Value Creation and Market Making with Vehicle-to-Grid Technology

Aaron Anderson

University of Virginia,

McIntire School of Commerce:

Global Commerce Scholars Thesis

April 23, 2018

Table of Contents

1.1 Motivation for the Exploration of Vehicle-to-Grid Competition Factors

Electric Cars are expected to penetrate the world automobile market in a major way over the next 10 years. Auto manufacturers have announced their intention to develop many new lines that are entirely Battery Electric Vehicles(BEVs). Because of CO2 reduction efforts and the realization that clean diesel technology is unrealistic, battery manufacturers have been engaged to improve and grow their output. Lithium-Ion efficiency is expected to grow through the addition of graphene-coated silicon cathodes and anodes that may reduce the size and the cost of batteries dramatically. The efficiencies that are gained from using baseline power production and the increase in available renewable energy resources has made the prospect of charging a geographically ubiquitous fleet of BEVs a practical opportunity.

While the conversation about how to integrate their usage in to the current grid structure has focused on Smart-Charging as a tool to ensure an orderly queue, many novel ways to integrate BEVs more deeply into our electric grid have been proposed. Through the addition of an inverter these BEVs would be capable of providing many services directly to the grid by discharging power at their location behind an electric meter or as a grid-integrated generation resource. Because current energy markets rely on being able to deliver power when it is generated, BEVs have the ability to deliver power through time-based offsets or geographic offsets that can solve many of the technological and market constraints that have resulted from long periods of regulated competition. Through the provision of Frequency Regulation, Transmission and Distribution Capacity, Peak-Demand Shaving and a number of other emergency backup options, Vehicle-to-Grid technologies offer an alternative use to automobile batteries that will be underutilized if not employed for this purpose. Current revenue generation opportunities reveal large amounts of efficiency in the form of profits that can easily pay for the charging and battery technology. The scale of production for EV batteries will keep their costs well below those of stationary battery technology for quite some time.

It will be important to understand how best to deploy V2G systems in order to maintain the reliability of the grid and to ensure that entrepreneurial profit is available that encourages the development of this resource. The markets and systems for the procurement and delivery of electricity are complex and are controlled by many that have been given market protections so that social welfare is preserved. Competition has been strengthened through the opening of the Transmission Grid and the Generation Markets to many suppliers and participants, and federal agencies have been directed to make rules and encourage structures that are resource and supplier neutral. The net result has been to moderate prices and to provide deep justification for regulatory protections to specific operators or suppliers. Because V2G operations will provide efficiencies to each horizontal (Generation, Transmission, Distribution and Ancillaries), it will be important to ensure that those efficiencies can be captured by the investors and developers of the technology itself or there would be no incentive to create a pathway to participation. This will be difficult given that Vehicle-to-Grid is likely to further moderate prices. Battery Storage and other distributed energy resources are likely to result in a vertical externality that would require deregulation in the distribution markets to allow entrepreneurs to extract rent from distribution efficiencies. As BEVs will be able to distribute power to congested parts of the grid by having driven there, the need to expand or repair distribution and transmission grids may be deferred for many years.

There are also a number of concerns at the market level for trading the energy capacity of BEVs. Many markets have restrictions on quantities and duration of discharge that may limit the effectiveness of BEVs to deliver their potential benefits to the system. Many generators currently get paid to reserve capacity that can be deployed during periods of peak demand on the grid. These markets often require a minimum of 100 Kilowatts of power to be available for 2-6 hours of duration. This would limit a single vehicle operator from participating in the markets. Additionally, market coordination would be difficult if all retail operators were given access. The strongest case for resolving the cost of coordination and transactions in this situation would be to aggregate many operators under coordinating organizations that would be independent or associated with the existing utility companies or other Load-Serving Entities (LSEs) that currently operate in these markets.

Other new technologies such as Distributed Energy Resource Management (DERM) could integrate V2G to reduce the use of stationary batteries which would be underutilized when sized to provide all of the DERM's required storage services. By charging BEVs at homes during low cost periods, cars could be driven to commercial facilities and utilized to compress demands during the highest peaks and recharged during downward demand fluctuations to ensure continued transportation freedom.

It will be important to understand how much demand can be suppressed and how many reductions in the cost to operate BEVs that consumers will demand for participation. If enough vehicles are integrated it may be very difficult to maintain the level of economic incentive that keeps most BEV operators engaged. This is because increased efficiency may result in price reductions that will reduce the economic profit to Vehicle-to-Grid participants. The prospect of incentives from regulators may be required in the form of rebates and tax-credits for the construction of a charging infrastructure that is large enough to provide true efficiencies.

When the additional demand for electricity to power Electric Vehicles exceeds the baseline capacity available, it is possible that their participation in grid support will be required. New generators may find it difficult to scale as fast as BEVs become available. It is also possible that their participation will be in high demand from Wind and Solar generators that are trying to find a way to prop up their own revenues by charging cars and batteries when market prices are very low in order to sell at higher demand times. Finding a suitable partner will depend on the way that current participants choose to address V2G in their plans for the future.

1.2 Outline and Introduction to Electricity Markets and Vehicle-to-Grid

This paper demonstrates the explorable effect that electric vehicles will have on pricing and competitive balance in the electricity market. It is the industry expectation that there will be as many as one million electric only (battery powered) vehicles (BEVs) on the road by 2020 (International Energy Agency, 2017). I begin by outlining the technical and market forces relevant to the shock of adding electric vehicles as battery storage to the trade of electricity in the United States. This includes the many potential product offering that BEVs may present to current grid operators. We will then examine the economic literature relevant to current pricing models as they relate to the retail price scheduling and wholesale procurement of electric power in the United States. That literature allows us to build a framework for analyzing the shock of BEVs. We will continue with an examination of regulation, competition and possible mechanisms that would facilitate balance and incentives for the participation of BEVs in the electricity markets. In conclusion, we will discuss the risks of these market-entry options and conclude with a discussion of deployment opportunities.

2. Basics of Grid Activities and Battery Capabilities

2.1 Energy Converted to Electricity

Electricity, as we know it today is neither created nor destroyed. Electricity Generation stations, instead, convert it from mechanical work through a few types of transformational processes. The most common method is through electromagnetic induction where an alternating magnetic field is used to generate power. Power is the product of voltage and current. Current is the flow rate of an electrical charge and voltage is the electrical pressure of that charge. Current is measured in Amperes, and Voltage is measured in Volts. See the technical appendix for a deeper discussion about Generation, Transmission and Distribution specifics at the end of this document.

2.2 Electricity Production

There are many types of electricity generators. Most generate electricity by converting some form of potential energy into kinetic energy. Nuclear Power plants use the heat that is generated from a controlled fission reaction to produce steam; Natural Gas and Coal plants burn fossil fuels to generate steam, while Hydroelectric Dams store the potential energy of water behind a dam before funneling it into the turbines. These traditional generation sources are generally considered to be the most reliable forms of generation because of the opportunity to store the fuels and thus create a predictable supply of energy conversion.

The biggest limitations that electricity generators face is that they must produce when customers need the power yet they have generators that operate best at a steady state of output. They are often forced to build a wide range of generator sizes and differing fuel types to achieve this objective while minimizing costs.

2.2.1 Transmission

When electricity is initially produced it is in a voltage format that will experience heavy losses to the resistance inside of normal wiring. This resistance prevents low voltage electricity, the type that we use in normal appliances and commercial equipment, from being transported over long distances and in large quantities. This process used to avoid this problem is referred to as Step-Up Transformation. The Voltage gets stepped-up to a high-voltage format after it is initially generated so that it can be transported at lower resistance. This process is then reversed at the point-of-use and voltage is stepped down to a distribution level.

2.2.2 Distribution

Distribution is the neighborhood delivery level. Smaller transformers are placed in neighborhoods on poles or the ground to further step-down voltage to levels that are safe and consumable by small motors and other electrical devices. This stage of electricity transportation is the costliest and can create bottlenecks where neighborhoods or cities grow larger than the high-voltage transmission lines which feeds them.

2.2.3 BEVs as battery storage

The battery storage capability of a BEV represents a valuable, appropriately scaled storage tool for an electric grid that is considering stationary battery storage as an option for reducing peak/coincidental system loads, and as a method of shifting transmission and capacity to times of more efficiently operation. This reduces costs of operation where generation resources have fixed output levels or face transmission congestion issues. Battery storage can also function as a reservoir to smooth the momentary discontinuities in supply/demand matching that occur as dispatch algorithms race to keep up with the constant changes in the state of the grid system (Boynuegri et.al., 2014). This activity is called Frequency Regulation (FR).

2.2.4 Fast Charging

Bi-directional charging systems will also be necessary for BEVs to act as storage devices and backup power sources. These systems are expensive and often require infrastructure upgrades. The cost of bi-directional fast chargers, the hassle of coordinating vehicle usage, and potential battery degradation contribute to the cost of participating in grid operations. These issues must be considered when pricing and allocating to BEV operators. While the cost of electricity as fuel is thought to be at least half that of gasoline, those savings will not fully recuperate the cost of fast-charging or battery degradation.

3. Vehicle-to-Grid and Participant Objectives

3.1 Electrical Utilities and their Market Power

Utility companies generate, transmit and distribute electricity to consumers. Not all Utilities are vertically integrated. Many provide a limited combination of those services. There are five main types of Utility companies. Investor Owned Utilities, Public Power Utilities, Cooperatives, Federal Power Programs, and Independent Power Producers (FERC, 2015b, pp.36-40):

1. Investor Owned Utilities (IOUs) are for-profit companies that are licensed to operate in specific areas of a state. The interstate generation and transmission resources of IOUs are regulated by FERC and the local distribution for retail sales are regulated by state commissions.

2. Public Power Utilities (also called "Municipals") are not-for-profits that are owned by cities, counties, universities or military bases, and are usually regulated only by local authorities. Municipals often generate some of their own power and manage their own transmission and distribution systems while purchasing power from outside generators at negotiated, wholesale rates.

3. Cooperatives are also not-for-profits but are owned by their members. These entities must be democratically governed and operated at cost. Members vote for a Board of Directors and any excess revenues are returned to members. Cooperatives are most often operated in rural areas and agricultural districts where infrastructure would benefit their members and provide services that were not available from traditional Utilities.

4. Federal Power Programs are entities that have been established to solve a unique local electricity problem. The Bonneville Power Administration (BPA), the Tennessee Valley Authority, Western Area Power Administration (WAPA), the Southwestern Power Administration (SWPA), and the Southeastern Power Administration were established to manage and market hydroelectric generation and transmission in their respective regions. The BPA WAPA, SWPA, and SEPA are all Power Market Administrations that are responsible for the wholesale marketing of electricity that is produced at government owned hydroelectric facilities. The TVA is an independent, government-owned corporation that owns generation and transmission facilities that acts to transmit power to municipals and cooperatives as the primary wholesaler in its region.

5. Independent Power Producers are privately owned generation resources that operate their own plants and sell to utilities or, in deregulated retail markets, directly to retail consumers. In these arrangements, a transmission and distribution charge would also be assessed to the retail customer through an IOU or Muni.

There are many types of firms that have formed to provide electricity service to U.S. consumers, and many more that are engaged in the procurement of fuels to generate that electricity. Furthermore, many firms exist to provide the construction, maintenance and coordination of those services. It is important to note that those firms are composed of for-profit companies, government established not-for-profits corporations, and local cooperatives whose purpose is to serve rural communities. These firms have different objectives in their pricing and allocation practices.

For-profit firms are often limited in their ability to exploit the inelastic demand of consumers concerning electricity pricing. Regulators require that proposals for pricing go through an intensive review process, and the menu of prices presented to consumers is intended to establish predictable amounts of power at a consistent rate of return for producers. These firms often manage growth and earnings stability by cutting costs and creating scenarios for market expansion by selling excess power to neighboring areas and by carefully maintaining pricing schedules that cover fixed costs while grouping consumers into segments that allow for price discrimination based on bulk-rate discounts. While being forced to maintain a surplus production capacity by regulators, firms have a wide array of facilities that can produce at varying cost which places a priority on dispatching low-cost power first and stepping up production according to blocks of demand. Most large power production facilities operate at fixed levels of fuel and output efficiency (FERC, 2015b, p. 37).

Other firms operate under similar technical constraints, but, in the case of government and cooperative firms, they seek returns that are used to guarantee reliability and maintain service quality. These firms also are interested in providing power at a price that maximizes economic growth in the communities that they operate in (FERC, 2015a, p. 30).

When state and federal commissions examine this market, they chose a variety of objectives to pursue. These commissions seek to foster innovation when it supports their central mandate: to ensure a reliable supply of electricity to all Americans. This reliability mandate is considered an important national security concern, and anti-competitive protections have been central to achieving that mandate. As such, we see a lot of regulated, monopolistic pricing-programs, or some variation thereof, in every corner of the U.S. (FERC, 2015a. p.25).

Although protected monopolies exist, there is still a robust wholesale market where these geographically defined monopolies, power marketing agencies, and independent generators can sell to each other in order to meet the demands they must serve inside their respective service districts. Regulators have made these markets possible by forcing open access to transmission lines and by standardizing complex aspects of generation and transmission technology.

The literature on the subject of competitive balance in the electricity market has its history in demand economics and explains the current pricing relationships that are prevalent in the retail market. While there are substitutes, like gas and wood heating or self-generation, they are rarely competitive. The low cost of large scale production allows utilities to price at rates that usually out-compete on price. The literature suggests that monopolistic pricing has evolved into a menu of prices where price taking consumers select themselves into segments that can be grouped by price elasticity and consistent quantities of allocation(Laffont & Tirole, 1993). This allows producing firms to guarantee rates of return and to buy or sell power while knowing precisely what that power is worth at a retail level.

The wholesale market is complicated by the wide variety of suppliers, but it is made simple by the current lack of storability for electricity. In the most common auctions (day-ahead) price fluctuates by the relatively predictable fluctuations in consumer demand. Because electricity is measurable and its behavior is predictable in an engineered system, some have shown that the probability of most shocks, like transmission congestion and unexpected demands, are already accounted for in auction pricing (Wilson, 2008, 369-382). When shocks do prevent competitive pricing, regulators use mechanisms to detect and limit manipulation (FERC, 2015b, p.90).

It becomes clear that the amount of available information about power markets will allow us to understand the objectives for suppliers; and because of open-access to rate-cases and pricing schedules we are able to infer the demand characteristics of consumers with regard to their selection from the menu of rates. We know from experience that firms generally act as monopolists in the retail market, and that customers are at the mercy of available prices without strong substitutes. When we introduce electric vehicle capability into this scenario, we give new power to consumers to reduce their cost of consumption by using batteries to relieve consumption constraints or to shift their selections in the menu of prices. This new flexibility will force firms to react if their total revenues are affected and costs are not proportionately reduced.

Firms will want to adjust rates if BEVs are charged in a way that impede operators' abilities to coordinate and predict demand. They are also likely to negatively react when BEVs are feeding back to the grid at times which affect peak demand predictions and the expected revenues that are expected under the common fixed-cost-recovery provisions. Many other possible reactions may occur. Through this exercise of mapping objectives between the production firms and consumers with newly formed market power, we will be able to discuss rational solutions and ways to manage this shock. Based on work by game theorists, we should expect either increased benefits to all participants through cooperation or reduced efficiency through unilateral reactions(McMillan, 1992). It is not clear, however, that full information revelation is necessary given the monitoring tools used to track the momentary production/consumption of electricity.

