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A Value of Distributed Energy Resources Study for the District of Columbia

Framework, Impacts, Key Findings, and Roadmap

Prepared for the Public Service Commission for the District of Columbia

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AUTHORS

Synapse Energy Economics:

Jennifer Kallay
Asa Hopkins, PhD
Melissa Whited
Courtney Lane
Shannon Liburd
Divita Bhandari

New City Energy:

Zach Wilson

Synapse Energy Economics, Inc.

485 Massachusetts Avenue, Suite 3
Cambridge, Massachusetts 02139

617.661.3248 | www.synapse-energy.com

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EXECUTIVE SUMMARY

The District of Columbia is entering a phase of accelerated decarbonization efforts. These efforts increasingly center on the electrification of space and water heating in buildings and vehicles, which may create pressure on the distribution system. The impetus for this transition is in part the rapid advancement of climate-related public policy in the District of Columbia. Recent legislation passed in the District includes the *Clean Energy DC Omnibus Amendment Act of 2018* (D.C. Law 22-257), the *Climate Commitment Amendment Act of 2022* (D.C. Law 24-176), and the *Clean Energy DC Building Code Amendment Act of 2022* (D.C. Law 24-177). The *Healthy Homes Act* is currently under consideration in the Council of the District of Columbia. This study aims to further public understanding of challenges and opportunities that may arise with rapid adoption of both building and vehicle electrification, with more detail around time (hours, months, years) and space (location on the distribution system). Specifically, the purpose of this study is to inform the Public Service Commission of the District of Columbia (DC PSC) and stakeholders regarding the potential value of distributed energy resources (DER) to address costs in the electric system associated with generation, transmission, and distribution. DERs include solar photovoltaics, battery storage, energy efficiency, demand response, and managed charging of electric vehicles.

The Study Team, consisting of Synapse Energy Economics and New City Energy, found that wholesale energy and capacity market costs, distribution upgrade costs, and the societal costs associated with greenhouse gas (GHG) emissions are the greatest contributors to the costs caused by increasing electric loads, and therefore also the largest sources of value for DERs that can avoid those costs. The Study Team reviewed 13 states and determined that seven of those states (New York, California, New Hampshire, Rhode Island, Vermont, Connecticut, Massachusetts) have adopted DER valuation frameworks in some capacity, with New York and California having more comprehensive frameworks. The value of avoided energy and GHG costs resulting from DERs has been studied extensively in these other jurisdictions. In contrast, distribution upgrade costs are both less well studied and vary significantly based on the local grid configurations, including certain equipment (e.g., transformer) size and location and load profiles. This study therefore dedicates substantial attention and analysis to characterizing avoidable distribution costs and their potential impact on policy and program design.

The Study Team used District-specific feeder peak load and upgrade cost data to inform District-specific findings and recommendations. Electrification is likely to occur unevenly across the District's 765 feeders and because of this spatial variation, a circuit-by-circuit approach is warranted. This study is novel in that it considers how conditions may evolve for various types of distribution system feeders. The Study Team selected four feeder types (three radial feeders and one LVAC feeder) to examine a range of potential outcomes and possible interventions including: high and low baseline peak loads, summer- and winter-peaking loads, and broad and narrow peaking load shapes.

Table ES-1 below summarizes the Study Team's key findings.

Table ES- 1. Summary of Key Findings

	Key Findings
1	Aggressive electrification of buildings and transportation could increase summer demand peaks and the risk of costly distribution system upgrades to meet the increased demand. Smart DER policies can provide a means to manage this risk proactively and benefit ratepayers, so long as solutions materialize in a timely manner. When the need for large investments can be deferred or avoided, the ratepayer benefits can be substantial.
2	New loads from 100 percent electrification of vehicles will be greater in volume, but new loads from both vehicles and buildings have a high potential to exacerbate current peak times if electrification is not well planned and/or inadequate relief measures are provisioned. Electrification of heating loads on some feeders may also create new peaks on winter mornings and evenings in addition to the summer afternoon and evening peaks that are currently typical.
3	As electrification pressure builds, many feeders may exceed their normal rating for only a few hours per year at first. As a result, initially only a few hours have the potential to cause high costs from distribution system upgrades. Therefore, the potential avoided costs suggest a high value for early action. In many instances, and in all modeled feeders, DER-based strategies have the potential to defer expensive system upgrades until 2045 or later, and potentially avoid these upgrades altogether. (Pepco's distribution system baseline stayed within or almost within the bounds of the normal rating of the feeders over the study period.)
4	Because large distribution capacity projects are relatively expensive, and because they are driven by the peak hour of load, "needle" peaks that cause the feeder to exceed its normal rating during only a few overloaded hours are among the most expensive events in terms of $/MWh. These peaks have the potential to drive hundreds of millions of dollars of capacity investment across the District when a few hours of relief could defer or avoid the upgrade. Because the large cost of a distribution system upgrade is spread across more hours of pressure in our "Maximum Pressure" scenario, it may make more sense to invest in upgrades to the system. However, when the pressure is partially reduced, such that only a few remaining hours are creating pressure, the same logic applies: the hourly value of responsive load curtailment is much greater.
5	The technical potential for relief of pressure via DERs is significant, and in most of the cases studied even exceeds the potential pressure itself. The relief measures modeled are layered and include load-shaping measures from building efficiency, EV charge timing, photovoltaics, and load flexibility measures such as demand response and battery dispatch. Within these measures, load-shaping is expected to deliver the greatest load reductions, and combinations of measures are required to address the range of pressure scenarios observed. Notably, local solar delivery timing is not especially well matched to modeled summer and winter peaks because the pressure is most intense after 6 pm. Potential modifications of solar programs to favor western-facing arrays may be beneficial.
6	It will likely be important for the District to put careful thought into relief measures for winter-peaking feeders because more feeders may become winter-peaking over time with increased electrification. The modeled relief in this study (building retrofits, EVs, and solar generation) was more adept at addressing potential pressures on summer-peaking feeders than on winter-peaking feeders.
7	The District should focus on solutions with the highest avoided costs. The types of impacts that are likely to have the highest avoided costs include: distribution capacity, energy, generation capacity, and GHGs.
8	The selection of an avoided GHG value and discount rate are important decisions as they shape the benefits that can be achieved by DERs and their cost-effectiveness.

The Study Team recommends addressing these findings by taking steps to determine the types and designs of targeted DER deployment that can best defer or avoid the cost of more expensive types of distribution system upgrades. The study provides a technical potential based on a suite of DERs which can be used to determine the economic potential using avoided cost values (including utility-system and societal perspectives). Defining the economic and achievable potential of different approaches will require additional design and modeling work. Defining what is achievable requires consideration of the budget for incentives, the rate of uptake for various DERs, maintenance of a stable and reliable electric distribution grid, and the timing of distribution system capacity upgrades among other issues. The need for a costly capacity upgrade should be identified by the utility years in advance to allow for planning and construction. Location-based DER incentives must be implemented quickly in order to incentivize sufficient DER investment in a timely fashion. It will be important for policies and programs to be designed to bring greater certainty around the timing and quantity of DER deployment, such that DERs become more comparable to other distribution system investments. Further, it is notable that DERs have benefits related not only to electrification but also other sources of load growth.

The DC PSC has a number of open formal cases which may be informed by the conclusions and recommendations in this study. They include:

- Formal Case No. 1050 - In the Matter of the Investigation of the Implementation of Interconnection Standards in the District of Columbia.
- Formal Case No. 1086 - In the Matter of the Investigation into the Potomac Electric Power Company's Residential Air Conditioner Direct Load Control Program.
- Formal Case No. 1130 - In the Matter of the Investigation into Modernizing the Energy Delivery System for Increased Sustainability.
- Formal Case No. 1155 - Potomac Electric Power Company's Application for Approval of its Transportation Electrification Program.
- Formal Case No. 1160 - In the Matter of the Development of Metrics for Electric Company and Gas Company Energy Efficiency and Demand Response Programs Pursuant to Section 201(b) of the Clean Energy DC Omnibus Amendment Act of 2018.
- Formal Case No. 1163: In the Matter of the Investigation into the Regulatory Framework of Microgrids in the District of Columbia.
- Formal Case No. 1166: In the Matter of the Investigation Into Energy Storage And Distributed Energy Resources In The District Of Columbia.
- Formal Case No. 1167: In the Matter of the Implementation of Electric And Natural Gas Climate Change Proposals.

- Formal Case No. 1172: In the Matter of the Consideration of Federal Funding under the Infrastructure Investment and Jobs Act and Inflation Reduction Act.
- Formal Case No. GD2019-01-M In the Matter of the Implementation of the 2019 Clean Energy DC Omnibus Act Compliance Requirements.

We recommend next steps focused on the deferral and avoidance of more expensive utility solutions and new efforts (efforts that are not already underway) that can be taken towards the goal of a cost-effective and reliable electric system as part of a low-emissions energy system approaching net zero. To cost-effectively address temporal- and feeder-specific pressures, Pepco should continuously examine the extent to which it can address the distribution system pressures through low-cost utility solutions such as load transfers, feeder up-rating, and conservation voltage reduction. In addition to this effort, the District should take the following steps.

1. First, the District should establish baselines and set up a way to continuously monitor feeder-level loads against normal ratings to allow sufficient time to deploy solutions.
2. Second, the District can use the information about the magnitude, temporal, and spatial aspects of avoided costs to evaluate existing DER compensation mechanisms. We recommend the District start by updating the benefit-cost analysis for existing DER compensation mechanisms and adjusting the design of existing mechanisms to better align the relief provided by these mechanisms with anticipated pressures.
3. Some DER compensation mechanisms that could be effective at providing relief, such as certain rate designs and VDER tariffs, may not be in use by the District. As a third and optional step, the District can conduct benefit-cost analysis on proposed designs for new DER compensation mechanisms.
4. Lastly, the District should repeat this roadmap process periodically to evaluate the performance of all DER compensation mechanisms and update them as needed. The District can require a more significant set of study updates every five years to the avoided costs and other major inputs.

Figure ES-1 below illustrates this roadmap.

Figure ES-1. Roadmap for Establishing DER Compensation Mechanisms

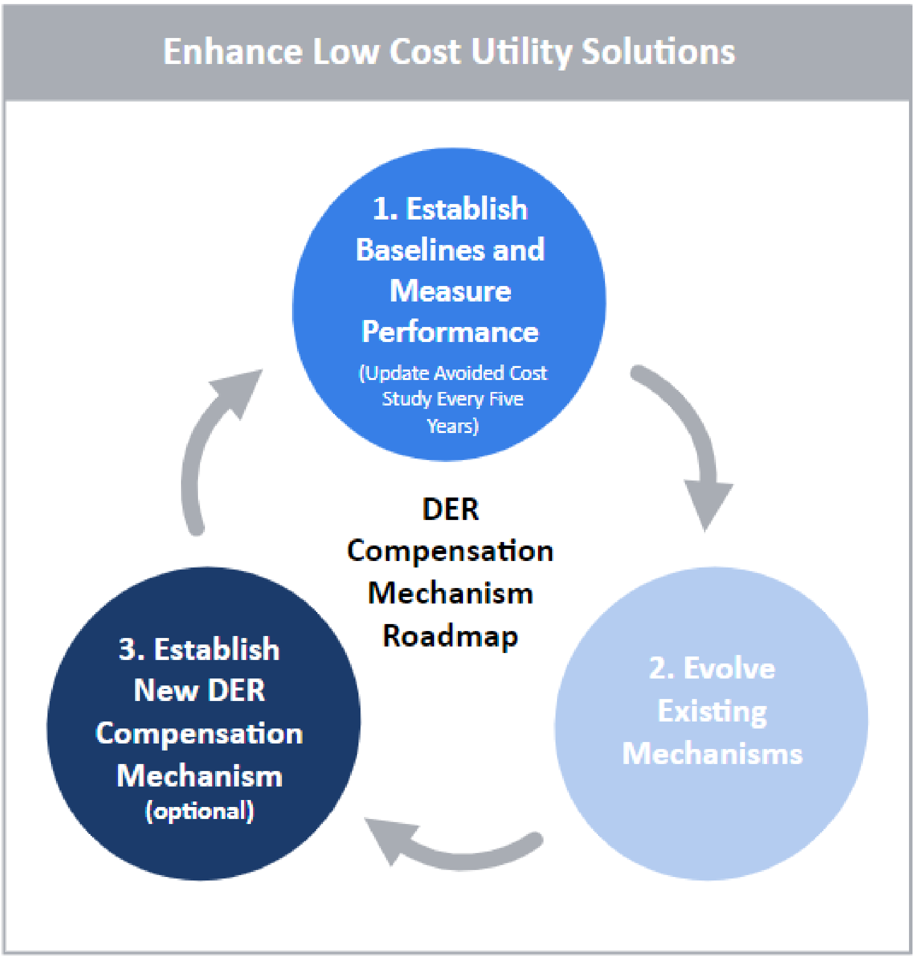

Table ES-2 provides a summary of more specific roadmap recommendations associated with different DER compensation mechanisms.

Table ES-2. Summary of Roadmap Recommendations

DER Compensation Mechanisms	Recommendations
Incentive/ Rebate Programs	1) Proactively address future electrification pressure through modification or expansion of existing energy efficiency and demand response incentive/rebate programs to the extent doing so is cost-effective. a. Reexamine incentive levels for weatherization and building envelope upgrades, investment in high efficiency HVAC systems, and improvements in controls systems and grid responsive equipment and appliances that can engage in demand response. Determine what incentive level would reflect the load shaping and load shedding value that these measures support. b. Reassess programs to ensure they account for the value of load flexibility and the breadth of emerging technologies that can support load flexibility, including ongoing assessment of the state-of-the-art in advanced commercial HVAC controls, water cooling and heating, space cooling and heating, and refrigeration measures. As a starting point, all energy efficiency programs should also consider how grid responsiveness can be enabled concurrently with efficiency measures. c. Add an incentive tier for those who weatherize their home, adopt controls, and/or enroll in a demand response program at the same time as, or within a specific number of months after, electrification. d. Include a new incentive tier for those who can reduce or shift load if they live in areas with potential distribution system pressures to properly capture the feeder-specific value they offer. e. Add another program type to the demand response programs for those customers who are interested in higher rewards in exchange for taking on more risk, for example more events, events that occur year-round, less predictable timing of events, or penalties for non-performance.
	2) Amend solar incentives to include storage and account for temporal- and feeder-specific values.
Rate Designs	3) Implement additional time- and location-varying rates to appeal to customers with various types of DERs, including solar and batteries.
VDER Tariffs	4) Develop VDER tariffs for technologies that can export to the grid.
	5) Consider implementing various complexity levels in a VDER tariff, or pairing VDER tariff options with other compensation options to appeal to customers with different preferences.
Contracts with DER Providers	6) Use RFPs and contracts with DER providers where specific solutions are required to address feeder-specific pressures. Pursue RFPs after other low-cost mechanisms (such as energy efficiency programs and rate design) are employed.

1. INTRODUCTION

The mission of the Public Service Commission of the District of Columbia (DC PSC) is to serve the public interest by ensuring that financially healthy utility companies provide safe, reliable, and quality utility services at reasonable rates for District of Columbia (District) customers, while fostering grid modernization, conservation of natural resources, preservation of environmental quality, and advancement of the District's climate policy commitments. The Exelon-Pepco merger settlement set aside shareholder funds to support grid modernization efforts. The DC PSC established a Pilot Projects Governance Board to make recommendations on such efforts, including studies. The Final Report of the MEDSIS Stakeholder Working Groups recommended such a study to consider the temporal and locational (feeder-specific) benefits of distributed energy resources (DERs). The DC PSC entered into a contract with Synapse Energy Economics, Inc. (Synapse) and its subcontractor, New City Energy, LLC (NCE)—together, the Study Team—to assist with developing a framework and quantitative temporal and locational District-specific values for the services provided by DERs in the District and a roadmap for developing DER compensation mechanisms to enable implementation of cost-effective DERs. This study goes beyond VDER studies conducted by other jurisdictions to date as it examines a subset of distribution feeders projected to approach feeder limits given high levels of electrification and analyzes relief opportunities. NCE analyzed feeder-level constraints, provided power flow modeling, developed electrification scenarios, modeled pressure on feeders (in scenarios where loads exceed feeder normal ratings), designed load-shaping and load-shedding relief scenarios, and developed quantitative values for avoided distribution costs.[1] Synapse developed the economic modeling framework, quantified values for the other avoided costs, and led roadmap design.

DERs consist of resources that are located close to customer loads on the distribution system. These resources include technologies such as solar photovoltaics, battery storage, energy efficiency, demand response, and electric vehicles. By exporting renewable energy, modulating demand according to system needs, or providing voltage support, these resources can provide a range of services to the grid from the distribution system level up to the bulk power level.

The context for this study is the drive for renewable energy and decarbonization while maintaining a reliable and affordable supply of electricity.[2,3] The District of Columbia has made significant progress on

[1] The Study Team is aware that distribution system constraints are often seen as a limit to DER deployment. The Study Team created power flow models for photovoltaics representing 1 to 100 percent of total annual load (MWh), modeled battery energy storage systems to prevent PV backflow at the substation, and modeled advanced inverters to address voltage variability. Both batteries and advanced inverters were extremely effective at keeping power flows within the target bounds in our modeled scenarios. We could see that hosting capacity might be extended through batteries and advanced inverters, potentially even up to very high levels of PV penetration. However, hosting capacity was not the focus of this study and additional research and analysis is required to support any formal conclusions.

[2] D.C. Law 24-176. *Climate Commitment Amendment Act of 2022*. Available at: https://code.dccouncil.gov/us/dc/council/laws/24-176#:~:text=%22(b)(1),in%20additional%20renewable%20energy%20generation.

[3] D.C. Law 24-0314. *Local Solar Expansion Amendment Act of 2022*. Available at: https://lims.dccouncil.gov/Legislation/B24-0950.

solar generation. The total renewable portfolio standard (RPS) certified solar capacity of 225.5 MW at year-end in 2022 exceeded the estimated solar capacity of 189.9 MW required to meet the District of Columbia's 2.6 percent solar requirement for 2022.[4] The District's DER portfolio also includes demand response and CHP bringing the total to nearly 400 MWs.[5] In the event significant building and transportation electrification occurs absent any changes in compensation mechanisms, distribution system planning, coordination of all available resources, and customer behavior, the need for distribution system upgrades may drive substantial increases in distribution system costs.

As DER installations increase, the Study Team recommends that the DC PSC seek to maximize the temporal- and feeder-specific benefits of DERs, where cost-effective. Full realization of many of those benefits requires system planning that can appropriately value them for the purposes of decision-making. The goal of temporal- and feeder-specific DER compensation mechanisms is to defer more expensive distribution system upgrades. This can be accomplished by coordinating or incentivizing DER investment where DERs can alleviate distribution system pressures at a lower cost than traditional utility solutions. DER compensation mechanisms can also increase DER deployment to achieve greenhouse gas (GHG) emissions reductions, enhance local economic development, and further equity goals.

Without a framework to monitor, coordinate, and compensate DERs appropriately, it is unlikely that the optimal level of DERs will be installed at the most beneficial locations in the city or operate at the most beneficial times.

Without a framework to monitor, coordinate, and compensate DERs appropriately, it is unlikely that the optimal level of DERs will be installed at the most beneficial locations in the city or operate at the most beneficial times. The DC PSC has implemented several compensation mechanisms and programs to support the development of DERs, but more can be done to ensure that DERs receive compensation for the feeder-specific and/or temporal-specific value that they bring to the grid. In particular, DERs are generally not targeted to locations on the distribution grid where they are most needed, and customers are not typically incentivized through time-varying pricing that would encourage the adoption of DERs to reduce or shift load when the distribution system is constrained and/or wholesale market prices are peaking.

The objective of this report is to propose a valuation framework for DERs in the District and recommend next steps regarding compensation mechanisms and designs that will encourage the most beneficial development and integration of DERs into the District's electric grid, while supporting achievement of the District's energy policy goals. As part of the roadmap, this report describes potential updates to existing compensation mechanisms and/or new mechanisms needed to coordinate and incentivize DERs <u>where</u> and <u>when</u> they can provide the most value.

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[4] DC PSC. *Renewable Energy Portfolio Standards: A Report for Compliance Year 2022*. May 1, 2023. Available at: https://dcpsc.org/getmedia/1fc46e74-d0f6-43a2-a0fb-bd99b75cf0cb/DCPSC-2023_RPS_Report-FINAL.aspx.

