVAN ET AL., NEXANT. CALIFORNIA STATEWIDE PEV SUBMETERING PILOT – PHASE 2 REPORT 82-83 (Apr. 26, 2019), https://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442461657.

options for doing so, such as sub-metering EV load located behind an existing meter, rather than requiring fully separate revenue grade metering. It should also investigate the potential for networked charging using the metering and communication capabilities internal to the charger itself (or the EV), which may avoid the need for traditional metering or sub-metering.

5. ***Can and should rate regulation prevent cost shifting to consumers who do not own or operate electric vehicles?***

<u>*Over the long-term and in the aggregate, rates should not shift costs to non-participants*</u>

Rate regulation both can and should prevent cost shifting to consumers that do not own or operate electric vehicles. That being said, the Commission should take a global, long-term view on the issue, meaning the Commission should prevent cost-shifting to non-EV consumers from EV load as a whole, as opposed to attempting to ensure that each EV charging site (*e.g.*, home or public) or charger type is cost-neutral for non-users. A global view respects the fact that a viable EV market requires charging services to be available to EV users at multiple public and private sites, and those individual sites are all part of a broader ecosystem.

In addition, the costs of transportation electrification should be considered over the long-term because the potential benefits to the ratepayer body are dominantly long-term in nature and dependent on the amount of beneficial charging that occurs. Furthermore, many future EV uses, such as vehicle-to-grid discharge, have the potential to create additional ratepayer benefits. In particular, a longer-term outlook is necessary when considering the development of public charging infrastructure because higher capacity charging may require infrastructure upgrades in front of the meter. It is not unusual for public charging stations to initially experience low utilization rates, which may appear to create a cost-shift in the short-term to the extent that the necessary investments are socialized. At the same time, availability of public and/or high capacity charging is a critical component to EV market growth, as well as creating equitable opportunities for EV ownership among segments that may not otherwise have access to home charging (*e.g.*, occupants of rental residences).

III. Commission Questions Regarding Storage-Specific Issues

6. ***How can electric vehicles provide battery storage for the electric grid and on what scale? What level of battery storage for use by the electric grid is projected to be available from EVs over the next five, ten and twenty years?***

Using EVs as battery storage requires bidirectional vehicle-to-grid (V2G) technology. Although there have been successful vehicle-to-grid pilot programs in California[26], New York[27], and even in Virginia[28], it is difficult to project the level of EV battery storage available for use by the electric grid over the next two decades as it is very dependent on developing policies and technology.

Similar to stationary storage, EVs can also provide battery storage to the electric grid. The primary difference between EV storage and stationary storage is that EVs will have greater use limitations than stationary storage because they have a primary use apart from providing electricity-related services. Due to availability limitations, it may be more difficult for individual EVs to provide services that require longer duration cycling. For example, providing resource adequacy capacity on a cold winter morning may be challenging for an individual EV where the window of need (*e.g.*, 6 – 9 AM) overlaps with the timing of a personal commute and the need to maintain an adequate charge to support that commute. However, a fleet of EVs may be able to provide energy storage related services because of their centralized management, predictable

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[26] Robert Walton, *California Oks $100M SDG&E Commercial EV Charging Plan, Testing Electric Buses as Grid Assets*, UTIL. DIVE (Aug. 16, 2019), https://www.utilitydive.com/news/california-oks-100m-sdge-commercial-ev-charging-plan-testing-electric-bu/561071/.

[27] Keshia Clukey, *New York Electric School Buses to Feed Power Grid*, BLOOMBERG L. (Sept. 25, 2019, 12:34 PM), https://news.bloomberglaw.com/environment-and-energy/new-york-electric-school-buses-to-feed-power-grid.

[28] Charles Morris, *V2G Value Propositions: Fermata Energy is Focused on Building Financially Viable Solutions for Vehicle-to-Grid*, Charged (Oct. 6, 2019), https://chargedevs.com/features/v2g-value-propositions-fermata-energy-is-focused-on-building-financially-viable-solutions-for-vehicle-to-grid/ (describing a demonstration program in Danville, Virginia that uses EVs for peak shaving and other behind-the-meter demand charge management).

usage patterns and driving routes. To the extent that EVs are available, they may provide the same services that stationary storage can provide, including frequency regulation, resource adequacy capacity, distribution capacity, voltage control, and other ancillary services.

More workplace and public charging is likely to enhance the amount of storage capacity available for grid services from personal vehicles in at least two ways. First and most directly, an EV must be "plugged in" to provide a grid service. Many workplace charging stations will have EVs "plugged in" for large portions, if not all, of the work day, therefore making them potentially available for storage capacity. Second, with increased non-home charging options, EV owners will be less concerned about range issues and more likely to allow an EV to be used for energy storage when needed.

The availability of EVs to provide energy storage related services is also correlated to the number and type of EVs in operation (*i.e.*, heavy duty vehicles with larger batteries provide comparatively greater capacity). We refer the Commission to our responses to Questions 1 and 2 for projections of EV adoption.

7. ***What, if any, technological impediments exist to the use of electric vehicles as battery storage for the electric grid at scale? For example, are any technological grid modifications necessary to facilitate the use of EVs as battery storage for the grid? How does cycling (charging and discharging) of an electric vehicle's battery (associated with discharging the battery into the grid) affect the life of the battery? Do manufacturers of electric vehicles have concerns regarding the use of EV batteries for grid storage?***

We are not aware of any major technological impediments to the use of EVs as battery storage that are unique to EVs. That said, there is a more general need for advanced distribution management systems and communication protocols to coordinate and operationalize the use of distributed energy storage (*e.g.*, a distributed energy resource management system, or DERMS). With respect to the effects of charge and discharge cycles and potential manufacturers concerns, we encourage the Commission to seek information on these topics directly from manufacturers.

The amount and depth of cycling is a prominent factor, though not the only factor, in the performance of lithium ion batteries over time, but in our understanding defining the "cost" of cycling is complex and difficult to model because it is non-linear. In addition, batteries used by different manufacturers may have different operational parameters.

We suggest that identifying and characterizing potential technical barriers would be best accomplished through a working group or stakeholder group due to the potential complexity of the technical questions involved.

8. ***What technical studies, if any, should be undertaken to ensure the safe interconnection of electric vehicles to utility distribution systems for purposes of providing grid storage? What potential impacts of such interconnection should be studied?***

The interconnection of EVs is not fundamentally different from the interconnection of stationary battery storage or distributed generation. There are two categories of V2G systems: (1) those that utilize a bi-directional inverter within the EV supply equipment (*i.e.*, charging station) and (2) those that utilize a bi-directional onboard inverter within the EV. The former category is the functional equivalent of a stationary inverter used for non-EV battery storage. The latter category does not implicate any fundamentally different issues with respect to safety and reliability. However, certain technical issues may remain unresolved with respect to the certification of mobile inverters under UL 1741.[29] Specifically, UL 1741 SA (for smart inverters) contains test criteria that mobile inverters cannot meet. It may be necessary to study whether an alternative standard could function as an acceptable replacement for UL 1741 SA.

This issue is discussed in greater detail in Working Group #3 Report on revisions to California's interconnection standards, which among other things addresses measures to

[29] UL 1741 is a product safety standard governing inverters, charge controllers and other equipment associated with off-grid and grid-connected power systems. It is used in conjunction with IEEE 1547 as a required certification standard for distributed generation interconnection, including in 20 VA. ADMIN. CODE §§ 5-314-10 to -170 (2020) (governing interconnection of small electric generators).

facilitate V2G systems.[30] We encourage the Commission to review Issue #23 in the Working Group #3 Report, which includes a series of proposals related to both stationary and mobile V2G applications as well as related background information (*e.g.*, V2G use cases).[31]

9. ***What, if any, legal impediments exist to the use of electric vehicles as battery storage for the electric grid at scale? For example, does discharging an electric vehicle's battery into the grid potentially void its warranty? Are there homeowner association or homeowner insurance limitations that restrict deployment?***

Although successful vehicle-to-grid pilot programs exist across the country,[32] including in Virginia[33], vehicle-to-grid applications of EVs are not yet prevalent. The warranty for an EV's battery is specific to each battery and would have to be examined on a case-by-case basis. As vehicle-to-grid applications become more prevalent, car manufacturers will need to address any issues related to EV battery warranties.

In Virginia, a recently passed law restricts homeowners associations from prohibiting EV charging stations as long as certain requirements are met.[34] One such requirement is that the EV owner must "obtain and maintain insurance covering claims and defenses of claims related to the installation, maintenance, operation, and use of the electric vehicle charging station."[35] While the law does not distinguish between charging and discharging, it arguably covers all uses and

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[30] Working Group Three, Final Report, Ca. Pub. Utils. Comm'n, Docket No. R. 17-07-007, at 6-7 (June 14, 2019), https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M309/K943/309943907.PDF.

[31] *Id.* at 61-98.

[32] *See e.g.*, *eMotorWerks Deploys a 30MW Virtual Energy Storage Battery for California Energy Markets with Smart-Grid Electric Vehicle Chargers and EVs under JuiceNet Platform*, ENEL X (Sept. 11, 2018), https://evcharging.enelx.com/news/releases/475-virtual-energy-storage-battery (describing a 30 MW highly distributed virtual energy storage battery consisting of EVs that is being used in California's wholesale energy markets as a flexible and reliable grid asset).

[33] *See* Morris, *supra* note 28.

[34] Act of Apr. 9, 2020, ch. 1012, 2020 Va. Acts SB 630, https://lis.virginia.gov/cgi-bin/legp604.exe?201+ful+CHAP1012.

[35] *Id.* (codified at VA. CODE ANN. § 55.1-1823.1(C) (2020)).

potential uses of the electric vehicle charging station. It remains to be seen if this insurance requirement could be a barrier to vehicle-to-grid applications in the future.

10. What rate designs should be employed to compensate EV owners for power delivered to the grid?

Effective retail rate designs to encourage managed charging may include compensating customers who discharge their EV batteries to the grid in the same way that such rate designs compensate controllable distributed generation resources such as solar-paired storage. However, there are cases where certain rate designs may be more appropriate for EV discharge. For instance, given the potential use limitations associated with the need to maintain sufficient charge for travel, critical peak pricing designs with short duration response windows may be more attractive to EV owners than a TOU rate. This would allow less frequent – but higher value – discharge that targets time periods of particular stress on the grid.

In addition, the Commission would need to modify at least some non-residential rates that use demand-based billing determinants because retail rates do not employ a framework for addressing "negative" demand. These modifications could involve the greater use of time-varying volumetric rates in place of demand rates, discussed in response to question 4. This would need to be coupled with compensation for exports similar to net metering. They could also involve the designation of rates or specific programs that apply a capacity-based rate for export-capable demand response.

11. What utility equipment damage liability considerations, if any, should be taken into account in the development of policy for EV storage?

General standards for interconnection sufficiently address potential damage to utility equipment from grid discharge capable EVs. We see no reason why EV storage is any different from stationary storage from the standpoint of safety, reliability, and potential damage to utility equipment.

12. What utility-sponsored programs (such as peak shaving programs) could be implemented to permit a utility to reliably call on electric vehicles to provide power to the grid?