Ideally this exercise will reveal a negotiation strategy for the introduction of Vehicle to Grid technology which encourages the penetration of electric vehicles while also rewarding electric utilities for encouraging innovation.

3.2 Battery Powered Electric Vehicles as Vehicle-to-Grid Innovation

There are many concerns about the widespread penetration of electric vehicles. Consumer willingness to participate effectively will determine the reliability of V2G (Kempton, 2016). Other concerns also threaten the central purpose of the vehicle as a transportation tool: battery capacity and the limitations behind travel distance and charging times. Most consumers will not want to be inconvenienced by rigorous schedule or administrative constraints, and it will be necessary that BEVs have higher battery capacity and that high-speed chargers are available to quickly recharge when necessary. These scenarios, bigger batteries, faster chargers and non-compliant BEV operators, present new challenges to a grid that requires predictability and reliability. Technical efficiencies will need to considered along with the probabilities associated with human error and forgetfulness, and daily capacities will need to be overestimated if fast charging is done during periods of peak demand on the electrical system. Involuntary load shedding, system failures, and high wholesale prices can result from inaccurate predictions of demand.

Because utilities must plan and construct sufficient delivery capacity years in advance, and electricity must be used when it is produced and when needed, it has been necessary to share supply and demand signals through pricing arrangements with retail consumers. This can be accomplished by scheduling charge times to match pricing and by introducing bi-directional chargers which enable an electric vehicle battery to discharge to the grid at times and in quantities that support reliable and profitable operation for firms and regulators (Kempton & Letendre, 1997, pp.157-175). This activity will be referred to in this paper as Vehicle-to-Grid capability (V2G).

The primary objective of Vehicle-to-Grid activities will be to more fully utilize the on-board battery while lower the cost to operate them. Fast-chargers are expensive, charge times inconvenience drivers and batteries degrade whether they are used or not. If financial and systemic benefits can be gained by increasing the utilization of Battery Electric Vehicles, the benefits can be magnified and their risks can be mitigated. Cleaner air, fewer greenhouse gases, integration of renewable generation sources, and the optimization of battery life are all potential benefits and noble objectives for encouraging V2G to flourish.

3.3 Regulation Objectives

The regulatory structure of electricity markets is complex and far-reaching. Electricity has always been heavily regulated because of the naturally monopolistic nature of the industry. High barriers-to-entry are coupled to a highly inelastic consumer demand. The need for electricity is balanced with the dangers and difficulties of generating and transmitting it. These relationships have made electricity a heavily regulated product. Considering that electricity markets are regulated at every level of production and consumption, we can expect that regulators take a lot of responsibility for the sources of competition in all electricity markets.

Many of the baseline electric utility resources are regulated to control abuses by large investor owned monopolies, and regional oligopolies have become necessary because of the massive investments that are required for reliable production capacity. The necessary scale of traditional electricity generation has created barriers-to-entry, and the baseline needs have traditionally been filled by low marginal-cost, large-scale production methods like hydroelectric dams, gas, coal and nuclear power. The current energy administration is concerned that these basic reliability resources should be protected from competition because of the national security risks associated with not having adequate fuel storage on site, and to prevent vulnerabilities to price fluctuations in alternative fuels that may threaten our access to baseline power needs (Perry, 2017).

3.3.1 FERC

Electricity markets are regulated by the Federal government to protect interstate commerce and to provide for national security. Various Federal laws have enabled oversight and reliability standards. The highest level of industry coordination comes from the Federal Energy Regulatory Commission (FERC), an independent agency within the U.S. Department of Energy. FERC was originally established to coordinate the interconnection of hydroelectric power plants across the country. They now act as the regulators for all interstate commerce with regard to electricity transmission and wholesale power markets. They are also responsible for the interstate commerce of natural gas and oil.

The Energy Policy act of 2005 required that FERC also enforce regulations concerning the reliable access to energy resources. Their two market facing mandates are:

1. Ensuring that rates, terms, and conditions are just, reasonable and not unduly discriminatory or preferential;
2. Promoting the development of safe reliable and efficient energy infrastructure that serves the public interest;

As such, FERC decisions about access and oversight in the wholesale energy market are not reviewable by the President or Congress except through the Federal Courts. All intrastate retail sales of Power are regulated at the state level (FERC, 2015a, p.24).

3.3.2 NERC: Reliability through Interconnections

In 2006 FERC designated the North American Reliability Corporation (NERC), a non-profit international regulatory body to ensure the bulk reliability of the electricity market. Their duty is to develop reliability standards, assess long-term and seasonal reliability, create system awareness and educate industry personnel. There are four grid interconnection areas under the authority of NERC:

1. Western interconnection: from Colorado to the West, including parts of Baja Mexico, British Columbia and Alberta Canada
2. Eastern Connection: All other US states except parts of Texas, and the rest of Canada excepting Quebec
3. The Quebec Interconnection
4. ERCOT Interconnection: most of Texas, excluding the Northern Panhandle

These interconnection areas are connected to each other only by small Direct Current transfer stations that are capable of temporary support which might be needed in the case of massive system blackout. They are connected to each other by single Direct Current stations that are capable of reconciling phase conditions that exist on different interconnection areas. DC power is capable of bridging this gap because it is not phase dependent (FERC, 2015a, p.25). In this case we will focus on the Eastern connections, specifically within the Mid-Atlantic region and the areas of Virginia served by the Regional Transmission Operator, PJM, under the jurisdiction of the Virginia State Corporation Commission.

3.3.3 ISOs and RTOs

Within the three main interconnection areas in the US there are regional transmission operators (RTOs) and independent system operators (ISOs). These organizations are similar and vary only in the level of responsibility to the transmission grid. RTOs and ISOs coordinate, control and monitor the operation of the electricity system within their territory. Some areas in the U.S. do not have ISOs/RTOs. In those areas, utility companies are responsible for the same rules of reliability and interconnection that the FERC enforces, but they must coordinate through their own councils or coordination cooperatives (FERC, 2015a, p.27). Most recently, FERC has been responsible for rules that require markets to accept generation bids that are fuel-source neutral. Another recent letter from the Trump administration has FERC considering subsidies that support coal and nuclear power in order to counter the reduced cost of Natural Gas generation as continental gas exploration has increased in scale (Perry, 2017).

The RTO in this study, PJM, was formed by an agreement between many vertically integrated firms in the Mid-Atlantic to assure that variations in regional demand could be met by establishing a central marketplace. This has enabled a broad range of steps in generation output that can more evenly match customer demand across a large region and ensure efficient output levels for a wide variety of fuel-types. These regional markets also allow for more procurement options when maintenance and capital improvements are required.

3.3.4 PUCs and State Corporation Commissions

States also have the responsibility to regulate those Utilities whom operate within their state's boundaries. Each state is responsible for the commissions that are established to conduct this activity. Many states have established Public Utility Commissions (PUCs) while others use the Corporation Commissions that regulate incorporated businesses in their jurisdictions. At the state level, commissioners are primarily concerned with establishing retail rates and tariffs that serve the economic interests of their constituents, ensure fair and reliable retail markets for electricity, and regulate the environmental and economic effects of utility operation. They are often acting as a body of mediation and legal action where disputes can be resolved between utilities and their customers. Rules that are established at this level primarily involve the relationship between a Utility and its retail customers or land-use and environmental concerns (FERC, 2015a, p.27).

The Virginia State Corporation Commission requires that all Load-Serving Entities (LSEs) in the state keep their rate agreements filed and that those LSEs justify rate increases through confidential reviews of cost and revenue histories. For Investor Owned Utilities the Commission requires a review of expected rates of return for similar private companies. Those agreed upon rates are then applied to the cost of generation and transmission plus accelerated recovery for capital improvements through additional riders that can be attached outside of full rate-case adjustments (State Corporation Comission, 2018).

4.1 Market Coordination: Access

In the early days of electrification, towns and cities developed non-profit structures that eventually led to the Depression era rural electrification program which extended the non-profit model to rural electric cooperatives. In areas where populations were dense, some investor-owned utilities were allowed to operate as regulated monopolies with exclusive franchises that entitled them to specific service territories. All of these business models still exist today but have given way to integrated resource planning with state commissions at the center of infrastructure planning proposals and permitting.

The RTO referred to as PJM, which operates from southern Virginia up through New Jersey and as far West as Chicago, was started as a power pool in 1927. It started the trend of regional coordination between grid operators. These power pools were formed to prevent Blackouts and later to pool resources for the war effort in the 1940s (FERC, 2015b, p.40). These multi-lateral agreement pools gave control of generation and transmission resources over to a central operating authority. Cost and capacity data were submitted to the central authority, and that authority established an energy management system which operated according to unit cost data, unit commitments, and economic dispatch.

4.1.1 Transmission Grid Access

Starting in 1978 with the passage of the Public Utility Regulatory Policies Act (PURPA), FERC was charged with increasing the efficiency of electricity generation and the inclusion of small-scale, renewable generation. In order to make this change, states were asked to estimate the size of the costs that would be avoided by increased efficiency and other qualifying generation facilities (QFs). Many states underestimated the cost savings to avoid disruption, but states like

Texas, California and Massachusetts were liberal about estimating the avoided costs, and, in turn, attracted an unexpected number of QFs willing to provide power (FERC, 2015b, p. 39). In many cases, these QFs were capable of exceeding the amount of avoidable cost and providing a surplus of lower cost power generation. This made PURPA a very successful program. It would be extended as an avoided cost auction where Independent Power Producers that had not been QFs could participate. By opening up protected markets to independent generators a new model of electrical service was being formed. This competitive initiative further pressed a transformation of the fully-protected, monopoly model.

Leading up to the Energy Policy act of 1992, FERC had been able to condition mergers and acquisitions in the electricity industry upon providing voluntary access to transmission systems. After the act was signed the commission was able to grant access by request, and, under order number 888, access and reciprocity was granted to transmitting utilities and entities such as Municipals, Co-ops and federal power companies.

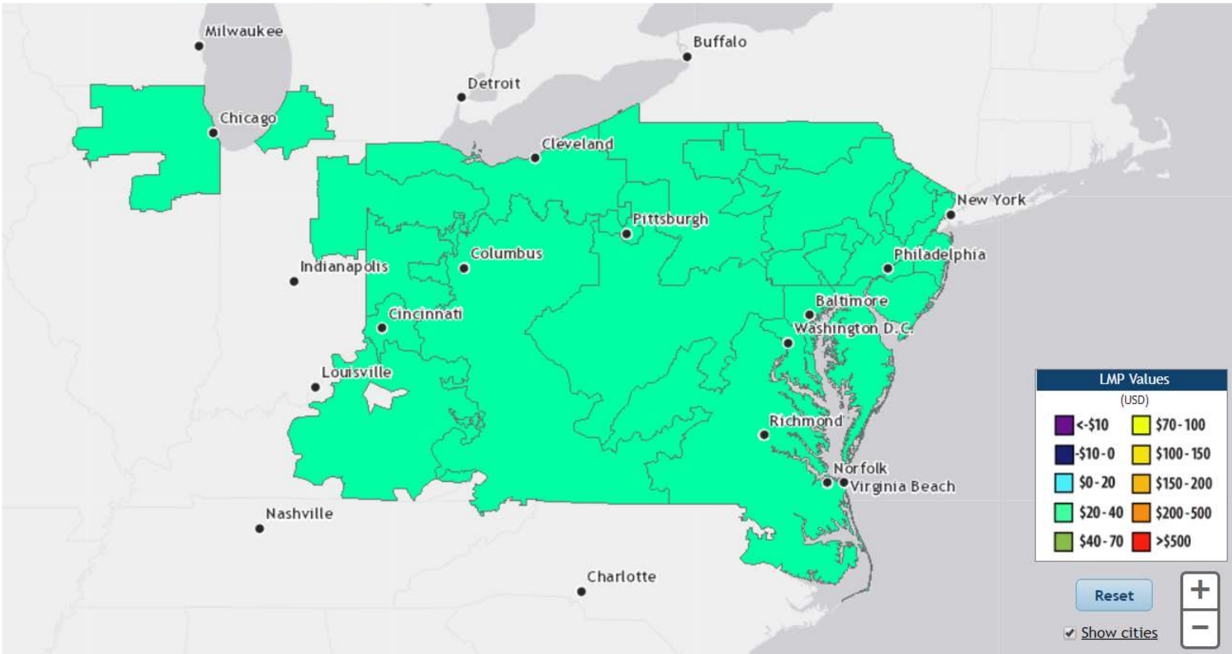
Under the subsequent rules, the Open-Access Same-Time Information System (OASIS) was established to maintain real-time transmission capacity coordination. Upon the open-access model, ISOs and RTOs would be expanded. This created region-wide wholesale markets that would extend transactions beyond the bi-lateral contracts and power pool agreements that had been ubiquitous. This is important, because today those ISOs and RTOs have formed the basis of the wholesale market, providing access to day-ahead and real-time auctions, demand response services and ancillary services like frequency regulation, spinning reserves and black-start commitments.

4.1.2 Open-Access Transmission Tariff

As open access to transmission systems has become a requirement for all interconnections, the necessity was born for a tariff to describe rates and mechanisms that are used to exchange power across service area boundaries and to share the cost of transmission. Each transmission operator and vertically integrated utility that is required to share access has the responsibility to construct an Open Access Transmission Tariff (OATT) that is filed with FERC (FERC, 2017). These OATTs also describe any additional capacity procurement processes and the method of cost-sharing that will be allocated to each Load Serving Entity which distributes energy to retail customers in that same interconnection region.

Transmission access is heavily protected. Any attempts to restrict access to these resources is seen as a violation of the OATT. If a generation wholesaler happens to own a Transmission line, it is necessary that fair-market pricing be established to share those lines. This is rarely an issue except during time of high congestion. Transmission costs are almost always reflected in the Locational-Marginal Price established by the RTO and is paid equally to any one bidding to provide that region with electricity. The RTO will also coordinate so that generation resources are compensated at prices inside of their nodes and that imports to higher priced nodes share congestion costs proportional to the difference in price between the nodes.

Locational Marginal Pricing Map



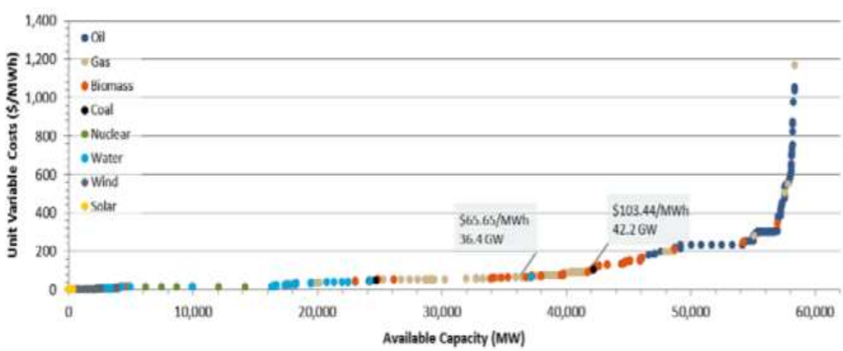
4.2 Wholesale Markets

4.2.1 Resource stack and Spot-Market Auctions

Vertically-integrated-firms are responsible for adequately serving the needs of the consumers within their FERC established service areas. In other markets, Power Pools, Munis, COOPs and individual providers are, along with Vertical-Firms, considered to be load serving entities (LSEs). LSEs are responsible for procuring an adequate amount of power capacity to serve their customers at all times. Much of this capacity is reserved through contractual relationships or, in the case of vertically-integrated firms and LSEs with in-house generation, through the scheduling of internal generation resources by operational and costs priorities and requests to the RTO/ISO for the acquisition of additional power on the spot market (which generally operates on a day-ahead and real-time schedule that is based on constantly updated predictive models that the RTO/ISO generates). In order to maximize the revenue of a given generator, bids are made by generation resources that match their marginal costs of production and the price is established at the required quantity set by the load prediction model of the RTO/ISO. Bidders that are not chosen to fulfil load requirements are given an opportunity to update their bids at some point near the end of the day's peak demand. The chart to the left shows a hypothetical example of pricing and clearing at differing levels of demand (NREL, 2017).