[5] DC PSC Staff reports that the District's DER capacity currently includes, in addition to solar, 83 MWs of cogeneration/CHP, 25 MWs of Pepco's Direct Load Control program, 18 MWs from DC SEU energy efficiency programs, and 73 MWs of commercial load control.

In assessing potential solutions for constraints or pressures emerging on the distribution system, there are additional considerations to keep in mind. These ideas are developed further in the Additional Considerations section of the Roadmap.

- Complex Distributed Systems: DERs are part of a complex system and require whole system design, which may include standards, communications, and coordinated operations across the grid. While designs for coordination and interoperability across distributed energy resources are not elaborated on in this report, they are essential to ensuring resources across these complex systems are optimized.

- Increasing Resilience Risks: Energy distribution systems are facing greater risks from what once were considered "once-in-a-hundred year" events. Cost and reliability can be considered in the context of increasing risks.

- Beneficial Loads: Load flexibility will likely increase in value as renewable generation increases and more atypical events occur across the energy delivery supply chain. Targeted programming for major systems like the water utility, streetlights, public transit, may yield especially large benefits because more flexible loads can potentially provide similarly large and broad benefits to the rest of the system during either normal or emergency operation. In addition, as buildings are fully electrified, we suggest bearing in mind that with proper systems in place, buildings can provide supply (rooftop PV, back up generation), storage (battery, EV, thermal), and flexible load (pre-cooling, variable lighting). Coordination of all these resources will be essential to maximize benefits to consumers.

- Infrastructure Capital Cycles: The distribution system is a collection of many thousands of assets that each have a lifecycle and an investment logic. It will be important to evaluate where the assets are in the capital cycle and understand when in the capital cycle DERs can provide the most value.

- Price Uncertainty: Because the market for regional capacity is evolving, it will be beneficial to track developments in wholesale prices and price structures and to ensure that the local market designs align with these evolving conditions.

The remainder of this report is organized as follows:

- Section 2 provides an overview of the current District compensation mechanisms.

- Section 3 discusses the state of VDER tariff development in other jurisdictions.

- Section 4 summarizes the proposed VDER framework for valuing DERs across the full range of values they can provide.

- Section 5 discusses the methodology for avoided distribution costs, including distribution grid feeder selection, modeled distribution grid pressures, and modeled distribution grid relief.

- Section 6 summarizes the quantitative impacts for implementation.
- Section 7 outlines a recommended roadmap focusing on DER compensation mechanisms for implementation in the District.
- Appendix A provides a more detailed description of the VDER framework and the associated values.
- Appendix B provides a description of the approaches and best practices gleaned from other jurisdictions regarding approaches to determining the value of DERs.
- Appendix C describes the detailed methodology and assumptions used to develop the energy generation and generation capacity benefits calculated by the EnCompass modeling.
- Appendix D describes the detailed methodology and assumptions used in the distribution system feeder analysis.
- Appendix E provides a snapshot of the detailed DER impacts by hour and feeder type. (An electronic version is available on the DC PSC website.)

2. Current DER Compensation Mechanisms in the District

DER compensation mechanisms can include incentive/rebate programs, rate designs, VDER tariffs, and contracts with third-party providers. Synapse provides a summary of the District's current DER compensation mechanisms below. A variety of potential DER programs – too many to list here -- are under discussion in open formal cases overseen by the Commission or other District agencies.

2.1. Incentive/Rebate Programs

Energy efficiency programs: The DC Sustainable Energy Utility (DCSEU) currently operates wide-ranging energy efficiency programs for residential and commercial customers. In 2021, these programs produced over 100,000 MWh of electricity savings.[6] Pepco has also proposed to implement energy efficiency programs. As proposed, none of the DCSEU or Pepco efficiency programs target peak hours or geographic locations that are likely to become constrained.

[6] DC SEU. *A Decade of Transformation – 2021 Annual Report*. Available at https://doee.dc.gov/sites/default/files/dc/sites/ddoe/publication/attachments/DCSEU-AnnualReport-Final-11.30.2021.pdf.

Demand response programs:

- The DC PSC approved Pepco's residential air conditioner direct load control (DLC) program in 2011.[7] This program allows Pepco to cycle certain customer appliances during periods of high wholesale market prices. If this program were targeted to customers in specific locations where feeder capacity pressures are emerging, it could help to address the timing and location of these pressures. As of December 2022, the DLC program had the ability to provide 24.8 MW of peak demand reduction.[8]

- In addition, Pepco has proposed to implement a "Bring Your Own Device" residential demand response program, which also seeks to reduce residential HVAC demand during peak periods. The program offers incentives to customers (through rebates and bill credits) for a range of smart thermostats. As this program is not targeted to customers in specific areas where pressures are emerging, deployment is not optimized to address locations of greatest capacity needs.

- Though not regulated by the DC PSC, third-party curtailment service providers operate in the District as well. These service providers participate in the PJM wholesale market to provide capacity at the wholesale level.

Solar programs:

- The *Renewable Portfolio Standard Expansion Amendment Act of 2016*[9] established the Solar for All program, which is administered through the Department of Energy and Environment. The goal of this program is to reduce electricity bills by 50 percent for 100,000 low- and moderate-income households through the installation of solar. Funding for the program comes from the Renewable Energy Development Fund, which is funded through compliance fees paid by electricity suppliers who do not meet the annual renewable portfolio standard requirements.[10] This program is not designed to address timing or feeder-specific pressures.

- The *Local Solar Expansion Amendment Act of 2022*[11] increased the solar renewable portfolio standard for local solar from 10 percent to 15 percent by 2041. RPS compliance

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[7] DC PSC. FC1086, Order No. 16602. November 3, 2011. Available at: https://edocket.dcpsc.org/apis/api/Filing/download?attachId=73374&guidFileName=bedc7d0a-0edd-42d6-8d80-56c6be03eb48.pdf.

[8] Pepco's First Quarter 2023 Performance Tracking Report (May 15, 2023) https://edocket.dcpsc.org/apis/api/Filing/download?attachId=189938&guidFileName=e3fd4dc1-9658-4274-8529-dc14ea8f5b4f.pdf

[9] D.C. Law 21-154; Section 8-1774.16 - Solar for All Program. Available at: https://casetext.com/statute/district-of-columbia-official-code/division-i-government-of-district/title-8-environmental-and-animal-control-and-protection/subtitle-d-i-energy-conservation/chapter-17n-sustainable-energy/subchapter-ii-management-of-sustainable-energy-programs/section-8-177416-solar-for-all-program.

[10] DC Department of Energy and Environment. *Solar for All Annual Report FY2020*. Available at https://doee.dc.gov/sites/default/files/dc/sites/ddoe/service_content/attachments/FY%202020%20SFA%20Annual%20Report.pdf.

[11] D.C. Law 24-314. *Local Solar Expansion Amendment Act of 2022*. Available at: https://code.dccouncil.gov/us/dc/council/laws/24-314.

is met by retiring SRECs (solar renewable energy certificates) or paying a compliance fee if insufficient amounts are retired. This policy is not designed to address specific temporal- or feeder-specific pressures, and the compensation for solar (through net metering and SRECs) does not reflect temporal- or feeder-specific differences in value. This measure could result in the addition of up to 1 GW of new solar capacity by 2041.

2.2. Rate Designs

Retail electricity rates

Several medium- and large general service rate schedules offer standard offer supply service with time-of-use (TOU) rates. Some commercial rates include a demand charge. However, rates for residential customers (such as those who may be electrifying) generally do not include a time-varying component (other than prices that vary by season). None of Pepco's rates include feeder-specific price signals.

Electric vehicle charging rates

Pepco's plug-in vehicle charging rate schedule (R-PIV) has TOU standard offer service rates.[12]

Net energy metering

Residential and commercial customers who install systems powered by solar, wind, tidal, geothermal, biomass, hydroelectric facilities, digester gas, combined heat and power (CHP), fuel cells and microturbines are eligible for net metering. This allows them to offset their regular retail rate by the number of kilowatt-hours (kWh) generated during the month. As the retail rate is not time-varying, the net metering rate does not reflect the temporal nature of costs on the system. The net metering rate also does not reflect geographically variable costs on the system.[13]

2.3. VDER Tariffs

There are currently no VDER tariffs in the District. Pepco does offer Qualifying Facilities (QF) tariffs for small cogeneration facilities or power production facilities under 100 kW (as defined in the *Federal Power Act*, pursuant to Section 210 of the *Public Utility Regulatory Policies Act of 1978*). However, these QF tariffs only provide for revenues from PJM's energy and generation capacity market, and thus do not fully compensate resources for other benefits or services they may provide.

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[12] DC PSC. FC1130 and FC1155. *Electric Tariff 2022-05. In the Matter of the Motion of Potomac Electric Power Company's Multi-Dwelling Unit Plug-In-Vehicle Tariff Rate. P.S.C.-D.C. No. 1 (ET2022-05).* December 2, 2022. Available at: https://dcregs.dc.gov/Common/DCR/Issues/IssueCategoryList.aspx?DownloadFile=%7B9E3BFF1D-86FA-47F5-B3EE-33B80AD46F3F%7D.

[13] NC Clean Energy Technology Center. DSIRE Database. *Net Metering: District of Columbia*. Last Updated February 22, 2023. Available at: https://programs.dsireusa.org/system/program/detail/105/net-metering.

2.4. Contracts with Third-Party DER Providers

Pepco has implemented a Distribution System Planning-Non-Wires Alternatives (DSP-NWA) process, whereby Pepco identifies an expected locational constraint that could potentially be solved through the deployment of DERs. As part of this process, Pepco then produces a Locational Constraints Report which identifies expected need for additional electric grid capacity in a specific location. Pepco develops and issues a request for proposals (RFP) to address the constraint using DERs, and then it evaluates responses for cost-effectiveness relative to traditional utility solutions. This process helps to address the timing and location of constraints.

3. Status of DER Valuation Framework Development in Other Jurisdictions

In this section, we summarize the status of DER valuation framework development in other jurisdictions. In general, comprehensive DER valuation frameworks are relatively nascent. We surveyed 13 states that have explored DER valuation frameworks to varying degrees over the past decade. Table 1 below summarizes this research and the avoided costs for the highest value impacts.

- Seven of those 13 states (New York, California, New Hampshire, Rhode Island, Vermont, Connecticut, Massachusetts) have adopted DER valuation frameworks in some capacity. New Hampshire, Rhode Island, Vermont, Connecticut, and Massachusetts apply a DER valuation framework to determine cost-effectiveness of energy efficiency and may apply this framework to other demand-side resources. New York and California have more comprehensive frameworks which we summarize in greater detail below.
- Three states (Delaware, Pennsylvania, and Maine) do not appear to have adopted DER compensation frameworks at the time this report was written.
- The remaining three states (Maryland, New Jersey, and Hawaii) have an ongoing proceeding to consider DER compensation frameworks. New Hampshire also has an ongoing proceeding which may change its framework from what is in place now.

We provide more detailed information on many of these jurisdictional efforts in Appendix B. We provide two detailed summaries of solar-focused studies, one for Maine and one for the District. However, we do not provide a detailed summary of the other solar-focused studies (including Pennsylvania, New Jersey, and Maryland) as they are less relevant than studies that are technology-agnostic.

New York

Under its "Reforming the Energy Vision" proceeding, the New York Public Service Commission (NY PSC) established a mechanism called the "Value Stack" to compensate DERs based on the value they provide to the system. The Value Stack has thus far primarily been applied to larger solar and battery storage projects. In addition, the NY PSC established a benefit-cost analysis (BCA) framework and required each utility to file a BCA handbook. The BCA framework is intended for application to investments in Distributed System Platform capabilities, competitive procurement of DERs, procurement of DERs through tariffs, and energy efficiency programs. The methodologies for evaluating avoided distribution costs for compensation under the Value Stack have been the subject of continued discussion and evolution.

California

In 2004, California initiated a proceeding to develop a consistent set of avoided costs across various types of DERs, including energy efficiency, demand response, and distributed generation.[14] In particular, the proceeding sought to coordinate methodologies and input assumptions for the devleopment of avoided costs to be applied to various DERs. The California Public Utilities Commission (CPUC) ultimately adopted the avoided cost forecast methodology and associated spreadsheet model (the "Avoided Cost Calculator") prepared by the consulting firm E3. Since then, the assumptions, data, and models used in the avoided cost calculator have been regularly updated and are described in Appendix B.

More recently, California has developed a Locational Net Benefits Analysis (LNBA) methodology that expands on the Avoided Cost Calculator by including location-specific values and certain additional avoided cost components. In its 2017 decision on the LNBA, the CPUC adopted several use cases for the values produced by the LNBA: as a heat map showing high-value locations for the installation of DERs, to identify candidate distribution system investments for deferral, and for incorporation into the Avoided Cost Calculator for cost-effectiveness evaluation and for informing DER incentive levels.[15] These use cases have largely been implemented, with each investor-owned utility having developed granular heat maps showing the value of DERs in various locations, and the distribution system avoided by location being identified in competitive solicitations for non-wires alternatives.[16]

[14] California Public Utilities Commission, Order Instituting Rulemaking (R.) 04-04-025, April 22,2004.

[15] CPUC Decision 17-09-026, September 28, 2017.

[16] *See*, for example, PG&E's Distribution Investment Deferral Framework Request for Offer here: https://www.pge.com/en_US/for-our-business-partners/energy-supply/electric-rfo/wholesale-electric-power-procurement/2019-didf-rfo.page?WT.mc_id=Vanity_rfo-didf&ctx=large-business

Table 1. Summary of DER Compensation Framework Development in Other Jurisdictions

State	DE	MD	PA	NJ	NH	Avoided Energy Supply Components (AESC) Study		NY	HI	CA	ME
						ME	NH RI VT CT MA				
Conducted VDER Study?	No	Yes (2018)	Yes (2012)		Yes (2020)	Yes (2018 and 2021)		Yes (2021)			Yes (2015)
Who Contracted the Study?	n/a	Maryland PSC	Solar Industry Advocates		Commission	AESC Study Group		NYSERDA and utilities	HI Division of Consumer Advocate	CPUC	Comm-ission
Technology Assumed?	n/a	Solar			No technology assumed						Solar
Values Vary By	n/a	Utility and year	Location (city)		Vary by location (distribution infrastructure)	Season and on- vs. off-peak period; year; ability to provide firm capacity		Technology, time and year, and DRV & LSRV zone	Time and month	Utility, location (climate zone), time, and month	n/a; Transmission values vary by utility
Has Commission Adopted VDER Compensation Framework?	No – state uses net metering	Proceeding is ongoing	No	Proceed-ing ongoing. Current compensation structure embedded with policy incentive	Proceeding ongoing; full report released	Most recent order opted for an alternative study (ME)	Yes, for determining cost-effectiveness of EE and demand-side resources (NH, RI, VT, CT and MA)	Adopted	Proceeding ongoing	Adopted	No – state currently uses modified net metering based on utility costs

State	DE	MD	PA	NJ	NH	Avoided Energy Supply Components (AESC) Study						NY	HI	CA	ME
						ME	NH	RI	VT	CT	MA				
All-In Avoided Costs	n/a	$0.15 - $0.42/ kWh, depend-ing on utility	$0.26 - $0.32/ kWh, by location		Not eval-uated	n/a						Depend-ent on project, location, utility, and DRV/ LSRV area.	$0.05- $0.24/ kWh, varying by hour of day and month	Depend-ent on project, location, utility, and output profile.	$0.17- $0.18/ kWh
Avoided Energy Costs	n/a	$0.04- $0.06/ kWh, depend-ing on utility and year	$0.056 - $0.063/ kWh by location		Not eval-uated	$0.043- $0.063/ kWh [1]	$0.044- $0.064/ kWh [1]	$0.051- $0.071/ kWh [1]	$0.039- $0.059/ kWh [1]	$0.044- $0.064/ kWh [1]	$0.030- $0.047/ kWh [1]	Varies by project, time, and location. All hours (annual average): $0.018- $0.035/ kWh	Com-bined into all-in rate below, varying by hour and month.	Range of hour-of-day averages: $0.014- $0.10/ kWh	$0.06/ kWh
Avoided Gener-ation Capacity Costs	n/a	$0.004 - $0.01/ kWh, depend-ing on utility and year	$0.016 - $0.22/ kWh by location		No level-ized value	$16.2- $42.1/ kW-yr [2]	$20.4-48.8/ kW-yr [2]					Varies by project, time, and location. $0.00- $0.06/ kWh [3] $0.06- $0.15/ kWh [4]	Com-bined into all-in rate below, varying by hour and month.	Range of hour-of-day averages: $0.00 - $0.10/ kWh	$0.015/ kWh, plus $0.002/ kWh (avoided reserve capacity)

State	DE	MD	PA	NJ	NH	Avoided Energy Supply Components (AESC) Study						NY	HI	CA	ME
						ME	NH	RI	VT	CT	MA				
Avoided Distri-bution System Costs	n/a	No systematic valuation; illustrative example up to $0.114/ kWh	Embedded in transmission capacity		No level-ized value	Not explicitly evaluated						Determined by presence in Distribution Relief Value area. Up to $0.85/ kWh for exports during DRV windows.	Not eval-uated	Range of hour-of-day averages: $0.00 - $0.20/ kWh	Not eval-uated
Avoided Carbon and Criteria Pollut-ants	n/a	Health Benefits: $0.002 - $0.006/ kWh by year Compliance Market Value: De minimis Social Value of CO2: Not monetized	$0.02-$0.05/ kWh, by location		Not eval-uated	GHG: $0.045-$0.054/ kWh [5] Nox: $0.0006-$0.0008/ kWh [1]			GHG: $0.039-$0.046/ kWh [5] Nox: $0.0005-$0.0007/ kWh [1]	GHG: $0.045-$0.054/ kWh [5] Nox: $0.0006-$0.0008/ kWh [1]		Avoided RPS compliance value is greater of REC compliance and/or social cost of carbon. Social cost of carbon not explicitly built into value stack calculator.	Not eval-uated	Range of hour-of-day averages: $0.00 - $0.05/ kWh	Social Cost of Carbon: $0.021/ kWh Social Cost of SO2: $0.051/ kWh Social Cost of Nox: $0.011/ kWh

Notes:

1. *15-year levelized retail value, varies by on- or off-peak period and season*
2. *15-year levelized retail value, varying on uncleared vs. cleared resource*
3. *Levelized over typical solar production curve, varying by month*
4. *Levelized over 240 peak system hours*
5. *5-year levelized retail value, varying by on- or off-peak period and season*

4. OVERVIEW OF THE DER VALUATION FRAMEWORK

The fundamental purpose of a VDER valuation framework is to account for the most significant costs and benefits provided by DERs, and then use these costs and benefits to inform the development of appropriate DER compensation mechanisms. Because of this objective, VDER frameworks generally focus on the utility system and societal impacts that directly affect utility ratepayers.[17] In this way, DER compensation mechanisms can be set in a manner that appropriately compensates DERs for the value they provide, while minimizing cost-shifting to other utility customers.

Table 2 lists the key utility system and societal impacts that may be included in a VDER analysis, provides a short description of each, and identifies if the impacts are included in this VDER analysis.

[17] While host customer impacts may be one factor considered when setting DER compensation levels, host customer impacts do not directly impact the value of DERs to utility ratepayers in general and are not included in this framework unless they are a component of a broader benefit category. As an example of broader benefits of host customer impacts, a reduction in a host customer's energy bills may reduce customer arrearages and utility bad debt, which then benefits all customers.