The general model of dispatchable demand response programs that feature capacity commitment and pay for performance elements are suitable for "on-call" EV discharge. Programs of this type are common in regional and state wholesale markets though they are frequently limited to non-export arrangements. Non-export arrangements may be sufficient in cases where the discharge from one or more EVs serves to reduce on-site demand but is never large enough to produce exports to the grid. Standalone charging stations would require an arrangement that enables exports since a standalone charging unit has no other on-site demand to reduce. The Dynamic Load Management (DLM) programs operated by investor-owned utilities in New York provide a general illustration of this type of model as implemented at the state-jurisdictional level.[36]

13. What aspects of storage and discharge to the electric grid are subject to regulation at the state level? What aspects are subject to regulation at the federal level? Are there some areas subject to overlapping jurisdiction?

The general jurisdictional boundaries for energy storage regulation correspond to the compensation regime and market participation as a retail or wholesale arrangement.[37]

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[36] *See* LONG ISLAND POWER AUTH., TARIFF FOR ELECTRIC SERVICE § XIII (June 2020), https://www.lipower.org/wp-content/uploads/2020/06/LIPA-Tariff-June-2020.pdf (outlining the utility's Dynamic Load Management practices, which specifies the terms and structure of the utility's Commercial System Relief Program and Distribution Load Relief Program).

[37] *See, e.g.*, Order on Department Jurisdiction over Electric Vehicles, the Role of Distribution Companies in Electric Vehicle Charging and other Matters, Mass. Dep't of Pub. Utils., Docket No. 13-182, at 13 (Aug. 4, 2014), https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/9233599; Phase 1 Decision Establishing Policy to Expand the Utilities' Role in Development of Electric Vehicle Infrastructure, Cal. Pub. Utils. Comm'n, Docket No. R. 13-11-07, Decision No. 14-12-079, at 5, 8-9 (July 29, 2010), https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M143/K682/143682372.PDF; Policy and Interpretive Statement Concerning Commission Regulation of Electric Vehicle Charging Services, Wash. Utils. & Transp. Comm'n, Docket No. UE-160799, at 9 (June 14, 2017), https://www.utc.wa.gov/_layouts/15/CasesPublicWebsite/CaseItem.aspx?item=document&id=00050&year=2016&docketNumber=160799&resultSource=&page=1&query=160799&refiners=&isModal=false&omItem=false&doItem=false.

This jurisdictional arrangement is analogous to storage paired with net metered solar facilities. For instance, a customer that installs storage in conjunction with a solar system and participates in net metering is compensated via state-jurisdictional tariffs, including net metering (*e.g.*, for TOU rate arbitrage or demand charge management). By contrast, participation in the wholesale market takes place under federal jurisdiction via federally approved open access tariffs (*e.g.*, the PJM OATT). This should be no different for EVs discharging onto the grid.

However, the recent Petition for Declaratory Order filed by the New England Ratepayers Association at the Federal Energy Regulatory Commission (FERC) calls into question whether net metering will remain under state jurisdiction.[38] This petition, if granted, could have significant consequences not only for net metering, but it also could potentially affect the jurisdictional arrangement of V2G technology. Although a significant number of comments in opposition to this petition have been filed at FERC,[39] it remains to be seen whether FERC will dismiss this petition.

IV. Commission Questions Regarding Public Charging Stations

14. Is the market for providing public charging stations competitive or should it be considered a natural monopoly with service provided exclusively by regulated utilities? If the market is competitive, to what extent is utility ownership of charging stations appropriate and are there specific geographic areas where utility ownership of charging stations may be appropriate?

The market for providing public charging stations is competitive nationally and will become more competitive in Virginia as the EV market matures. The national experience with public charging indicates that a competitive market will flourish under the right conditions. At

[38] New England Ratepayers Association, Petition for Declaratory Order Concerning Unlawful Pricing of Certain Wholesale Sales, Fed. Energy Regulatory Comm'n, Docket No. EL20-42, at 1-3 (Apr. 14, 2020), https://elibrary.ferc.gov/idmws/file_list.asp?document_id=14851599.

[39] A total of 57,523 comments were filed in opposition to the NERA petition, 30 of which were comments from Public Utility Commissions (including the Virginia State Corporation Commission). *See Docket Sheet*, Fed. Energy Regulatory Comm'n, Docket No. EL20-42, https://elibrary.ferc.gov/idmws/docket_sheet.asp (last visited June 19, 2020). By contrast, 22 comments were filed in support of the NERA petition. *See id.*

present the market in Virginia is immature, which is largely attributable to (1) the relative immaturity of the EV market as a whole in Virginia and (2) the punitive effects of demand rate structures on high capacity charging installations. States with mature EV markets have well-distributed public charging supplied by numerous providers at diverse locations. In fact, a non-utility owned charging network is already starting to grow in Virginia due to the competitively-bid public-private partnerships under the Statewide Appendix D Volkswagen settlement program.[40] We urge the Commission to be cautious about reaching conclusions on market competitiveness, whether in an overall sense or for specific market segments, based on the state of the market at the present time in Virginia.

Public charging stations should not be considered a natural monopoly with service provided exclusively by regulated utilities. Beyond the issue of whether the public charging market is, or will be competitive, Public charging stations simply do not fit the characteristics of a natural monopoly service. A natural monopoly most appropriately occurs where a single provider can offer a service at a lower cost than would be obtainable in a competitive market. This is typical in industries that have very high fixed costs, the classic example being utility distribution service, where it would be economically wasteful for multiple providers to build duplicative infrastructure to compete for the same customers.

The market for public EV charging stations is far more analogous to the market for traditional internal combustion engine refueling than it is to electric distribution service. In both cases, the station owner procures a commodity fuel from a wholesale distributor and re-distributes it to customers that choose to patronize the station. Should a station owner select a poor location, fail to maintain the establishment, or otherwise fail to provide good service, the

[40] *See e.g.*, EVgo, *Virginia Department of Environmental Quality and EVgo Announce Opening of First DC Fast Chargers in Statewide Charging Network* (Oct. 3, 2019), https://www.evgo.com/about/news/virginia-department-of-environmental-quality-and-evgo-announce-opening-of-first-dc-fast-chargers-in-statewide-charging-network/.

station may fail. The risk of unprofitability and potential failure is properly on the station owner rather than the public as a whole. There seems to be little reason to believe that a competitive EV charging market would result in unnecessary economic waste or costs. By contrast, the costs of an unprofitable public charging station owned by a regulated utility would be borne by all ratepayers. We see no compelling reason for placing this additional risk on ratepayers as a general matter.

Moreover, the question of whether monopoly service would be preferable hinges on a utility's ability to provide equivalent service at a lower overall cost. A suite of competitive providers with years of experience in providing EV charging service already exists. By contrast, a utility entering into this market would be stepping outside of its historic role of generating and distributing electricity. The only way a utility would have a cost advantage over a competitive provider is if the utility were not subjected to the same rate structures that tend to be punitive to competitive public charging stations owners. However, this advantage would be the product of a failure in rate structure rather than a failure of the competitive market. If a utility were forced to charge itself as it charges other customers, its costs would be identical.

Utility ownership of charging stations is only potentially appropriate in narrow circumstances where a demonstrated public need exists. We recommend that utility ownership of public charging stations be limited to narrow circumstances where a demonstrated public need exists and it is evident that the services will not be provided by the competitive market. It is plausible that such circumstances will exist. For instance, competitive charging station providers may focus their deployment efforts in areas with higher population densities and higher EV ownership rates, which in turn could lead to inequities in public charging availability in rural or lower income regions and local areas. That said, at this point it is difficult to know if or where such inequities may arise. Consequently, we believe it is premature to attempt to define any specific market segments, geographic areas, or other divisions between the competitive public charging market and potential utility monopoly service right now. Reliable evidence of any durable failures of the competitive market will only become clear when the market has had time to develop and mature under more advanced and accurate rate structures. We urge the Commission to remain open to utility-owned public charging infrastructure proposals and consider equity issues in its evaluation of any proposals, but at the same time seek to ensure that the need is well-documented and the public benefit appropriately weighed against the risk to ratepayers. Commissions around the country are adopting various tests to evaluate utility infrastructure proposals, and we urge the Commission to do the same.[41]

15. ***What is the proper role, if any, of utility investment in the deployment of public charging stations?***

The role of utility investment in public charging should be consistent with:

- The core competencies and capabilities of utilities;
- The boundaries of what constitutes a service with the characteristics of a natural monopoly and a public service; and
- Preserving fair competition in the interest of economic efficiency where competitive markets can exist.

After balancing these considerations, the role of utility investment in public charging should be limited to: (i) the construction of "make ready" infrastructure that provides a foundation for

[41] *See, e.g.*, Order on Department Jurisdiction over Electric Vehicles, the Role of Distribution Companies in Electric Vehicle Charging and other Matters, Mass. Dep't of Pub. Utils., Docket No. 13-182, at 13 (Aug. 4, 2014), https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/9233599; Phase 1 Decision Establishing Policy to Expand the Utilities' Role in Development of Electric Vehicle Infrastructure, Cal. Pub. Utils. Comm'n, Docket No. R. 13-11-07, Decision No. 14-12-079, at 5, 8-9 (July 29, 2010), https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M143/K682/143682372.PDF; Policy and Interpretive Statement Concerning Commission Regulation of Electric Vehicle Charging Services, Wash. Utils. & Transp. Comm'n, Docket No. UE-160799, at 9 (June 14, 2017), https://www.utc.wa.gov/_layouts/15/CasesPublicWebsite/CaseItem.aspx?item=document&id=00050&year=2016&docketNumber=160799&resultSource=&page=1&query=160799&refiners=&isModal=false&omItem=false&doItem=false.

public charging to flourish through non-utility ownership of public charging stations in a competitive market, and (ii) utility ownership of public charging stations to serve documented gaps in, or underserved segments of, an otherwise competitive market where alternative solutions cannot be identified.

EV charging infrastructure is beyond the utilities' historic core competencies and capabilities because, historically, utilities' infrastructure investments have been to make the large fixed investments necessary to generate and deliver electricity to consumers as a whole. As a result, utility experience and capabilities are highest in planning and constructing the fixed infrastructure necessary to get electricity to a customer meter. Secondly, the utility role has not historically extended behind the customer meter to marketing devices that consume electricity because well-functioning competitive retail markets adequately serve customer needs of this type (*e.g.*, appliances, space conditioning systems). This has remained true even where policy-makers and regulators intervene to support a public policy purpose, such as energy conservation. In this case, regulatory intervention influences consumer investment decisions through incentives that work in concert with, rather than upset, the competitive market. There is no reason to believe that the public EV charging market will fail to produce the services that customers expect, or otherwise imply a need for monopoly service in the interest of economic efficiency.

Moreover, EV charging infrastructure is not a public service that requires a monopoly. The term "public service" implies provision of a basic need, such as electricity or water to the general public. But monopolies do not satisfy all basic needs because economic efficiency disfavors monopolies unless a competitive market will not or cannot effectively satisfy that need. The simple fact that "public" charging stations serve the general public, and arguably provide a fairly basic need, is by itself insufficient to justify the designation of public charging as a whole as a monopoly utility service. For instance, food is a basic human need, but the competitive markets almost exclusively meet that need so there is no need to invoke a monopoly. In other words, monopoly service is a last and least-favored option even where a product serves a basic human need.