4.2.2 Capacity Auctions

The OATTs of RTOs and ISOs outline the shared responsibility of procuring additional capacity through Capacity auctions.



In most interconnections, the RTO/ISO is responsible for procurement of the additional capacity to meet reliability concerns through auctions. These auctions sometimes occur up to three-years early in order to respond with second and third auctions on the occasion that adequate reserve capacity is not met (PJM, 2017a). These auctions are constructed so that any LSE or independent generator can bid additional capacity, beyond that required to serve their retail customers, where a specific quantity is pledged at a price consistent with opportunity costs for that power.

This reserved capacity is expected to be accessed for a duration of a few hours during the rare system wide peak events in a given year. A price is taken at the quantity that clears the reliability obligation and the bidders are expected to maintain the availability of that reserve capacity throughout the year. Periodic tests are performed to ensure that those resources would be available at a 12-hour notice.

Winning bidders are paid according to the price taken in the auction multiplied by the number of days in the reservation period (sometimes seasonal, most often yearly). This reserve capacity may also be accounted for through demand response programs that LSEs establish. Demand Response programs can be cited to reduce the amount of reserve capacity that LSEs are billed for. Costs of the reliability capacity are divided amongst the LSEs according to their size and need, after considering the amount of demand response that they have procured from their own customers in the form of interruptible power, energy efficiency measures or other demonstrable peak-load reduction methods (PJM, 2017a).

4.2.4 Ancillary Services

Regional Transmission Operators like the local one called PJM are responsible for procuring emergency backup power, peak-demand reserves, and frequency regulation services. These products are used to supplement the power that can be procured in the daily and day-ahead wholesale markets. These products are procured through registered and committed providers and those providers are often rewarded for forgoing the consistent revenues that are available from those regular auctions. Procurement for these ancillary resources occurs in auctions and registration activities that proceed the execution of these services by as much as 3-years (PJM 3, 2018).

4.3 Retail Markets (State Corporation Comission, 2018)

Selling retail electricity can be done by the traditionally, vertical integrated model or by a more competitive commodity model where electricity is openly-traded at a going-rate. When the market is vertically integrated, a Utility is responsible for generation, transmission, and distribution. Their rates are set by the state commission according to the cost of supplying that power and an additionally reasonable rate-of-return. This rate-tariff is presented to the state commission and, after a comment period and the introduction of evidence to support claims about costs and expected returns, the rate is either accepted or returned for alteration. This process is referred to as a rate-case and is given a regular period of review under each state's legal framework.

The tradeable-commodity method of purchasing generated electricity is monitored by the location of the market at a particular transmission hub location and competitive pricing is enforced. State corporations are responsible for monitoring the effective rate that their constituents are paying in this deregulated model and ensuring that a number of traditional options are also available to customers that wish to remain in the traditional, cost-recovery model.

Under both methods of purchasing power, there are many types of customers, and they are charged for power based of the size and duration of the demand that they present. All electricity customers have some type of meter connecting their facility to the distribution system. These meters usually measure the size and duration of the load that is demanded. Increasingly, meters are also used to measure the reactive demand (kVrA) of the load. These measures are used to characterize the overall quantity of consumption, the magnitude of the consumption as a measurement of the highest peak during a given period of time, and the size of the field of current that is established by motors or other electromagnetic features of the facility.

4.4 Demand Profile and Drivers

Customers have traditionally been price takers, as the marginal cost of utility-scale power production is far lower than most retail level consumers could find substitutes. Additionally, the small fraction of customer income that electricity purchases consume shows that income effects do not have a significant effect on willingness to consume or standard levels of marginal consumption (Wilson, 1993). We generally observe demand fluctuations that are consistent with the operation of heating and cooling machinery, lighting requirements or industrial motors and pumps.

Consumer demand is often segmented as either base-load or peak-load. Because of the lack of full scale storage, a refrigerator that runs continuously versus an air conditioner or heater that runs intermittently based on weather conditions, explains the fluctuating character of the demand profile for electricity. This variation is as unpredictable as the turning off and on of every light switch in the entire country. Day and night, seasonal weather differences, and industrial production schedules all act to create a complicated market coordination process for system planners. As demand grows, the cost of providing power rises while the most economical resources are dispatched first. Power prices are typically highest during times of peak demand and much energy is devoted to predicting weather effects and economic growth in order to forecast those peak demands.

4.4.1 Inelastic demand and substitutes

Most retail demand is inelastic, in accordance with the menu of prices and consumption is based the use of tools that are essential to lifestyle and industrial processes. The use of these tools responds slowly to price, and demand tends to drive only wholesale prices when the system is under stress. Other options for consumers who wish to reduce the cost of their electricity consumption are to build their own generation facilities or implement major energy efficiency measures. Governments and Utilities have also implemented demand-response programs that reward consumers for reducing their demand during peak production moments, forgoing additional revenue in order to avoid the risk of procurement costs that may exceed established retail rates.

4.4.2 Residential demand

Approximately 37 percent of electricity demand comes from residential customers (FERC, 2015b). Load shape is most varied in this market segment. Prices are typically the highest because of inelastic demand and the complexity of residential distribution systems. Residential demand is also small in its magnitude compared to the variation in its duration profile. Many residential accounts peak below 5kW capacities.

4.4.3 Commercial Demand

Commercial customers include offices, restaurants, hotels, warehouses, and medical, religious and educational facilities. Over 50% of commercial consumption (FERC, 2015b) is from heating and cooling loads where peaks are coincident to high and low temperatures at times of high building occupation. This segment accounts for about 36 percent of total electricity demand.

4.4.4 Industrial Demand

Industrial customers demand the remaining 27 percent of power consumed on the grid (FERC, 2015b). These customers often use large motors that pump water, grind minerals and process large amounts of raw material. The lowest prices are afforded to these customers as their load profiles are the most predictable and mutable. They can also take delivery at high-voltage where industrial machinery and the presence of customer-owned stepdown transformers shifts infrastructure costs to the customer. Industrial and Commercial rate schedules are often characterized by duration rates that are very low and measured in kWh, but also include high demand charges (kW) which encourage flatter demand profiles or energy management systems that limit the magnitude of peak demands. Industrial customers also represent the most elastic segment, where loads can be shifted to alternative shifts and energy sensitive production schedules. Because of the scale of consumption, industrial and commercial customers may see large economic benefits from reducing their peak demands and flattening their load profiles or introducing energy efficiency measures in their facilities (FERC, 2015b, p53).

Most residential customers purchase power by the kilowatt hour. This is because, compared to the large variation in demand at commercial or industrial facilities, residential customers have relatively small peaks in power consumption (2-7kW versus 25-1000kW at commercial facilities). This allows generation and transmission facilities to establish a constant supply for these customers at predictable costs as they are able to control for average amounts of consumption over a large number of similarly characterized consumers.

4.5 Load forecasts and Reliability models (PJM Interconnection 1, 2016)

Power pool operators, ISOs and RTOs often engage in load forecasting activities in order to comply with reliability standards as set forth in their OATTs. These forecasts establish expected loads for each time period in a day, season and year. Load-forecasting models are usually regression models that account for the heating and cooling equipment specifications of a region, weather data, historic consumption, economic data and demographic profiles. Short-term, medium-term, and long-term forecasts are used for different purposes.

Long-term forecasts act to inform auctions for reserved capacity that is used as a buffer to shocks that may occur throughout the year such as system crashes or extreme weather. Medium-term forecasts can be used to correct long-term forecasts with updates to economic or weather expectations, and short-term forecasts, the most accurate of all the models, are used to schedule power that will most certainly be generated, transmitted and consumed from trades in the day ahead or real-time market.

These reliability models are intended to establish a total capacity level that exceeds predicted demands by 20 percent, in most cases, according to FERC regulations. This seems like a large margin, but, what is more surprising is that, some load predictions are sticky when faced with actual changes in demand while their models depend heavily on equipment and the potential loads from the equipment that is connected (PJM, 2017c).

In the PJM RTO a model called the Reliability Pricing Model is used. This model uses a large number of variables to predict demand. Historic temperatures and auto-regression is used, but, more importantly in this model, the actual heating and cooling equipment that is on-line, industrial and commercial equipment, and correction factors for congestion. This model was built to accurately overestimate needs to prevent system failure under extreme conditions. Some of the time variables involve historic demands that average more than 18 years of actual demand. Unfortunately, this estimator takes away incentives to reduce peaks at the local level because of the slow reaction of the model to account for efficiency upgrades (PJM Interconnection 2, 2016). These upgrades must be formally registered and often times automated to the control of the RTO to result in reductions in cost-sharing to local retail providers.

5 Tools for Analysis

The literature regarding V2G potential is prevalent in the electrical engineering world where many have considered the optimization of dispatch models and the revenue potential for storage-based arbitrage and as a generation resource in the wholesale procurement auctions. Few of these papers focus on the market power of BEV operators (Benjamin K Sovacool et al, 2018) or the reaction that Utilities and other major players in the power market might have to widespread BEV penetration.

5.1 Game Theory

It is possible to access the extensive world of game theory by thinking in the world like a game theorist. To do this we follow the example of McMillan (1992) in teasing out the principles that are most important to the type of games we are playing. We stick to the basic idea that efficient outcomes are ones where we achieve the best outcome for all players given the constraints of the game, and we assume that each player has made the most rational choices available given the information and abilities granted to them. Objectives are necessarily defined in order to establish the value of the possible paired outcomes.

The simple two-party games are the easiest to understand and analyze. When I am unable to limit participants to only two groups it will be to suggest that an outside party may behave slightly different if alternative objectives are established. It is, however, reasonable to assume that, when this is the case, it is because one of the parties (generally the vertically integrated firm) has a dominant strategy. That is, the monopolist has control over allocation and price even though this relationship does not fully favor the monopolist. At different rates and allocations, the consumer may simply be forced to consume less at a higher price or more at a lower price which leaves the monopolist in a position of needing to engineer an optimal pricing relationship for both parties (McMillan, 1992). This is only possible if the preferences of the consumer are well understood by the monopolist, and this can be achieved by offering predefined ranges of consumption and price which the buyer will self-select into.

Most of these games come with the assumption that varying strategies for the participant are often less important than the structure of the game itself. Choice is important, but if the options of a game are limited, then the likely outcomes can be predetermined. Since this is true, then it is important for a negotiator or market participant to understand the possible outcomes, and, in more complicated games, index the available settling points to the options and the expected values of each party. We can do this broadly by knowing what our next best alternatives are and by applying the lessons we have learned about shaping the game or loosening its restrictions.

After explaining the basic structure of many of the outcome matrices, McMillan makes it clear that properly constructing incentives for cooperation and information sharing are essential to finding efficiencies when most settling points are not naturally in favor of it. In auctions, structures such as reserve pricing, open/closed bidding, and strategies to avoid the winner's curse can result in more collective benefits by commitment and information sharing (2015, pp 142-143).

I expect that we can infer changes in market forces and behavior by observing the objectives of the participants and the range of possible decisions that they can make about finding a balance in their competitive relationship. In McMillan's discussion of dominant strategies, he reveals that worse outcomes may come from absolute assertion of market power, and that outcomes in complex arrangements can be determined by technical constraints or geographic locations. We also see in his discussion of contracts and procurement details that we can assume those arrangements reveal information about the potential direction that future pricing and allocation measures will take (2015, pp. 163-178).

By characterizing the shock of V2G activities through current pricing contexts, we can better understand the tensions in those relationships.

5.2 Nonlinear Pricing

In some monopolistic scenarios, like those that exist in the electric utility industry, we see a downward sloping supply curve where production stops when marginal revenue reaches zero, or, alternatively, the supply curve is tied to demand elasticity of the consumer. When these markets become more competitive and the product is sufficiently differentiated, or in the case competitive oligopolies where perfect substitutes exist and the number of firms is still small, pricing that ensures a predictable rate of return can be achieved by matching supply constraints to variability in demand (Wilson, 1993, pp. 98-122). For the Utility firms, fixed costs can be huge. The cost of building transmission lines, distribution systems and generation plants can be large and the varying levels of utilization for each customer create issues of scale at different moments of use.

5.2.1 Multi-part Tariffs

Wilsons work emphasizes the idea that we can limit supplier surpluses by creating a menu of price schedules that would balance the need of vertically integrated monopolies to guarantee returns while minimizing prices to retail customers. Customers would in turn be incentivized to operate inside a predictable demand profile that results from the segmentation aspect of tariff option boundaries. These boundaries consist of steps in fixed monthly charges and strategically placed steps in duration charges (Wilson, 1993, pgs. 141-163).

When a customer selects into one of these ranges, they often remain there to avoid stepping into the next range. An indifference barrier has been formed by the next step in fixed fees at a higher rate of consumption. This barrier also moves most consumers toward the center of the range of prescribed quantity in that range and the utility is able to coordinate and plan for that customers consumption without risking over or under procurement to serve their load. This then allows them to cover fixed and marginal costs which coincide with the blocks of generation that are formed by the technical limitations of the production facilities.

5.2.2 Disaggregated Model

The size of the steps in a specific fixed "subscription" rate form a boundary where a customer would choose to pay a higher marginal rate all the way up to the duration limit in the tariff. When this fixed rate becomes large in the case of high-quantity consumers, an additional charge (demand charge) is added to the first order duration charge, which is calculated by measuring the magnitude of demand at its highest peak.

5.2.3 Capacity Pricing

While the fixed rate in a given schedule would be acceptable to someone who had low peak-demand yet were paying a discounted rate for duration, this third "capacity charge" would compensate the firm for the additional fixed costs of serving high peak demands (especially during time-periods of high, coincidental, system-wide demands) while not further reducing the duration rate that equates directly to marginal costs of production (Wilson, 1993, 259-277). These demand charges also serve to incentivize the customer to monitor and control their peaks, reducing the probability that peak loads that cannot be satisfied momentarily by the system.

5.2.4 Effects of Transmission Constraints and Technical Constraints

Because firms may have:

1. multiple sources of generation with an array of technical constraints
2. a wide variation in location-specific deliverability constraints
3. and outside regulatory constraints,

a variety of mechanisms may act to serve a broad range of market conflicts. Wilson's work on transmission constraints presents us with analytical tools to understand the efficient method to price geographically complicated problems, similar to the locational problem in game theory, by testing the shock of deliverability constraints on the level of transmission capacity limitations that exist in isolated nodes of the network. His conclusions are that we should assume that a premium is always achieved in the market to account for the regularity of congestion shocks and that the day-ahead market reflects hedged prices against the risk of transmission congestion (Wilson, 2008). From this we assume that Locational Marginal Prices reflect the total costs of delivery. This belief is also reflected in the fact that the RTO provides compensation to adjust when Day-Ahead prices are lower than Real-Time prices.