Table 2. Overview of Utility System and Societal Impacts

Type of Impact		Impact Description	Included in Study
Utility System			
Energy	Energy Generation	Cost of producing or procuring energy from generation resources on behalf of customers	Y
	Energy Demand Reduction Induced Price Effects (DRIPE)	Price effect in the wholesale markets caused by a reduction or increase in demand	Y
	Environmental Compliance	Cost to comply with environmental regulations	Y, incl. in energy generation
	Renewable Portfolio Standard Compliance	Increase or decrease in cost of compliance with renewable portfolio standards (RPS)	Y, incl. as a component of greenhouse gas emissions
	Ancillary Services	Services required to maintain electric grid stability and power quality (i.e., frequency regulation, voltage regulation, spinning reserves, and operating reserves)	Y
	Market Price Risk Reduction	Risk of fuel cost volatility	Y
Generation Capacity		Cost of generation capacity required to meet the forecasted system peak load	Y
Transmission	Transmission Capacity	Cost to construct and maintain the high-voltage transmission system to transport electricity safely and reliably	Y
	System Losses	Cost associated with electricity lost through the transmission system	Y
Distribution	Distribution Capacity	Cost of substation and distribution line infrastructure to meet customer electricity demand	Y
	System Losses	Cost associated with electricity lost through the distribution system	Y
	Operations and Maintenance (O&M)	Expenses to maintain safe and reliable operation of distribution facilities	Y
	Voltage	Cost of voltage regulation needed to ensure reliable and continuous electricity flow across the power grid	Y
Other	Utility DER Procurement and Program Administration Costs	Cost of utility procurement and administration of DERs, through utility ownership, financial incentives to host customers, or developer contracts; may also include administrative costs such as outreach to trade allies, technical training, marketing, payments to third-party consultants, and other administrative costs	N, program-specific
	Utility Performance Incentives	Cost of incentives offered to the utility to encourage successful, effective implementation of DER programs	N, program-specific
	Credit and Collections	Changes in utility costs associated with arrearages and bad debt	Y
	Construction and Procurement Cost Risks	Risk associated with construction and procurement costs being higher than anticipated	N
	Reliability	Value of maintaining generation, transmission, and distribution system to withstand instability, uncontrolled events, cascading failures, or unanticipated loss of system components; this category reflects the value above that which is already included in standard system design and operation	N

Type of Impact		Impact Description	Included in Study
Societal			
Greenhouse Gas Emissions		Non-embedded societal cost of greenhouse gas emissions (i.e., the social cost of carbon from electricity generation and methane leakage)	Y
Other Environmental		Externalities associated with liquid and solid waste emissions, land use, and water use	N
Public Health		Costs borne by society associated with pollution health impacts such as from NO_X and $PM_{2.5}$. These costs include medical costs and reduction in productivity	Y, for NO_X and $PM_{2.5}$ only
Other	Resilience	Value associated with the ability to anticipate, prepare for, and adapt to changing conditions and withstand, respond to, and recover rapidly from disruptions	Y
	Equity	Value of fair treatment, advancement, opportunity, and access for all individuals (low-income customers in disadvantaged communities only)	Y

Notes:

(1) This study does not include macroeconomic and job impacts, even though such impacts are sometimes characterized as societal impacts. Macroeconomic impacts should not be added to the monetary values, because they represent a different type of economic impact—increased economic activity in an area—rather than direct reductions in energy or environmental costs to ratepayers. Thus, they are not included.

(2) In some instances, regulators may decide to evaluate the macroeconomic impacts alongside the value of DER to ratepayers.[18] In doing so, regulators should be aware that those impacts may include spending that would have occurred with or without the DER; or it may fall outside the boundaries of energy-related spending. The analysis should only count the net benefits associated with the DER. For this type of macroeconomic impact analysis, the net benefits will be specific to the type of DER that is installed, the host customer bill savings, and the type and location of the resource being avoided (such as a power plant in another state or a local substation).

[18] Specifically, macroeconomic impacts typically result from the spending of money – whether the money is spent to construct or install a DER, or through host customers spending the money that they have saved from reduced energy bills. In the first case, the construction or installation of a DER is simply displacing a different type of energy resource, and thus the macroeconomic impacts should only represent any net economic activity above and beyond what would have occurred without the DER. Second, host customer spending of bill savings simply represents spending on something else, rather than on energy bills. This is also simply a different type of spending, and thus the impacts must only account for the net effect on the local economy.

5. AVOIDED DISTRIBUTION COST METHODOLOGY

5.1. Distribution Grid Feeder Selection

The Study Team utilized District-specific feeder peak load and upgrade cost data to inform District-specific findings and recommendations. Pepco's distribution system serves approximately 337,000 customers (310,000 residential customers and 27,000 commercial customers) in the District. Approximately 75 percent of the total energy in the District is consumed by commercial customers. The District has approximately 765 feeders in total and roughly 50 percent of the District is served by underground distribution lines. The distribution feeder types in the District include radial and Low Voltage Alternating Current (LVAC) feeders. The total non-coincident peak load was approximately 2,100 MVA in 2021.

Avoided distribution costs can be significant and levels of these potential benefits vary by feeder. Of the nearly 800 distribution system feeders in DC, Pepco provided data for 32 feeders. The chief selection criterion was that capacity on these feeders was approaching the feeders' normal rating. The normal rating of a feeder is a selected ampere rating that protects the equipment from destruction or degradation. Pepco selected this subset of feeders to represent multiple kinds of grid architecture, levels of pressure on the feeders, and levels of expected DER penetration.[19]

Of these, the Study Team identified 27 feeders for further analysis based on data availability. The Study Team categorized these feeders by level of pressure at peak demand (proximity of peak demand to the normal rating of the feeder), the seasonality of the peak (i.e., the seasons when the peak occurs), and the shape and duration of peak demand (i.e., how sustained or broad the pressure is after the peak) as follows:

- Levels of peak pressure: very high, high, medium, and low
- Peak seasonality: summer-peaking, winter-peaking, and all-season
- Shape of pressure:
    - "Needle peaks," which have high, spiking values that are relatively isolated
    - "Following" load, where the level of pressure remains high for 200+ annual hours
    - "Graded" pressure, where the level of pressure drops of steadily and gradually
    - "Minimal," where nearly no following pressure exists after the peak

[19] Feeder 4 is part of Pepco's Low Voltage AC (LVAC) network that serves the central business district. LVAC feeders have physical properties that are different from the rest of the feeders included in this study.

Based on this categorization, the Study Team selected four feeders to represent types of pressure on the distribution system, as follows:

- Feeder 1 (F1): High Pressure (84 percent of normal rating), Summer Peak, Following Load
- Feeder 2 (F2): Very High Pressure (91 percent of normal rating), Summer Peak, Needle Peak
- Feeder 3 (F3): Very High Pressure (91 percent of normal rating), Winter Peak, Following Load
- Feeder 4 (F4): Low Pressure (46 percent of normal rating), Summer Peak, Minimal Load Throughout

In modeling these feeders, the Study Team evaluated: 1) the baseline load; 2) the introduction of two layers of electrification pressure: building and vehicle electrification, and the combination of these pressures; 3) a Main Relief scenario comprised of load shaping measures: building efficiency, EV load shaping, and photovoltaics; and 4) Load Flexibility provisioned after load shaping. These steps are illustrated in a series of heatmaps below, and the aggregated impacts of these pressures and relief are depicted in stacked bar charts after each relief scenario is defined.

The baseline load on these feeders (before electrification pressure) is characterized in the heatmaps provided in Figure 1 below. The percentages in the heatmaps represent the current load relative to the normal rating of the feeder. The heatmap color scale is based on the normal rating of the feeder such that pressure at the same percent of a normal rating will show up the same across different feeders. The figure shows the relative loading of each feeder on an hourly and monthly basis, and it provides an indication of the steepness or pervasiveness of the peaks. The distribution system baseline provided by Pepco stayed within or almost within the bounds of the normal rating of the feeder through the study period.

Figure 1. Baseline Load on Selected Feeders as a % of Normal Rating, 2045

Feeder 1

	1:00	2:00	3:00	4:00	5:00	6:00	7:00	8:00	9:00	10:00	11:00	12:00	13:00	14:00	15:00	16:00	17:00	18:00	19:00	20:00	21:00	22:00	23:00	0:00
Jan	55%	54%	52%	52%	52%	56%	58%	64%	65%	62%	57%	59%	58%	57%	58%	58%	59%	61%	65%	65%	66%	66%	66%	61%
Feb	53%	51%	51%	49%	50%	52%	56%	60%	61%	56%	55%	54%	52%	52%	50%	51%	50%	52%	57%	59%	58%	59%	57%	55%
Mar	51%	49%	48%	47%	47%	48%	48%	64%	66%	64%	47%	46%	47%	44%	46%	46%	45%	45%	49%	52%	53%	52%	51%	48%
Apr	37%	35%	35%	34%	35%	36%	37%	40%	42%	41%	39%	40%	41%	42%	40%	40%	40%	41%	43%	46%	46%	44%	40%	39%
May	45%	43%	41%	42%	42%	41%	42%	47%	47%	47%	54%	52%	55%	54%	56%	57%	58%	57%	59%	58%	57%	56%	54%	49%
Jun	55%	52%	50%	50%	50%	51%	51%	54%	55%	58%	59%	61%	65%	66%	68%	72%	68%	70%	72%	71%	70%	68%	64%	59%
Jul	67%	65%	63%	62%	60%	59%	60%	63%	67%	68%	71%	73%	75%	77%	81%	82%	82%	82%	83%	83%	84%	79%	77%	71%
Aug	64%	62%	59%	58%	56%	55%	56%	59%	62%	63%	67%	69%	71%	74%	76%	79%	76%	78%	76%	77%	78%	76%	71%	68%
Sep	55%	52%	49%	48%	48%	49%	50%	55%	56%	58%	61%	61%	65%	70%	71%	70%	75%	69%	68%	69%	66%	65%	60%	57%
Oct	37%	35%	34%	34%	34%	33%	36%	38%	38%	40%	41%	40%	43%	43%	44%	45%	47%	48%	51%	52%	50%	45%	42%	40%
Nov	44%	41%	40%	40%	39%	39%	42%	45%	45%	46%	45%	45%	44%	43%	42%	43%	46%	49%	52%	54%	52%	51%	48%	45%
Dec	51%	50%	48%	48%	47%	49%	49%	53%	53%	56%	56%	56%	58%	59%	60%	59%	61%	64%	67%	62%	60%	60%	56%	54%

Feeder 2

	1:00	2:00	3:00	4:00	5:00	6:00	7:00	8:00	9:00	10:00	11:00	12:00	13:00	14:00	15:00	16:00	17:00	18:00	19:00	20:00	21:00	22:00	23:00	0:00
Jan	41%	40%	38%	38%	38%	39%	42%	48%	48%	42%	40%	40%	42%	40%	41%	42%	43%	45%	50%	51%	49%	50%	47%	44%
Feb	39%	38%	37%	36%	37%	37%	38%	41%	42%	38%	36%	35%	37%	33%	33%	34%	36%	38%	42%	45%	44%	44%	42%	41%
Mar	37%	36%	35%	35%	34%	35%	35%	36%	36%	33%	34%	34%	35%	34%	33%	35%	34%	35%	37%	41%	42%	41%	37%	34%
Apr	26%	25%	25%	24%	25%	27%	27%	28%	37%	34%	28%	28%	29%	29%	28%	30%	29%	30%	32%	35%	34%	33%	31%	29%
May	34%	31%	29%	28%	28%	27%	28%	30%	32%	33%	32%	33%	38%	41%	42%	42%	45%	43%	45%	46%	48%	46%	43%	38%
Jun	44%	42%	39%	40%	39%	37%	37%	39%	40%	42%	41%	45%	46%	51%	52%	56%	59%	61%	59%	61%	59%	57%	53%	49%
Jul	57%	55%	52%	50%	50%	49%	48%	50%	50%	53%	57%	57%	59%	65%	66%	70%	85%	91%	90%	86%	90%	86%	82%	62%
Aug	49%	45%	45%	44%	41%	40%	40%	42%	44%	43%	46%	50%	54%	58%	60%	62%	62%	64%	63%	63%	64%	61%	57%	52%
Sep	40%	39%	35%	35%	34%	34%	35%	37%	39%	42%	44%	47%	46%	51%	55%	55%	60%	55%	54%	56%	53%	52%	48%	44%
Oct	25%	24%	22%	22%	22%	22%	24%	27%	29%	29%	29%	31%	30%	29%	29%	30%	33%	33%	35%	36%	35%	33%	31%	28%
Nov	34%	31%	30%	30%	29%	30%	32%	34%	35%	34%	32%	32%	30%	31%	30%	31%	34%	37%	42%	41%	40%	40%	38%	36%
Dec	43%	41%	39%	39%	39%	38%	40%	43%	45%	46%	45%	46%	48%	50%	50%	50%	50%	52%	53%	53%	51%	48%	47%	45%

Feeder 3

	1:00	2:00	3:00	4:00	5:00	6:00	7:00	8:00	9:00	10:00	11:00	12:00	13:00	14:00	15:00	16:00	17:00	18:00	19:00	20:00	21:00	22:00	23:00	0:00
Jan	75%	73%	73%	71%	73%	76%	80%	86%	89%	84%	81%	77%	78%	79%	78%	75%	73%	76%	82%	86%	91%	84%	83%	78%
Feb	71%	67%	67%	66%	66%	69%	71%	77%	76%	77%	78%	77%	75%	73%	72%	73%	73%	74%	78%	77%	77%	73%	72%	71%
Mar	61%	57%	56%	57%	57%	60%	64%	70%	71%	67%	64%	63%	61%	58%	59%	56%	57%	58%	64%	69%	72%	69%	68%	65%
Apr	42%	40%	40%	40%	44%	49%	52%	58%	51%	47%	46%	44%	43%	42%	43%	42%	44%	46%	48%	53%	51%	49%	46%	44%
May	53%	50%	47%	47%	47%	46%	51%	54%	57%	58%	60%	60%	63%	66%	67%	72%	74%	74%	74%	71%	69%	65%	62%	58%
Jun	54%	52%	51%	49%	49%	49%	51%	56%	58%	63%	66%	69%	72%	72%	75%	76%	79%	74%	72%	71%	70%	67%	64%	59%
Jul	71%	68%	64%	63%	63%	61%	62%	65%	67%	73%	78%	79%	82%	87%	85%	84%	85%	85%	87%	84%	83%	80%	77%	73%
Aug	63%	59%	56%	57%	55%	56%	58%	61%	62%	65%	67%	71%	74%	78%	82%	79%	81%	82%	84%	81%	80%	75%	73%	66%
Sep	56%	52%	50%	48%	48%	50%	52%	54%	53%	56%	57%	60%	63%	66%	69%	72%	76%	72%	74%	77%	75%	70%	65%	59%
Oct	55%	52%	52%	51%	51%	52%	54%	54%	53%	53%	56%	60%	64%	64%	64%	70%	70%	72%	73%	75%	70%	67%	62%	57%
Nov	53%	49%	49%	47%	48%	53%	56%	62%	61%	56%	54%	52%	55%	54%	53%	53%	50%	54%	60%	62%	63%	59%	57%	56%
Dec	63%	61%	57%	59%	58%	60%	65%	70%	73%	69%	63%	60%	60%	57%	59%	57%	58%	62%	66%	68%	70%	68%	67%	64%

Feeder 4

	1:00	2:00	3:00	4:00	5:00	6:00	7:00	8:00	9:00	10:00	11:00	12:00	13:00	14:00	15:00	16:00	17:00	18:00	19:00	20:00	21:00	22:00	23:00	0:00
Jan	24%	22%	22%	23%	22%	24%	30%	34%	36%	36%	34%	33%	32%	32%	31%	31%	27%	28%	29%	30%	28%	28%	27%	26%
Feb	21%	21%	20%	20%	21%	21%	24%	28%	33%	33%	30%	30%	29%	29%	28%	28%	28%	28%	26%	26%	25%	25%	24%	23%
Mar	22%	22%	22%	22%	22%	25%	26%	27%	30%	30%	29%	31%	30%	30%	28%	28%	29%	28%	27%	28%	27%	25%	26%	23%
Apr	22%	21%	21%	20%	21%	21%	23%	25%	28%	28%	28%	28%	28%	28%	28%	28%	28%	27%	26%	26%	26%	24%	24%	23%
May	24%	23%	22%	22%	22%	23%	25%	28%	29%	31%	32%	34%	34%	33%	33%	33%	32%	30%	29%	28%	27%	26%	26%	25%
Jun	25%	25%	24%	24%	24%	28%	32%	35%	37%	38%	37%	38%	38%	37%	38%	37%	36%	34%	32%	31%	29%	29%	28%	26%
Jul	29%	29%	29%	29%	33%	34%	36%	41%	43%	45%	46%	41%	41%	41%	41%	40%	40%	38%	34%	34%	33%	32%	31%	30%
Aug	26%	25%	25%	26%	29%	30%	32%	34%	36%	37%	38%	38%	38%	38%	38%	38%	37%	35%	31%	30%	30%	29%	29%	28%
Sep	25%	25%	24%	25%	27%	29%	30%	31%	34%	34%	34%	34%	36%	36%	37%	36%	34%	31%	28%	28%	27%	27%	26%	26%
Oct	19%	18%	18%	18%	18%	20%	20%	22%	24%	25%	26%	27%	28%	28%	28%	27%	26%	24%	23%	23%	22%	22%	21%	20%
Nov	22%	20%	20%	20%	19%	20%	23%	25%	26%	30%	29%	29%	29%	30%	28%	27%	26%	26%	26%	26%	25%	26%	24%	23%
Dec	22%	22%	21%	21%	21%	23%	24%	26%	29%	33%	31%	31%	31%	31%	30%	28%	27%	27%	27%	27%	27%	26%	25%	23%

Capacity planning and load forecasting are dynamic processes. The Study Team obtained historical and forecasted data more than a year ago for a subset of feeders based on criteria provided to Pepco. These criteria were designed to identify feeders approaching their maximum capacity. The Study Team recognizes that the Company continues to assess significant changes in residential and commercial customer loads in the wake of the COVID-19 pandemic. The Study Team further acknowledges that Pepco recently updated the methodology used to forecast load for capacity planning purposes. For this study, forecast scenarios were developed and applied to the data provided by Pepco in order to reveal potential challenges that could reasonably be expected to emerge under anticipated policy changes based on the Study Team's independent professional judgement.

5.2. Modeled Distribution Grid Pressure

In all cases, modeled pressure on the distribution grid is a combination of the existing loads and projected additional pressure from electrification of buildings and vehicles. The original load shape (as defined by the peak seasonality and degree of following pressure) has a significant impact on when and how much pressure is modeled, on how much relief is feasible, and on the economics of load shaping and load flexibility (which are the two main types of relief). As a rule, feeders are not currently overloaded, so projected pressure on the system is primarily a function of new pressure as buildings and vehicles are electrified in the scenarios considered.[20] However, modeling a high rate of electrification shows many feeders may come under pressure during the study period due to the electrification of buildings and vehicles. Because the projected impacts of potential electrification scenarios carry some degree of uncertainty, such pressures could emerge with greater or lesser urgency than identified in this study.

A range of potential adoption patterns for building and vehicle electrification means there are multiple scenarios for when pressures will occur. The modeling included several scenarios, all based on District policies and targets, which appear in more detail in Appendix D. This section explores the rapid electrification growth scenario (referred to as the Maximum Pressure scenario), which assumes the District achieves all its electrification policies and targets. The Maximum Pressure scenario assumes the electrification of most buildings and vehicles in the coming decade, and the District needs to act now to relieve much of this new and incremental pressure on the distribution system.

The building and vehicle electrification pressures are very different. Figure 2 below shows heatmaps of pressure on each feeder from rapid building electrification growth. Building electrification pressure is modeled as a percent increase based on the current hourly loads. For feeders that are heavily loaded, the pressure is significant and for lightly loaded feeders the pressure is not significant. The heatmaps are scaled as a percentage of the normal rating, so the relative impact of the pressure from electrification is apparent. In all cases, the shape of the pressure is similar, with peak pressure in the hour ending at 8am (that is, between 7 and 8 am) in January, substantial pressure overnight in January, moderate pressure all winter, and light pressure in summer afternoons.

[20] The main exception to this is major real estate development.