In fact, with respect to EVs, Virginia should preserve fair competition wherever competitive markets can exist. Utility interventions should be narrow and targeted in order to avoid undermining the broader competitive market. Environmental Advocates support a competitive market for charging infrastructure and urge the Commission to preserve fair competition in this market where possible. Nevertheless, there may be circumstances where direct utility ownership is in fact the most attractive solution.

The emerging nature of the EV marketplace makes it important for the Commission to give utilities clear guideposts for these investments, such as through the adoption of a standard of review for weighing proposed utility investments in EV charging services. There are multiple options for deploying charging infrastructure, and Commissions around the country are using a variety of approaches to evaluate utility proposals to deploy infrastructure:

- The state of Massachusetts requires utility proposals to meet a need regarding EV advancement that the competitive EV charging market is not likely to be meet; proposals also must not hinder competitive EV charging market development.[42]
- The California Commission evaluates utility filings on a case-specific basis, using a balancing test to weigh the benefits of utility ownership against competitive harm. This involves an inquiry into whether there are regulatory protections that could mitigate any

[42] Order on Department Jurisdiction over Electric Vehicles, the Role of Distribution Companies in Electric Vehicle Charging and Other Matters, Mass. Dep't of Pub. Utils., Docket No. 13-182, at 13 (Aug. 4, 2014), https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/9233599.

unfair advantages to the utility.[43] Proposals for utility ownership of EV charging infrastructure must include an analysis of how utility ownership impacts competition.[44]

- Oregon has adopted a statutory test for the Commission's review of utility proposals for programs and investments in EV charging infrastructure: the Commission must consider whether a given investment will be prudent; used and useful; reasonably expected to support the electric company's electrical system; reasonably expected to improve the electric company's system efficiency and operational flexibility, including integration of variable generating resources; and reasonably expected to stimulate innovation, competition and choice in the vehicle charging and services market.[45]

The Commission should be vigilant to ensure that a regulated utility's entry into this competitive market is limited and does not adversely impact competitive providers of EV charging services. After all, this would defeat the purpose of utility investments in this area, which is to help jumpstart a vibrant EV market that will spur additional customer adoption of EVs through the proliferation of a network of charging locations. There is a real risk that utilities could intentionally, or unintentionally, abuse their competitive advantage due to their name recognition, better understanding of systems, prior relationship with customers, ability to set rates and ability to rate-base investments to decrease costs for charging, thus undercutting competitors.

16. Under what utility tariffs do public charging stations take service from the electric utility and what adjustments to rate design or additional tariffs might be needed to support additional deployment of public charging stations?

Based on the categorizations of chargers in Table 2 and the rate options reflected in Table 6 below, standalone Level 2 chargers would typically take service under the small General Service rates offered by each of Virginia's three investor-owned utilities.

[43] Phase I Decision Establishing Policy to Expand the Utilities' Role in Development of Electric Vehicle Infrastructure, Cal. Pub. Utils. Comm'n, Docket No. R. 13-11-07, Decision No. 14-12-079, at 5, 8-9 (July 29, 2010), https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M143/K682/143682372.PDF.

[44] *Id.* at 11 (issuing "Conclusion of Law" number 3, which notes that the commission should take "a more detailed, tailored approach to assessing the 'impacts on competition' side of the balancing test" it employs).

[45] S.B. 1547, 2016 Leg. Assemb., 78th Sess. (Or. 2016).

Table 6 – Level 2 Charger Rate Options

Utility	Rate Option	Demand Range (kW)	Energy Charges	Demand Charges
Dominion	GS-1[46]	<30	2-tier seasonal inclining block (summer supply); declining block (distribution and winter supply); flat transmission	None generally, but excess non-coincident demand charges apply if demand exceeds 30 kW
APCo	SGS[47]	≤25	Flat generally, but optional 2-period TOU with moderate rate spread for approved energy storage devices	None
	GS-TOD[48]	<100	2-period TOU with moderate rate spread	None
ODP	GS[49]	≤50	Flat	None

All of the rates listed in Table 6 use fully volumetric rates. None of the rates listed in Table 6 are time differentiated except for Appalachian Power's GS-TOD rate. None of these rate options allow for sub-metering, though both SGS and GS-TOD from Appalachian Power expressly allow for separate metering. The difference between separate metering and sub-metering is that separate metering would require a customer to pay the full basic service charge for a rate schedule, whereas sub-metering would typically require the customer to pay only an incremental sub-metering charge that is confined to the costs of the sub-metering device. It is not clear whether an EV load would qualify for the energy storage load management option under Appalachian Power Schedule SGS.

[46] Va. Elec. & Power Co., *Schedule GS-1: Small General Service*, (May 20, 2019), https://www.dominionenergy.com/library/domcom/media/home-and-small-business/rates-and-regulation/business-rates/virginia/schedule-gs1.pdf?la=en&modified=20190702202633 (outlining rate schedule for demand of less than 30 kW per billing cycle).

[47] Appalachian Power Co., *Virginia S.C.C. Tariff No. 25*, Schedule S.G.S., at Sheet No. 10-1 to 10-3 (Mar. 20, 2019), https://www.appalachianpower.com/global/utilities/lib/docs/ratesandtariffs/Virginia/Tariff25June1-2020Net Metering-UnbundledStandard.pdf (prescribing rate schedule for small general service).

[48] *Id.* at Schedule G.S.-T.O.D., at Sheet No. 13-1 to 13-2 (prescribing general service time-of-day rate schedule).

[49] Old Dominion Power Co., *Rates, Terms and Conditions for Furnishing Electric Service*, Schedule GS: General Service, at Sheet No. 10-10.1 (Apr. 17, 2020), https://lge-ku.com/sites/default/files/odpelecrates.pdf.

Level 3 charging stations (also known as DCFCs), whether standalone or sited behind an existing customer meter, would typically need to take service under a medium or large general service rate schedule due to the size of the associated charging capacity (*i.e.*, 50 kW or greater). Table 7 lists the rates available to Level 3 charging stations considering that a standalone Level 3 charging station will have a demand of at least 50 kW. These rates would also apply to Level 2 charging stations installed by a customer with a load that exceeds the maximum demand for the smaller rate class, or where incremental charging load causes that maximum demand applicable to the smaller rate class to be exceeded.

Table 7 – Level 2/3 Charger Rate Options

Utility	Rate Option	Demand Range (kW)	Energy Charges	Demand Charges
Dominion	GS-2[50]	30 - 500	Non-Demand: Flat with seasonal supply charge	Demand rates apply at usage of more than 200 kWh/kW. None otherwise.
	GS-2[51]	30 - 500	Demand: Flat, minor distribution charge; declining block generation energy charge	Non-coincident demand charge for distribution and transmission; seasonal non-coincident demand charge for generation.
	GS-2T[52]	30 - 500	Two-period TOU for generation energy with small price differential; flat, minor distribution charge.	Flat non-coincident distribution demand charge; on-peak transmission demand charge; on-peak seasonal generation demand charge with non-coincident demand credit.
APCo	GS[53]	25 – 1,000	Flat, declining block energy charges for all components.	Moderate non-coincident demand charges for all components with ($/kWh) cap on effective energy rate. Optional on-peak with excess demand charge provision.
	GS-TOD[54]	<100	2-window TOU with moderate rate spread	None
	MGS[55]	25 – 1,000	Flat, moderate energy charges for all components	Moderate non-coincident demand charges for all components with ($/kWh) cap on effective energy rate. Optional on-peak with excess demand charge provision.
ODP	PS[56]	50 - 250	Flat, small energy charge	Large seasonal non-coincident demand charge.
	TODS[57]	250 – 5,000 (kVa)	Flat, small energy charge	Large base, intermediate, and peak period demand charges

[50] Va. Elec. & Power Co., *Schedule GS-2: Intermediate General Service* (May 20, 2019), https://www.dominionenergy.com/library/domcom/media/home-and-small-business/rates-and-regulation/business-rates/virginia/schedule-gs2.pdf?la=en&modified=20190702202700 (outlining rate schedule for demand of 30-500 kW per billing cycle).

[51] *Id.*

[52] Va. Elec. & Power Co., *Schedule GS-2T: Intermediate General Service Time of Use* (May 20, 2019), https://www.dominionenergy.com/library/domcom/media/home-and-small-business/rates-and-regulation/business-rates/virginia/schedule-gs2t.pdf?la=en&modified=20190702202724.

[53] Appalachian Power Co., *supra* note 47, at Schedule G.S., at Sheet No. 12-1 to 12-3 (prescribing rate schedule for general service).

[54] *Id.* at Schedule G.S.-T.O.D., at Sheet No. 13-1 to 13-2 (prescribing general service time-of-day rate schedule).

[55] *Id.* at Schedule M.G.S., at Sheet No. 11-1 to 11-3 (prescribing rate schedule for medium general service).

[56] Old Dominion Power Co., *supra* note 49, at Schedule PS: Power Service, at Sheet No. 15-15.1

[57] *Id.* at Schedule TODS: Time-of-Day Secondary Service, at Sheet No. 20-20.1.

There are several shortcomings in the current suite of rates available for Level 2/3 charging, which would be used by public charging stations. First, the maximum demand limits for smaller general service rates will in most cases result in Level 2/3 charging stations taking service under rate options that rely heavily on demand charges. While some available rates for Level 2/3 charging do contain time variation, they still rely heavily on demand-based charges (*i.e.*, on-peak demand rates). Second, the available time-varying rate options generally feature long duration peak periods that limit the alignment between time-varying costs and rates. For instance, Dominion Virginia's Schedule GS-2T has a 12-hour on-peak period from June – September and a 15-hour on-peak period for the remainder of the year.[58] Appalachian Power's on-peak period in the available rates has a 13-hour duration year-round.[59]

Table 8 shows how the rates available for high capacity charging affect charging costs for a hypothetical DCFC station (Level 3 Charger) with two charging ports that each have a 50 kW demand. For the rates with on-peak demand charges, it assumes that at least one episode of charging takes place during the on-peak period each billing period. It includes a low-utilization scenario (15 sessions per month) and a moderate utilization scenario (60 sessions per month), with alternative scenarios reflecting charging that is almost entirely on-peak, or almost entirely off-peak.[60]

[58] Va. Elec. & Power Co., *supra* note 52 (outlining rate schedule for "Intermediate General Service Time of Use").

[59] Appalachian Power Co., *supra* note 47, at Schedule G.S.-T.O.D., at Sheet No. 13-1 to 13-2.

[60] The 15 session per month utilization rate approximates use of the station every other day. As used here, it represents what would likely be a station with below average utilization, such as one of the least used stations in a DCFC fleet. The 60 sessions per month scenario is likely a better representation of current average DCFC utilization rates, but we are not aware of any Virginia-specific data on public DCFC utilization that would allow this to be validated.