5.3 Auction Theory and Mechanism Design

We will also need to analyze the reaction of auctions to the inclusion of V2G as a capacity resource. Paul Milgrom (Milgrom & Ebook Central - Academic Complete, 2004) stresses the importance of designing auctions to satisfy a variety of desirable goals. His work has been used to create radio frequency bandwidth auctions that have maximized price for governments sellers and improved access to the most appropriate products for a variety of buyers. This is often done by requiring each potential buyer to register their intentions or reveal information about the value of various products (2004, p. 40). He also shows that by optimizing a price at the auction you will prevent side-deals or post auction transactions that would reduce the auction efficiency (2004, pp.19-21).

What complicates auction mechanisms is that by introducing many elements to allocation and pricing constraints, we make it more difficult to identify the most appropriate tools from the array of possibilities. What Milgrom deduces from studying various mechanisms is that many auction rules result in equivalent outcomes (2004, pp. 64-97). In other words, just like the results we have from studying game theory, appropriate auction mechanisms require adjustment of price and allocation, and will not always fully favor the seller but can be used to maximize the overall quantity of allocation while controlling price. This gives us that a well-designed auction must be used to achieve multiple purposes: information revelation, participation constraints that result in appropriate allocations and limit post-auction transactions, and incentives that accurately reflect the benefits of information sharing and allocation standards.

The auctions of electrical power in the day-ahead and real-time markets have been constructed to force the revelation of information by asking for quantities and prices simultaneously. It is well known what the costs of production are for the various participating firms. We have a record of them because of the repeated nature of the auctions and the transparent nature of the regulated firms. Because pricing at or near marginal costs is occurring, market makers like PJM have created products separate from the daily trading that focus on providing support for the rare moments of high demand and limited supply or equipment failure.

When the auction master predicts demand peaks or supply shortages, price limits are established and reserve power that has been acquired in capacity auctions years before can be applied to soften supply constraints (PJM, 2017a). This ensures that prices are limited by an alternatively profitable auction. Milgrom (2004, pp 265-278) discusses this type of auction as simultaneous ascending bids. Milgrom contends that by creating substitutes and compliments across multiple auctions, we can achieve the regulators objective of limiting prices and maximizing the public benefit. Through variations in allocation that encourage firms to choose the less risky option of participating in the advance auctions for reserve capacity, we can limit non-competitive outcomes in the real-time auctions.

6.1 Vehicle-to-Grid and the technological constraints of Battery Electric Vehicles

Electric Vehicles have taken many forms in the last twenty years. Beginning with the early adoption of Hybrid-Electric Vehicles Willett Kempton and Steven Letendre (1997) have posited that this new technology could be leveraged to benefit the grid while quantifying the potentially disastrous consequences of not creating incentives for appropriate charging schedules through "smart charging." (Kempton et al, 2018) Their work also catalogs a number of important potential revenue producing activities that would benefit the grid and the electric vehicle operator. Those characterizations have been based on vehicle charging and discharge capabilities at the time of their study. These parameters have been altered by a growth in scale and new developments in battery technology, charging capability and reactions by Utility markets that would shift the recommendations that they have made.

Many limitations about duration and quantity of committed capacity exist in the current market rules. Aggregation of multiple BEV/Fast-Charger combinations would be required to participate under current wholesale rules (PJM Interconnection, 2018).

6.2 Participation Options

6.2.1 Frequency regulation as an ancillary service

The holy grail of early speculation about V2G services has been to provide frequency regulation to RTOs and ISOs (Benjamin K Sovacool et al, 2018). The need for frequency regulation is a result of mismatched supply and demand, and this is an example of the reservoir type services that BEVs can provide. While this is a service that batteries are uniquely positioned to provide, the lack of seasoned rule-making has resulted in financial losses to many stationary battery storage investments.

After allowing battery storage units to provide frequency regulation for a few years, in the Spring of 2017 PJM introduced a new dispatch model for selecting and operating their frequency regulation market that heavily favored traditional sources. While this new process was implemented to avoid problems created by using batteries for this purpose, corrections to market operations did not account for the value that batteries bring by their high response time to needs on the grid (FERC 2, 2018).

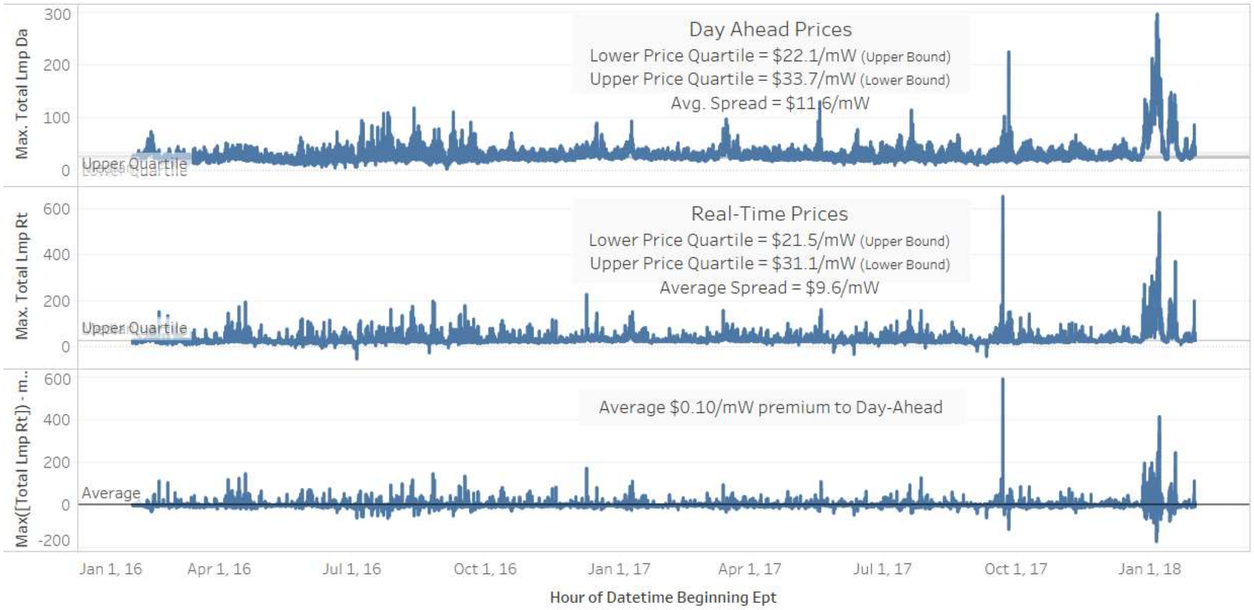
Batteries can respond to frequency needs in seconds. Traditional frequency response requires up to 15-minutes to come on line. Because batteries do not generate their own power, the cost of providing FR increased for battery owners and profits dropped dramatically.

The value to the grid behind this service has not been lost, but a participation constraint has been created by the RTO in favor of generators that had traditional provided that service (FERC 2, 2018). This occurrence also characterizes the power that regulators have to make technical adjustments in favor of incumbents. A small number of battery investors without participation guarantees could not continue reshaping large incumbent's revenues without a strong reaction. In this case through a policy shift in operational requirements. The ability of battery storage entities to provide this service is a result of the speed at which batteries can charge and discharge while being able to respond very quickly.

6.2.2 Power delivery arbitrage by valley filling and selling at peak-demand

The capability of charging at moments of low price and discharging at a profit is a function of the spread in the purchase price, whether retail or wholesale (BEVs could operate in either market if located behind a retail meter), and the total capacity of the battery considering state of charge (Kempton & Letendre, 1997). The newest BEVs have a capacity of 60kWh. Which means that they are able to provide any combination of duration and flow that equals 60kWh (e.g. 5 hours at 12kW). The charge and discharge rates are also limited by the rating of the charger which forms the connection between the grid and the car.

Low cost chargers are not capable of discharge. The ones that are capable of discharge have a current price tag that starts at $10,000 and goes up to $25,000 when capable of communications options and features that enable use by the general public. These chargers are capable of charge and discharge rates that exceed 10kWh. A 25kWh charger would be capable of charging a 60kWh battery in roughly 2.5 hrs. Upon discharge we would expect a 10% loss from inverting the power back to AC from the DC state in the battery. This is the result of energy lost through heat at the individual cells and the transformer/inverter.



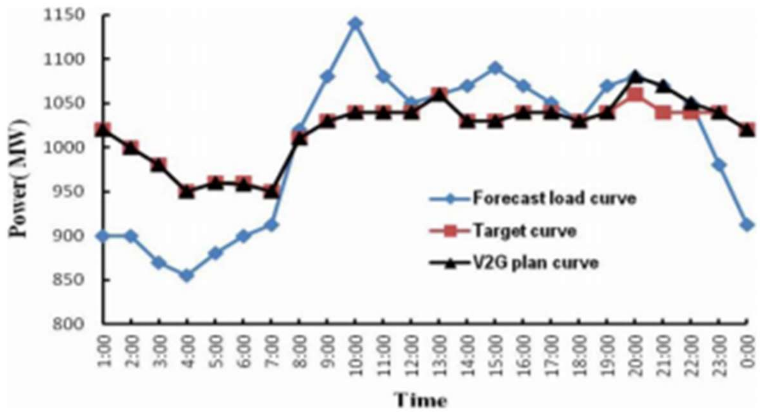
The trends of maximum of Total Lmp Da, maximum of Total Lmp Rt and Max([Total Lmp Rt]) - max([Total Lmp Da]) for Datetime Beginning Ept Hour. The data is filtered on Datetime Beginning Ept Month, which ranges from February 2016 to January 2018.

In order to estimate the current value of time-based arbitrage, as an example, we can use the data above from the 2016-2018 PJM Data Miner. We can see that the spread in the Day-Ahead and Real-Time Prices is around $10/mW which translates to $0.01/kW. We could then multiply the 60kWh by the loss factor of 10% and assume that we might earn $0.54 from 4 hours of work if the spread remained constant for that time period. If the energy to re-sell were purchased under an EV-only, retail plan, spreads could grow to around $0.02/kW. This would increase a yearly benefit to nearly $730. This would still not account for the cost of a bi-directional charger in almost 20-years.

This opportunity may be lucrative at larger spreads, but the size of the battery and losses present few incentives for this kind of participation. However, this is an accurate example of charger costs, battery capacity, and charge/discharge rates. Additionally, time-of use spreads rarely exceed $.05 (except during periods of extreme demand), as typical kWh prices rarely vary by more than $0.015 according to PJM market records[1].

6.2.3 Direct-Load Control

Direct-Load Control is more accurately referred to as behind-the-meter peak-shaving. This activity involves placing a car and a fast-charger behind a meter at a commercial facility with a load profile that allows for reduction in demand charges (also referred to as Capacity Charges, (Wilson, 1993)). When a fully charged electric vehicle is discharged during times of peak demand, a customer that is on a Capacity Charge tariff may choose to limit their load profile (Kempton & Letendre, 1997). This activity can reduce monthly charges by as much as $500/month in states like California where demand charges are highest or by as little as $250/month in states like Virginia where they are the lowest[2].



[1] Calculations based on (Kempton & Letendre, 1997), prices and vehicle capabilities updated to reflect level-3 charger from Princeton Power and 2018 Nissan Leaf Battery Capacity and on-board dispatch capabilities in a commercial building with 480 Volt 200+Amp Service

[2] Using a 25kW capacity charger and assuming demand charges between $10-20 based on scenarios described in (Kempton & Letendre, 1997)

7 Data Analysis

7.1 Data for market parameters in PJM

Statistics in this paper about electricity supply and demand rely on a data set from the Regional Transmission Operator from the last 3 years to characterize pricing and demand structures. I have downloaded a large set to a SQL server and use Tableau and other data analysis software to map pricing, demand and time-of-use characteristics to identify pain points in the system and to create summary statistics about price ranges and price elasticity of demand. The data are aggregated at the RTO level and, in order to limit the scope of this inquiry, do not include available data on local operations and specific equipment involved.

While available data includes information about congestion, the pricing does not show a clear connection to actual emergency events so I have relied on investigational reports by the regulator to characterize those events. Individual event reports will be cited alongside of that analysis.

7.2 Data Gathering Process

Data is available from the Regional Transmission Operator, PJM, through their website and on energy.gov. The PJM market data is very specific and used to reconcile transactions between traders in that system. It is very accurate and potentially very granular. The datasets can be very large if not sorted in to system-wide counts. I have used RTO level data for most descriptions of the markets. More local data is available if a deeper look at local pricing issues and transmission congestion analysis is desired.

I have downloaded the data from PJM's Data Miner as .csv files and imported them into a SQL server in order to join tables and compare prices over time. Data analysis and visualizations in this paper have been done using Tableau and the analysis tool therein.

7.3 Missing Data and Externalities

Little information is available about the actual costs of operating the distribution system yet this is an area I believe will experience great efficiency from the introduction of V2G. By moving electricity geographically from suburban residential areas to dense urban locations the central portion of the grid is supplanted by the physical movement of the vehicle. This means that the congestion that would be caused by moving the electricity from a rural generation location to the urban area could be avoided by the exact quantity of power that could be discharged from the vehicle battery at the opposite side of the congested transmission area. This same principle can be applied to different sides of the distribution grid if similar principles are applied to a denser geographic area.

Low night-time congestion could be used to move excess power into battery storage and, if distributed evenly across that distribution system, could be discharged when congestion in that distribution area is high. Local distribution systems have transformers that step-down power to specific users. This unit of distribution, below the final transformers, would be the limited geographic area that V2G could be discharged to when located behind a residential meter but would reduce congestion on the upstream side of the transformer by reducing the demand to that point. To study this, we would need to understand the costs associated with maintaining those systems. This information is closely guarded by the entities that enjoy regulatory protection in most of these cases. Some information is available, but Sam Lovick argues that, often, a new technology like this creates benefits across multiple areas of the market but is prevented from reaping that benefit because of protections intended to protect incumbents from unfair competition. If there are extensive benefits to the distribution network from V2G, those rents will be very difficult to extract for the V2G participant. Unless the incumbents or state regulators recognize V2G for themselves.

8 Market Analysis

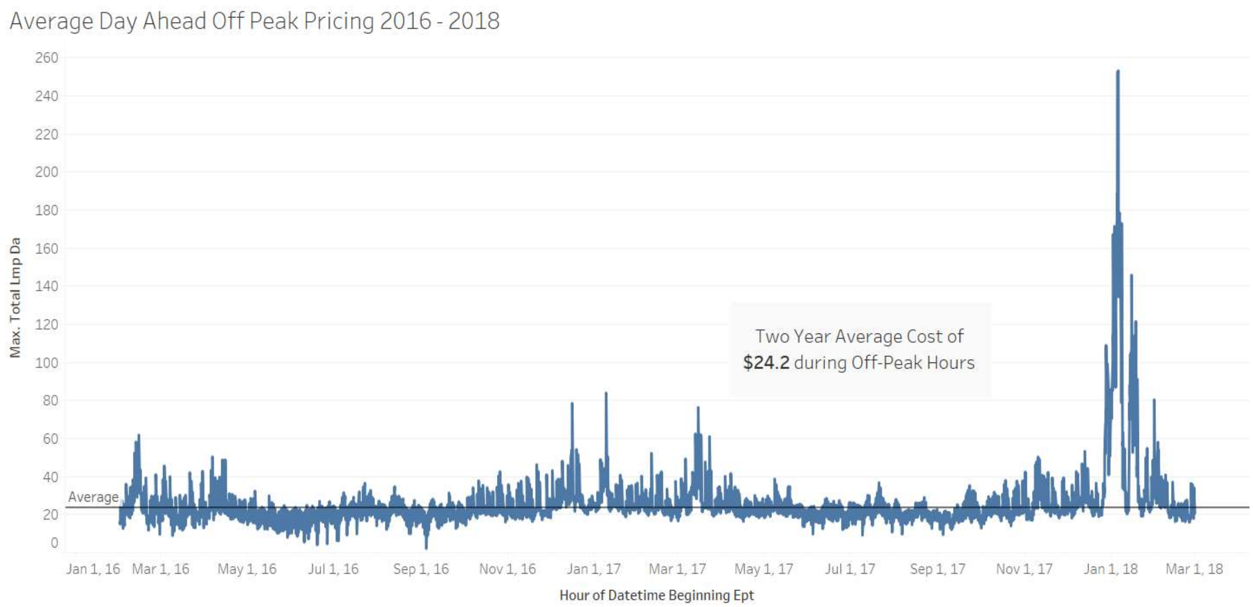
By examining current tariffs for Dominion (dba Virginia Electric and Power Company), we will examine the simple retail case and the only current situation created specifically for Electric Vehicles in the existing filings. A copy of the relevant tariff documents can be found as Exhibits 1 and 2. Pricing at this level represents the rates paid for each aspect of electricity delivery.