Figure 2. Heatmaps of Rapid Building Electrification, New Peak Demand as a % of Normal Rating, 2045

Feeder 1

	1:00	2:00	3:00	4:00	5:00	6:00	7:00	8:00	9:00	10:00	11:00	12:00	13:00	14:00	15:00	16:00	17:00	18:00	19:00	20:00	21:00	22:00	23:00	0:00
Jan	63%	62%	63%	59%	61%	69%	74%	79%	76%	66%	54%	56%	55%	53%	56%	56%	54%	56%	55%	56%	58%	62%	64%	65%
Feb	49%	44%	45%	43%	44%	46%	48%	55%	50%	42%	39%	38%	40%	39%	40%	39%	35%	38%	43%	42%	40%	43%	46%	52%
Mar	34%	33%	33%	31%	32%	35%	34%	38%	37%	39%	36%	39%	41%	39%	35%	34%	32%	29%	29%	31%	33%	33%	36%	39%
Apr	22%	22%	22%	22%	24%	22%	21%	22%	22%	20%	19%	19%	18%	23%	21%	17%	17%	16%	17%	19%	17%	21%	23%	23%
May	6%	6%	6%	6%	5%	5%	6%	6%	5%	6%	6%	6%	5%	6%	7%	7%	7%	8%	7%	7%	6%	8%	8%	7%
Jun	9%	8%	7%	8%	8%	7%	7%	7%	8%	7%	8%	7%	8%	9%	10%	11%	12%	13%	12%	12%	10%	10%	12%	10%
Jul	11%	10%	10%	10%	9%	8%	8%	7%	9%	9%	9%	11%	12%	14%	14%	14%	15%	18%	16%	14%	15%	14%	13%	11%
Aug	10%	10%	10%	9%	8%	8%	8%	7%	8%	9%	10%	10%	11%	13%	13%	16%	16%	17%	14%	14%	13%	12%	13%	12%
Sep	9%	8%	8%	9%	7%	6%	6%	7%	6%	8%	9%	10%	13%	11%	14%	12%	14%	15%	12%	12%	12%	11%	12%	11%
Oct	18%	17%	18%	17%	17%	18%	17%	18%	16%	16%	16%	17%	16%	16%	15%	16%	13%	14%	14%	14%	13%	15%	18%	18%
Nov	29%	28%	29%	27%	29%	29%	27%	27%	26%	27%	25%	27%	30%	30%	31%	30%	30%	29%	27%	26%	27%	29%	27%	30%
Dec	39%	37%	40%	39%	42%	42%	42%	43%	37%	37%	34%	35%	33%	32%	31%	30%	30%	30%	28%	30%	32%	31%	38%	38%

Feeder 2

	1:00	2:00	3:00	4:00	5:00	6:00	7:00	8:00	9:00	10:00	11:00	12:00	13:00	14:00	15:00	16:00	17:00	18:00	19:00	20:00	21:00	22:00	23:00	0:00
Jan	44%	44%	42%	43%	43%	47%	53%	59%	52%	43%	37%	37%	36%	36%	36%	34%	36%	39%	42%	44%	45%	46%	46%	46%
Feb	34%	30%	31%	30%	31%	31%	34%	39%	35%	27%	25%	25%	26%	26%	23%	24%	24%	27%	30%	32%	31%	32%	34%	38%
Mar	23%	22%	21%	21%	21%	24%	23%	24%	26%	22%	23%	24%	25%	24%	20%	20%	20%	18%	20%	22%	22%	22%	25%	28%
Apr	15%	15%	15%	15%	16%	15%	14%	14%	18%	16%	11%	11%	12%	12%	12%	9%	10%	10%	12%	13%	12%	15%	16%	16%
May	4%	4%	4%	3%	3%	3%	4%	4%	4%	3%	4%	4%	4%	4%	5%	4%	5%	6%	5%	5%	5%	6%	6%	5%
Jun	7%	6%	5%	6%	6%	5%	4%	5%	5%	5%	5%	5%	6%	7%	7%	9%	10%	10%	10%	10%	9%	8%	10%	7%
Jul	9%	8%	8%	7%	7%	6%	6%	6%	6%	7%	7%	8%	10%	10%	10%	11%	16%	18%	17%	14%	13%	12%	14%	9%
Aug	7%	7%	7%	6%	6%	5%	5%	5%	6%	6%	6%	7%	8%	9%	9%	12%	12%	13%	11%	11%	10%	9%	10%	9%
Sep	6%	6%	5%	6%	5%	4%	4%	5%	4%	6%	6%	8%	9%	8%	10%	9%	10%	11%	9%	9%	9%	8%	9%	8%
Oct	12%	11%	11%	11%	11%	11%	11%	12%	11%	11%	11%	12%	11%	12%	11%	11%	10%	10%	10%	10%	9%	11%	13%	12%
Nov	20%	18%	19%	18%	19%	20%	19%	19%	19%	17%	17%	18%	19%	19%	19%	19%	19%	19%	19%	19%	19%	19%	19%	20%
Dec	31%	29%	30%	29%	31%	30%	32%	32%	29%	27%	26%	25%	23%	22%	20%	20%	21%	22%	21%	23%	23%	24%	28%	28%

Feeder 3

	1:00	2:00	3:00	4:00	5:00	6:00	7:00	8:00	9:00	10:00	11:00	12:00	13:00	14:00	15:00	16:00	17:00	18:00	19:00	20:00	21:00	22:00	23:00	0:00
Jan	73%	71%	74%	71%	72%	76%	76%	85%	82%	67%	62%	59%	55%	48%	49%	47%	46%	49%	51%	55%	61%	61%	68%	69%
Feb	60%	59%	59%	59%	57%	62%	60%	60%	55%	53%	48%	48%	50%	50%	48%	45%	39%	41%	46%	47%	45%	48%	53%	61%
Mar	44%	43%	43%	42%	46%	51%	48%	50%	51%	45%	44%	38%	35%	34%	30%	30%	29%	27%	30%	34%	35%	36%	46%	50%
Apr	22%	20%	21%	20%	23%	21%	22%	27%	24%	21%	19%	19%	19%	19%	19%	16%	16%	16%	15%	18%	18%	20%	22%	22%
May	6%	7%	6%	6%	5%	5%	6%	6%	6%	6%	7%	7%	6%	7%	8%	8%	9%	9%	9%	8%	7%	9%	9%	7%
Jun	9%	8%	7%	7%	6%	6%	6%	6%	7%	8%	8%	8%	9%	9%	10%	11%	13%	12%	12%	11%	10%	9%	12%	9%
Jul	11%	9%	10%	9%	9%	7%	8%	7%	8%	9%	9%	11%	13%	14%	13%	15%	15%	17%	15%	13%	13%	12%	12%	11%
Aug	9%	8%	9%	8%	7%	7%	7%	7%	7%	9%	8%	9%	9%	11%	12%	13%	12%	17%	15%	11%	11%	10%	12%	11%
Sep	8%	7%	8%	8%	6%	6%	7%	6%	6%	6%	8%	8%	10%	10%	12%	11%	13%	14%	12%	13%	13%	12%	13%	12%
Oct	15%	15%	16%	15%	17%	18%	19%	18%	15%	15%	14%	15%	15%	13%	12%	13%	11%	11%	11%	12%	11%	12%	16%	16%
Nov	33%	33%	32%	32%	32%	35%	33%	40%	41%	40%	38%	39%	38%	39%	41%	41%	34%	35%	33%	34%	34%	30%	30%	32%
Dec	38%	40%	39%	40%	40%	43%	40%	39%	41%	35%	33%	31%	31%	29%	29%	28%	28%	26%	25%	27%	28%	29%	35%	33%

Feeder 4

	1:00	2:00	3:00	4:00	5:00	6:00	7:00	8:00	9:00	10:00	11:00	12:00	13:00	14:00	15:00	16:00	17:00	18:00	19:00	20:00	21:00	22:00	23:00	0:00
Jan	17%	18%	18%	18%	18%	20%	24%	27%	26%	24%	23%	22%	21%	20%	19%	18%	16%	16%	17%	17%	17%	17%	18%	18%
Feb	14%	13%	13%	13%	13%	15%	17%	19%	19%	17%	15%	15%	15%	16%	15%	14%	12%	12%	12%	12%	12%	13%	13%	15%
Mar	11%	11%	10%	10%	11%	11%	12%	13%	13%	15%	15%	15%	15%	15%	14%	14%	13%	11%	10%	10%	10%	10%	11%	12%
Apr	8%	8%	7%	8%	9%	9%	9%	9%	8%	8%	9%	9%	8%	9%	9%	7%	7%	7%	6%	6%	6%	7%	8%	9%
May	2%	2%	2%	2%	2%	2%	3%	3%	2%	2%	3%	3%	2%	3%	3%	3%	3%	3%	2%	2%	2%	2%	3%	3%
Jun	3%	2%	2%	3%	2%	2%	3%	3%	3%	3%	3%	3%	3%	3%	3%	4%	4%	4%	3%	3%	3%	3%	3%	3%
Jul	3%	3%	3%	3%	3%	3%	3%	4%	4%	4%	4%	4%	5%	5%	4%	5%	5%	6%	4%	4%	4%	4%	4%	3%
Aug	3%	3%	3%	3%	3%	3%	3%	3%	3%	3%	3%	3%	4%	4%	4%	5%	5%	5%	4%	3%	3%	3%	4%	3%
Sep	3%	2%	2%	3%	2%	2%	2%	3%	3%	3%	3%	4%	5%	4%	5%	4%	4%	4%	3%	3%	3%	3%	3%	3%
Oct	6%	6%	6%	6%	6%	7%	6%	7%	6%	6%	6%	6%	6%	5%	5%	5%	4%	4%	4%	4%	3%	4%	6%	6%
Nov	10%	10%	11%	10%	10%	10%	10%	10%	10%	10%	9%	10%	11%	11%	11%	10%	9%	8%	8%	8%	8%	9%	9%	10%
Dec	11%	11%	12%	11%	12%	13%	14%	14%	14%	14%	13%	13%	13%	13%	12%	11%	10%	9%	8%	9%	9%	9%	11%	11%

Figure 3 below shows heatmaps of the pressures from rapid vehicle electrification growth for all representative feeders. Similar to Figure 2 above, the electrification pressure is modeled as a percent increase based on the current hourly loads. Also, the heatmaps are scaled relative to the feeder normal rating. The shape of pressure is similar across the feeders, peaking in the evening (in the hour ending at 8 pm). However, unlike building electrification pressures, the default modeling for vehicle electrification pressures has a constant magnitude at each hour across seasons. As with building electrification, the overall impact of the pressure is significant where a feeder was already under pressure, and moderate where the feeder was not already strained.

Figure 3. Heatmaps of Rapid Vehicle Electrification, New Peak Demand as a % of Normal Rating, 2045

Feeder 1

	1:00	2:00	3:00	4:00	5:00	6:00	7:00	8:00	9:00	10:00	11:00	12:00	13:00	14:00	15:00	16:00	17:00	18:00	19:00	20:00	21:00	22:00	23:00	0:00
Jan	28%	19%	15%	11%	9%	7%	7%	12%	19%	20%	17%	17%	20%	28%	30%	31%	40%	44%	58%	59%	55%	53%	46%	28%
Feb	28%	19%	15%	11%	9%	7%	7%	12%	19%	20%	17%	17%	20%	28%	30%	31%	40%	44%	58%	59%	55%	53%	46%	28%
Mar	28%	19%	15%	11%	9%	7%	7%	12%	19%	20%	17%	17%	20%	28%	30%	31%	40%	44%	58%	59%	55%	53%	46%	28%
Apr	28%	19%	15%	11%	9%	7%	7%	12%	19%	20%	17%	17%	20%	28%	30%	31%	40%	44%	58%	59%	55%	53%	46%	28%
May	28%	19%	15%	11%	9%	7%	7%	12%	19%	20%	17%	17%	20%	28%	30%	31%	40%	44%	58%	59%	55%	53%	46%	28%
Jun	28%	19%	15%	11%	9%	7%	7%	12%	19%	20%	17%	17%	20%	28%	30%	31%	40%	44%	58%	59%	55%	53%	46%	28%
Jul	28%	19%	15%	11%	9%	7%	7%	12%	19%	20%	17%	17%	20%	28%	30%	31%	40%	44%	58%	59%	55%	53%	46%	28%
Aug	28%	19%	15%	11%	9%	7%	7%	12%	19%	20%	17%	17%	20%	28%	30%	31%	40%	44%	58%	59%	55%	53%	46%	28%
Sep	28%	19%	15%	11%	9%	7%	7%	12%	19%	20%	17%	17%	20%	28%	30%	31%	40%	44%	58%	59%	55%	53%	46%	28%
Oct	28%	19%	15%	11%	9%	7%	7%	12%	19%	20%	17%	17%	20%	28%	30%	31%	40%	44%	58%	59%	55%	53%	46%	28%
Nov	28%	19%	15%	11%	9%	7%	7%	12%	19%	20%	17%	17%	20%	28%	30%	31%	40%	44%	58%	59%	55%	53%	46%	28%
Dec	28%	19%	15%	11%	9%	7%	7%	12%	19%	20%	17%	17%	20%	28%	30%	31%	40%	44%	58%	59%	55%	53%	46%	28%

Feeder 2

	1:00	2:00	3:00	4:00	5:00	6:00	7:00	8:00	9:00	10:00	11:00	12:00	13:00	14:00	15:00	16:00	17:00	18:00	19:00	20:00	21:00	22:00	23:00	0:00
Jan	24%	16%	13%	10%	7%	6%	6%	11%	17%	17%	15%	14%	17%	24%	26%	27%	35%	38%	50%	51%	48%	46%	40%	24%
Feb	24%	16%	13%	10%	7%	6%	6%	11%	17%	17%	15%	14%	17%	24%	26%	27%	35%	38%	50%	51%	48%	46%	40%	24%
Mar	24%	16%	13%	10%	7%	6%	6%	11%	17%	17%	15%	14%	17%	24%	26%	27%	35%	38%	50%	51%	48%	46%	40%	24%
Apr	24%	16%	13%	10%	7%	6%	6%	11%	17%	17%	15%	14%	17%	24%	26%	27%	35%	38%	50%	51%	48%	46%	40%	24%
May	24%	16%	13%	10%	7%	6%	6%	11%	17%	17%	15%	14%	17%	24%	26%	27%	35%	38%	50%	51%	48%	46%	40%	24%
Jun	24%	16%	13%	10%	7%	6%	6%	11%	17%	17%	15%	14%	17%	24%	26%	27%	35%	38%	50%	51%	48%	46%	40%	24%
Jul	24%	16%	13%	10%	7%	6%	6%	11%	17%	17%	15%	14%	17%	24%	26%	27%	35%	38%	50%	51%	48%	46%	40%	24%
Aug	24%	16%	13%	10%	7%	6%	6%	11%	17%	17%	15%	14%	17%	24%	26%	27%	35%	38%	50%	51%	48%	46%	40%	24%
Sep	24%	16%	13%	10%	7%	6%	6%	11%	17%	17%	15%	14%	17%	24%	26%	27%	35%	38%	50%	51%	48%	46%	40%	24%
Oct	24%	16%	13%	10%	7%	6%	6%	11%	17%	17%	15%	14%	17%	24%	26%	27%	35%	38%	50%	51%	48%	46%	40%	24%
Nov	24%	16%	13%	10%	7%	6%	6%	11%	17%	17%	15%	14%	17%	24%	26%	27%	35%	38%	50%	51%	48%	46%	40%	24%
Dec	24%	16%	13%	10%	7%	6%	6%	11%	17%	17%	15%	14%	17%	24%	26%	27%	35%	38%	50%	51%	48%	46%	40%	24%

Feeder 3

	1:00	2:00	3:00	4:00	5:00	6:00	7:00	8:00	9:00	10:00	11:00	12:00	13:00	14:00	15:00	16:00	17:00	18:00	19:00	20:00	21:00	22:00	23:00	0:00
Jan	37%	25%	20%	15%	11%	9%	10%	16%	25%	26%	23%	22%	26%	37%	40%	41%	53%	58%	76%	78%	73%	70%	61%	37%
Feb	37%	25%	20%	15%	11%	9%	10%	16%	25%	26%	23%	22%	26%	37%	40%	41%	53%	58%	76%	78%	73%	70%	61%	37%
Mar	37%	25%	20%	15%	11%	9%	10%	16%	25%	26%	23%	22%	26%	37%	40%	41%	53%	58%	76%	78%	73%	70%	61%	37%
Apr	37%	25%	20%	15%	11%	9%	10%	16%	25%	26%	23%	22%	26%	37%	40%	41%	53%	58%	76%	78%	73%	70%	61%	37%
May	37%	25%	20%	15%	11%	9%	10%	16%	25%	26%	23%	22%	26%	37%	40%	41%	53%	58%	76%	78%	73%	70%	61%	37%
Jun	37%	25%	20%	15%	11%	9%	10%	16%	25%	26%	23%	22%	26%	37%	40%	41%	53%	58%	76%	78%	73%	70%	61%	37%
Jul	37%	25%	20%	15%	11%	9%	10%	16%	25%	26%	23%	22%	26%	37%	40%	41%	53%	58%	76%	78%	73%	70%	61%	37%
Aug	37%	25%	20%	15%	11%	9%	10%	16%	25%	26%	23%	22%	26%	37%	40%	41%	53%	58%	76%	78%	73%	70%	61%	37%
Sep	37%	25%	20%	15%	11%	9%	10%	16%	25%	26%	23%	22%	26%	37%	40%	41%	53%	58%	76%	78%	73%	70%	61%	37%
Oct	37%	25%	20%	15%	11%	9%	10%	16%	25%	26%	23%	22%	26%	37%	40%	41%	53%	58%	76%	78%	73%	70%	61%	37%
Nov	37%	25%	20%	15%	11%	9%	10%	16%	25%	26%	23%	22%	26%	37%	40%	41%	53%	58%	76%	78%	73%	70%	61%	37%
Dec	37%	25%	20%	15%	11%	9%	10%	16%	25%	26%	23%	22%	26%	37%	40%	41%	53%	58%	76%	78%	73%	70%	61%	37%

Feeder 4

	1:00	2:00	3:00	4:00	5:00	6:00	7:00	8:00	9:00	10:00	11:00	12:00	13:00	14:00	15:00	16:00	17:00	18:00	19:00	20:00	21:00	22:00	23:00	0:00
Jan	22%	15%	12%	9%	7%	6%	6%	10%	15%	16%	14%	13%	16%	22%	24%	25%	32%	35%	46%	47%	44%	42%	37%	22%
Feb	22%	15%	12%	9%	7%	6%	6%	10%	15%	16%	14%	13%	16%	22%	24%	25%	32%	35%	46%	47%	44%	42%	37%	22%
Mar	22%	15%	12%	9%	7%	6%	6%	10%	15%	16%	14%	13%	16%	22%	24%	25%	32%	35%	46%	47%	44%	42%	37%	22%
Apr	22%	15%	12%	9%	7%	6%	6%	10%	15%	16%	14%	13%	16%	22%	24%	25%	32%	35%	46%	47%	44%	42%	37%	22%
May	22%	15%	12%	9%	7%	6%	6%	10%	15%	16%	14%	13%	16%	22%	24%	25%	32%	35%	46%	47%	44%	42%	37%	22%
Jun	22%	15%	12%	9%	7%	6%	6%	10%	15%	16%	14%	13%	16%	22%	24%	25%	32%	35%	46%	47%	44%	42%	37%	22%
Jul	22%	15%	12%	9%	7%	6%	6%	10%	15%	16%	14%	13%	16%	22%	24%	25%	32%	35%	46%	47%	44%	42%	37%	22%
Aug	22%	15%	12%	9%	7%	6%	6%	10%	15%	16%	14%	13%	16%	22%	24%	25%	32%	35%	46%	47%	44%	42%	37%	22%
Sep	22%	15%	12%	9%	7%	6%	6%	10%	15%	16%	14%	13%	16%	22%	24%	25%	32%	35%	46%	47%	44%	42%	37%	22%
Oct	22%	15%	12%	9%	7%	6%	6%	10%	15%	16%	14%	13%	16%	22%	24%	25%	32%	35%	46%	47%	44%	42%	37%	22%
Nov	22%	15%	12%	9%	7%	6%	6%	10%	15%	16%	14%	13%	16%	22%	24%	25%	32%	35%	46%	47%	44%	42%	37%	22%
Dec	22%	15%	12%	9%	7%	6%	6%	10%	15%	16%	14%	13%	16%	22%	24%	25%	32%	35%	46%	47%	44%	42%	37%	22%

Figure 4 below shows heatmaps of combined pressures from rapid building and vehicle electrification for all representative feeders – referred to as the Maximum Pressure Scenario. Data and heatmap scaling are handled as described in Figure 2 and Figure 3 above, as the combined pressures are the sum of the two separate pressures. For building and vehicle electrification in combination, the pressures (not even including the baseload) overwhelm Feeders 1 and 3. The combined pressure is substantial for much of the winter and evenings all year (from 7 pm to 11 pm) with maximum pressures in winter evenings.