Table 8 – Comparison of Effective Rates for High Capacity Public Charging

	ODP PS	ODP TODS	DOMINION GS-2 (No Demand)	DOMINION GS-2T	APCo GS-TOD	APCo MGS - TOD
Fixed Charge ($/month)	$75.00	$75.00	$19.89	$24.59	$13.82	$12.39
Demand Charge ($/kW)	$18.15	$16.93	$0.00	$11.39	$0.00	$4.10
On-Peak Energy	$0.0434	$0.0434	$0.1190	$0.0678	$0.1376	$0.0811
Off-Peak Energy	$0.0434	$0.0434	$0.1190	$0.0430	$0.0518	$0.0811
15 Total Sessions/Month, Composed of 14 Off-Peak Sessions and 1 On-Peak Session						
Annual Bill	$23,074	$21,607	$1,309	$14,362	$684	$5,799
Cost/Session	$128.19	$120.04	$7.27	$79.79	$3.80	$32.22
Cost/kWh	$2.56	$2.40	$0.15	$1.60	$0.08	$0.64*
60 Total Sessions/Month, Composed of 59 Off-Peak Sessions and 1 On-Peak Session						
Annual Bill	$24,245	$22,778	$4,521	$15,523	$2,083	$7,989
Cost/Session	$33.67	$31.64	$6.28	$21.56	$2.89	$11.10
Cost/kWh	$0.67	$0.63	$0.13	$0.43	$0.06	$0.22*
15 Total Sessions/Month, Composed of 14 On-Peak Sessions and 1 Off-Peak Session						
Annual Bill	$23,074	$21,607	$1,309	$14,556	$1,353	$5,799
Cost/Session	$128.19	$120.04	$7.27	$80.87	$7.51	$32.22
Cost/kWh	$2.56	$2.40	$0.15	$1.62	$0.15	$0.64*
60 Total Sessions/Month, Composed of 59 On-Peak Sessions and 1 Off-Peak Session						
Annual Bill	$24,245	$22,778	$4,521	$16,387	$5,068	$7,989
Cost/Session	$33.67	$31.64	$6.28	$22.76	$7.04	$11.10
Cost/kWh	$0.67	$0.63	$0.13	$0.46	$0.14	$0.22*

* The Appalachian Power MGS-TOD rate has a maximum energy cost limiter that limits charges apart from the fixed charge to an effective rate of $0.18647/kWh. With consideration of the customer charge, the maximum effective rate is $0.19-$0.20/kWh under the low and moderate utilization scenarios.

The estimates found in Table 8 demonstrate:

- Even at a relatively higher utilization rate, the effective rate for charging is quite high for rates that feature a demand component. This is most pronounced for Old Dominion Power, which does not offer a rate for high capacity charging without a demand charge.

- The available time-varying rates, with the exception of Appalachian Power's GS-TOD rate, all have demand rates and would actually steer customers towards non-time differentiated rates (if available) due to the outsized effects of demand rates on costs. Appalachian Power's GS-TOD rate would not be available for all high capacity charging stations due to the 100 kW demand cap.

- Under the demand-based time differentiated rates, a public charging station owner is charged a nearly identical effective rate for charging almost exclusively on-peak vs. charging almost exclusively off-peak.

Thus the principal problems with the currently available rates for public charging are that they: (a) lack time differentiation or (b) rely on demand charges as the principle means of time differentiation, resulting in very expensive electricity at lower utilization rates. As a consequence, the available rates fail to consistently motivate beneficial charging behavior.

There are several options for mitigating the punitive effects of demand charges on public charging stations. Discussed in more detail below, these options are not mutually exclusive and may be combined:

- Substituting time-varying volumetric charges for demand charge components.
- Establishing limits or caps on demand charges, through various means.
- Allowing the aggregation of billed demand measurements.
- Modifying the calculation of demand charges from being based on monthly maximum demand to the daily maximum demand.

Volumetric Rate Substitution for Demand Rates

Substituting volumetric rates for demand-based time-differentiated rates is a relatively straightforward matter. Such a design is already present in Appalachian Power's GS-TOD rate. A more volumetric design treats each instance of charging as a unique event and applies an identical set of price signals. We recommend the use of time-varying rates with meaningful volumetric components and rate spreads as a primary option for public charging stations. There are numerous examples of this type of rate structure for non-residential EV loads, including public charging applications. The examples below should not be considered an exhaustive list:

- California (SCE): Southern California Edison ("SCE") offers rates under Schedules TOU-EV-7 through TOU-EV-9 for separately metered EV charging stations with different load sizes (*e.g.*, TOU-EV-8 applies to loads from 20 kW – 500 kW).[61] The rates offer a demand charge free rate for five years (from March 1, 2019 through March 1, 2024), followed by the phase-in of a modest demand charge over the following five years for the TOU-EV-8 and TOU-EV-9 rate schedules.[62] Customers on Schedule TOU-EV-7 (demand of less than 20 kW) retain an energy-only option.[63] Time-varying volumetric energy charges are increased to recover costs that would otherwise be recovered in the demand charge.[64]

- <u>Connecticut (Eversource)</u>: Eversource Energy's Electrical Vehicle Rate Rider allows separately metered public charging stations to pay energy charges in place of any otherwise applicable demand rate that would apply under the standard general service rate schedules. The energy charge is determined by the average rate for that rate component. This rider does not have a sunset or phase-out clause.[65]

- <u>Nevada (Nevada Power Company & Sierra Pacific Power Company)</u>: Both utilities offer Schedule EVCCR-TOU to customers under the larger commercial rate schedules that install separately metered DCFC stations. The rates offer a ten-year discount schedule under which demand rates are reduced by 100% in the first year (starting April 1, 2019) and the discount declines by 10% each year thereafter to zero after the tenth year (starting April 1, 2029). Customers pay a substitute transition energy charge in place of the demand charges.[66]

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[61] *See Rate Schedules TOU-EV-7, TOU-EV-8, TOU-EV-9 for Business Customers Charging Electric Vehicles*, S. CAL. EDISON (2018), https://www.sce.com/sites/default/files/inline-files/TOU-EV-7_8_9%20Rate%20Fact%20Sheet_WCAG_0.pdf.

[62] *See, e.g.*, S. Cal. Edison, *Schedule TOU-EV-8: General Service Time-of-Use, Electric Vehicle Charging, Demand Metered*, Cal. Pub. Utils. Comm'n, Docket No. U 338-E, Sheet No. 66647-E (Mar. 22, 2019), https://library.sce.com/content/dam/sce-doclib/public/regulatory/tariff/electric/schedules/general-service-&-industrial-rates/ELECTRIC_SCHEDULES_TOU-EV-8.pdf.

[63] *See* S. Cal. Edison, *Schedule TOU-EV-7: General Service Time-of-Use, Electric Vehicle Charging*, Cal. Pub. Utils. Comm'n, Docket No. U 338-E, Sheet No. 66642-E (Mar. 22, 2019), https://library.sce.com/content/dam/sce-doclib/public/regulatory/tariff/electric/schedules/general-service-&-industrial-rates/ELECTRIC_SCHEDULES_TOU-EV-7.pdf.

[64] *Id.*

[65] Conn. Light & Power Co., *Electric Vehicle Rate Rider* (Mar. 6, 2019), https://www.eversource.com/content/docs/default-source/rates-tariffs/ct-electric/ev-rate-rider.pdf?sfvrsn=e44ca62_0.

[66] Nev. Power Co., *Schedule No. EVCCR-TOU: Electric Vehicle Commercial Charging Rider Time-of-Use* (Mar. 25, 2019), https://www.nvenergy.com/publish/content/dam/nvenergy/brochures_arch/about-nvenergy/rates-regulatory/electric-schedules-south/EVCCR-TOU_South.pdf; Sierra Pac. Power Co., *Schedule No. EVCCR-TOU: Electric Vehicle Commercial Charging Rider Time-of-Use* (Mar. 25, 2019), https://www.nvenergy.com/publish/content/dam/nvenergy/brochures_arch/about-nvenergy/rates-regulatory/electric-schedules-north/EVCCR-TOU_Electric_North.pdf.

Demand Charge Caps

A demand charge cap can be either a maximum percentage of a customer's bill associated with demand charges, or an effective volumetric rate. A demand charge cap provides an easy to understand maximum rate, but has the drawback of potentially diminishing the price signal sent by time-differentiated rates unless separate maximums are set for on-peak and off-peak rates. For example, Appalachian Power's Schedule MGS specifies a maximum energy rate.[67] Similar mechanisms exist in the generally applicable rate structures of other utilities (*e.g.*, Duke Energy Kentucky).[68]

Several utilities have adopted this approach specifically for EV charging. For instance, in 2019 Minnesota Power received approval to deploy a pilot rate for commercial EV charging that caps demand charges at 30% of a ratepayer's bill.[69] The adopted rate features an on-peak demand charge with a five-hour on-peak window (reduced from 14 hours by the final order) and the demand charge component is limited to 30% of the sum of the basic service charge, demand charge, and energy charge.[70] The Pennsylvania Electric Company (PECO) uses a slightly different rate to produce a similar effect for public or workplace fleet DCFC stations. PECO's Electric Vehicle DCFC Pilot Rider (Schedule EV-FC) applies a five-year discount to billed distribution demand for customers with publicly available or workplace DCFC charging

[67] *See* Appalachian Power Co., *supra* note 52, at Schedule M.G.S., at Sheet No. 11-1 to 11-3.

[68] *See e.g.*, Duke Energy Ky., *Rate DS: Service at Secondary Distribution Voltage* (May 1, 2020), https://www.duke-energy.com/_/media/pdfs/for-your-home/rates/electric-ky/sheet-no-40-rate-ds-ky-e.pdf?la=en.

[69] Order Approving Pilot with Modifications, and Setting Reporting Requirements, Minn. Pub. Utils. Comm'n, Docket No. 19-337 (Dec. 12, 2019), https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={00B4FB6E-0000-CC1C-B230-7AED232B58CE}&documentTitle=201912-158272-01.

[70] Minn. Power, *Electric Rate Book*, Pilot for Commercial Electric Vehicle Charging Service, at § V, pp. 104.0-104.2 (May 16, 2019), https://www.mnpower.com/Community/ElectricRates (click on the hyperlink text near top of the page to view the Minnesota Power Rate Book).

stations.[71] The demand discount is set at 50% of the maximum nameplate capacity of connected DCFCs.[72]

Demand Aggregation

An aggregate billed demand scheme would allow customers with multiple meters, such as business with a network of charging stations, to be billed based on the maximum aggregate demand across all locations rather than charges equivalent to the sum of the maximum demands of each station. This arrangement reflects the fact that for generation capacity and transmission demand, customers with multiple locations look no different from a cost of service perspective than a customer at a single location with similar characteristics. An aggregation mechanism can be easily paired with time-differentiated rates and will produce demand cost mitigation as long as each one of a collective group of charging stations are not operating at their full capacities during a single interval within a peak period. This option has several attractive characteristics:

- It should be easy to pair with existing time-varying rate designs.
- It retains the time-varying price signal in a manner that a demand charge cap may not.
- It can produce lower charges at both high and low utilization rates because even at high utilization rates, it is unlikely that all stations in a network would be operating at full capacity during the same interval.
- It directly addresses the fact that separate measurement of on-peak demand for each station produces unequal results for EV supply equipment with dispersed locations as compared to a customer with an equivalent peak load at a single location.
- It may also incentivize charging network owners to seek ways to manage their networks as a collective group in a way that diversifies the load impacts they have on the system.

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[71] PECO Energy Co., *Electric Service Tariff*, Electric Vehicle DCFC Pilot Rider (EV-FC), at 84 (Feb. 22, 2019), https://www.peco.com/SiteCollectionDocuments/CurrentTariffElec.pdf.