All examples will address Generation, Transmission and Distribution costs and constraints, as well as the economic outcomes for participants. We will assume that retail pricing is relevant to the underlying costs with the exception that retail rates are relatively constant compared to the real-time costs of procuring power and delivering it from the wholesale market. This analysis will act to characterize the competitive relationship with regard to potential V2G opportunities and define the limitations of scope, function and competition as the electricity markets are currently structured. Following this discussion, we will look to market entry options best suited to these constraints that give Vehicle-to-Grid participants and incumbents the best incentives to cooperate.

8.1 Simple Residential Rate-Case

I begin with the simplest case of slow charging a BEV, at night, using a low rate of charge. This activity is consistent with the current norm of plugging a car in to a garage outlet at night and letting it charge until the morning. In the case of the 60kWh Nissan Leaf, this could take a full 8 hours at a 7kWh transfer capacity and longer at even lower charger capacity (Exhibit 1).

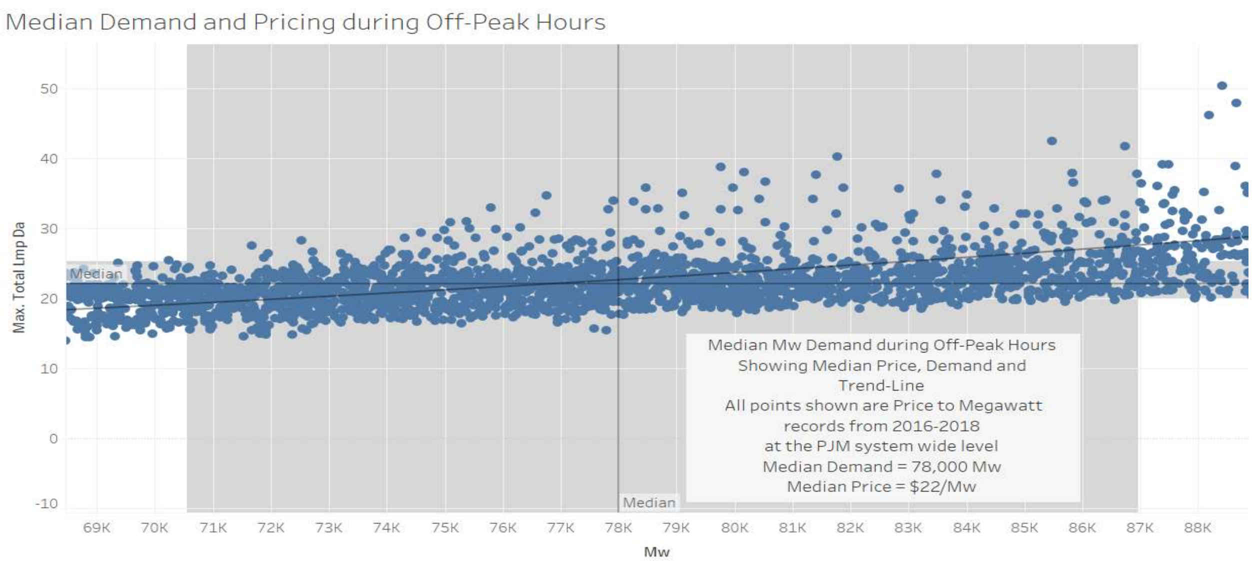
The BEV operator in this scenario is a typical residential customer, on either a simple residential rate schedule, or one with reduced night time kWh rates which are intended to encourage this behavior. The consumer is a price taker, and it is assumed that reduced rates for night-time charging are an experimental rate schedule intended to derive information about demand profiles



The trend of maximum of Total Lmp Da for Datetime Beginning Ept Hour. The data is filtered on Datetime Beginning Ept Hour, which keeps 9 of 24 members.

and incentive compatibility in order to better construct future tariffs. Dominion as the utility has the rational objective of maximizing its revenue by selling more electricity within its low-cost capacity block while avoiding the wholesale pricing risks of procuring during high demand time-periods. The consumer is limited to continuing this behavior by considering the additional cost of charging at other times. In the case of the simple residential rate (Virginia Electric and Power Company, 2017, p. Schedule 1), customers pay around $.07/kWh and a basic monthly charge of $7.00. Under the EV pilot-rate (Schedule 1-EV), the customer will pay $0.13/kWh to charge during the day and as little as $0.014/kWh to charge at night only. To fully charge a 60kWh battery (equivalent to 150 miles of use) this would cost the customer $4.20 per day under the traditional plan and $0.85 per day under the EV pilot-rate. This low rate also assumes that Dominion can procure electricity during this time for rates that average below this $14/Megawatt threshold. Current price averages in the day ahead market would suggest that Dominion is sacrificing market value if selling this low. The 2-year average for Day-Ahead Prices are $24.2/Megawatt hour or $.0242/kWh.

Also, another important risk to consider is that of rising prices at the wholesale market because of the increased demand. This risk can be characterized when we view the trend line in the graph below.



The plot of maximum of Total Lmp Da for Mw. The data is filtered on Datetime Beginning Ept Hour, which keeps 9 of 24 members.

The trend-line shown is described in Exhibit 2 and reveals a definite procurement risk as the number of Electric Vehicles increases. If the number of vehicles consuming half of their battery capacity per day were to increase from the 1000 allowed in the EV-rate to 200,000, the median price could rise as much as $0.12/Mw or $0.014 with 200,000 new EVs. These prices are consistent with a profitable state under current residential electricity rates, but not sustainable under the current EV-rate.

The following chart compares the two rate schedules discussed above:

Dominion Tariff Items	Fixed Fee	Additional Customer Costs to Install additional meter	Night time charging: 60kWh battery-full charge	Day-time Charging: 60kWh battery-full charge	Cost/Benefit to Customer compared to best alternative	Cost/Benefit to Utility
Schedule 1	$7.00	$0	$.07/kWh: $4.20/day	$.07/kWh: Same	-$3.35	Potential need to acquire energy at market
EV Pilot-Rate	$7.00	$1200	$.014/kWh: $0.85/day	$0.13/kWh: $7.80/day	+$3.35 or -$3.60	-$3.35 or +$3.60

For the Utility, they have given up $3.36 per day to test the rate (alternatively, half of that at 75 miles of daily vehicle usage), but also to entice the customer to maintain those night-time charging habits. At the limited scale of the 1000 vehicles permitted under this schedule, no dramatic cost-shifts should be experienced by Dominion and it would take one-year of participation at the maximum rate for the consumer to re-capture the cost of their infrastructure upgrades.

The current arrangement works well for the utility, but, if high rates of BEV penetration cause capacity issues at night or overwhelm a local distribution system, then the utility may wish to assert more control over charge scheduling. Once demand increases for this type of rate, Dominion will be forced to raise their off-peak rates to facilitate the increasing scale of participation. This would reduce the savings to BEV owners and push their preference back toward remaining on the normal residential rate thus being more indifferent to time-of-day restrictions. In order to build more distribution capacity or engage more expensive generation resources, utilities would have to charge higher fixed rates for this service or raise the variable kWh rate. Participants might also consider faster charging times to account for larger batteries. This would exacerbate pricing and congestion issues if coordination cannot be established through pricing pressures.

Participation Factors:

1. No fixed charge differences between plans
2. Low charging cost compared to the price of gasoline fueled vehicles
3. Low number of available spots signals an experiment, should expect higher rates in future tariffs to account for actual procurement costs and increased demand

Incentive Factors:

1. Very low cost to consumers incentivizes slow and off-peak charging.
2. Predictable, low capacity demand does not stress Transmission or Distribution Grids.
3. High penetration rates for BEVs resulting in night-time demands might require dispatch of higher marginal cost production resources further reducing profitability for Dominion.

In the above example we should expect Electric Vehicle owners to be satisfied with using either schedule, but Dominion will need to increase off-peak rates for the EV-only case. Given that consumption estimates remain in the capacity ranges of existing baseline generators, production firms should be satisfied that the demands would remain predictable in quantity, but that increased demand will raise electricity prices slightly. We should expect further testing to maximize those off-peak revenues up to the point that consumers were indifferent to the price/convenience trade-off. In the future the utility will have to grapple with high BEV penetration as it bumps up against steps in bulk production. Regulators may consider subsidies if motivated by clean-air issues or the possibility of capture value from reduced transmission and congestion costs.

8.2 Analysis: Vehicle-to-Grid with Peak-Shaving

In this example we will consider an activity that does not currently have a tariff designed for the consumer/producer interaction. The commercial rates that are established for users who peak above 500kW contain the fixed-fee and kWh charges that we see in the residential model, but they also contain a demand charge (Schedule GS-3). This demand charge presents the possibility to reduce the expense of exceeding average capacity by discharging the battery to reduce the peak load of the consumer (Sec. 6.2.3). For the commercial retail consumer these costs can fluctuate dramatically and inefficiently if average consumption is exceeded only a few times in a billing cycle. When heating and cooling capacities peak or machinery is operated simultaneously the maximum demand in any 30-minute interval can raise the monthly bill by around $7.50/Kilowatt. Meaning that a 50Kw peak can result in an additional $375 per month. If that size of peak were an outlier during the month, an electric vehicle could discharge during that time and eliminate that additional charge. In a year this particular estimate would save the rate-payer $375 x 12, or $4500 per vehicle and charger per year. Many demand charge rates exceed this estimate, but factors of prediction and limits to the variability in demand could lower that number. Because we know that a bi-directional charger would cost in the range of $15,000-$36,000, it could take 3-8 years to break-even. We must also consider that the vehicle would need to be available predictably, and that excessive throughput at the battery may degrade its purpose as transportation. So, we consider that the battery may cost as much as $5500 to replace

(Brockman, 2014), adding another 1-2 years to the break-even point. This does not seem particularly attractive until you consider that many commercial facilities already have fleets that require fast-chargers to operate effectively and tolerates underutilization of vehicles in order to ensure that fluctuations in demand can be met (GAO, 2017).

The objective of this demand charge for the vertically integrated firm, Dominion Power, is to recover the costs associated with peak demands (R. B. Wilson & Electric Power Research Institute, 1993). As we discussed in the section about the responsibilities of the Regional Transmission Operator, PJM, is responsible for securing an appropriate amount of power to cover excessive peaks, but because the predictive model is slow to respond to changes in demand, the utilities will incur similar costs without regard to the reduction in peak-demands locally, especially if by informal activity such as peak-shaving behind-the-meter. Because of the Reliability Pricing Model that is used to predict and acquire reserve capacity, small reductions in demand by this type of discharge to capacity would not be registered in the model until the activity was consistent for up to 18 years (PJM 5, 2017). Information is available to Dominion about exact consumption patterns through monitoring software, but their only option for recovering those rents avoided by the customer is to sell excess power into the markets at a real-time rate. Even this is difficult given the timing of real-time auctions which take place in the morning and are only repeated in the afternoons (PJM 6, 2017).

If we assume that the loss in revenue from peak-shaving to the utility is offset by a demand charge rate increase, then each behind the meter load-control participant will have caused the rate to increase. If that increase exceeds the percentage of load that was shaved, the customer will have either lost any savings that had been gained or redistributed the cost of capacity procurement to its neighbors. Structurally this is a problem because the increases in efficiency at the level of reduced peak demand and transmission congestion are not captured by any market participant. By keeping the information about behind-the-meter peak-shaving private, we can still point to an event where the EV battery was able to continue reducing each monthly bill. This activity, however, is adversely causing the overall rate to increase. The issues we cannot solve without understanding Dominion's additional distribution efficiencies from this activity are:

1. At what scale is Dominion Virginia indifferent to this peak shaving?
2. Are there costs and efficiencies that they are realizing behind their meter to the RTO?
3. Is demand information already discernable, therefore negating the question of an alternative method of revelation beyond the multi-part tariff?

It is rational to assume that at low levels of participation Dominion may not notice the reduction in individual levels of demand, but that at high levels of participation Dominion could make a case for lost revenues while being protected from revealing congestion relieving efficiencies caused by reduced peak traffic.

Reliability concerns could easily emerge because of the lack of commitment required by the peak-shaver, but equally as possible, regulators might be convinced to change the RPM and consider including this activity into a wider, more formal plan to coordinate this activity as a specific demand-reduction tool. The challenge would be providing adequate revenues to the V2G operator while ensuring cost-recovery to Dominion. If the full benefit of demand reduction and transmission/distribution congestion were realized, similar revenues might be realized for the V2G participant.

Participation factors:

1. The Utility relies on demand charges to limit the variation in consumption.

2. The retail customer is assumed to be trying to limit their peak-demands but faces no requirement to participate or formalize their commitment.
3. Regulators have relied on historic volatility to shape their market rules, but do not have a mechanism that accounts for voluntary reduction outside of recognized energy efficiency measures and centrally automated demand reduction.

Incentive Factors:

1. Dominion is faced with a revenue reduction while not experiencing a recognized cost reduction from the RTO.
2. The customer has the freedom to act at will but faces the possibility of increased future rates.
3. RTO benefits from reduced demand and congestion but does not have a mechanism for advanced procurement reduction. May be faced with the need to adjust frequency if a discrepancy is created between predicted quantities and actual quantities of demand.

Overall this activity could be a good way to introduce V2G to small numbers of commercial or government fleets. At low levels of activity some building and fleet operators could pay for chargers and increase battery utilization for the short-term. It is likely that at an increased scale of participation that dominion and the regulators would seek to formalize this activity and rebalance revenues in favor of incumbent utilities.

8.3 Wholesale participation

A potential solution to this problem would be to allow BEVs to participate in RTO level wholesale capacity auctions. This activity is currently limited by an allocation reserve of one

Megawatt at four hours of duration (PJM, Generators Manual, 2018), the equivalent of 160 vehicles. By creating an aggregator that could coordinate the activity of these vehicles, in a way that provided information to the market about committed capacity reduction, we could see that Dominion may receive a break on its capacity cost allocations and in turn a reduction in demand charges in its tariff. This relationship would also result in additional saving for Dominion by reduced transmission and distribution costs when congestion is present. The discharged reserves would have been acquired during off-peak times and discharged behind the meter avoiding congestion costs compared to other reserve capacity that would have been discharged over the grid.

We should not only expect to see participation constraints in the capacity reserve auctions reduced, but also incentives which are sized to reflect the lack of transmission and congestion costs. Customers would still need to purchase expensive chargers and to employ software for the dispatch of these resources. The complexity of dispatch software would be less expensive as it would not require peak-consumption prediction, but only coordination commands as prescribed by reserve capacity rules. Full compliance with PJM software and coordination services would be required and potentially burdensome for small scale sellers (PJM, Generators Manual, 2018).