Figure 4. Heatmap of Combined Building and Vehicle Electrification, Peak Demand of New Loads as a % of Normal Rating, 2045

Feeder 1

	1:00	2:00	3:00	4:00	5:00	6:00	7:00	8:00	9:00	10:00	11:00	12:00	13:00	14:00	15:00	16:00	17:00	18:00	19:00	20:00	21:00	22:00	23:00	0:00
Jan	87%	80%	77%	69%	68%	75%	81%	91%	96%	86%	72%	73%	74%	81%	86%	88%	94%	98%	113%	115%	113%	114%	110%	93%
Feb	74%	62%	59%	53%	51%	52%	56%	67%	69%	62%	57%	54%	59%	68%	70%	71%	74%	80%	88%	89%	88%	88%	90%	80%
Mar	60%	51%	47%	41%	39%	41%	41%	50%	56%	59%	54%	56%	57%	56%	57%	61%	64%	73%	87%	90%	88%	86%	82%	67%
Apr	47%	41%	37%	32%	30%	28%	29%	35%	41%	40%	36%	36%	37%	43%	43%	44%	50%	60%	75%	78%	73%	74%	70%	51%
May	34%	24%	21%	16%	12%	11%	13%	18%	25%	26%	24%	22%	25%	34%	35%	37%	46%	50%	64%	66%	61%	60%	54%	35%
Jun	37%	26%	22%	18%	14%	13%	14%	19%	27%	27%	25%	24%	28%	36%	39%	41%	51%	56%	70%	71%	65%	63%	58%	37%
Jul	39%	29%	25%	22%	18%	15%	15%	20%	28%	29%	27%	27%	30%	41%	43%	45%	54%	61%	73%	73%	70%	67%	59%	39%
Aug	38%	28%	24%	19%	15%	14%	16%	19%	28%	29%	27%	27%	30%	38%	40%	43%	53%	61%	72%	72%	68%	65%	60%	40%
Sep	36%	26%	22%	19%	14%	12%	14%	19%	26%	28%	27%	27%	30%	37%	40%	42%	50%	59%	69%	71%	67%	63%	58%	39%
Oct	46%	36%	32%	28%	24%	24%	25%	30%	36%	36%	34%	33%	36%	45%	45%	47%	53%	55%	69%	70%	67%	67%	64%	46%
Nov	58%	47%	44%	39%	36%	36%	34%	40%	45%	41%	41%	43%	50%	59%	61%	61%	70%	70%	79%	82%	77%	76%	71%	57%
Dec	67%	55%	55%	49%	49%	48%	49%	55%	56%	57%	51%	52%	50%	53%	56%	57%	63%	74%	86%	89%	87%	84%	85%	66%

Feeder 2

	1:00	2:00	3:00	4:00	5:00	6:00	7:00	8:00	9:00	10:00	11:00	12:00	13:00	14:00	15:00	16:00	17:00	18:00	19:00	20:00	21:00	22:00	23:00	0:00
Jan	68%	60%	55%	51%	49%	52%	59%	69%	69%	61%	52%	51%	50%	60%	62%	61%	71%	77%	90%	91%	90%	90%	85%	70%
Feb	55%	46%	43%	39%	36%	36%	41%	49%	52%	44%	40%	39%	43%	50%	49%	51%	58%	62%	72%	73%	73%	71%	72%	62%
Mar	46%	38%	34%	30%	27%	29%	30%	34%	42%	40%	38%	39%	39%	39%	40%	43%	48%	56%	70%	73%	70%	67%	65%	52%
Apr	37%	31%	27%	24%	22%	20%	20%	25%	34%	33%	26%	25%	27%	34%	34%	34%	41%	48%	62%	64%	60%	60%	56%	40%
May	29%	20%	17%	13%	10%	9%	10%	14%	20%	21%	19%	18%	20%	28%	29%	31%	39%	42%	54%	56%	52%	51%	46%	29%
Jun	31%	22%	18%	15%	12%	10%	11%	16%	21%	22%	20%	20%	23%	31%	33%	34%	44%	48%	59%	60%	56%	54%	49%	31%
Jul	33%	24%	21%	17%	15%	12%	12%	16%	23%	23%	21%	22%	25%	34%	36%	37%	50%	54%	62%	62%	59%	57%	51%	33%
Aug	31%	23%	19%	15%	12%	11%	12%	15%	23%	23%	21%	21%	24%	31%	33%	35%	44%	51%	61%	62%	57%	55%	50%	33%
Sep	30%	22%	18%	15%	11%	9%	11%	15%	21%	23%	21%	22%	23%	29%	32%	34%	41%	49%	59%	60%	57%	53%	49%	32%
Oct	36%	27%	24%	20%	17%	16%	18%	23%	28%	28%	26%	26%	29%	37%	37%	38%	44%	46%	58%	59%	56%	55%	52%	36%
Nov	44%	35%	32%	27%	25%	25%	25%	30%	35%	33%	31%	32%	36%	44%	45%	46%	53%	55%	66%	68%	63%	63%	57%	44%
Dec	55%	45%	43%	39%	38%	36%	38%	42%	46%	44%	41%	39%	38%	43%	45%	47%	52%	60%	71%	74%	70%	69%	68%	52%

Feeder 3

	1:00	2:00	3:00	4:00	5:00	6:00	7:00	8:00	9:00	10:00	11:00	12:00	13:00	14:00	15:00	16:00	17:00	18:00	19:00	20:00	21:00	22:00	23:00	0:00
Jan	106%	95%	93%	84%	80%	84%	86%	101%	108%	94%	84%	80%	76%	85%	88%	88%	96%	107%	127%	133%	134%	131%	129%	106%
Feb	93%	83%	78%	72%	66%	70%	70%	76%	80%	79%	69%	69%	76%	87%	88%	86%	92%	95%	107%	109%	109%	107%	110%	98%
Mar	76%	67%	62%	55%	54%	59%	58%	66%	76%	71%	67%	59%	57%	64%	65%	66%	75%	85%	106%	111%	107%	106%	107%	87%
Apr	55%	44%	40%	34%	32%	29%	32%	43%	49%	47%	42%	41%	43%	51%	51%	52%	62%	74%	91%	96%	91%	90%	83%	59%
May	44%	31%	26%	20%	15%	14%	16%	22%	31%	32%	30%	29%	31%	44%	45%	48%	60%	66%	84%	86%	79%	79%	69%	44%
Jun	46%	32%	26%	22%	17%	15%	16%	23%	32%	34%	31%	30%	34%	46%	49%	52%	65%	70%	87%	89%	82%	79%	72%	46%
Jul	47%	34%	29%	23%	20%	17%	17%	23%	33%	34%	31%	33%	37%	50%	52%	53%	66%	75%	91%	91%	86%	82%	73%	48%
Aug	46%	32%	28%	23%	18%	16%	17%	23%	33%	35%	31%	31%	36%	46%	52%	53%	65%	75%	91%	88%	84%	80%	73%	47%
Sep	46%	32%	27%	21%	17%	15%	16%	22%	32%	33%	31%	30%	34%	45%	49%	50%	62%	72%	88%	91%	86%	82%	74%	48%
Oct	52%	39%	35%	29%	26%	26%	28%	34%	40%	40%	37%	36%	40%	50%	52%	54%	63%	68%	86%	87%	82%	82%	77%	52%
Nov	70%	58%	52%	47%	42%	44%	43%	50%	56%	56%	58%	61%	64%	76%	80%	82%	87%	90%	100%	103%	98%	95%	88%	68%
Dec	75%	65%	59%	55%	52%	52%	49%	56%	66%	62%	55%	53%	56%	65%	68%	69%	76%	84%	101%	105%	100%	99%	96%	70%

Feeder 4

	1:00	2:00	3:00	4:00	5:00	6:00	7:00	8:00	9:00	10:00	11:00	12:00	13:00	14:00	15:00	16:00	17:00	18:00	19:00	20:00	21:00	22:00	23:00	0:00
Jan	39%	32%	29%	26%	24%	24%	30%	37%	41%	40%	36%	35%	34%	40%	42%	42%	47%	51%	62%	63%	60%	59%	55%	40%
Feb	34%	28%	25%	21%	18%	19%	23%	29%	34%	33%	29%	28%	29%	36%	37%	37%	43%	47%	56%	57%	53%	51%	48%	37%
Mar	32%	26%	22%	18%	16%	16%	18%	22%	28%	31%	29%	28%	28%	31%	32%	35%	38%	45%	55%	56%	54%	52%	48%	34%
Apr	29%	22%	19%	16%	14%	14%	15%	19%	24%	23%	22%	22%	22%	28%	28%	29%	35%	41%	52%	53%	49%	49%	45%	31%
May	24%	17%	14%	11%	8%	7%	8%	12%	18%	18%	16%	16%	18%	24%	25%	27%	34%	37%	48%	49%	45%	44%	39%	25%
Jun	25%	17%	14%	11%	9%	7%	9%	13%	19%	18%	17%	16%	18%	25%	26%	27%	35%	38%	49%	50%	46%	44%	39%	25%
Jul	25%	18%	14%	12%	10%	8%	9%	13%	19%	20%	18%	17%	19%	26%	27%	28%	35%	40%	50%	50%	47%	45%	40%	25%
Aug	25%	17%	14%	11%	9%	8%	9%	12%	18%	19%	17%	16%	19%	26%	27%	28%	35%	39%	49%	50%	47%	45%	40%	25%
Sep	25%	17%	14%	11%	8%	7%	8%	12%	18%	19%	17%	17%	18%	25%	27%	28%	35%	39%	49%	50%	47%	44%	40%	25%
Oct	28%	21%	18%	15%	12%	12%	12%	17%	22%	22%	20%	19%	21%	27%	28%	29%	35%	38%	49%	50%	47%	46%	42%	27%
Nov	32%	25%	22%	19%	17%	16%	16%	20%	26%	25%	22%	23%	27%	34%	35%	35%	40%	42%	53%	54%	51%	49%	45%	31%
Dec	32%	26%	23%	19%	17%	18%	20%	24%	29%	30%	27%	26%	26%	31%	31%	33%	38%	44%	54%	56%	53%	51%	47%	33%

Figure 5 below shows heatmaps of combined pressures from rapid building and vehicle electrification on top of the original baseload for all representative feeders. Data and heatmap scaling are handled the same as Figure 2, Figure 3, and Figure 4 above. In combination, the modeled pressures and the original loads totally overwhelm Feeders 1 and 3, significantly exceed Feeder 2, and begin to approach the limit of Feeder 4. On Feeder 3 the peak pressure is 232 percent of the normal rating for the hour ending at 9 pm in January. For the more strained feeders (1 and 3), the only times not under substantial pressure are the mornings in the spring and fall.

Figure 5. Heatmap of Peak Demand with Combined Building and Vehicle Electrification and Baseline Load, as a % of Normal Rating, 2045

Feeder 1

	1:00	2:00	3:00	4:00	5:00	6:00	7:00	8:00	9:00	10:00	11:00	12:00	13:00	14:00	15:00	16:00	17:00	18:00	19:00	20:00	21:00	22:00	23:00	0:00
Jan	135%	128%	119%	118%	110%	119%	128%	143%	151%	138%	121%	119%	123%	129%	135%	138%	144%	155%	173%	176%	173%	173%	166%	142%
Feb	117%	105%	100%	96%	90%	94%	95%	115%	117%	106%	103%	101%	106%	116%	116%	117%	119%	128%	140%	141%	140%	139%	137%	126%
Mar	105%	93%	88%	82%	80%	79%	83%	114%	118%	110%	99%	97%	101%	98%	98%	101%	105%	113%	129%	135%	133%	132%	128%	111%
Apr	84%	75%	72%	66%	65%	64%	64%	72%	83%	77%	73%	72%	77%	82%	82%	83%	87%	99%	116%	122%	117%	116%	108%	89%
May	78%	67%	62%	57%	53%	51%	55%	64%	70%	71%	76%	74%	77%	82%	85%	90%	96%	106%	121%	123%	117%	115%	108%	82%
Jun	88%	77%	72%	68%	64%	64%	64%	71%	79%	83%	84%	84%	87%	100%	102%	106%	113%	125%	139%	138%	133%	129%	119%	97%
Jul	103%	91%	87%	80%	75%	73%	74%	82%	94%	96%	95%	98%	102%	111%	114%	121%	134%	139%	153%	153%	151%	146%	135%	109%
Aug	97%	89%	83%	76%	69%	67%	71%	78%	89%	92%	92%	95%	97%	107%	111%	119%	127%	139%	146%	146%	141%	141%	128%	104%
Sep	89%	78%	71%	67%	61%	62%	64%	74%	80%	86%	87%	88%	95%	99%	107%	109%	118%	128%	138%	139%	131%	128%	118%	95%
Oct	81%	70%	65%	60%	54%	56%	59%	65%	73%	75%	73%	70%	73%	82%	83%	86%	92%	99%	116%	118%	112%	110%	103%	83%
Nov	94%	83%	76%	72%	71%	70%	72%	80%	86%	87%	81%	80%	87%	98%	97%	96%	108%	111%	123%	128%	123%	123%	115%	96%
Dec	118%	104%	99%	95%	94%	92%	95%	104%	107%	111%	107%	105%	103%	100%	105%	106%	115%	129%	144%	148%	147%	139%	138%	115%

Feeder 2

	1:00	2:00	3:00	4:00	5:00	6:00	7:00	8:00	9:00	10:00	11:00	12:00	13:00	14:00	15:00	16:00	17:00	18:00	19:00	20:00	21:00	22:00	23:00	0:00
Jan	106%	94%	89%	83%	81%	84%	95%	110%	108%	97%	86%	83%	85%	93%	95%	95%	107%	120%	138%	138%	137%	134%	127%	107%
Feb	87%	78%	74%	68%	65%	65%	71%	84%	87%	76%	73%	74%	77%	81%	77%	81%	90%	98%	108%	113%	113%	110%	110%	98%
Mar	79%	68%	66%	61%	59%	57%	62%	68%	77%	72%	70%	66%	68%	70%	70%	70%	79%	84%	100%	106%	102%	102%	98%	84%
Apr	63%	56%	52%	48%	46%	46%	45%	52%	72%	67%	54%	52%	54%	60%	61%	59%	68%	75%	93%	98%	94%	93%	86%	69%
May	62%	51%	46%	40%	37%	34%	38%	44%	51%	53%	50%	51%	56%	60%	66%	70%	77%	85%	99%	102%	100%	95%	88%	66%
Jun	73%	61%	55%	54%	50%	47%	48%	54%	59%	63%	61%	64%	65%	81%	84%	85%	95%	108%	116%	119%	114%	109%	100%	79%
Jul	88%	78%	72%	64%	61%	59%	59%	66%	73%	75%	76%	80%	83%	91%	95%	102%	135%	145%	146%	141%	144%	137%	134%	95%
Aug	77%	67%	64%	58%	52%	50%	50%	57%	67%	65%	67%	71%	76%	88%	88%	94%	102%	114%	121%	123%	117%	116%	104%	82%
Sep	67%	61%	52%	49%	44%	43%	44%	52%	59%	65%	65%	69%	69%	74%	84%	87%	95%	104%	112%	115%	109%	105%	97%	74%
Oct	61%	50%	45%	42%	38%	37%	41%	49%	56%	56%	53%	54%	56%	66%	65%	66%	75%	78%	91%	93%	88%	85%	81%	63%
Nov	69%	60%	56%	52%	50%	51%	52%	60%	66%	67%	59%	63%	60%	71%	72%	72%	80%	87%	102%	102%	99%	97%	92%	76%
Dec	98%	86%	80%	78%	77%	73%	74%	80%	87%	89%	86%	84%	82%	81%	86%	88%	93%	104%	117%	120%	115%	114%	111%	95%

Feeder 3

	1:00	2:00	3:00	4:00	5:00	6:00	7:00	8:00	9:00	10:00	11:00	12:00	13:00	14:00	15:00	16:00	17:00	18:00	19:00	20:00	21:00	22:00	23:00	0:00
Jan	188%	174%	173%	162%	160%	167%	173%	195%	205%	185%	171%	156%	154%	148%	150%	148%	151%	181%	211%	226%	232%	222%	220%	191%
Feb	156%	144%	136%	129%	122%	129%	129%	137%	141%	149%	147%	145%	147%	154%	153%	149%	160%	162%	172%	176%	174%	170%	174%	161%
Mar	141%	127%	120%	113%	116%	124%	128%	143%	153%	144%	137%	122%	118%	122%	125%	124%	136%	145%	171%	175%	177%	171%	175%	152%
Apr	99%	85%	82%	75%	78%	82%	89%	106%	105%	98%	92%	89%	88%	94%	93%	97%	104%	121%	143%	149%	145%	143%	132%	107%
May	101%	85%	77%	71%	65%	62%	69%	79%	92%	95%	93%	93%	99%	113%	115%	121%	130%	144%	163%	162%	153%	147%	136%	106%
Jun	102%	88%	81%	73%	70%	67%	70%	77%	91%	99%	101%	105%	109%	123%	130%	134%	148%	145%	162%	165%	156%	151%	140%	110%
Jul	121%	106%	99%	89%	84%	79%	83%	95%	106%	113%	113%	117%	122%	132%	134%	140%	153%	159%	174%	179%	173%	163%	151%	126%
Aug	110%	96%	89%	80%	76%	75%	79%	88%	101%	102%	101%	106%	108%	119%	126%	132%	144%	163%	179%	175%	167%	159%	148%	117%
Sep	106%	89%	81%	74%	70%	68%	72%	80%	88%	91%	93%	94%	100%	116%	124%	126%	142%	151%	169%	175%	168%	158%	144%	112%
Oct	105%	89%	84%	77%	73%	72%	74%	76%	87%	88%	89%	93%	98%	99%	107%	119%	130%	146%	163%	167%	156%	151%	136%	105%
Nov	124%	107%	102%	97%	91%	97%	98%	117%	121%	117%	115%	117%	118%	128%	134%	137%	138%	147%	163%	166%	164%	159%	150%	127%
Dec	143%	132%	121%	119%	114%	118%	120%	125%	136%	125%	119%	117%	120%	127%	129%	131%	139%	148%	166%	174%	169%	166%	156%	139%

Feeder 4

	1:00	2:00	3:00	4:00	5:00	6:00	7:00	8:00	9:00	10:00	11:00	12:00	13:00	14:00	15:00	16:00	17:00	18:00	19:00	20:00	21:00	22:00	23:00	0:00
Jan	60%	53%	48%	44%	42%	44%	54%	65%	71%	70%	65%	63%	62%	64%	66%	67%	70%	77%	87%	87%	84%	83%	77%	61%
Feb	54%	46%	42%	38%	37%	38%	45%	55%	61%	60%	56%	54%	55%	61%	62%	61%	67%	74%	80%	81%	77%	75%	71%	58%
Mar	51%	47%	44%	40%	38%	40%	44%	48%	57%	56%	54%	53%	54%	55%	56%	61%	63%	69%	79%	81%	77%	75%	73%	56%
Apr	49%	41%	37%	34%	32%	33%	35%	41%	47%	47%	46%	48%	48%	51%	52%	54%	58%	66%	75%	76%	72%	71%	65%	51%
May	47%	39%	36%	32%	28%	29%	33%	39%	46%	49%	48%	49%	49%	51%	53%	57%	60%	67%	76%	76%	72%	70%	65%	49%
Jun	48%	41%	37%	34%	32%	34%	41%	48%	55%	56%	54%	54%	53%	54%	59%	62%	64%	72%	80%	81%	74%	73%	67%	51%
Jul	52%	45%	43%	39%	40%	40%	44%	55%	62%	64%	64%	57%	57%	59%	61%	65%	68%	75%	82%	81%	78%	75%	69%	55%
Aug	50%	42%	39%	36%	37%	38%	40%	46%	53%	55%	54%	54%	55%	55%	60%	63%	65%	73%	79%	79%	75%	74%	68%	52%
Sep	46%	41%	37%	34%	34%	36%	37%	43%	51%	53%	51%	51%	54%	53%	59%	61%	63%	69%	77%	77%	74%	71%	65%	50%
Oct	47%	38%	35%	32%	28%	30%	32%	39%	45%	45%	45%	44%	45%	50%	50%	51%	55%	61%	71%	73%	69%	68%	62%	46%
Nov	52%	43%	40%	37%	34%	34%	37%	42%	50%	55%	51%	49%	50%	55%	56%	56%	60%	66%	76%	78%	74%	74%	66%	52%
Dec	53%	48%	44%	39%	37%	41%	43%	49%	58%	61%	57%	57%	56%	57%	58%	61%	62%	71%	81%	82%	79%	76%	71%	55%

5.3. Modeled Distribution Grid Relief – Load Shaping

> Load shaping is provided by long-term, fairly durable relief measures such as building energy efficiency, EV load flattening, and solar PV adoption.
>
> In contrast with load shaping, load flexibility (also known as peak shaving or demand response) is more dynamic and can respond to short-term or immediate signals, and thereby adjust load responsively to avoid peak pricing or strain on the distribution system.