[72] *Id.*

The potential drawbacks are that if the model is confined to transmission and generation capacity costs, it fails to address the effective costs of demand-based charges for distribution service, and the price signal it sends unavoidably diminishes as the billing period progresses because each interval sets a new minimum cost benchmark. For example, if a network sets an aggregate on-peak demand of 500 kW early in a billing period, the EV supply equipment provider has no incentive to keep aggregate on-peak demand below that threshold for the remainder of the billing period because the minimum demand charge has already been locked in. The only remaining incentive for off-peak charging would be provided by the rate spread between on-peak and off-peak volumetric rates, which would be minimal to non-existent if the rate relies primarily on demand-based charges.

This method of determining demand is used by Xcel Energy in Minnesota for a specific electric light rail project.[73] It has also been proposed in pilot form by Puget Sound Energy (PSE) in Washington for the purpose of supporting transportation electrification, though PSE's proposal would make the rate generally available to a limited number of customers rather than limiting it to customers with EV charging load.[74] This proposal has not yet received final approval.

<u>*Daily Demand Charges*</u>

A daily demand charge occupies something of a middle ground between traditional demand charges based on monthly maximum demand and fully volumetric rates. A daily demand

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[73] Final Order Approving Xcel's Proposal for the Hiawatha Light Rail Line Tariff, Minn. Docket No. 08-579 (Aug. 21, 2008), https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={0568C41D-B3C9-40B0-9367-AC8097837EC7}&documentTitle=5458834.

[74] Puget Sound Energy, *Prefiled Direct Testimony (Nonconfidential) of Jon A. Piliaris*, Docket No. UE-190529 (June 20, 2019), https://www.utc.wa.gov/_layouts/15/CasesPublicWebsite/CaseItem.aspx?item=document&id=00001&year=2019&docketNumber=190529&resultSource=&page=1&query=190529&refiners=&isModal=false&omItem=false&doItem=false (document is titled "UE-190259 and UG-190530-PSE-Exh-JAP-01T-6-20-19.pdf") (referring to its proposal as a "conjunctive demand" pilot rate).

charge uses the highest recorded demand each day to calculate charges, either during all hours or during a time-varying demand pricing period. In doing so it reflects an averaged contribution to costs and does not penalize ratepayers for a small number of anomalously high demands. A daily demand charge could also be preferable to a monthly demand charge because a daily demand charge allows the customer the option to manage the bill every day while under a monthly demand charge the customer can no longer effectively manage the bill once the high demand is set. Compared to a volumetric charge the averaging effect of a daily demand charge is less because it is derived from peak daily demands whereas a volumetric rate charges a ratepayer based on fully averaged demand across all intervals over a longer time period.

A daily demand charge design can benefit customers with EV charging stations that have higher utilization rates and higher load factors because at a certain load factor threshold a customer prefers demand charges to energy charges. This could be the case for fleet charging, where it may be possible to manage predictable charging needs in a way that consistently cycles vehicles through charging cycles and optimizes the use of the charging equipment. A daily demand charge for distribution demand could be paired with the demand aggregation mechanism discussed above.

To our knowledge this type of rate design has not been deployed as a targeted EV rate. However, it has been deployed in residential and small commercial time-varying rate pilots in Nevada[75] and New York[76], and in standby rates in New York.[77] It is also being explored in

[75] Nev. Power Co., *Schedule No. ORS-DDP: Optional Residential Service – Daily Demand Pricing* (Jun 14, 2018), https://www.nvenergy.com/publish/content/dam/nvenergy/brochures_arch/about-nvenergy/rates-regulatory/electric-schedules-south/ORS_DDP_South.pdf.

[76] Consol. Edison Co. of N.Y., *Schedule for Electricity Service*, Rider AB – Smart Home Rate, at Tariff Leaf 327.12 to Tariff Leaf 327.18 (2019), https://www.coned.com/_external/cerates/documents/elecPSC10/electric-tariff.pdf.

[77] *See, e.g.*, *id.* at Service Classification No. 9: General – Large, at Tariff Leaf 452 (applying As-Used Daily Demand Delivery Charges for customers taking services under Standby Rates).

California as a potential rate option for customers with on-site energy storage. The settlement adopted in SCE's 2018 rate case required SCE to study storage-specific non-residential rates that incorporate the conversion of distribution costs from a monthly maximum demand charge to a daily peak demand charge.[78]

We recommend that the Commission consider all of these options for facilitating the growth of public charging in Virginia in a way that also supports beneficial charging patterns. Rate designs should feature time-varying pricing and mitigate the punitive effects that demand-based rates have on charging costs. They should also incentivize off-peak charging generally. Specifically, the Commission should seek to establish more granular time-varying pricing periods for public EV charging than the time-varying rates that are offered by Appalachian Power Company and Virginia Electric & Power Company (Dominion), which contain on-peak pricing periods that extend from 12 -15 hours.

[78] Decision on Southern California Edison Company's Proposed Rate Designs and Related Issues, Cal. Pub. Utils. Comm'n, Docket No. A. 17-06-030, D. 18-11-027, at 65, ¶ 10 (Nov. 29, 2018), https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M248/K308/248308326.PDF; *see* S. Cal. Edison Co., Motion Of Southern California Edison Company (U 338-E) And Settling Parties For Adoption Of Medium And Large Power Rate Group Rate Design Settlement Agreement, Cal. Pub. Utils. Comm'n, Docket No. A. 17-06-030, at app. A, A-26, § 4.J (June 30, 2017), https://static1.squarespace.com/static/54c1a3f9e4b04884b35cfef6/t/5b68e8f470a6add62b07e6bf/1533602042643/Large+Commercial+Settlement+Agreement+.pdf.

V. Conclusion

Environmental Advocates appreciate the Commission's attention to this matter and look forward to any additional opportunities the Commission may provide for developing the record on how Virginia may best deploy electric vehicles, charging infrastructure, and rate design to improve air quality, grow the economy, and lower utility customer costs.

June 23, 2020

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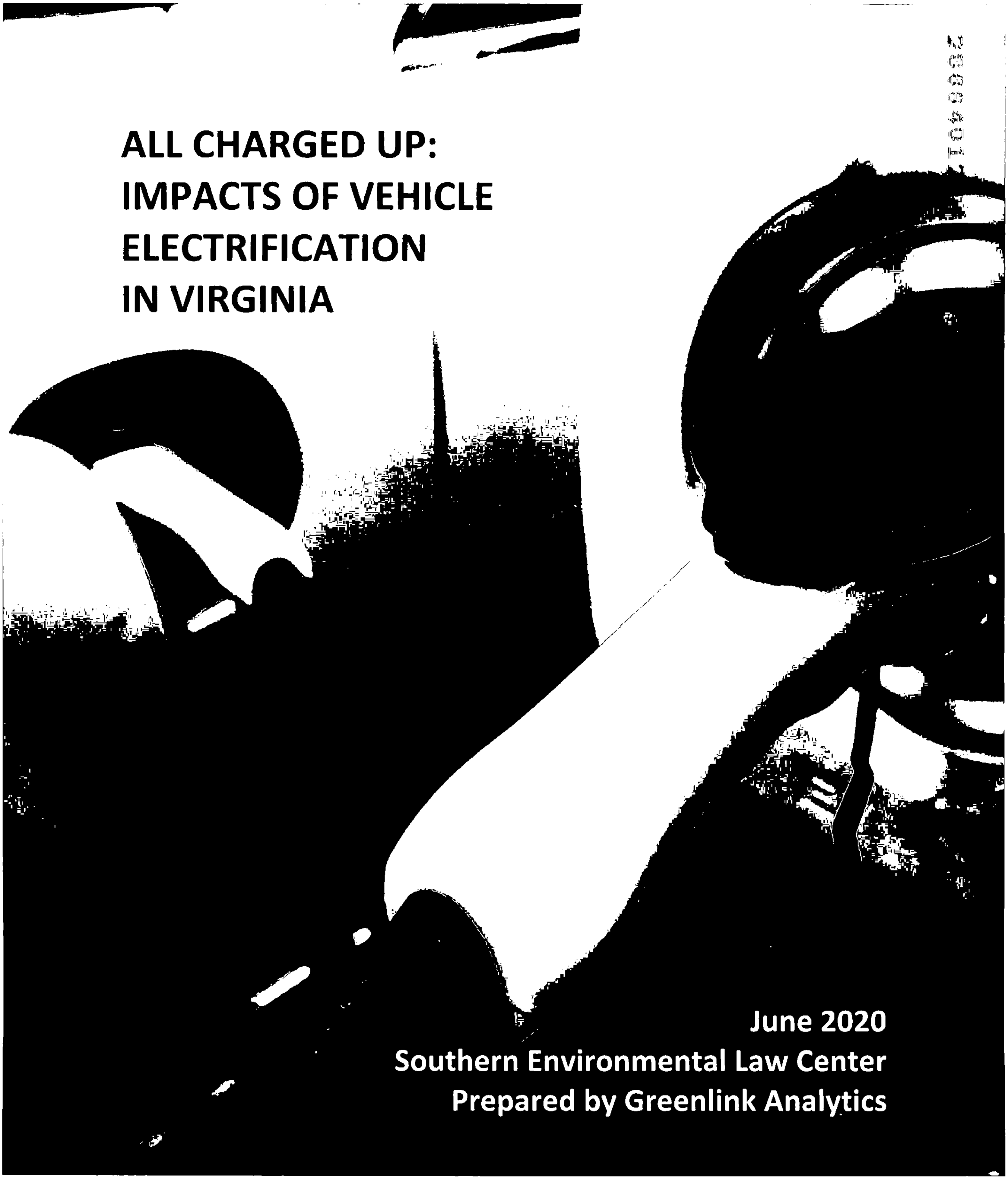
ATTACHMENT A



ALL CHARGED UP: IMPACTS OF VEHICLE ELECTRIFICATION IN VIRGINIA

June 2020

Southern Environmental Law Center

Prepared by Greenlink Analytics

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2006401 27

Executive Summary

The case for electric vehicles as a near-term solution to everything from climate change to national security to economic development has been made in many different contexts. Detailed assessments of the impacts of electric vehicle adoption often are not available, however. This study evaluates the changes in electricity demand and CO_2 emissions that could occur under six different projections of electric vehicle adoption in Virginia.

The projections of vehicle adoption are taken from various third parties and represent a wide range of potential consumer behaviors through 2040. Greenlink Analytics then used energy system modeling software, ATHENIA, to evaluate the impacts on electric power demand and emissions under each of these scenarios. With electric vehicles growing to up to two-thirds of all new vehicle sales by 2040, the results show electricity demand increasing anywhere from 4% to 13% statewide, with the vast majority of electric vehicle demand occurring in the territory of Virginia Electric and Power Company ("Dominion"). While this level of electric vehicle deployment leads to an increase in power sector CO_2 emissions, Figure ES-1 shows how net transportation-related emissions decline relative to a scenario that meets these transportation demands with petroleum fuels, including anticipated changes to the power sector as a result of the Virginia Clean Economy Act.