The greatest benefit to the system would come from the delivery of reserve capacity at the local distribution level which would avoid congestion issues during periods of high-stress to the transmission grid. This inside delivery would also result in congestion reduction to distribution level networks, resulting in the deferment of upgrades to both systems. When local networks have solar and other renewables installed locally, Vehicle-to-Grid systems could maximize those benefits if distributed on the downstream side of transformers around an urban area.

The most recent California ISO Transmission Plan avoids $2.6 Billion in costs attributable directly to generation and efficiency gains at the local distribution level because of battery storage and rooftop solar (California ISO, 2018). Those gains could be strengthened and extended to areas like the local PJM Interconnection by creating reserve capacity products and encouraging distributed storage efforts like V2G.

Participation Factors:

1. Fast, Bi-directional chargers are expensive.
2. Participation by customers can result in reduced transportation availability.
3. Capacity auctions limit participants to One Megawatt minimums and four-hour duration.
4. Reserve capacity is only required to perform once-a-month and with day-ahead notice.
5. If allowed to participate in the retail market, moral hazard by selling when wholesale prices are higher than retail prices would allow V2G to profit without work.

Incentive Factors:

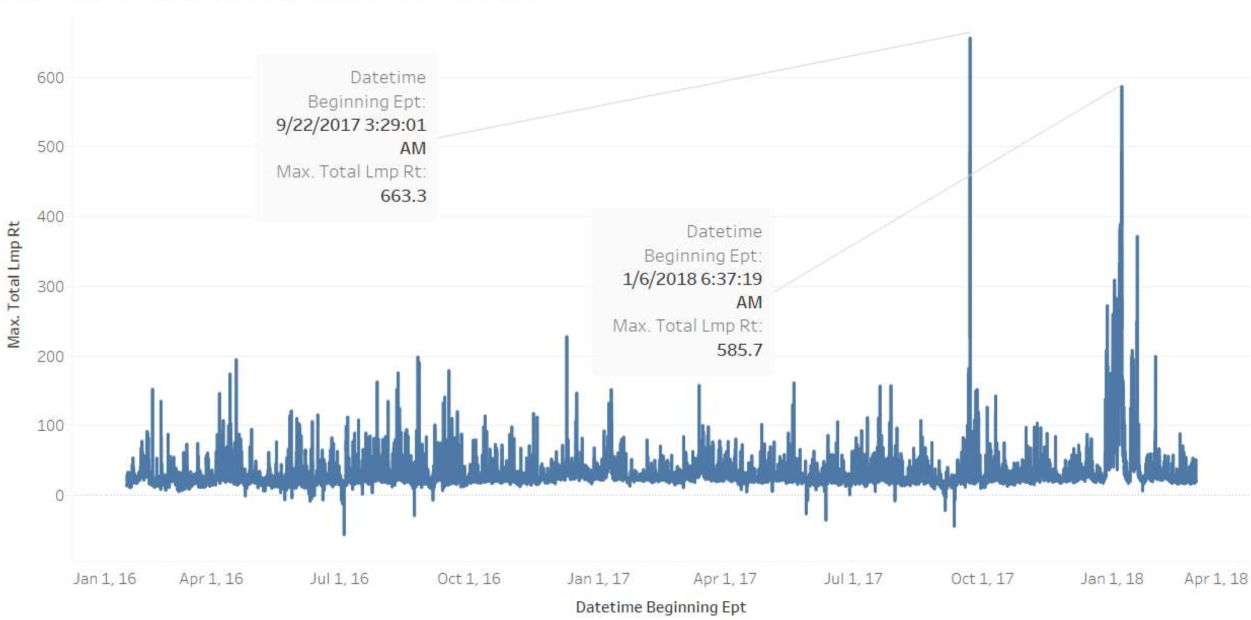
1. Behind-the-meter peak shaving is very lucrative in the short-term.
2. Capacity reserve rates at auction would not result in comparable savings.
3. Reduction in transmission and congestion costs should be reflected in reserve auction.
4. Real-Time price averages do not justify regular participation by BEV owners (Figure 3).

After considering these trade-offs we can assume that a new class of capacity reserve product could be created to reduce participation constraints for V2G operators and that incentives should be adjusted to reflect congestion savings and the forgone savings from behind-the-meter discharge. These changes would add balance to the relationship between Dominion and its BEV customers, shifting the responsibility for balance to an auction that is designed to account for the relationship between peak-demand and reserves, where participation and incentives are balanced by moderated market power.

9 Discussion and Recommendations

By looking at the extreme pricing days over the last 2-years, we can identify some of the most important targets for Vehicle-to-Grid as a specialty, highly valuable resource to inject efficiency

Extreme Pricing Events, PJM RTO, 2016-2018



The trend of maximum of Total Lmp Rt for Datetime Beginning Ept.

into the grid system. Because stationary batteries must rely on regular revenue, it makes sense to look at irregular opportunities for Battery Electric Vehicles to support the grid, as their primary purpose is for transportation. The graph below highlights the two most extreme events over the last two years. The PJM, the Regional Transmission Operator, has published reports on these situations and I rely on their assessment of the source of these stress points.

Beginning with the event on September 22, 2017, PJM analysis shows that temperatures were high, predicted demand was below actual demand, and the neighboring Interconnection, MISO, was calling for resources and under a shortage. Adequate generation was available to meet

PJM's needs, but Transmission congestion from west to east was severe. Multiple emergency pricing calls were made costing the RTO and passing those costs on to its members. Estimated costs were $2.3 Million

The January 6th, 2018 pricing was due to a cold snap (PJM 7, 2018). Many generators were unable to operate because of night-time boiler failures, but congestions costs also exceeded $275 Million. Other congestion related failures brought the cost of this event up to $400 Million. This single event could have been prevented or severely limited by improved capacity performance. V2G could limit the effects of this kind of event by delivering small amounts of power throughout the grid in order to rebalance the system. But this event and the previous one could act as a limit to estimate the extent of investment that might be made available to avoid these issues in the future. If $200 Million were invested at an average cost of $25,000, could provide an additional 8,000 megawatts of power to manage events like this. If these resources could be coordinated with drivers, future events could pay drivers or provide year-round incentives to drivers that were willing to react to events or make their vehicles available on a predictable schedule.

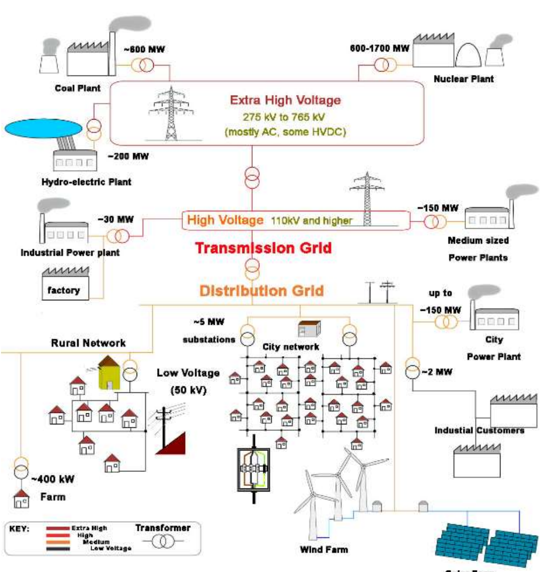
9.1 Consumer's Willingness to Participate

An area neglected by many researchers so far has been the consumer's willingness to participate in any scheme which might potentially limit access to their vehicle or result in inconveniences. BEVs would need to be available at specific times to meet many of the requirements for successful V2G operations. Kempton found that many consumers like the idea of supporting the environment while saving on energy but were less excited about having to monitor requirements for participation. He argues that consumers would prefer systems under the control of a commercial aggregator or the utility companies themselves (George R. Parsonsa, 2013). This would allow them to avoid the initial cost of installing chargers and navigating markets or real-time cost-benefit calculations.

Another recent review on the body of V2G literature by Kempton et al expects that the technical nature of these opportunities will breed deep confusion about best practices and the perceived value of participation. These insights should direct us toward a focus on solutions that reduce individual customer participation. The best solutions should reward individual participants while putting the operational responsibility on a third-party or utility companies. Third-parties and regulators would also benefit from purchases and operations at scale to reduce transaction costs and to coordinate for maximum efficiencies within the grid system (Benjamin K Sovacool et al, 2018).

9.2 Distributed Energy Resources

Local neighborhoods would like a bunch of small nodes of low voltage power if viewed as branches coming down from various levels of decreased voltage. The ability for local generation resources to feed the grid is limited by their ability to increase their voltage to levels that allow



re-entry into the larger, high voltage transmission networks. This also means that the local capacity for batteries and generation are limited by the use patterns inside that local node. Batteries or Vehicle-to-Grid could capture excess solar or wind produced locally to discharge at night. This could dramatically increase the quantity of power that could be generated for that local node. Otherwise expensive voltage-up stations would need to be installed to service the larger node. This would also require extensive coordination. If the solar-battery combination were connected to a higher voltage section of power line, it could be shared over a much larger network.

9.3 Locating at Urban Transportation Hubs

Because the efficiencies gained from reducing transmission congestion are very valuable, the scale of V2G usefulness in preventing grid emergency is limited, and that customer participation is an important consideration, we should look to a solution that serves these points.

Transmission networks often travel along transportation corridors and public transportation like trains, and buses often have hubs and stations where commuters park their cars. These parking lots present a unique opportunity to locate a large number of fast chargers at a point in the grid that could be easily used to access urban distribution grids. By concentrating a group of Battery Electric Vehicles at a train station located on the edge of a large urban area, local upgrades to voltage transformers would be less expensive at scale than the higher number of transformers that might be required in a deeper distribution position.

Many emergency pricing situations occur during heavy cooling-load periods while many commuters are at work. By having cars parked and batteries working with the grid while commuters are at work, the issue of customer participation, scale of cost and usefulness, and ideal discharge location would be optimized. Energy delivered to these cars during the late afternoon when demands have slowed could also be used when cold weather causes problems during winter nights. If a strategic number of bi-directional chargers were paired with BEVs inside local distribution nets, congestion and generation issues at those times could be relieved.

Other options like airport parking or locations that are adjacent to large industrial demands could also serve to provide vehicle owners benefits like free parking, charging, and public transport passes, while delivering value to the grid and those wishing to promote clean-air standards and alternative energy.

10 Conclusion

Opportunities to utilize electric vehicles as electricity market participants are broad. By using simple systems that coordinate charging times, rate structures can be developed that reward car owners for charging at times that create value for utilities and grid operators. Using more advanced tools, like bi-directional chargers, would allow retail users to control the consumption profile of any building they are connected to. This usage would benefit the grid by managing peak loads and reducing electricity bills for commercial and industrial facilities. These facilities often have fleets of vehicles that are underutilized and participation would be an alternate way to derive value from cars that are parked much of the time. At large scale participation this behavior would hurt utility company revenues and could raise retail prices.

Vehicle-to-Grid participants would need to make a choice when it comes to more intensive participation in the markets. Buying energy at retail prices and selling into the wholesale market presents a number of problems. The greatest is the possibility that a retail customer could buy at set rates when the wholesale market is under pressure and have arbitrage opportunities that do not require any changes in the state-of-charge for the vehicle battery.

Wholesale participation is limited by the need to coordinate many vehicles in order to increase the performance and reduce the transaction costs of a large number of small participants in the auctions.

When we also consider that vehicle operators are most concerned with reducing the burden of monitoring the markets and conducting transactions, it would be ideal if an aggregator or central coordinator could standardize an incentive and operate a large number of vehicles as an aggregator. This could be done by a utility, a cooperative, or a private business.

In order to extract the benefits of congestion reduction, vehicles should feed the grid from locations that optimize this purpose. By concentrating discharge at transformer locations that feed the local distribution grid, the problem of moving power across the grid from distant generation sources could be eased through charging during off-peak periods and discharging during peak demand periods closer to the point of consumption. This could be achieved through a number of initiatives that take advantage of commuter behavior. Parking lots at airports and transportation hubs present the greatest balance of benefits for grid operators, vehicle operators and government agencies that are already trying to promote the use of clean-air vehicles.

Other opportunities to coordinate with solar and wind electricity generators could allow them to store power at times when they are currently earning very little for their product and sell it at times of higher pricing. These types of relationships could expand the scale of usefulness for V2G beyond its current scale limitations.

By considering how to satisfy the needs of all the electricity market participants, we can expect to see V2G as a welcome participant and a vital new market-maker.

Exhibit 1

Charger Model	Base Price	Basic Description	Cloud Services Fees/Yr	CS Description	Managed Services Fees	Managed Services Description	Warranty Fees	Warranty Description	Notes
Level 1									
Clipper Creek		https://store.clippercreek.com/							
ACS-20	$379	16A, 120V, w/25' cable, H-wired	$0		0	Installation of Outlets/Circuit by Licensed Electrician	0	3yr Warranty	Wall Mount, 25 amp breaker, GFCI
PCS-15	$395	12A, 120V, Portable	$0		0		0	3yr Warranty	Plug to any 15 amp circuit
ACS-25	$469	20A, 120V, w/25'cable, H-wired	$0		0	Installation of Outlets/Circuit by Licensed Electrician	0	3yr Warranty	Wall Mount, 25 amp breaker, GFCI
Level 2									
Clipper Creek		https://store.clippercreek.com/							
LCS-30	$499	24A, 240V, 25'cable, H-wired				Installation of Outlets/Circuit by Licensed Electrician		3yr Warranty	Versions w/plugs to outlet available 
HCS-40	$565	32A, 240V, 25'cable, H-wired				Installation of Outlets/Circuit by Licensed Electrician		3yr Warranty	Versions w/plugs to outlet available
CS-60	$2,895	48A, 240V, 25' cable, keypad and usage tracking	$108	Per Month code maintenance fee to track access, app for users		Installation of Unit by Licensed Electrician		1yr Warranty	$700 Mounting Pole suggested
Charge-Point		Charge Point Data Sheets available, costs and specifics in this table come from phone conversation 8/9/2017, at 1:30PM, with Jack CSR						1yr free	Site survey and initial quote are free
CT4000	$4,500	6' Bollard, Single Port as Priced: Variable Customer Fee settings, mobile app charge scheduling, waitlist through app, Customizable branding, multi-language displays, driver phone suiuport, 15 minute interval recording, Load shed capbilities, up to 7.2kW charging, one or two standard ports, instructional video on LCD screen,	$280	Gateway and yearly cloud services per port	$349.00	Initial Activation and Maintenance services: http://www.chargepoint.com/files/datasheets/ds-services.pdf	$840.00	1Year Base Warranty; Extended Warranty (Assure): http://www.chargepoint.com/files/datasheets/ds-assure.pdf	
CPF25	$1,500	Single Pedestal w/CMK Priced: 7.2kW output, 32A @ 240VAC, No Screen, Cellular Gateway allows for remote settings and operations from user app, one account, RFID access	$240	Fleet Plan is a cloud data and scheduling management fee for 1,2,3,4 or 5 years, *Gateway USA cellular service also available	$349.00	Initial Activation and Maintenance services: http://www.chargepoint.com/files/datasheets/ds-services.pdf	$840.00	1Year Base Warranty; Extended Warranty per Year (Assure): http://www.chargepoint.com/files/datasheets/ds-assure.pdf	
AeroVironment		http://store.evsolutions.com							
Nissan Station	$589	30A, 240V, 25' cable, UL listed;						3 year parts and service warranty	
TurboDock Commercial Station	$1,798	16A, 240V, 3.8kW, 20' cable, Bluetooth App access for fleet and customer management/charge control			$1,398.00	Installation Bundle Available, One-time fee			
Level 3									
Charge-Point		See note above for Charge Point Level 2							
Express 100	$14,000	**24kW**; CHAdeMO available, Control through Service Plan: 14000 w Chademo	$560	Commercial Service, Service Provider Plan for Fleet/Port per year	$349.00	One-Time Activation and Configuration: http://www.chargepoint.com/files/datasheets/ds-services.pdf	$840.00	1Year Base Warranty; Extended Warranty per year (Assure): http://www.chargepoint.com/files/datasheets/ds-assure.pdf	Available as Wall-mount 
Express 200	$36,000	**50kW**, CHAdeMO and Combo 1 standard,	$560	Commercial Service, Service Provider Plan, Per port, per year	$349.00	One-Time Activation and Configuration: http://www.chargepoint.com/files/datasheets/ds-services.pdf	$840.00	1Year Base Warranty; Extended Warranty per year (Assure): http://www.chargepoint.com/files/datasheets/ds-assure.pdf	79" high x 29.5" wide x 13" deep 
Express 250		50kW with option to upgrade to 62.5kW, 2 power modules and CCS1 and CHAdeMO cables, 10 second interval storage, full color LED displays (2), one for notifications, one for driver interaction, remote authentication capable, up to three different connectors at station, Power management, remote energy management through API,		Commercial or Enterprise Plan		Activation and Configuration; Installation and Validation:http://www.chargepoint.com/files/datasheets/ds-services.pdf		CP Express Assure Extended Plan after 1 Year free, and successful validation: http://www.chargepoint.com/files/datasheets/ds-assure.pdf	7'4" tall, 2'4" wide, 1'4" deep, 551 lbs 
Express Plus w/Power Cube		Priced as Power Cube upgrade. Up to 125 kW per station, 400kW output with Power Cube; other specs consistent with Express 250, RFID authentication available							
AeroVironment									
EV-50	Not yet available	Chademo only,							

Exhibit 2

For the Day-Ahead Prices to MW Demand, exponential Trend-Line Graph

Trend Lines Model

A linear trend model is computed for natural log of maximum of Total Lmp Da given Mw. The model may be significant at p <= 0.05.