The Study Team modeled two major kinds of pressure relief: load shaping and load flexibility. Load shaping is provided by long-term, fairly durable relief measures such as building energy efficiency, EV load flattening, and solar PV adoption – all of which are modeled with gradual implementation occurring at a similar rate as modeled pressures (using the rapid growth curve). In contrast with load shaping, load flexibility (also known as peak shaving or demand response) is more dynamic and can respond to short-term or immediate signals, and thereby can adjust load responsively to avoid peak pricing or strain on the distribution system. While establishing the markets and infrastructure to enable load flexibility may involve similar long-term efforts as with load shaping measures, the capability is targeted at short-term, dynamic interventions. This section discusses load shaping, while load flexibility is the subject of the following section.

The Study Team developed models for a set of load shaping measures and combined these into a Main Relief Scenario intended to represent the technical potential for load shaping measures to relieve pressure on the distribution system. The Main Relief scenario assumes: (1) building efficiency is prioritized when buildings are fully electrified; (2) EV charging load is flattened across 24 hours, indicating a mix of home, work, and public charging, and slow charging (as feasible); and (3) customers adopt a modest amount of PV, designed to meet local installation targets in ways that do not max out market potential or create backflow at substations.

The modeling simulated the selected load-shaping relief measures proportional to the initial feeder load. As a result, the impacts of relief are similar across feeders. In reality, pressure is likely to arise on some feeders faster than others and relief is likely to come in varying degrees. These scenarios are intended to show the technical potential for relief. In practice, it will be important to monitor actual feeder pressures and effectiveness of relief measures and then to develop response strategies to address developing situations on individual feeders.

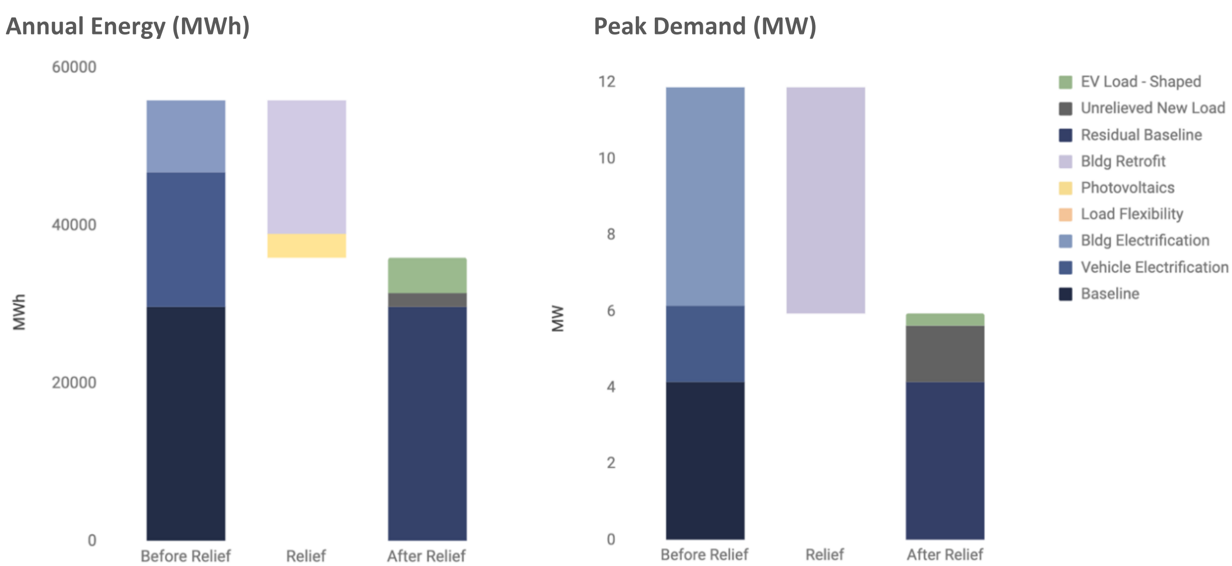
For all feeders, peak load nearly doubles with the building and vehicle electrification pressures, but the combination of load-shaping relief measures brings the load back to near current levels. Figure 6 below provides an example of the building and vehicle pressures and relief for Feeder 1. (The figure does not show results for each feeder, as the relative contributions of pressures and relief is similar across feeders.) The graphic on the left shows load composition on an annual basis. The graphic on the right shows the peak load reduction from relief in the peak hour in 2045, when all pressure has developed and buildings and vehicles are 100 percent electrified. Both graphics together show how the load-shaping relief stacks up annually and in the peak hour. They also demonstrate the following:

- Vehicle electrification contributes two-thirds of the new load from electrification across the whole year and closer to 25 percent at peak hour, with building electrification contributing the remainder. (These scenarios are based on national profiles of EV adoption and building electrification and may differ from District-specific developments.)

- Building retrofits paired with electrification offers the most reduction in energy consumption, with PV contributing some beneficial energy on an annual basis but making no contribution at the peak hour.

- EV load shifting does not reduce the total annual energy consumption. Though the EV charging load still exists following relief, this load has been shaped to reduce pressure on peak hours, moving that charging to hours with less pressure. (Note: Not all EV pressure in peak hours is relieved in this way. Only a portion is relieved based on modeling a flattening of load. EV load shifting may yield further benefits not counted here.)

Figure 6. Composition of Energy and Peak Demand with Main Relief Load Shaping



Despite the similarity in the modeled load composition across feeders, the magnitude and timing of pressure and value of load shaping relief varies across the four representative feeders. In all cases except Feeder 3, the Main Relief scenario is effective in avoiding loads in excess of the feeder's normal rating. Table 3 below shows the year that the pressure exceeds the normal rating for Feeders 1, 2, and 3 in the Maximum Pressure scenario (marked by the first "x" in the study period), and when the normal rating of Feeder 3 is exceeded after application of the Main Relief scenario (marked by a second "x" further along in the study period). The normal rating of Feeder 4 is not exceeded in any modeled scenario.

Table 3. Year Pressure Exceeds Normal Rating by Feeder

	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	…	2045
F1			x																		
F2		x																			
F3				x		x															
F4																					

Figure 7 below shows heatmaps for the four feeders after applying both the Maximum Pressure scenario and Main Relief measures.

Figure 7. Heatmaps of Main Relief Applied to Maximum Pressure, Peak Demand as a % of Normal Rating, 2045

Feeder 1

	1:00	2:00	3:00	4:00	5:00	6:00	7:00	8:00	9:00	10:00	11:00	12:00	13:00	14:00	15:00	16:00	17:00	18:00	19:00	20:00	21:00	22:00	23:00	0:00
Jan	72%	72%	69%	71%	67%	71%	70%	76%	79%	74%	66%	71%	67%	66%	67%	66%	74%	74%	81%	82%	80%	78%	75%	69%
Feb	75%	73%	70%	70%	69%	68%	66%	72%	75%	68%	61%	62%	62%	65%	60%	61%	64%	66%	74%	76%	73%	76%	74%	65%
Mar	65%	67%	63%	60%	60%	58%	59%	68%	65%	61%	61%	62%	64%	58%	62%	59%	62%	63%	65%	68%	66%	66%	61%	56%
Apr	60%	58%	57%	56%	56%	54%	53%	56%	59%	61%	59%	60%	58%	60%	59%	57%	61%	60%	66%	67%	63%	63%	61%	53%
May	63%	61%	60%	59%	57%	56%	57%	60%	66%	66%	61%	60%	56%	56%	58%	53%	71%	65%	72%	70%	68%	66%	64%	58%
Jun	77%	73%	73%	73%	72%	70%	66%	69%	58%	71%	70%	53%	57%	55%	62%	58%	77%	72%	82%	90%	81%	86%	79%	71%
Jul	81%	80%	76%	78%	77%	77%	70%	68%	73%	66%	66%	69%	63%	65%	63%	70%	81%	83%	89%	88%	85%	85%	87%	75%
Aug	79%	71%	73%	72%	70%	69%	69%	68%	67%	68%	66%	65%	65%	65%	63%	71%	73%	79%	85%	83%	80%	79%	79%	71%
Sep	72%	69%	68%	67%	67%	66%	66%	65%	70%	71%	66%	67%	68%	69%	69%	68%	75%	75%	77%	80%	78%	77%	74%	66%
Oct	62%	60%	58%	56%	59%	55%	54%	53%	58%	60%	60%	60%	61%	62%	64%	61%	63%	63%	69%	71%	67%	66%	61%	55%
Nov	63%	61%	60%	60%	59%	57%	58%	59%	59%	57%	59%	60%	60%	59%	60%	57%	61%	65%	70%	71%	67%	68%	68%	58%
Dec	66%	64%	64%	65%	61%	64%	61%	61%	66%	68%	67%	72%	75%	69%	73%	72%	69%	70%	76%	74%	74%	72%	68%	62%

Feeder 2

	1:00	2:00	3:00	4:00	5:00	6:00	7:00	8:00	9:00	10:00	11:00	12:00	13:00	14:00	15:00	16:00	17:00	18:00	19:00	20:00	21:00	22:00	23:00	0:00
Jan	58%	57%	55%	56%	54%	55%	56%	62%	61%	56%	52%	54%	53%	50%	51%	52%	58%	58%	66%	66%	65%	61%	61%	54%
Feb	58%	57%	56%	55%	54%	53%	53%	54%	57%	52%	48%	49%	48%	50%	48%	46%	50%	53%	59%	60%	58%	60%	58%	52%
Mar	52%	53%	51%	49%	48%	47%	47%	47%	48%	49%	49%	50%	51%	47%	48%	47%	51%	51%	53%	56%	55%	54%	49%	43%
Apr	47%	46%	45%	44%	44%	44%	41%	44%	51%	48%	45%	48%	46%	48%	48%	45%	49%	49%	53%	54%	52%	52%	49%	42%
May	51%	49%	48%	46%	45%	44%	43%	45%	51%	51%	46%	45%	43%	44%	45%	42%	58%	52%	59%	58%	58%	55%	52%	47%
Jun	64%	61%	60%	60%	59%	55%	51%	54%	44%	56%	55%	40%	43%	44%	50%	50%	66%	62%	69%	78%	70%	73%	67%	61%
Jul	70%	69%	65%	63%	63%	65%	57%	55%	59%	51%	51%	56%	53%	56%	54%	63%	71%	80%	91%	89%	87%	85%	81%	64%
Aug	65%	59%	59%	56%	55%	54%	53%	51%	54%	54%	53%	51%	53%	51%	50%	60%	61%	65%	73%	71%	68%	65%	64%	56%
Sep	57%	53%	52%	52%	51%	49%	51%	51%	53%	55%	50%	52%	52%	55%	55%	55%	62%	62%	64%	66%	65%	62%	59%	50%
Oct	48%	45%	43%	42%	43%	42%	41%	43%	47%	48%	46%	49%	48%	48%	47%	46%	50%	49%	54%	55%	52%	53%	49%	42%
Nov	49%	48%	47%	46%	46%	45%	45%	48%	49%	46%	48%	49%	47%	47%	47%	46%	50%	52%	58%	58%	55%	56%	55%	48%
Dec	55%	55%	55%	55%	52%	54%	53%	52%	57%	56%	56%	62%	64%	58%	62%	62%	59%	59%	63%	64%	63%	61%	58%	54%

Feeder 3

	1:00	2:00	3:00	4:00	5:00	6:00	7:00	8:00	9:00	10:00	11:00	12:00	13:00	14:00	15:00	16:00	17:00	18:00	19:00	20:00	21:00	22:00	23:00	0:00
Jan	102%	101%	98%	101%	97%	102%	103%	106%	110%	103%	102%	98%	85%	86%	84%	85%	93%	99%	109%	114%	112%	104%	99%	95%
Feb	99%	93%	92%	90%	89%	89%	93%	98%	95%	99%	93%	93%	86%	79%	78%	85%	90%	97%	105%	103%	99%	97%	96%	88%
Mar	91%	85%	82%	81%	83%	84%	84%	92%	92%	88%	89%	86%	87%	79%	77%	71%	78%	82%	92%	94%	95%	94%	91%	80%
Apr	78%	74%	72%	72%	73%	74%	74%	82%	78%	75%	71%	73%	70%	70%	75%	72%	77%	75%	82%	85%	81%	82%	78%	68%
May	84%	81%	80%	78%	77%	78%	78%	79%	89%	80%	75%	75%	67%	75%	81%	77%	100%	91%	101%	96%	92%	91%	87%	77%
Jun	87%	84%	82%	80%	78%	79%	78%	74%	82%	78%	74%	72%	71%	84%	91%	89%	106%	89%	97%	96%	95%	93%	89%	80%
Jul	101%	98%	94%	92%	92%	93%	85%	80%	89%	84%	85%	91%	84%	83%	84%	80%	95%	99%	107%	110%	106%	102%	100%	89%
Aug	95%	89%	89%	87%	86%	84%	87%	89%	88%	91%	85%	84%	77%	85%	86%	92%	100%	97%	106%	110%	101%	99%	101%	83%
Sep	87%	86%	84%	83%	81%	81%	79%	79%	82%	84%	75%	77%	85%	86%	90%	91%	95%	94%	98%	103%	99%	96%	92%	80%
Oct	88%	84%	83%	83%	83%	84%	81%	81%	72%	73%	69%	70%	72%	72%	71%	69%	87%	90%	94%	98%	97%	95%	85%	77%
Nov	80%	78%	76%	77%	76%	79%	77%	82%	85%	79%	78%	73%	73%	77%	76%	71%	76%	82%	87%	91%	92%	86%	87%	74%
Dec	87%	86%	85%	85%	82%	83%	87%	92%	98%	97%	89%	88%	87%	85%	88%	83%	86%	88%	95%	97%	98%	91%	90%	83%

Feeder 4

	1:00	2:00	3:00	4:00	5:00	6:00	7:00	8:00	9:00	10:00	11:00	12:00	13:00	14:00	15:00	16:00	17:00	18:00	19:00	20:00	21:00	22:00	23:00	0:00
Jan	43%	42%	42%	42%	41%	42%	45%	48%	50%	50%	45%	46%	46%	45%	47%	45%	44%	44%	47%	50%	46%	46%	46%	40%
Feb	42%	41%	41%	40%	40%	40%	40%	44%	49%	47%	44%	45%	44%	45%	44%	44%	46%	46%	46%	46%	43%	44%	43%	37%
Mar	42%	40%	40%	40%	39%	39%	39%	41%	44%	47%	44%	45%	44%	44%	47%	44%	47%	46%	47%	46%	42%	43%	42%	36%
Apr	43%	43%	43%	41%	41%	40%	40%	41%	45%	46%	46%	45%	46%	43%	43%	42%	42%	44%	47%	46%	43%	43%	43%	38%
May	43%	43%	41%	41%	40%	40%	40%	43%	47%	48%	45%	43%	42%	41%	44%	40%	49%	46%	48%	45%	44%	43%	42%	37%
Jun	46%	46%	45%	45%	44%	45%	46%	47%	43%	49%	52%	35%	36%	39%	43%	41%	46%	47%	48%	51%	47%	49%	46%	41%
Jul	48%	47%	47%	47%	50%	52%	49%	50%	52%	47%	47%	48%	46%	44%	45%	50%	49%	50%	51%	52%	49%	48%	48%	42%
Aug	46%	43%	44%	43%	46%	47%	46%	47%	48%	48%	48%	44%	43%	47%	46%	46%	47%	49%	50%	48%	47%	46%	45%	39%
Sep	43%	43%	43%	43%	45%	47%	47%	46%	48%	50%	46%	46%	46%	49%	47%	45%	47%	46%	46%	47%	46%	45%	43%	38%
Oct	40%	39%	39%	38%	38%	39%	37%	39%	41%	42%	41%	41%	41%	41%	42%	38%	44%	42%	43%	43%	42%	42%	40%	35%
Nov	41%	40%	39%	39%	38%	38%	38%	40%	42%	43%	41%	40%	41%	44%	44%	40%	44%	43%	45%	46%	43%	43%	43%	37%
Dec	41%	40%	39%	39%	39%	39%	39%	40%	44%	49%	47%	43%	43%	44%	47%	43%	44%	44%	45%	46%	45%	43%	42%	35%

5.4. Modeled Distribution Grid Relief – Load Flexibility

In addition to the load-shaping Main Relief scenario described above, this study evaluated the impact of load flexibility as an additional source of value. Load flexibility can be provided by an array of communication and operational technologies. Historically, the markets for load flexibility were primarily demand response markets and focused on commitments made by commercial and industrial consumers, as well as some smart-appliance-based demand response programs for residential loads. All of these technologies and market mechanisms for engaging them are advancing rapidly. In addition, battery energy storage systems (BESS) are increasingly participating in capacity and demand response markets. As battery prices decrease and more advanced smart appliances and smart buildings measures reach maturity, load flexibility solutions are developing quickly. Though the Study Team modeled power flow and dispatch scenarios for batteries in some detail in designing overall scenarios, the modeling for the value of load flexibility does not assume any particular technology. As a result, the value is the same whether the flexibility is provided by battery storage, conventional demand response, or new smart buildings technologies. In all cases, the analysis simply looks at the value of being able to reduce load by a certain percentage during peak hours.

The Study Team looked at the value of load flexibility in the Baseline, Max Pressure, and Main Relief scenarios and considered targeted volumes of hours from 100 to 1,000 hours and levels of load flexibility from 15 to 40 percent of peak load. The main load flexibility scenario elected was for reductions of 30 percent of peak load during the top 266 hours (the number of hours in which wholesale capacity prices are concentrated) and targeting of the highest cost hours after load shaping Main Relief was applied. While 30 percent reductions of peak load for that many hours may be ambitious, the technologies to accomplish this level of curtailment are diverse and rapidly advancing. With proper incentivization in the coming years, the Study Team believes 30 percent is an attainable technical potential.

By design, load flexibility targets peak hours and has the greatest impact in terms of MW during peak hours, and yet it does not necessarily show up as a large volume of MWh annually, as illustrated in Figure 8 below. While these figures are for Feeder 1, the pattern is almost identical on the other feeders, especially Feeder 3 (the most heavily loaded feeder).

Figure 8. Composition of Energy and Peak Demand with Main Relief Load Shaping and 30 Percent Load Flexibility in the Top 266 Hours

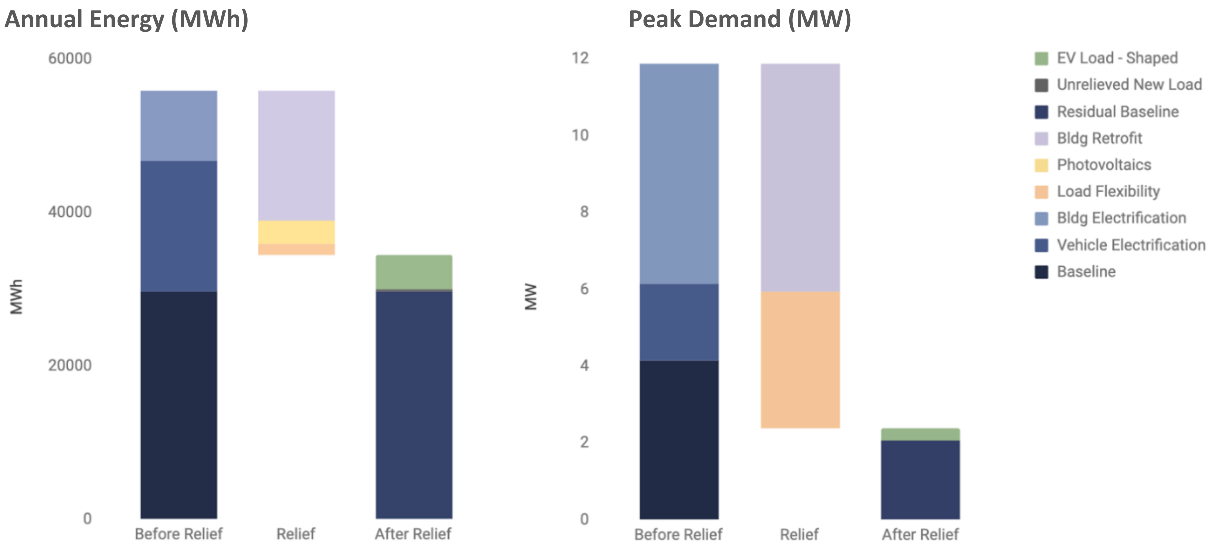


Figure 9 below shows heatmaps for the four feeders after applying both the Maximum Pressure, Main Relief Load Shaping, and 30 Percent Load Flexibility (in the top 266 hours) scenarios. The pressure on all the feeders is fully relieved when load flexibility is applied in addition to load shaping.