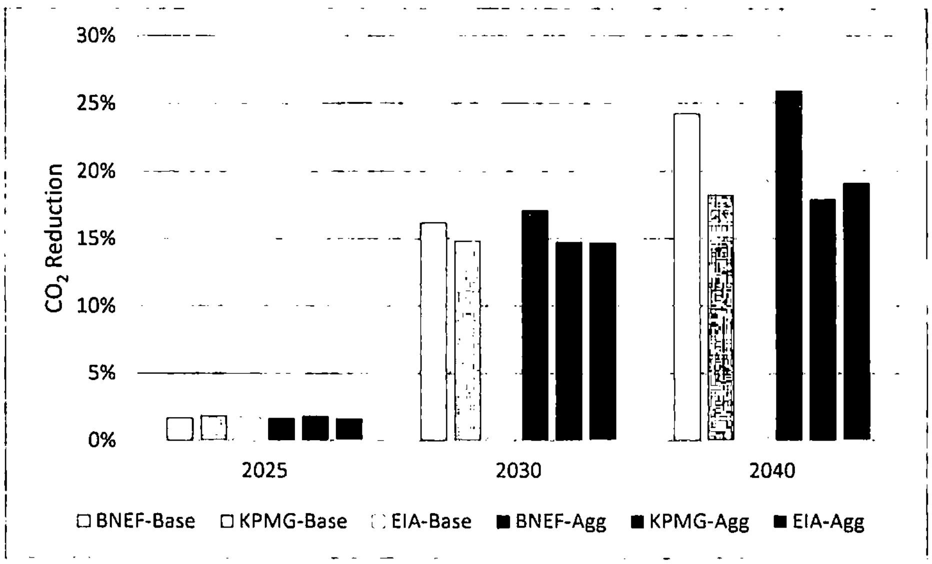

Figure ES-1: Net Avoided Non-Aviation Transportation CO_2 Emissions by Electric Vehicle Adoption under Six Scenarios

Electric vehicles are an appealing decarbonization technology for Virginia, but even under the most-aggressive adoption schedule, electric vehicles only reduce total transportation sector CO_2 emissions by 26%. For full decarbonization, additional policies will be necessary. In addition, policy-makers will need flexible and dynamic electricity rate structures to aide in successful grid integration of electric vehicle loads and managing the impact on electricity bills.

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Table of Contents

Introduction

Electric vehicles (EVs) are a promising and developing technology that merge two heretofore largely independent sectors of the energy economy – electricity and transportation. Providing mobility services with electricity-powered vehicles instead of petroleum fuels can provide a great number of benefits, including:

- *Reducing long term electric rate increases as well as consumer vehicle costs.* As utility revenues increase due to increased demand from charging EVs, utilities will need less frequent and less severe rate increases. Additionally, anticipated lower EV ownership costs yield lifetime financial savings to consumers purchasing electric vehicles over those who purchase internal combustion engine (ICE) vehicles.[1, 2]
- *Improving national energy security.* By reducing the amount of petroleum the country uses, the nation's reliance on imported oil falls. While the U.S. currently is a net oil exporter as a whole, we still rely on oil imports to meet day-to-day energy needs, and most regions of the U.S. remain net importers of petroleum.[3]
- *Increasing grid stability.* By harnessing the potential of bidirectional power flows and information and communications technologies, EVs can serve both as transport and as distributed, mobile energy storage units.[4, 5, 6]
- *Supporting job creation.* In many states, portions of the EV supply chain already have a base of operations. As EVs market share grows, many companies will see their labor needs increase and increase hiring.[7, 8]
- *Spurring economic development.* The implications of increased EV adoption for the economy may also go beyond job impacts and lead to state-level GDP and income expansion.[9] While this is regularly a concern of policymakers, it may be especially pertinent in light of the current economic recession.

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[1] Southwest Energy Efficiency Project. 2018. "Electric Vehicle Cost-Benefit Analysis." Accessed at: http://www.swenergy.org/pubs/azevstudy

[2] MJ Bradley and Associates. 2016. "Mid-Atlantic and Northeast Plug-In Electric Vehicle Cost-Benefit Analysis: Methodology and Assumptions." Accessed at: https://mjbradley.com/sites/default/files/NE_PEV_CB_Analysis_Methodology.pdf

[3] https://www.eia.gov/todayinenergy/detail.php?id=42735

[4] Wagner, Leonard. 2014. "Overview of Energy Storage Technologies." *Future Energy: Improved, Sustainable and Clean Energy Options for our Planet: 2nd Edition*. Ed: Trevor M. Letcher.

[5] Chau, K.T. 2014. "Pure Electric Vehicles." *Alternative Fuels and Advanced Vehicle Technologies for Improved Environmental Performance: Towards Zero Carbon Transportation.* Ed: Richard Folkson.

[6] Funabashi, Toshihisa. 2016. "Introduction." *Integration of Distributed Energy Resources in Power Systems Implementation, Operation and Control.* Ed: Toshihia Funabashi.

[7] https://www.energy.gov/eere/electricvehicles/about-electric-vehicles

[8] Southeast Energy Efficiency Alliance. 2020. "Electric Vehicles: A Growing Opportunity in Georgia." *Retrieved in May 2020 from: https://mk0southeastene72d7w.kinstacdn.com/wp-content/uploads/SEEA_GeorgiaEVAnalysis_FINAL_2020_03_05.pdf*

[9] Electrify the South. 2017. "The Economic Opportunities of Electric Vehicles in Georgia." *Retrieved in May 2020 from: https://c5233ed5-8d1e-48a9-bd6f-0bb2a20fd091.filesusr.com/ugd/aad50d_f60b1f64a2ba49b397bbebff91535809.pdf*

- *Improving environmental outcomes by reducing emissions.* Even with highly carbon-intensive electricity generation sources, research shows that an EV's energy efficiency advantage outperforms a similarly-used ICE vehicle in terms of CO_2 emissions. In other words, total emissions associated with an EV are less than the emissions of a similarly-used ICE vehicle, even where the EV is charged by carbon-intensive power plants. As a result, an emissions gap exists between an EV and an equivalent ICE vehicle, and the gap is expected to widen as electricity grids decarbonize. Environmental results continue to favor EVs when factoring in other pollutants, especially when considering public health impacts, due to population proximity and emissions height differences between the power sector and vehicle tailpipes.[10, 11]

Consumer adoption of EVs remains a key uncertainty, but vehicle manufacturers globally are making large investments and converting key portions of their product lines to electric offerings.[12] EV's specific benefits are also regionally differentiated, so while many of the benefits may be true on average or in the aggregate, they may not hold for a specific state or locality.[13]

The remainder of this study investigates the emissions implications of 6 scenarios of EV adoption in Virginia, covering light duty, medium duty, and heavy duty vehicles with 100 to 300 miles of range. These scenarios vary EV adoption rates in a low-medium-high fashion under two different policy settings: current baseline conditions and under a $30/ton CO_2 fee, which accelerates EV adoption by increasing petroleum fuel costs relative to electricity at a time when electricity supplies are decarbonizing.[14] Greenlink used its ATHENIA model to assess these impacts, which looks at likely outcomes of the use of energy on an hourly time scale. Results are forecast through 2040 for Virginia.

Methodology

Forecast Modeling

Greenlink's ATHENIA tool models future energy landscapes by analyzing historical time-varying trends in energy generation along with other market variables, such as fuel prices and

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[10] McLaren, Joyce *et. al.* 2016. "Emissions Associated with Electric Vehicle Charging: Impact of Electricity Generation Mix, Charging Infrastructure Availability, and Vehicle Type." National Renewable Energy Laboratory. Golden, Colorado. *Retrieved in May 2020 from: https://afdc.energy.gov/files/u/publication/ev_emissions_impact.pdf*

[11] Holland, Stephen P., Erin T. Mansur, Nicholas Z. Muller, and Andrew J. Yates. 2016. "Are There Environmental Benefits from Driving Electric Vehicles? The Importance of Local Factors" American Economic Review 2016, 106(12): 3700–3729.

[12] https://www.cnn.com/interactive/2019/08/business/electric-cars-audi-volkswagen-tesla/

[13] *See* 11.

[14] A number of various policies might be selected to accelerate the adoption of EVs. A CO_2 price was used here to estimate the impact that might be provided by a change in policy to accelerate EV adoption.

generation costs. ATHENIA utilizes a deep-learning neural network architecture to learn and project hourly dispatch behavior at the unit level (both existing and proposed) for meeting Virginia's electricity demand in different scenarios. With different demand profiles from each of the EV scenarios, ATHENIA's dispatch module determines which resources are most likely to be selected to satisfy demand and reliability requirements. The environmental module of the model then outputs the emissions trajectories that are the primary focus of the remainder of this report.

Baseline Demand and Supply

Most analysts believe that Virginia's electricity demand will grow over the next several decades, although the degree of growth varies among forecasts.[15] Dominion and Appalachian Power Company's (APCo) integrated resource plans (IRP), which are the basis of the Baseline assumptions, have 15-year time horizons. As this study looks at various time horizons, for projections more than 15 years out to 2040 it extends the compound annual growth rate of demand from the IRPs. In cases where PJM and utility demand forecasts diverged, we used PJM projections. Resource additions and retirements are staged in the model to comply with the recently-adopted Virginia Clean Economy Act, following a least-cost pathway to meet demand while retiring CO_2-emitting generation by the years prescribed in the Act. In situations where a number of reasonable approaches were considered, this study used more conservative assumptions – *i.e.*, those projecting slower rates of technological progress and more gradual cost declines. As is called for in recent legislation, energy efficiency sees a dramatic increase in utilization from historical levels in Virginia.

EV Adoption Rates in Virginia

EV adoption projections vary widely across research organizations and are generally reported as a percent of new vehicle sales. Additionally, most published projections do not provide Virginia-specific results. To provide a Virginia-specific adoption pathway, we took total vehicle and total vehicle sales baseline data from the Energy Information Administration's 2020 Annual Energy Outlook (AEO) for the South Atlantic Census Division. We used Virginia-specific data from the Auto Alliance to determine the ratio of total vehicles and total vehicle sales in the South Atlantic to Virginia, as well as average vehicle lifetime.[16] This ratio was held constant to take the EIA Reference Case projection of EV deployments in the South Atlantic and derive a Virginia-specific estimate of EV adoption. The vehicle lifetime was used to retire 1/12th of all EVs purchased in a specific year until all vehicles from that year are assumed no longer in service. This avoids over-counting the number of EVs in use over the duration of the projections.

Having baseline projections of total new vehicle sales in Virginia through 2040 allowed us to apply multiple projections of EV adoption to the Virginia context. Three different baseline projections of EV adoption rates were produced for Virginia, based on published estimates from Bloomberg New Energy Finance (BNEF), KPMG, and the EIA representing High, Medium, and

[15] PJM, EIA, and other industry analysts agree on this point.

[16] Auto Alliance https://autoalliance.org/in-your-state/VA/pdf/?export

Low levels of adoption, respectively.[17] Additionally, we analyzed trajectories of EV adoption spurred by policy. These "aggressive" cases come from taking the percent-change in deployment between the EIA baseline scenario and the deployment under the EIA $30/ton CO_2 AEO Side Case.

Vehicle Charging Infrastructure

After determining vehicle adoption levels, we used the EV Infrastructure Projection Lite tool from the National Renewable Energy Laboratory to estimate the quantity and type of publicly-accessible vehicle charging infrastructure deployments required to adequately meet charging demand.[18] We used the default settings of the tool in all scenarios.