Model formula:	(Mw + intercept)
Number of modeled observations:	11639
Number of filtered observations:	1
Model degrees of freedom:	2
Residual degrees of freedom (DF):	11637
SSE (sum squared error):	670.11
MSE (mean squared error):	0.0575844
R-Squared:	0.613856
Standard error:	0.239967
p-value (significance):	< 0.0001

Individual trend lines:

Panes		**Line**		**Coefficients**			
Row	**Column**	**p-value**	**DF**	**Term**	**Value**	**StdErr**	**p-value**
Total Lmp Da	Mw	< 0.0001	11637	Mw	1.963e-05	1.443e-07	< 0.0001
				intercept	1.6096	0.0131	< 0.0001

Appendix

Virginia Electric and Power Company

Schedule 1

RESIDENTIAL SERVICE

I. APPLICABILITY AND AVAILABILITY

This schedule is applicable only to Customers (1) who elect to receive separately metered and billed Electricity Supply Service and Electric Delivery Service from the Company or (2) who are eligible for and elect to purchase Electricity Supply Service from a Competitive Service Provider in accordance with Va. Code § 56-577 A for use in and about (a) a single-family residence, flat or apartment, (b) a combination farm and one occupied single-family residence, flat or apartment, (c) a private residence used as a boarding and/or rooming house with no more than one cooking installation nor more than ten bedrooms, or (d) separately metered service to detached accessory buildings appurtenant to residential dwellings unless such buildings use electricity for commercial or industrial purposes.

A combination residence and farm, having more than one single-family residence, flat or apartment served electricity through a single meter, that was being billed under this schedule prior to April 1, 1971, may continue to be supplied electricity under this schedule provided each such dwelling unit is occupied by the owner or by a tenant working on the farm. Such multiple-residence farms connected on and after April 1, 1971, shall not be served under this schedule.

This schedule is not applicable for (a) individual motors rated over 15 HP, and (b) commercial use as in hotels, public inns, motels, auto courts, tourist courts, tourist camps, or trailer camps.

II. MONTHLY RATE

A. Distribution Service Charges

1. Basic Customer Charge
Basic Customer Charge $7.00 per billing month.

2. Plus Distribution kWh Charge

a. Billing Months of June – September

First 800 kWh	@	2.244¢ per kWh
Over 800 kWh	@	1.271¢ per kWh

b. Billing Months of October – May

First 800 kWh	@	2.244¢ per kWh
Over 800 kWh	@	1.271¢ per kWh

(Continued)

Virginia Electric and Power Company

Schedule 1

RESIDENTIAL SERVICE

(Continued)

II. MONTHLY RATE (Continued)

3. Plus each Distribution kilowatthour used is subject to all applicable riders, included in the Exhibit of Applicable Riders.

4. Plus, where the Customer receives service in accordance with Paragraph XXV – NET METERING of the Company's TERMS AND CONDITIONS and where the alternating current capacity of the Renewable Fuel Generator exceeds 10 kW, the Customer shall be billed a Distribution Standby Charge of $2.79 per kW of demand, minus the charge under II.A.2., above, but not less than zero.

B. Electricity Supply (ES) Service Charges

Paragraph II.B. is not applicable to Customers receiving Electricity Supply Service from a Competitive Service Provider.

1. Generation kWh Charge

a. Billing Months of June – September

First 800 ES kWh	@	3.795¢ per kWh
Over 800 ES kWh	@	5.773¢ per kWh

b. Billing Months of October – May

First 800 ES kWh	@	3.795¢ per kWh
Over 800 ES kWh	@	2.927¢ per kWh

2. Plus Transmission kWh Charge

a. All kWh @ 0.970¢ per kWh

b. Plus, where the Customer receives service in accordance with Paragraph XXV – NET METERING of the Company's TERMS AND CONDITIONS and where the alternating current capacity of the Renewable Fuel Generator exceeds 10 kW, the Customer shall be billed a Transmission Standby Charge of $1.40 per kW of demand, minus the charge under II.B.2.a., above, but not less than zero.

3. Plus each Electricity Supply kilowatthour used is subject to all applicable riders, included in the Exhibit of Applicable Riders.

(Continued)

Virginia Electric and Power Company

Schedule 1

RESIDENTIAL SERVICE

(Continued)

II. MONTHLY RATE (Continued)

4. Plus, where the Customer receives service in accordance with Paragraph XXV – NET METERING of the Company's TERMS AND CONDITIONS and where the alternating current capacity of the Renewable Fuel Generator exceeds 10 kW, each measured kW of Demand is subject to all applicable riders, included in the Exhibit of Applicable Riders.

C. The minimum charge shall be the Basic Customer Charge in II.A.1., above.

III. DETERMINATION OF DEMAND

Where demand is measured by the Company, such demand will be determined as the highest average kW measured during any 30-minute interval of the current billing month, rounded to the nearest tenth.

IV. METER READING AND BILLING

A. Meters may be read in units of 10 kilowatthours and bills rendered accordingly.

B. The Company shall have the option of reading meters monthly or bimonthly. When the meter is read at other than monthly intervals, the Company may render an interim monthly bill based on estimated kWh use during periods for which the meter was not read.

C. When bills are calculated for a bimonthly period, the Basic Customer Charge shall be multiplied by two; the number of kWh specified in the initial block of the Distribution kWh Charge and the Generation kWh Charge shall be multiplied by two before the rates per kWh are applied to the usage for the bimonthly period; the rate specified in II.A.4. shall be multiplied by two before the kW of demand is applied to such modified rate; the rate specified in II.B.2.b. shall be multiplied by two before the kW of demand is applied to such modified rate; and the minimum charge shall be the modified Basic Customer Charge.

V. TERM OF CONTRACT

Open order.

Appendix

Virginia Electric and Power Company

Schedule 1EV

RESIDENTIAL SERVICE
WITH ELECTRIC VEHICLE CHARGING
(EXPERIMENTAL)

I. APPLICABILITY

This schedule is applicable only where the Customer 1) owns or leases a licensed electric motor vehicle, subject to state inspection, which requires periodic battery charging, and 2) meets the applicability requirements of the following paragraphs. During the experimental period, should the Customer discontinue operating an electric motor vehicle, the Customer may continue to be served under this schedule for the duration of the experimental period.

This schedule is applicable only to Customers electing to receive separately metered and billed Electricity Supply Service and Electric Delivery Service from the Company for use in and about (a) a single-family residence, flat or apartment, (b) a combination farm and one occupied single-family residence, flat or apartment, or (c) a private residence used as a boarding and/or rooming house with no more than one cooking installation nor more than ten bedrooms, or (d) separately metered service to detached accessory buildings appurtenant to residential dwellings unless such buildings use electricity for commercial or industrial purposes.

This schedule is not applicable to (a) individual motors rated over 15 HP, (b) commercial use as in hotels, public inns, motels, auto courts, tourist courts, tourist camps, or trailer camps.

Service under this schedule shall terminate November 30, 2018, and the Customer shall select an alternative applicable rate schedule.

II. AVAILABILITY

This schedule is available to no more than 750 participants in the Company's Electric Vehicle (EV) Pilot Program who contract for service under this schedule to be effective on or before September 1, 2016.

III. MONTHLY RATE

A. Distribution Service Charges

1. Basic Customer Charge
Basic Customer Charge $7.00 per billing month.

(Continued)

Filed 01-14-16
Electric-Virginia

Superseding Filing Effective For Usage On and After 05-01-15. This Filing Effective For Usage On and After 12-01-15.

Virginia Electric and Power Company

Schedule 1EV

RESIDENTIAL SERVICE
WITH ELECTRIC VEHICLE CHARGING
(EXPERIMENTAL)

(Continued)

III. MONTHLY RATE (Continued)

2. Plus Distribution kWh Charge

a. All On-peak, Intermediate, and Off-peak kWh	@	2.064¢ per kWh
b. Plus All Super Off-peak kWh	@	0.011¢ per kWh

3. Plus each Distribution kilowatt-hour used is subject to all applicable riders, included in the Exhibit of Applicable Riders.

B. Electricity Supply (ES) Service Charges

1. Generation kWh Charge, April 16 through October 15:

All On-peak ES kWh	@	9.501¢ per kWh
All Intermediate ES kWh	@	3.818¢ per kWh
All Off-peak ES kWh	@	1.652¢ per kWh
All Super Off-peak ES kWh	@	0.444¢ per kWh

2. Generation kWh Charge, October 16 through April 15:

All On-peak ES kWh	@	4.605¢ per kWh
All Off-peak ES kWh	@	2.106¢ per kWh
All Super Off-peak ES kWh	@	1.388¢ per kWh

3. Plus Transmission kWh Charge

All kWh	@	0.970¢ per kWh

4. Plus each Electricity Supply kilowatt-hour used is subject to all applicable riders, included in the Exhibit of Applicable Riders.

C. The minimum charge shall be the Basic Customer Charge in Paragraph III.A.1., above.

(Continued)

Filed 01-14-16
Electric-Virginia

Superseding Filing Effective For Usage On and After 05-01-15. This Filing Effective For Usage On and After 12-01-15.

Virginia Electric and Power Company

Schedule 1EV

RESIDENTIAL SERVICE
WITH ELECTRIC VEHICLE CHARGING
(EXPERIMENTAL)

(Continued)

IV. DEFINITION OF ON-PEAK, INTERMEDIATE, OFF-PEAK, AND SUPER OFF-PEAK HOURS

A. For the period of April 16 through October 15, inclusive:

On-peak:	1 p.m. to 7 p.m.
Intermediate:	10 a.m. to 1 p.m. & 7 p.m. to 10 p.m.
Off-peak:	10 p.m. to 1 a.m. & 5 a.m. to 10 a.m.
Super Off-peak:	1 a.m. to 5 a.m.

B. For the period of October 16 through April 15, inclusive:

On-peak:	6 a.m. to 11 a.m. & 5 p.m. to 10 p.m.
Intermediate:	Not applicable
Off-peak:	5 a.m. to 6 a.m., 11 a.m. to 5 p.m. & 10 p.m. to 1 a.m.
Super Off-peak:	1 a.m. to 5 a.m.

V. METER READING AND BILLING

A. Meters may be read in units of 10 kilowatthours and bills rendered accordingly.

B. The Company shall have the option of reading meters monthly or bimonthly. When the meter is read at other than monthly intervals, the Company may render an interim monthly bill based on estimated kWh usage during periods for which the meter was not read.

C. When bills are calculated for a bimonthly period, the Basic Customer Charge shall be multiplied by two; and the minimum charge shall be the modified Basic Customer Charge.

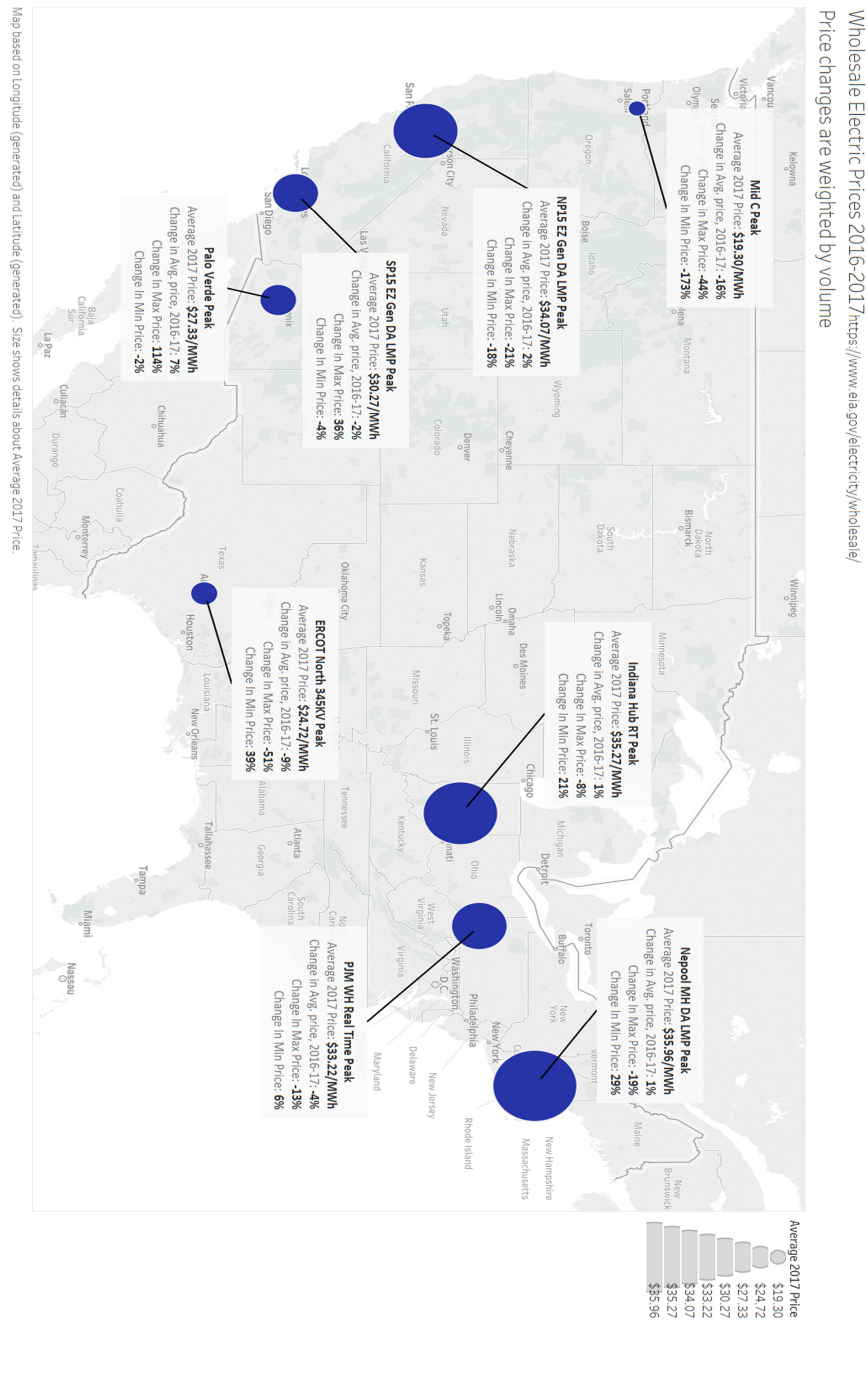
VI. TERM OF CONTRACT

The term of contract shall be for not less than twelve billing months.