Figure 9. Heatmaps of Main Relief and Load Flexibility Applied To Maximum Pressure, Peak Demand as a % of Normal Rating, 2045

Feeder 1

	1:00	2:00	3:00	4:00	5:00	6:00	7:00	8:00	9:00	10:00	11:00	12:00	13:00	14:00	15:00	16:00	17:00	18:00	19:00	20:00	21:00	22:00	23:00	0:00
Jan	72%	72%	69%	71%	67%	71%	70%	72%	74%	74%	66%	71%	67%	66%	67%	66%	74%	74%	74%	74%	74%	73%	73%	69%
Feb	72%	73%	70%	70%	69%	68%	66%	72%	69%	68%	61%	62%	62%	65%	60%	61%	64%	66%	74%	73%	73%	73%	74%	65%
Mar	65%	67%	63%	60%	60%	58%	59%	68%	65%	61%	61%	62%	64%	58%	62%	59%	62%	63%	65%	68%	66%	66%	61%	56%
Apr	60%	58%	57%	56%	56%	54%	53%	56%	59%	61%	59%	60%	58%	60%	59%	57%	61%	60%	66%	67%	63%	63%	61%	53%
May	63%	61%	60%	59%	57%	56%	57%	60%	66%	66%	61%	60%	56%	56%	58%	53%	71%	65%	72%	70%	68%	66%	64%	58%
Jun	74%	73%	73%	73%	72%	70%	66%	69%	58%	71%	70%	53%	57%	55%	62%	58%	67%	72%	74%	73%	74%	74%	73%	71%
Jul	74%	74%	74%	73%	73%	72%	70%	68%	73%	66%	66%	69%	63%	65%	63%	70%	74%	74%	74%	74%	74%	74%	74%	73%
Aug	74%	71%	73%	72%	70%	69%	69%	68%	67%	68%	66%	65%	65%	65%	63%	71%	73%	74%	74%	74%	74%	74%	74%	71%
Sep	72%	69%	68%	67%	67%	66%	66%	65%	70%	71%	66%	67%	68%	69%	69%	68%	73%	74%	74%	74%	73%	73%	74%	66%
Oct	62%	60%	58%	56%	59%	55%	54%	53%	58%	60%	60%	60%	61%	62%	64%	61%	63%	63%	69%	71%	67%	66%	61%	55%
Nov	63%	61%	60%	60%	59%	57%	58%	59%	59%	57%	59%	60%	60%	59%	60%	57%	61%	65%	70%	71%	67%	68%	68%	58%
Dec	66%	64%	64%	65%	61%	64%	61%	61%	66%	68%	67%	72%	59%	69%	73%	72%	69%	70%	73%	74%	73%	72%	68%	62%

Feeder 2

	1:00	2:00	3:00	4:00	5:00	6:00	7:00	8:00	9:00	10:00	11:00	12:00	13:00	14:00	15:00	16:00	17:00	18:00	19:00	20:00	21:00	22:00	23:00	0:00
Jan	58%	57%	55%	56%	54%	55%	56%	62%	61%	56%	52%	54%	53%	50%	51%	52%	58%	58%	61%	62%	61%	61%	61%	54%
Feb	58%	57%	56%	55%	54%	53%	53%	54%	57%	52%	48%	49%	48%	50%	48%	46%	50%	53%	59%	60%	58%	60%	58%	52%
Mar	52%	53%	51%	49%	48%	47%	47%	47%	48%	49%	49%	50%	51%	47%	48%	47%	51%	51%	53%	56%	55%	54%	49%	43%
Apr	47%	46%	45%	44%	44%	44%	41%	44%	51%	48%	45%	48%	46%	48%	48%	45%	49%	49%	53%	54%	52%	52%	49%	42%
May	51%	49%	48%	46%	45%	44%	43%	45%	51%	51%	46%	45%	43%	44%	45%	42%	58%	52%	59%	58%	58%	55%	52%	47%
Jun	60%	61%	60%	60%	59%	55%	51%	54%	44%	56%	55%	40%	43%	44%	50%	50%	56%	61%	62%	62%	62%	60%	62%	61%
Jul	61%	62%	61%	61%	62%	59%	57%	55%	59%	51%	51%	56%	53%	56%	54%	58%	59%	60%	64%	62%	62%	62%	60%	61%
Aug	60%	59%	59%	56%	55%	54%	53%	51%	54%	54%	53%	51%	53%	51%	50%	60%	61%	62%	62%	61%	62%	61%	61%	56%
Sep	57%	53%	52%	52%	51%	49%	51%	51%	53%	55%	50%	52%	52%	55%	55%	55%	62%	62%	62%	62%	62%	60%	59%	50%
Oct	48%	45%	43%	42%	43%	42%	41%	43%	47%	48%	46%	49%	48%	48%	47%	46%	50%	49%	54%	55%	52%	53%	49%	42%
Nov	49%	48%	47%	46%	46%	45%	45%	48%	49%	46%	48%	49%	47%	47%	47%	46%	50%	52%	58%	58%	55%	56%	55%	48%
Dec	55%	55%	55%	55%	52%	54%	53%	52%	57%	56%	56%	62%	61%	58%	59%	62%	59%	59%	62%	62%	61%	61%	58%	54%

Feeder 3

	1:00	2:00	3:00	4:00	5:00	6:00	7:00	8:00	9:00	10:00	11:00	12:00	13:00	14:00	15:00	16:00	17:00	18:00	19:00	20:00	21:00	22:00	23:00	0:00
Jan	93%	91%	87%	87%	84%	89%	86%	93%	91%	93%	89%	87%	85%	86%	84%	85%	93%	92%	92%	93%	93%	92%	91%	88%
Feb	93%	89%	92%	90%	89%	89%	93%	90%	89%	90%	93%	93%	86%	79%	78%	85%	90%	85%	91%	93%	92%	87%	92%	88%
Mar	91%	85%	82%	81%	83%	84%	84%	92%	92%	88%	89%	86%	87%	79%	77%	71%	78%	82%	92%	91%	88%	89%	91%	80%
Apr	78%	74%	72%	72%	73%	74%	74%	82%	78%	75%	71%	73%	70%	70%	75%	72%	77%	75%	82%	85%	81%	82%	78%	68%
May	84%	81%	80%	78%	77%	78%	78%	79%	89%	80%	75%	75%	67%	75%	81%	77%	81%	91%	92%	92%	92%	91%	87%	77%
Jun	87%	84%	82%	80%	78%	79%	78%	74%	82%	78%	74%	72%	71%	84%	91%	89%	93%	89%	93%	93%	92%	92%	89%	80%
Jul	93%	90%	88%	92%	92%	85%	85%	80%	89%	84%	85%	91%	84%	83%	84%	80%	83%	92%	93%	92%	93%	91%	91%	89%
Aug	90%	89%	89%	87%	86%	84%	87%	89%	88%	91%	85%	84%	77%	85%	86%	92%	92%	92%	92%	93%	92%	92%	92%	83%
Sep	87%	86%	84%	83%	81%	81%	79%	79%	82%	84%	75%	77%	85%	86%	90%	91%	91%	92%	93%	93%	91%	92%	92%	80%
Oct	88%	84%	83%	83%	83%	84%	81%	81%	72%	73%	69%	70%	72%	72%	71%	69%	87%	90%	91%	88%	86%	82%	85%	77%
Nov	80%	78%	76%	77%	76%	79%	77%	82%	85%	79%	78%	73%	73%	77%	76%	71%	76%	82%	87%	91%	92%	86%	87%	74%
Dec	87%	86%	85%	85%	82%	83%	87%	92%	86%	92%	89%	88%	87%	85%	88%	83%	86%	88%	93%	93%	91%	91%	90%	83%

Feeder 4

	1:00	2:00	3:00	4:00	5:00	6:00	7:00	8:00	9:00	10:00	11:00	12:00	13:00	14:00	15:00	16:00	17:00	18:00	19:00	20:00	21:00	22:00	23:00	0:00
Jan	43%	42%	42%	42%	41%	42%	45%	48%	50%	50%	45%	46%	46%	45%	47%	45%	44%	44%	47%	50%	46%	46%	46%	40%
Feb	42%	41%	41%	40%	40%	40%	40%	44%	49%	47%	44%	45%	44%	45%	44%	44%	46%	46%	46%	46%	43%	44%	43%	37%
Mar	42%	40%	40%	40%	39%	39%	39%	41%	44%	47%	44%	45%	44%	44%	47%	44%	47%	46%	47%	46%	42%	43%	42%	36%
Apr	43%	43%	43%	41%	41%	40%	40%	41%	45%	46%	46%	45%	46%	43%	43%	42%	42%	44%	47%	46%	43%	43%	43%	38%
May	43%	43%	41%	41%	40%	40%	40%	43%	47%	48%	45%	43%	42%	41%	44%	40%	49%	46%	48%	45%	44%	43%	42%	37%
Jun	45%	46%	45%	45%	44%	45%	46%	47%	43%	49%	52%	35%	36%	39%	43%	41%	43%	47%	46%	46%	45%	44%	44%	41%
Jul	46%	45%	45%	45%	50%	50%	49%	50%	52%	47%	47%	48%	46%	44%	45%	47%	47%	46%	46%	47%	45%	45%	45%	41%
Aug	44%	43%	44%	43%	46%	47%	46%	47%	48%	48%	48%	44%	43%	47%	46%	46%	47%	47%	47%	46%	45%	44%	43%	39%
Sep	43%	43%	43%	43%	45%	47%	47%	46%	48%	50%	46%	46%	46%	49%	47%	45%	47%	46%	46%	46%	45%	44%	43%	38%
Oct	40%	39%	39%	38%	38%	39%	37%	39%	41%	42%	41%	41%	41%	41%	42%	38%	44%	42%	43%	43%	42%	42%	40%	35%
Nov	41%	40%	39%	39%	38%	38%	38%	40%	42%	43%	41%	40%	41%	44%	44%	40%	44%	43%	45%	46%	43%	43%	43%	37%
Dec	41%	40%	39%	39%	39%	39%	39%	40%	44%	49%	47%	43%	39%	44%	47%	43%	44%	44%	45%	46%	45%	43%	42%	35%

6. Summary of Impacts

The impacts associated with this framework can serve as a starting point for the development of price signals or monetary incentives that will encourage the most beneficial development and integration of DERs and facilitate achievement of the District's energy policy goals. The impacts shown in this section are illustrative and may be used to inform the updates to existing DER compensation mechanisms and new DER compensation mechanisms that could be useful to explore in more detail. These modeling results represent technical potential. Defining the economic and achievable potential of different mechanisms in a specific project implementation context will require additional design and modeling work.

The Study Team performed sensitivities on the avoided GHG costs as their magnitude is substantial and subject to a high degree of variability. We modeled the following cases:

- A mid GHG case (M) which represents a mid-case for GHG costs and for the study discount rate. This case uses the 2016 Interagency Working Group (IWG) social cost of carbon, but with a 2 percent discount rate for the GHG cost. When presenting the average levelized impacts for this mid case, we discount all values by 3 percent for this case.

- The low GHG case (L) represents a low GHG cost and high study discount rate. This case uses the 2016 IWG social cost of carbon and assumes a 3 percent discount rate for the GHG cost. When presenting the average levelized impacts for this low case, we discount all values by 7 percent.

- The high GHG case (H) represents a high GHG cost and a low discount rate. It uses the 2022 EPA proposed social cost of carbon and applies a 2 percent discount rate for the GHG cost. When presenting the average levelized impacts for this high case, we discount all values by 2 percent.

6.1. All Avoided Cost Components

Table 4 presents a summary of avoided cost values in 2020$M for key impacts and in total across the study period, discounted by 7% (in the low GHG case), 3% (in the mid GHG case), and 2% (in the high GHG case) real discount rates. We show Feeder 1 throughout.

- Energy includes avoided energy generation, energy DRIPE, and ancillary services costs, avoided transmission losses, and market price risk reductions.

- Generation Capacity includes avoided cleared generation capacity costs.

- Transmission capacity includes avoided transmission capacity costs.

- Distribution capacity includes avoided distribution capacity, O&M, and voltage costs from one of the four feeder types (F1, F2, F3, or F4).
- Distribution losses includes avoided distribution losses.
- GHG includes avoided greenhouse gas (GHG) costs from one of the three GHG cases (low, mid, or high GHG).
- Public Health includes avoided NOx and PM2.5 costs.
- Other includes reduced credit and collections costs, improved equity, and improved resilience.

The avoided costs illustrate the costs in the Maximum Pressure case that may be avoided by the Main Relief, Load Shaping, and Load Flexibility Scenarios as modeled by the Study Team. (Detailed descriptions of the Maximum Pressure case, Main Relief case, and Load Shaping and Load Flexibility scenarios are provided in Section 5 and Appendix D.) The estimated annual carrying cost of a distribution system capacity upgrade is calculated as zero during years before the peak exceeds the normal rating on the feeder, and as the annual peak MW above the baseline peak load multiplied by the $385,500 per MW-year in $2020 after the normal rating is exceeded.[21]

Notably, some of the avoided costs only apply to certain DER compensation mechanism designs. For example, the credit and collections, equity, and resilience values (which we show separately) are only applicable to DER compensation mechanisms that are designed to address vulnerable populations and/or enhance resilience. Both the capacity and distribution-related avoided costs apply only to change in load during their respective peak hours when costs are caused. Appendix A provides more detail about each avoided cost, which implementers should reference when determining whether and how to apply each value.

We find a range of value from $28.7M to $77.2M in the present avoided costs achieved on Feeder 1 in the modeled Main Relief Scenario, as compared to the Maximum Pressure scenario. In the mid GHG case, the largest shares of avoided cost value come from distribution capacity, O&M, and voltage; GHGs; and energy.

[21] Pepco. FC1050. OPC Discovery Response 2-17. *Potomac Electric Power Company District of Columbia Marginal Distribution Cost Study*. Page 5. Adjusted from $2014 to $2020.

Table 4. Summary of Avoided Costs: 2023-2045 (2020$M)

Impacts	2020$M		
	Low GHG, F1, 7% Disc. Rate	Mid GHG, F1, 3% Disc. Rate	High GHG, F1, 2% Disc. Rate
Energy	5.4	9.1	10.5
Generation Capacity	1.2	2.1	2.4
Transmission Capacity	0.7	1.1	1.3
Distribution Capacity, O&M, and Voltage	13.0	22.0	25.4
Distribution Losses	0.4	0.6	0.7
GHG	3.0	10.5	27.2
Public Health	0.8	1.4	1.6
Subtotal (without Other)	**24.4**	**46.8**	**69.0**
Other (Credit and Collections, Equity, Resilience)	4.3	7.1	8.2
Total (with Other)	**28.7**	**54.0**	**77.2**

Figure 10 presents the results in Table 4 in graphical form: a summary of avoided cost values in 2020$M for key impacts and in total across the study period, discounted by 7 percent (in the low GHG case), 3 percent (in the mid GHG case), and 2 percent (in the high GHG case) real discount rates. We show Feeder 1 throughout. In this figure, we can see the increasing magnitude of the avoided GHG cost across the columns from left to right with different assumptions for the GHG cases. In the low GHG case, the avoided GHG costs are significantly lower than the avoided distribution capacity, O&M, and voltage costs and not a significant contributor to total avoided costs. In the high GHG case, the magnitude of the avoided GHG cost is similar to the avoided distribution capacity, O&M, and voltage cost and contributes greatly to the total avoided costs. The selection of an avoided GHG value and discount rate for the study are important decisions as they drive the results.

Figure 10. Summary of Avoided Costs: 2023-2045 (2020$M)

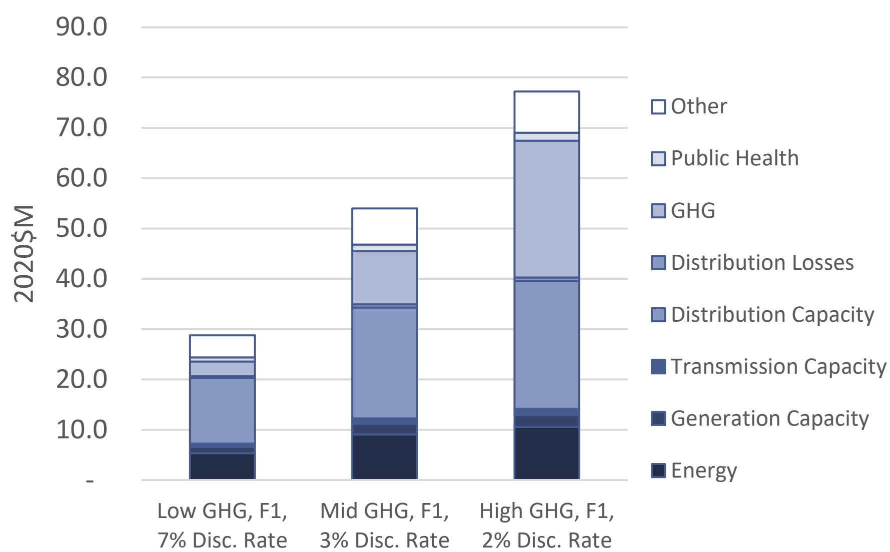


Figure 11 below illustrates total costs avoided in 2045 on Feeder 1 from implementing the Main Relief scenario. This figure shows how the costs saved by implementing the Main Relief measures are caused by changes in loads during different hours of the day. The dollars are cumulative and the year is divided into two, six-month periods (Winter: November-April, Summer: May-October) to illustrate seasonal differences in when costs are modeled to be avoided.

The avoided distribution capacity, O&M, and voltage costs are fully avoided by the Main Relief scenario. Because these are the largest costs and their potential has been exhausted by the modeled relief, we can see that most of the potential avoided cost value on this feeder has been captured in the modeled scenario. All other avoided cost categories represent ongoing potentials, where further load reductions would yield additional savings.

Figure 11. Feeder 1, Total Avoided Costs, Hourly for Summer and Winter, 2045 (Max Pressure minus Main Relief)

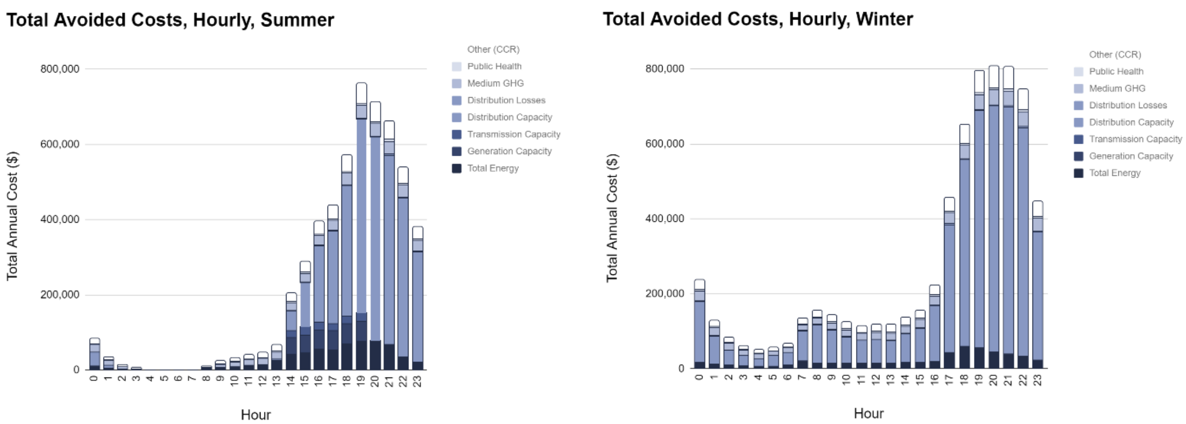


Table 5, Table 6, and Table 7 present summaries of low, average, and high avoided cost values in $/MWh for key impacts at decadal intervals throughout the study period. For the purposes of summary, the analysis for this table uses the averages over combinations of hours and months (such as July, hour ending 7pm or April, hour ending 3am). This allows generalization away from the specific load shapes and associated weather used for this analysis and shows the value that a DER relief measure might deliver when applied repeatedly across the same hour every day for a month. For example, a given measure aiming at summer peak might be utilized repeatedly during summer evenings, whether or not a given hour happens to be the time that would have caused peak-related costs. The average values in the table represent the average of all hour and month combinations (the average across the months of each year and hours of each day, for the given year).[22] The low values represent the hour and month with the lowest average value and the high values represent the hour and month with, on average, the highest value.

[22] This is slightly different from the average over all 8,760 hours of the year, due to the different lengths of months. It is presented this way for consistency with the Low and High values.