Electricity Demand Adjustments

Hourly demand profiles for electricity from EVs are built assuming existing rate incentives and observed consumer charging behaviors, which heavily favor late night, at-home charging. These charging behavior assumptions remain constant across all scenarios, with the daily distribution of charging demand shown in the table below. Virginia could also reduce overall impacts on the system and actually improve system performance through incentives to change charging behavior so as to flatten the load over time as EV deployment grows.

Table 1: Daily Charging Distributions

Time of Charging	% of Daily Vehicle Charging Demand
Late Night (home)	80%
Morning (home/work)	14%
Early Afternoon (work)	6%

As more EVs come into to the Virginia fleet, electricity demand levels increase. This increased demand modifies the hourly baseline demand, which ATHENIA uses to determine the most-likely dispatch of power sector resources. One particular source of uncertainty in the analysis is the progress of battery technologies regarding weight and energy density. This analysis uses the median of performance levels currently observed as published by auto manufacturers (Nissan, BMW, Chevrolet, Kia and Tesla) coupled with annual vehicle miles traveled to assess the amount of energy required and number of charges needed to keep vehicles operable for regular use as constant through 2040.

[17] BNEF produces a "regional" estimate whereby 60% of new vehicle sales are electric vehicles by 2040. KPMG made a Virginia-specific projection which was replicated for this study, whereby 46% of new vehicle sales are electric vehicles by 2040. The EIA 2020 AEO Reference Case projection shows 18% of new vehicle sales are electric vehicles by 2040.

[18] As of May, 2020, EVI Pro-Lite is accessible at: https://afdc.energy.gov/evi-pro-lite Details of the tool and its approach can be found here: https://www.nrel.gov/docs/fy18osti/70831.pdf

Emissions

ATHENIA contains unit-level CO_2 emissions rates, which are paired with unit-level generation to determine total power sector CO_2 emissions levels resulting from the increase in demand driven by EVs. Displaced tailpipe emissions from ICE vehicles that may have otherwise been used to meet the demand for transportation services are also calculated, assuming constant transportation service demands from the population, whether using EVs or ICE vehicles. Vehicle miles traveled (VMT) are expected to increase over the projection, and the VMT trajectory is not affected by the proportion of EVs deployed in a certain year. The net CO_2 emissions estimate comes from subtracting avoided tailpipe emissions from increased power sector emissions. In this study, values are reported for 2025, 2030, and 2040.

Findings

Vehicles in the Market and Supportive Infrastructure

EV sales are projected to grow in all scenarios. While current sales are modest, projections show that sales volumes eventually exceed 100,000 vehicles per year by 2035 in all but the most conservative set of projections. The variability in the projections is evident in Figure 1. EIA shows rapid near-term growth followed by slow and steady progress through the rest of the modeling horizon, KPMG expects steadily-increasing demand, and BNEF anticipates a major increase in the rate of demand in the latter half of the 2020s, which then moderates a bit through the 2030s. While the EIA trajectories show the fastest adoption of EVs in the next 2-3 years, by 2030 all other scenarios have eclipsed EIA's annual sales expectations. BNEF projections show the highest annual sales by 2024 and maintain that position through 2040.

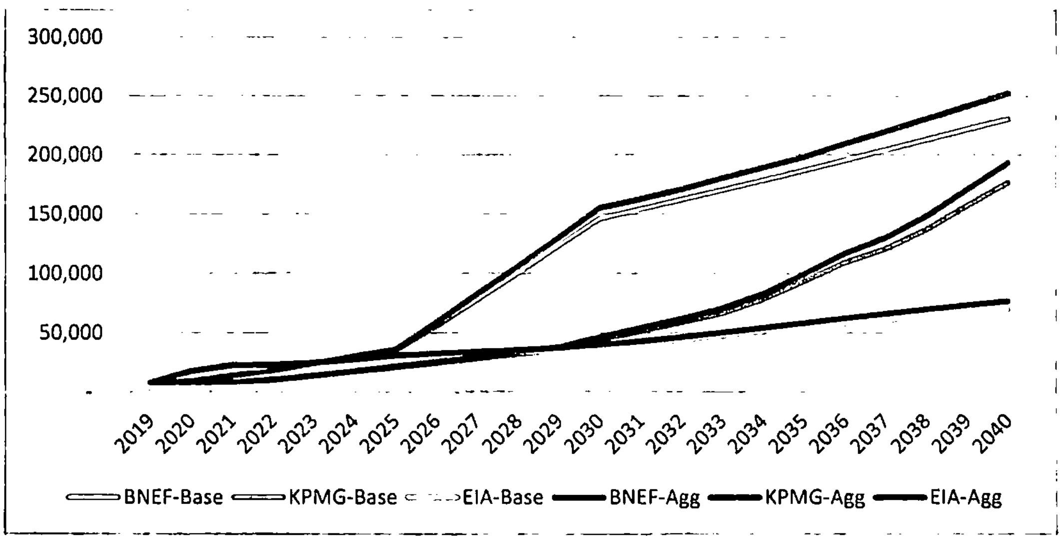

Figure 1: New Electric Vehicle Sales in Virginia

Market share for EVs is expected to increase in all scenarios due to declining EV cost trends, increasing emphasis on EVs by auto manufacturers, and other factors. Current vehicle sales in

Virginia are just under 400,000 per year and are expected to decline overall in the near term. The projection of total sales shows a slow and steady rebound over time such that 2040 new vehicle sales are approximately the same as 2019. Figure 2 shows these dynamics over the modeling horizon. It is clear that EV market share will increase from the current levels of about 2%; the range of 2040 market share ranges from 18% (EIA-Base) to 66% (BNEF-Aggressive).

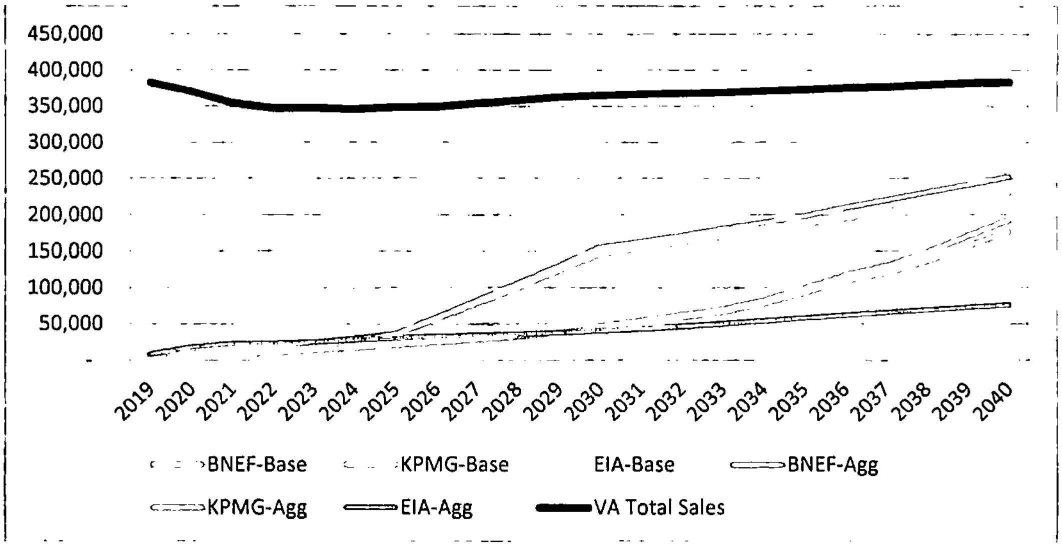

Figure 2: Virginia EV Sales and All Sales (Total Sales Emphasized)

EVs grow to become the majority of new vehicle sales by 2040 in both BNEF projections. However, that does not translate into becoming the majority of all vehicles on the road in 2040. Due to the length of vehicle lifetimes, EVs represent significantly less than half of the vehicles on the road by 2040 in every projection. The most conservative adoption scenario shows EVs as 7% of the entire fleet, and the most the aggressive adoption scenario shows EVs as about 20% of the entire fleet (Figure 3).

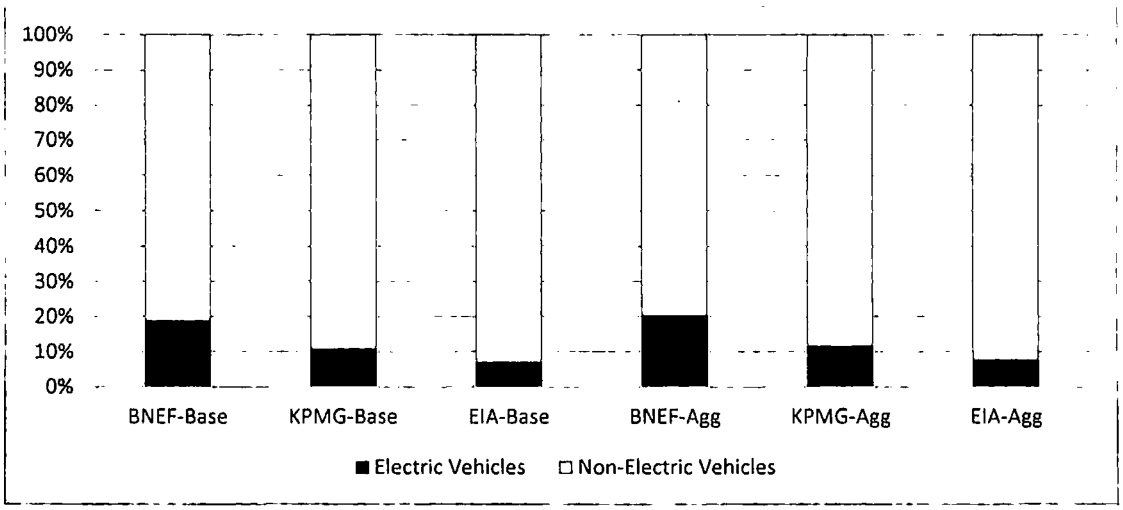

Figure 3: Virginia EVs as a Percentage of All Vehicles, 2040

Increasing the number of EVs will, by necessity, increase the amount of vehicle charging required. In this study, "publicly-accessible" charging infrastructure means that the charging is available for use by the public and is not restricted to specific private users through physical or legal means (charging in homes or reserved specifically for one company's commercial fleet or employees would not qualify as publicly-accessible). Estimates of vehicle charging infrastructure deployment show increases from today's 626 publicly-accessible EV charging stations in Virginia to up to slightly over 22,000 for the BNEF-aggressive case. Breakouts of publicly-accessible charging station types (workplace level-2 chargers, other level-2 chargers, and DC fast chargers) were produced for each scenario and are shown in Figure 4; aggregate totals in total EVs on the road by year and the resulting publicly-accessible charging infrastructure needed are reported in Table 2.