Filed 01-14-16
Electric-Virginia

Superseding Filing Effective For Usage On and After 05-01-15. This Filing Effective For Usage On and After 12-01-15.

Appendix



Wholesale Electric Prices 2016-2017 https://www.eia.gov/electricity/wholesale/
Price changes are weighted by volume
Mid C Peak
Average 2017 Price: $19.30/MWh
Change in Avg. price, 2016-17: -16%
Change In Max Price: -44%
Change In Min Price: -173%
NP15 EZ Gen DA LMP Peak
Average 2017 Price: $34.07/MWh
Change in Avg. price, 2016-17: 2%
Change In Max Price: -21%
Change In Min Price: -18%
SP15 EZ Gen DA LMP Peak
Average 2017 Price: $30.27/MWh
Change in Avg. price, 2016-17: -2%
Change In Max Price: 36%
Change In Min Price: -4%
Palo Verde Peak
Average 2017 Price: $27.33/MWh
Change in Avg. price, 2016-17: 7%
Change In Max Price: 114%
Change In Min Price: -2%
ERCOT North 345KV Peak
Average 2017 Price: $24.72/MWh
Change in Avg. price, 2016-17: -9%
Change In Max Price: -51%
Change In Min Price: 39%
Indiana Hub RT Peak
Average 2017 Price: $35.27/MWh
Change in Avg. price, 2016-17: 1%
Change In Max Price: -8%
Change In Min Price: 21%
PJM WH Real Time Peak
Average 2017 Price: $33.22/MWh
Change in Avg. price, 2016-17: -4%
Change In Max Price: -13%
Change In Min Price: 6%
Nepool MH DA LMP Peak
Average 2017 Price: $35.96/MWh
Change in Avg. price, 2016-17: 1%
Change In Max Price: -19%
Change In Min Price: 29%
Average 2017 Price
$19.30
$24.72
$27.33
$30.27
$33.22
$34.07
$35.27
$35.96
Map based on Longitude (generated) and Latitude (generated). Size shows details about Average 2017 Price.

Technical Appendix

Basics and Definitions:

Electricity, as we know it today is neither created nor destroyed. Electricity Generation stations, instead, convert it from mechanical work through a few types of transformational processes. The most common method is through electromagnetic induction where an alternating magnetic field is used to generate power. Power is the product of voltage and current. Current is the flow rate of an electrical charge and voltage is the electrical pressure of that charge. Current is measured in Amperes, and Voltage is measured in Volts.

In AC current, the type that is produced in most generators, the electrons move in the shape of a sine wave. This shape characterizes the current as AC, while the number of cycles in sine wave are referred to as Frequency. The current and voltage refer to the number of electrons moving on that wave and the force with which they move respectively. When combined as Power:

$$P = IV$$

"I" being current and "V" voltage, Power is measured in Watts. Watts are also used to measure the peak load that objects such as light bulbs can draw in the form of Load. Motors which have different speeds are often characterized by their amps as a function of their fixed magnetic fields. All power produced and consumed by standardized U.S. systems is limited to a frequency of 60 hertz in order to keep one aspect of the engineered system fixed. This allows for Transformers, Generators and Motors to predictably alter Current and Voltage requirements to achieve desired outputs through expected inputs.

Most power in the U.S is also standardized by established steps in Voltage. Once distributed as High-Voltage, Electricity is brought down to 120 Volts and increments thereof (240/480). Each of the wires that serve typical residential/commercial buildings carries 120 volts at a phase that compliments subsequent connections i.e single-Phase, two phase, or three-phase. Single phase is a single wave, two-phase is two waves that are exactly $\pi/2$ delayed from one another, and three-phase combines $\pi/2$ delay with a delay of π.

AC power is important to the power grid because it can be transformed and its wave shape makes it easier to account for phase and transformation. If power is being generated from one source this is not important, but when multiple sources are feeding power into a system the phases must be aligned. Multiple phases can be generated that are aligned or in exact balance to each other (imagine a sine and cosine wave acting together), otherwise the waves can be cancelled, diminished or magnified. We will discuss this more when explaining Transmission constraints in-depth, but power lines also present to us the issue of Resistance.

The amount of power that can be moved through a wire is inversely proportionate to the amount of resistance (Ohms). Ohms law states that Current is equal to Voltage divide by Resistance.

$$I = V/R$$

Or

$$R = V/I$$

This resistance results in power loss through heat but can be minimized by increasing voltage which decreases current. This process is referred to as Transformation. The Voltage gets stepped-up after it is initially generated so that it can be transmitted over long distances with less power loss to heat. This process is reversed at the point-of-use and voltage is stepped down. At this step-down stage, AC power loses little heat in a step-down transformer, but DC power is very inefficient at this process (because of the box like shape of its waveform); so, AC remains the current of choice for any system that requires this step-up and down process for long-distance transmission.

When power arrives at a consumer's location the energy is transformed to the appropriate voltage and consumed by the end-user generating load by turning on lights or operating motors. This load profile is what determines demand on the grid and must be balanced by the amount of Power that is being generated. Traditionally this balance was achieved by single utilities acting as monopolists over the entire generation, transmission and distribution facility. They were able to connect the current fields on their generators to the load that was being demanded from the consumers and match the supply to demand.

As Transmission systems have become increasingly interconnected, a single generating facility has much less control over the condition of Power in the Transmission systems and is required to cooperate with many new generators that have been allowed to access the system as a matter of market rights. Today this coordination activity is primarily conducted by Load-Balancing Authorities. This move toward central coordination is the result of the increasing interconnection of transmission grids and the recognition by the federal government that the reliability of the grid has become an issue of national security[3]. I'm wondering now why this change occurred

These Load-Balancing Authorities are also responsible for Frequency regulation that is needed as a result of phase corrections and balancing error. The amount of Power consumed is measured by a meter at a customer's location. This size of the load demand is measured in Watts or Kilowatts and the duration of that magnitude is measured in Kilowatt Hours. Customers are then billed by the magnitude and duration of their loads to account for the fixed and variable costs of supplying power.

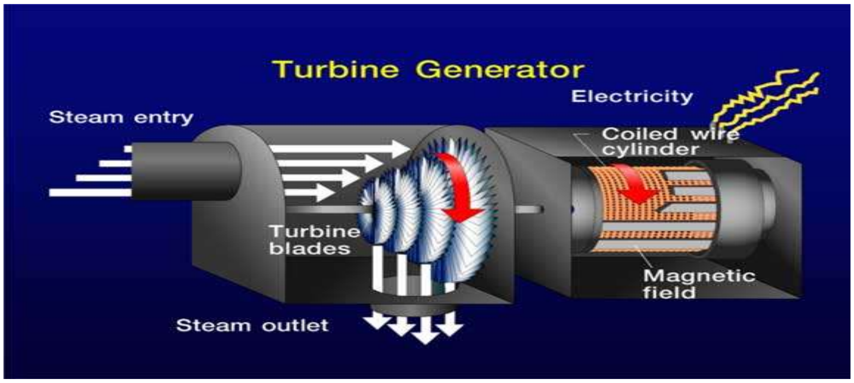
Generation

There are many types of electricity generators. Most generate electricity by converting some form of potential energy into kinetic energy. Nuclear Power plants use the heat that is generated from a controlled fission reaction to produce steam; Natural Gas and Coal plants burn fossil fuels to generate steam, while Hydroelectric Dams store the potential energy of water behind a dam before funneling it into the turbines.

These traditional generation sources are generally considered to be the most reliable forms of generation because of the opportunity to store the fuels and thus create a predictable supply of energy conversion. This reliability scenario is also consistent with the establishment of the strategic oil reserve and is dependent on the sense that electrical energy is not storable thereby relying on a defensible supply of fuel to generate power and enable transportation necessities.

[3] DPA act of 1950, and Federal Water Power act of 1920

These sources also have the common attribute where a turbine is used to convert the kinetic energy of the steam or flowing water to rotational energy in a turbine that directly spins a generator. Windmills convert the wind energy directly to rotational energy with their blades and most of the internal parts are- related to the generator.



A generator is typically a coil of wire wrapped around a shaft that spins inside of magnetic field where electrons can be directed into wires. As that spinning armature is surrounded by magnets that harvest the electricity, the power that is produced is characterized as Alternating Current (AC) Power. This characteristic is developed by the continuous cycle of approaching and retreating from the pole of the magnet at the same rate. Imagine a continuous, positive increase in signal as the magnet is approached and continuously decreasing signal (negative) as the magnet is passed. This can be visualized as a Sine wave.

Current and Voltage (Power = Current*Voltage) are a directly proportional to the intensity of the magnetic field and the rate of spin at the armature. If the magnetic field is generated by electromagnets then the current can be controlled by increasing or decreasing that field. The voltage is also a function of the number and length of the windings (wire around the armature).

An ideal or efficient output is reached when the field is adjusted to match a voltage output and the speed of spinning is optimized. This is often referred to as “maximum rated current.” Once this voltage is established and a rate of output or current is established there must be somewhere for the Electricity to travel because electric power flow is instantaneous and finite. Because battery storage is expensive and widely unavailable, electricity production must be carefully coordinated with its consumption.

Solar Power is quite different than the other generation resources that spin a generator. Solar or Photo-Voltaic Generators use the semi-conductor characteristics of Silicon. When organized into a disc and printed with a path that can direct electrons away from the wafer, Photons from the sun repeatedly strike the Silicon and are “trapped” while the electrons are harvested from the Photons.

References

Benjamin K Sovacool et al. (2018). The neglected social dimensions to a vehicle-togrid. *Environmental Research*.

Brockman, B. (2014, June 27). *Update on Nissan Leaf Battery Replacement*. Retrieved from mynissanleaf.com: http://www.mynissanleaf.com/viewtopic.php?f=4&t=17168#p374490

California ISO. (2018, March 3). *2017-2018 Transmission Plan.* Retrieved from caiso.com: http://www.caiso.com/Pages/documentsbygroup.aspx?GroupID=DF54CECB-A577-40D3-AB96-A3F68AF943F4

Federal Energy Regulatory Comission. (2015, July). *United States Electricity Industry Primer*. Retrieved from energy.gov: https://www.energy.gov/sites/prod/files/2015/12/f28/united-states-electricity-industry-primer.pdf

Federal Energy Regulatory Committee. (2017, November). *OATT Reform*. Retrieved from ferc.gov: https://www.ferc.gov/industries/electric/indus-act/oatt-reform.asp

FERC 2. (2018, March 30). *20180330124619-EL17-64-000.pdf.* Retrieved from ferc.gov: https://www.ferc.gov/CalendarFiles/20180330124619-EL17-64-000.pdf

FERC, Division of Energy market Oversight. (2015, November). *Energy Primer*. Retrieved from ferc.gov: https://www.ferc.gov/market-oversight/guide/energy-primer.pdf

GAO. (2017, April). *Report to the Committee on Oversight.* Retrieved from gao.gov: https://www.gao.gov/assets/690/684289.pdf

George R. Parsonsa, ∗. M. (2013). Willingness to pay for vehicle-to-grid (V2G) electric vehicles and theircontract terms. *Energy Economics*.

International Energy Agency. (2017). *iea.org/publications/freepublications/publication/GlobalEVOutlook2017.pdf*. Retrieved from https://www.iea.org: https://www.iea.org/publications/freepublications/publication/GlobalEVOutlook2017.pdf

Kempton, W. &. (1997). Electric vehicles as a new source for electric utilities. *Transportation Research D*, 2(3), 157-175.

Laffont, J. &. (1993). *A theory of incentivces and procurement and regulation.* Cambridge, Mass: MIT Press.

McMillan, J. (1992). *Games, strategies and managers.* New York: Oxford University Press.

Milgrom, P. R. (2004). *Putting auction theory to work.* Cambridge, UK, New York: Cambridge University Press.

Perry, R. (2017, September 28). *Secretary Rick Perry's Letter to the Federal Energy Regulatory Commission.pdf.* Retrieved from energy.gov:

https://www.energy.gov/sites/prod/files/2017/09/f37/Secretary%20Rick%20Perry%27s%20Letter%20to%20the%20Federal%20Energy%20Regulatory%20Commission.pdf

PJM 3. (2018, April 15). *Ancillary Services.* Retrieved from pjm.com: http://www.pjm.com/markets-and-operations/ancillary-services.aspx

PJM 4. (2017, November). *Capacity Auctions (RPM*. Retrieved from pjm.com: http://www.pjm.com/markets-and-operations/rpm.aspx

PJM 5. (2017, September 6). *media/committees.* Retrieved from pjm.com: http://www.pjm.com/~/media/committees-groups/committees/mc/20170619-webinar/20170619-item-04-dr-strategy.ashx

PJM 6. (2017, April). *rpm 101*. Retrieved from pjm.com: http://pjm.com/~/media/training/nerc-certifications/markets-exam-materials/rpm/rpm-101-overview-of-reliability-pricing-model.ashx

PJM 7. (2018, February 26). *PJM Cold Snap Performance.* Retrieved from pjm.com: http://www.pjm.com/-/media/library/reports-notices/weather-related/20180226-january-2018-cold-weather-event-report.ashx

PJM Interconnection 1. (2016, April 27). *"PJM Reliability Pricing Model.".* Retrieved from pjm.com: www.pjm.com/~/media/library/reports-notices/load-forecast/2016-load-forecast-whitepaper.ashx.

PJM Interconnection 2. (2016, June 5). *20160506-item-01b-faqs-for-5cps-and-peak-shaving.ashx.* Retrieved from pjm.com: http://www.pjm.com/~/media/committees-groups/task-forces/scrstf/20160506/20160506-item-01b-faqs-for-5cps-and-peak-shaving.ashx

PJM Interconnection. (2018, April 15). *Retail Electricity Consumer Opportunities for Demand Response.* Retrieved from pjm.com: http://www.pjm.com/-/media/markets-ops/dsr/end-use-customer-fact-sheet.ashx?la=en

PJM, Generators Manual. (2018, February 26). *M14D_Manual.* Retrieved from pjm.com: http://www.pjm.com/-/media/documents/manuals/m14d.ashx

State Corporation Comission. (2018, April 15). *Energy Regulation in Virginia.* Retrieved from scc.virginia.gov: https://www.scc.virginia.gov/power/index.aspx

Virginia Electric and Power Company, Entire Filed Tariff (Virginia State Corporation Comission October 1, 2017).

Wilson, R. (1993). *Nonlinear Pricing.* New York: Oxford University Press.