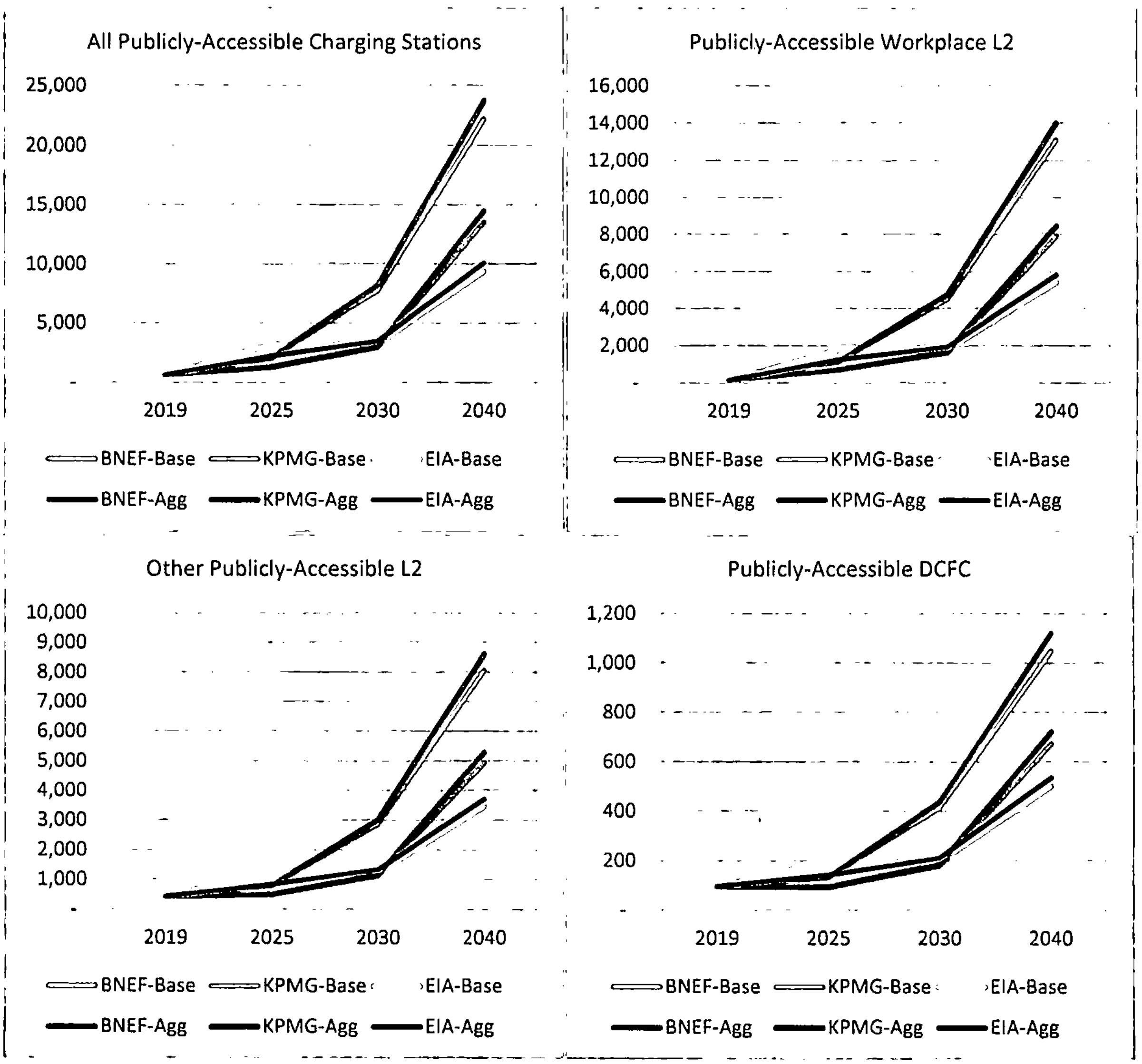

Figure 4: Publicly-Accessible EV Charging Infrastructure Deployments through 2040

Table 2: Total Electric Vehicles and Charging Stations in Virginia through 2040

	Number of EVs	Number of Charging Stations
2019	14,000	626
2025	74,000 – 120,000	1,300 – 3,200
2030	176,000 – 524,000	2,900 – 8,200
2035	353,000 – 1,070,000	6,300 – 16,000
2040	600,000 – 1,680,000	9,400 – 23,700

Electricity Demand Implications

Currently, EVs make up a very small amount of electricity demand in Virginia. However, if the number of vehicles increases by 40 times or more, as is expected even in the lowest scenario, EVs will become an important source of load growth. Figure 5 demonstrates that EV charging needs could exceed 15 million MWh per year by the late 2030s. With demand forecasts from PJM and the investor-owned utilities projecting a Virginia-wide electricity energy demand reaching 140-150 million MWh in this same timeframe, EVs could represent anywhere from 5%-12% of total electricity demand by 2040, as shown in Table 3 (note: total system demand is not consistent across scenarios due to the impact of EV charging, which results in some variations in the denominator and the resulting overall percentages). Over 90% of new EV charging is projected to occur in Dominion territory. At these penetration levels, policy-makers and utility regulators should exercise care regarding rate structures and consumer incentives to ensure low-cost, reliable power supplies.

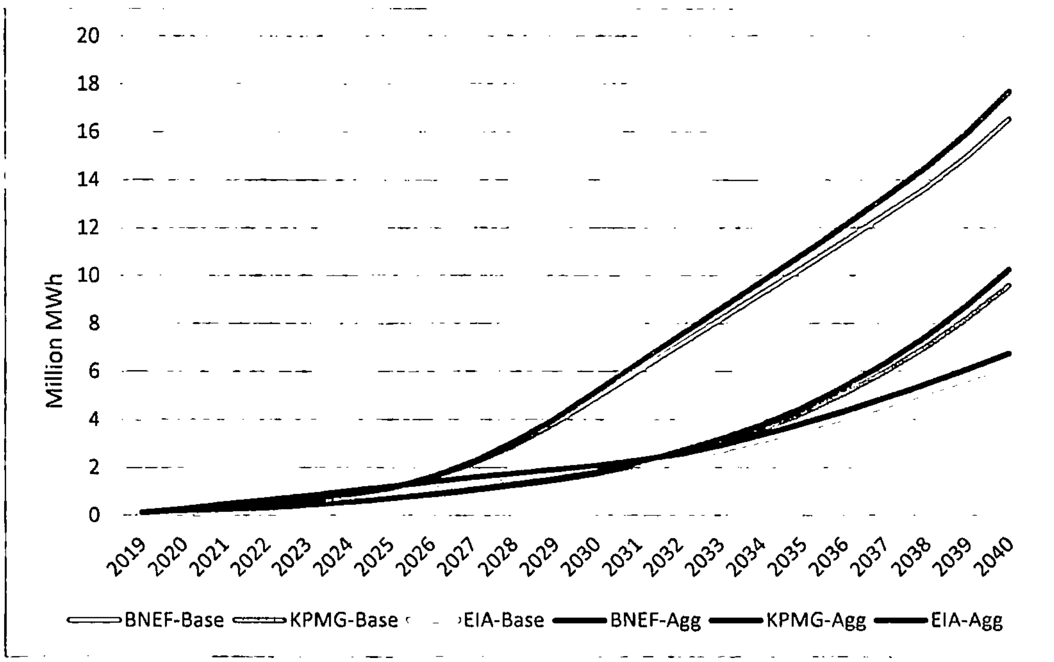

Figure 5: Projected Electricity Demand from Electric Vehicles

Table 3: EV Energy Demand in MWh and as a Percentage of Load

Year	Demand (million MWh)	Portion of Total Load (%)
2020	196,000 – 285,000	0.2%
2025	707,000 – 1,220,000	0.6% - 1%
2030	1,740,000 – 5,180,000	1.4% - 3.8%
2035	3,600,000 – 10,900,000	2.9% - 7.6%
2040	6,290,000 – 17,700,000	5.1% - 11.6%

Emissions Impacts

The Virginia Clean Economy Act, if properly implemented, will significantly reduce Virginia's power sector carbon footprint, but electricity generation will still be a source of CO_2 emissions throughout the modeling horizon. As a result, replacing ICE vehicles with EVs results in lower CO_2 emissions on net in every year and scenario. Light duty vehicle emissions experience the greatest impact, with transportation emissions for the whole of Virginia declining in all six scenarios evaluated in this study relative to a world where such vehicle electrification did not take place (Figure 6). Total non-aviation transportation CO_2 emissions decline by 1.5%-2% in 2025, but this figure grows rapidly such that by 2030 these emissions are 15%-17% lower than if projected transportation demand had been met by petroleum liquid fuels. Increases in rates of projected emissions reductions are slower between 2030 and 2040, growing to 18%-26% by 2040 across the six scenarios.

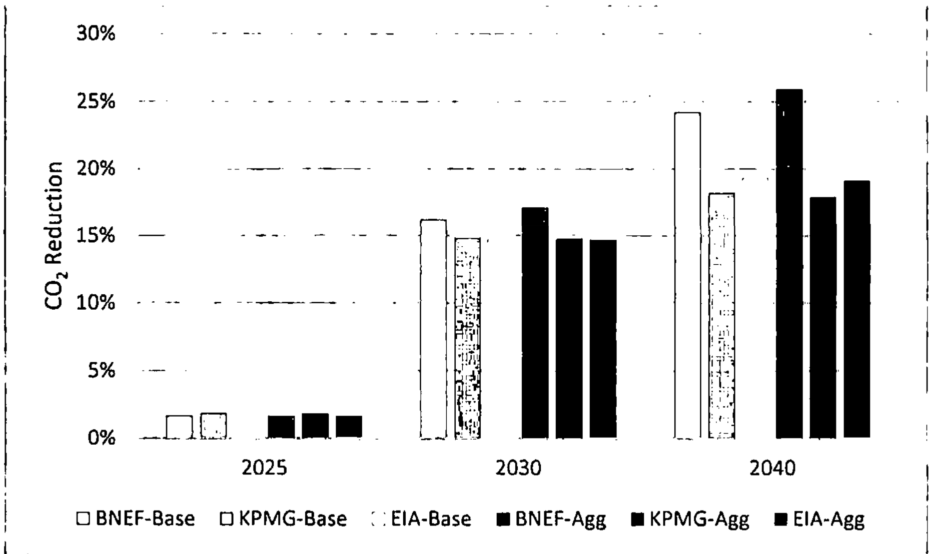

Figure 6: Net Avoided Non-Aviation Transportation CO_2 Emissions by Electric Vehicle Adoption

While these savings are significant and, in the most aggressive cases show a reduction in light-duty vehicle emissions exceeding 50%, none of these adoption levels suggest that a fully decarbonized transportation system is imminent or within easy reach by 2040.

Conclusions

Electric vehicle adoption is anticipated to grow rapidly in the coming twenty years, becoming the majority of new vehicles sold in a number of the scenarios analyzed as a part of the study. Given starting points, vehicle lifetime assumptions, and purchasing trajectories, electric vehicles are likely to make up less than a quarter of all vehicles in Virginia by 2040. This level of deployment may still eclipse one million vehicles in 2040, a level of electric vehicle usage that will require expanded investments and deployments in vehicle charging infrastructure. Charging these vehicles will also increase utility generation and sales, potentially by double-digit percentage increases versus a world where these vehicles still relied upon petroleum fuels. The modeled outputs suggest this is especially of-note for Dominion's territory. Finally, net transportation CO_2 emissions are projected to experience strong declines, on the order of 18%-26% across all scenarios.

These are promising results for electric vehicles as a decarbonization strategy for Virginia, but even with a CO_2 tax of $30 and the most aggressive adoption schedule assessed in this study, net reductions are only 26% of the transportation sector's total footprint by 2040. If achieving full decarbonization of the transportation sector is the goal, additional policies will be required. Additionally, dynamic, flexible electricity pricing mechanisms and other options are likely to be needed to help the grid successfully integrate and flatten the new load as a means of keeping the impact on electricity bills low.