The Study Team calculated the $/MWh avoided costs using different MWh outputs from the same Maximum Pressure, Main Relief, and Load Shaping and Load Flexibility scenarios as follows:

- We divided energy generation, energy DRIPE, ancillary services, market price risk reduction, transmission losses, distribution losses, GHG, public health, credit and collections, resilience, and equity by the total dollars of avoided costs by the difference in MWh between the Maximum Pressure case and Main Relief case. Load Flexibility is considered as an incremental load reduction beyond Main Relief and multiplies by the same avoided cost components.

- We divided generation capacity and transmission capacity by the total dollars of avoided costs by the difference in MWh between the Maximum Pressure case and Main Relief case, but only for those hours in which a wholesale market capacity constraint is present. Again, Load Flexibility is an incremental MWh load reduction and is multiplied by the same capacity costs in the hours when these costs occur.

- We divided distribution capacity, O&M, and voltage by the total dollars of avoided costs by the difference in MWh between the Maximum Pressure case and Main Relief case, but only for those MWh in which each feeder exceeds its normal rating . (As pressure on a feeder increases, these hourly values increase and the number of hours they are assigned to increase also, such that it is typically the case that the per-MWh cost of these upgrades decreases while the total cost increases.) When Main Relief does not fully relieve pressure on the feeder, as is the case on Feeder 3, Load Flexibility may reduce the load below the normal rating, in which case this incremental load reduction is accounted for as an additional potential avoided cost.

Table 5. Summary of Avoided Costs: Low for 2025, 2035, and 2045 (2020$/MWh)

Impacts		Low		
		2025	2035	2045
Energy		21	24	27
Generation Capacity		0		
Transmission Capacity		0		
Distribution Capacity, O&M, and Voltage	F1	0		
	F2	0		
	F3	0		
	F4	0		
Distribution Losses		2	2	2
GHG	L	23	14	13
	M	52	32	27
	H	113	85	83
Public Health		8		
Other (Credit and Collections, Equity, Resilience)		30	29	29

Table 6. Summary of Avoided Costs: Avg for 2025, 2035, and 2045 (2020$/MWh)

Impacts		Avg		
		2025	2035	2045
Energy		32	40	49
Generation Capacity		5	5	9
Transmission Capacity		3	3	3
Distribution Capacity, O&M, and Voltage	F1	1,258	279	238
	F2	136	245	254
	F3	109	224	193
	F4	0		
Distribution Losses		2	3	3
GHG	L	30	27	22
	M	70	59	47
	H	142	131	118
Public Health		8		
Other (Credit and Collections, Equity, Resilience)		34	34	35

Table 7. Summary of Avoided Costs: High for 2025, 2035, and 2045 (2020$/MWh)

Impacts		High		
		2025	2035	2045
Energy		87	185	295
Generation Capacity		111	135	216
Transmission Capacity		81	85	85
Distribution Capacity, O&M, and Voltage	F1	120,798	3,034	879
	F2	13,022	16,609	3,367
	F3	10,509	877	413
	F4	0		
Distribution Losses		5	7	7
GHG	L	36	35	29
	M	83	77	61
	H	164	163	142
Public Health		8		
Other (Credit and Collections, Equity, Resilience)		315	108	84

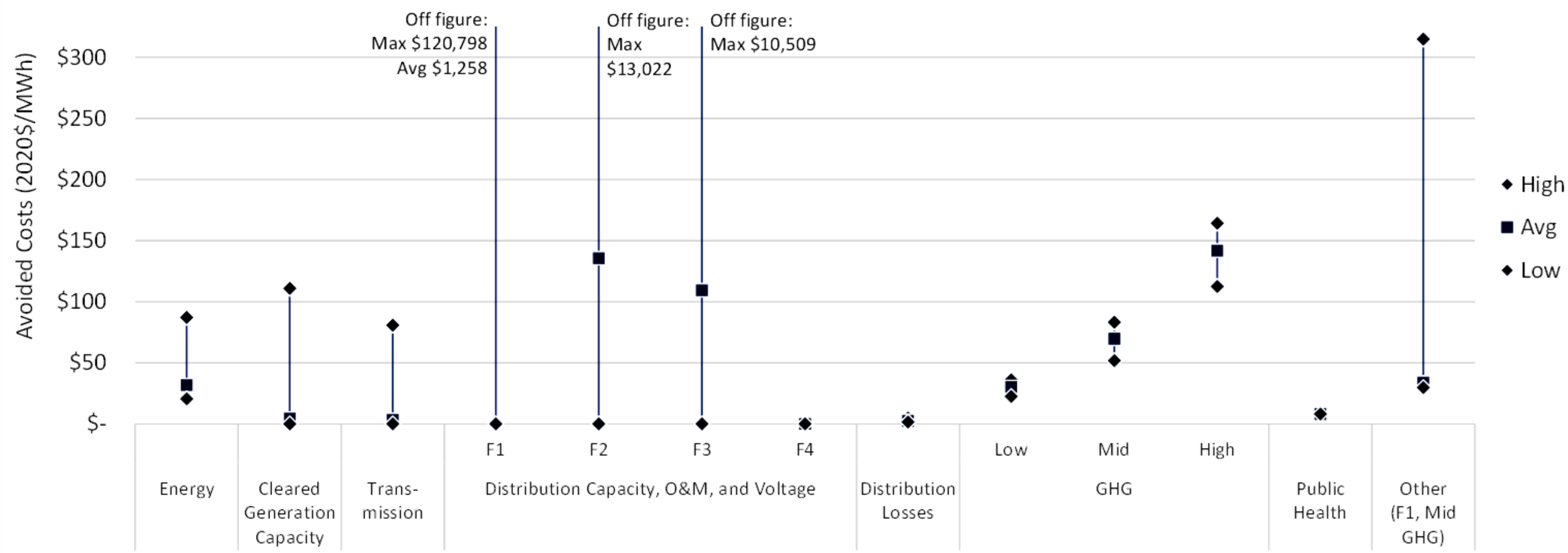
We find that the components with the potential to have a significant impact (depending on timing and/or location) are the avoided distribution capacity, O&M, and voltage costs, avoided energy costs, avoided generation capacity costs, and avoided GHGs.

- The low avoided costs show no value from avoiding generation capacity, transmission capacity, and distribution capacity, O&M, and voltage costs because the lowest hour-month combinations are times when these costs are not caused. Avoided energy costs increase over time due to increases in fuel costs. Avoided GHG costs decrease over time due to the declining emissions content of the generation mix. Avoided distribution losses, public health, and other costs are constant over the study period.

- The average and high avoided costs show value from avoiding generation capacity, transmission capacity, and distribution capacity, O&M, and voltage costs, with the highest value associated with distribution capacity, O&M, and voltage costs (except for Feeder 4 or F4). It is important to note that different feeders reach their highest avoided costs in different years and that the years shown in this table may not illustrate the highest value for each feeder or a trend. Avoided generation capacity costs and avoided transmission capacity costs are relatively static over time. Avoided energy, GHGs, distribution losses, public health, and other cost values are higher and exhibit similar trends over time as in the low avoided costs.

Figure 12 below presents a visual of the low, average, and high values for 2025, to facilitate comparison of the range of values for each component. While avoided distribution capacity, O&M, and voltage costs can have the highest $/MWh value, it also has a low value for most hours. For avoided energy and generation and transmission capacity costs, the average is near the low indicating that the values are clustered towards the low end of the range with fewer high values. This means that it will be very important to design efforts thoughtfully to achieve load reductions in the locations and hours with the high avoided $/MWh value, in order to realize the higher values. One of the twelve possible ranges for Other is shown (for F1 with the mid GHG case); the value of Other is calculated as a percent of the total of the other avoided costs and varies based on those values.

Figure 12. Summary of Avoided Costs: Low, Avg, and High for 2025 (2020$/MWh)



6.2. Avoided Distribution System Cost Detail - Load Shaping

The following section profiles the avoided distribution system costs in the Main Relief. The difference between the Maximum Pressure and Main Relief represents all the avoided distribution cost on Feeders 1, 2, and 4. Feeder 3 continues to experience pressure as the relief scenario is not well designed for a feeder that is winter-peaking. Despite the misalignment of the Main Relief scenario for Feeder 3, the pressure on the distribution system is fully relieved when load flexibility is applied in addition to load shaping. All modeled avoided costs are intended to be indicative, but not precise. For example, it is unlikely that the relief measures actually occurring on a feeder will be exactly the same in magnitude, timing, and measure mix as what is illustrated in this study.

In order to provide initial guidance for adjustments to existing DER compensation mechanisms and development of new ones, we illustrate the impacts for each feeder type for each hour in each year and for each hour in each month (across all years). We provide all visuals of a similar kind using the same scale across feeders to facilitate comparisons. In all cases the red to blue range for the heatmaps reflects the range of values across all feeders, and the red cells with white letters highlight instances where the value is more than 2x the top of the range for the background color encoding. The complete set of hourly data for all avoided costs is available in Appendix E, for direct integration into program benefit cost analysis.

Feeder 1: High Pressure, Summer-Peaking, Following

For Feeder 1, the maximum pressure scenario is projected to add 2.8 MW to the baseline peak load on the feeder by 2030, at an incremental annual cost of $1.09M in modeled infrastructure upgrades required, increasing to 7.0 MW and $2.7M per year carrying cost by 2045. With the Main Relief measures added, in our model the load above the normal rating and associated cost can be completely eliminated.

Figure 13 shows a heat map of the total avoided cost by hour and month aggregated for the whole study period for Feeder 1. These are the total nominal costs occurring in a particular month and hour if all of those hours are summed for the whole study period. This view shows when in general the most avoided cost occurs. The red cells indicate high avoided costs, and the dark blue cells are low avoided costs. In this figure, we can see nearly all high value hours for potential avoided costs are in the evening, with the highest concentration between 6pm and 11pm, and with longer periods of high value in January, July and August, starting as early as the hour ending 5pm in July. The highest value by a significant margin comes between 6 to 9pm in July.

The total avoided cost is $34.2M in cumulative (undiscounted) dollars and $22M in present value at a 3 percent discount rate.

Figure 13. Feeder 1, Total Distribution Capacity, O&M, and Voltage Avoided Costs ($000s) by Hour and Month, All Years

Hour	F1 | Total Avoided Distribution Costs (Thousand $) By Hour and Month, ALL Years											
Month	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**
1	179	21	1	-	-	-	0	-	-	-	-	17
2	66	1	-	-	-	-	-	-	-	-	-	1
3	31	-	-	-	-	-	-	-	-	-	-	-
4	11	-	-	-	-	-	-	-	-	-	-	-
5	6	-	-	-	-	-	-	-	-	-	-	-
6	18	-	-	-	-	-	-	-	-	-	-	-
7	41	-	-	-	-	-	-	-	-	-	-	-
8	203	6	6	-	-	-	-	-	-	-	-	1
9	308	12	10	-	-	-	-	-	-	-	-	3
10	137	2	3	-	-	-	-	-	-	-	-	6
11	50	0	-	-	-	-	-	-	-	-	-	2
12	34	0	-	-	-	-	-	-	-	-	-	1
13	37	1	0	-	-	-	0	-	-	-	-	0
14	36	9	-	-	-	-	18	4	-	-	-	0
15	56	8	-	-	-	0	65	16	2	-	-	1
16	79	8	0	-	-	4	180	77	4	-	-	2
17	126	13	1	-	-	20	480	194	24	-	3	16
18	378	68	9	-	1	127	1,273	583	74	-	13	147
19	1,137	350	143	34	30	468	2,724	1,046	232	37	151	595
20	1,636	477	269	68	41	441	2,276	1,133	312	50	205	696
21	1,526	415	220	40	23	344	2,070	885	187	20	135	619
22	1,504	406	209	31	15	227	1,146	592	116	10	113	510
23	1,020	267	107	5	3	80	504	255	35	1	41	280
24	308	38	3	-	-	-	11	1	-	-	-	31
											$	**34,243**

Figure 14 and Figure 15 below show heat maps of these same costs by the two, six-month periods (May to October and November to April) and spread out across all years, illustrating how these costs build over time and in each season. The total dollar value in the two heatmaps below sum to the same total as the heatmap above, it is just a different way of looking at the timing of costs, with an emphasis on how they build up over time as the feeder comes under increasing pressure. In these figures, we can see summer avoided costs are significant as soon as 2025, with a consistent concentration across all years between the hours of 6pm and 9pm. From 2025 to 2045, summer costs gradually double and spread out to affect the hours 4-11pm. By contrast, the winter costs are delayed in development and build steadily from 2028 onward. In 2045, the total summer costs (summing across all hours) are $1.1M and the total winter costs (summing across all hours) are $1.6M. These costs are concentrated in the evening in the near term, with some minor costs emerging in the morning as well over the longer term.

Figure 14. Feeder 1, Total Summer Distribution Capacity, O&M, and Voltage Avoided Costs ($000s) by Hour and Year

Hour	F1 | Total Avoided Distribution Costs (Thousand $) SUMMER Only																					
Year	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	0	0
2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
13	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	0
14	-	-	-	-	-	-	-	-	-	-	-	-	-	0	0	1	1	2	2	3	3	4	5
15	-	-	-	-	-	-	-	-	-	-	0	1	1	2	4	5	6	7	9	10	12	13	14
16	-	-	-	-	-	-	-	0	1	5	8	11	13	14	16	18	20	21	23	25	27	30	32
17	-	-	-	-	3	8	13	19	24	28	32	36	39	42	44	46	48	50	53	55	57	59	61
18	-	-	-	27	72	86	90	92	98	101	105	107	109	110	111	113	115	116	118	120	121	122	123
19	-	-	187	261	275	227	218	220	221	219	215	213	211	208	206	203	202	201	201	202	204	206	209
20	-	-	112	164	173	187	191	204	214	216	215	214	213	212	210	208	207	207	208	211	213	216	218
21	-	-	225	191	122	120	120	132	148	156	163	168	171	174	175	176	176	177	178	180	182	185	188
22	-	-	-	35	49	52	56	59	69	83	95	105	112	120	126	131	134	137	140	142	145	148	152
23	-	-	-	-	-	6	6	7	12	16	23	29	36	44	53	61	68	73	79	84	88	92	97
24	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	0	1	1	1	2	3	4
																						$	18,350

Figure 15. Feeder 1, Total Winter Distribution Capacity, O&M, and Voltage Avoided Costs ($000s) by Hour and Year

Hour	F1 | Total Avoided Distribution Costs (Thousand $) WINTER Only																					
Year	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
1	-	-	-	-	-	-	-	-	-	-	0	2	4	7	10	13	16	19	22	25	29	33	37
2	-	-	-	-	-	-	-	-	-	-	-	-	1	1	2	3	4	5	7	9	10	12	14
3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	1	2	3	4	5	7	8
4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	1	1	1	1	2	3	3
5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	1	1	2	2
6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	1	1	2	2	3	4	5
7	-	-	-	-	-	-	-	-	-	-	-	-	0	1	1	2	3	3	4	5	6	7	8
8	-	-	-	-	-	-	-	-	1	4	7	9	11	12	14	15	17	18	19	20	22	23	24
9	-	-	-	-	-	-	2	4	6	9	12	15	17	19	21	23	25	27	28	29	31	32	34
10	-	-	-	-	-	-	-	-	-	1	2	3	4	5	7	9	11	13	15	17	19	21	23
11	-	-	-	-	-	-	-	-	-	-	-	-	-	0	1	2	3	4	5	7	8	10	11
12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	1	2	2	3	4	6	7	9
13	-	-	-	-	-	-	-	-	-	-	-	-	-	0	1	2	2	3	4	5	6	7	9
14	-	-	-	-	-	-	-	-	-	-	-	-	0	1	2	2	3	4	5	6	7	7	9
15	-	-	-	-	-	-	-	-	-	-	1	1	2	2	3	3	4	5	6	7	9	10	11
16	-	-	-	-	-	-	-	-	-	0	1	2	3	3	4	5	6	7	8	9	11	13	15
17	-	-	-	-	-	-	-	-	1	2	4	5	6	7	8	9	10	12	14	16	19	23	27
18	-	-	-	-	-	1	4	8	9	11	13	16	20	25	31	35	41	47	55	63	70	79	87
19	-	-	-	-	27	26	37	47	61	74	85	99	113	127	142	157	172	185	197	208	219	228	237
20	-	-	-	-	43	69	78	95	108	124	139	152	169	185	201	216	229	241	252	261	269	277	285
21	-	-	-	-	28	62	74	86	96	106	119	132	145	159	172	185	198	211	223	233	242	250	258
22	-	-	-	-	23	63	74	79	84	96	109	121	133	146	160	173	187	199	210	221	230	238	245
23	-	-	-	-	-	12	27	40	46	51	59	68	79	88	97	106	117	129	140	151	162	172	181
24	-	-	-	-	-	-	-	-	0	5	9	12	15	18	21	23	27	31	35	39	43	48	52
																						$	15,893

Figure 16 shows a heat map of the average hourly avoided cost value for each year in the study period for Feeder 1. Because this view highlights the average value and the denominator is small in the initial period and increases year by year (because initially very few hours exceed the normal rating), we can see the relevance of taking action early. In other words, the hourly value of avoiding the feeder limit is highest when avoiding only a few hours of incremental consumption can defer potentially large investments. As the number of hours increases where pressure exceeds the feeder normal rating, the relevance of each hour decreases, while the total value increases. In this figure, we can see a very high relative value of intervention in a few hours in 2025, and a rapid drop off in the value of addressing individual hours. From the heatmaps above, we know these hours are in the summer (they are modeled in July).

Figure 16. Feeder 1, Average Distribution Capacity, O&M, and Voltage Avoided Costs by Hour and Year

Hour	F1 | Average Avoided Distribution Costs ($) ALL Months																						
Year	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
1	-	-	-	-	-	-	-	-	-	-	13	31	33	69	65	71	80	78	84	85	114	118	130
2	-	-	-	-	-	-	-	-	-	-	-	-	8	7	18	20	27	31	38	41	46	44	55
3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	18	16	21	25	31	31	29
4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5	4	4	3	13	17	18	22
5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	7	9	11	10	17
6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5	9	16	14	16	20	24	22
7	-	-	-	-	-	-	-	-	-	-	-	-	8	7	12	15	18	20	24	28	26	26	24
8	-	-	-	-	-	-	-	-	22	49	64	61	50	62	59	51	58	51	56	57	54	60	63
9	-	-	-	-	-	-	45	31	66	82	89	81	83	90	76	86	84	74	73	69	77	78	79
10	-	-	-	-	-	-	-	-	-	16	13	31	25	35	53	56	62	59	59	66	69	73	67
11	-	-	-	-	-	-	-	-	-	-	-	-	-	14	18	20	27	27	31	35	37	44	48
12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	15	18	20	24	28	31	42	43
13	-	-	-	-	-	-	-	-	-	-	-	-	-	7	18	15	13	23	21	25	34	39	46
14	-	-	-	-	-	-	-	-	-	-	-	-	8	21	18	35	35	51	49	50	57	60	72
15	-	-	-	-	-	-	-	-	-	-	26	41	33	62	65	66	89	106	105	107	106	118	132
16	-	-	-	-	-	-	-	31	88	148	166	142	125	132	147	147	151	157	161	161	186	194	202
17	-	-	-	-	202	152	272	244	331	279	306	295	299	263	229	238	239	274	266	259	283	293	291
18	-	-	-	1,068	1,417	1,061	906	763	772	690	650	610	582	540	535	517	518	513	517	511	506	508	501
19	-	-	10,260	2,137	3,036	1,894	1,948	1,679	1,565	1,363	1,224	1,241	1,155	1,115	1,046	967	956	927	870	880	827	801	773
20	-	-	10,260	1,068	3,036	2,122	1,948	1,985	1,742	1,625	1,454	1,352	1,347	1,281	1,193	1,119	1,058	1,014	975	914	895	855	804
21	-	-	10,260	2,137	2,024	1,516	1,495	1,557	1,521	1,363	1,301	1,271	1,214	1,135	1,076	1,054	996	955	898	861	830	798	780
22	-	-	-	1,068	810	1,288	861	824	1,014	1,133	1,110	1,017	1,056	1,059	1,035	972	912	873	843	798	764	727	715
23	-	-	-	-	-	227	317	397	375	443	536	569	615	685	688	679	691	681	685	659	646	628	607
24	-	-	-	-	-	-	-	-	22	82	64	71	91	83	82	106	120	133	140	148	166	173	183

In summary, Feeder 1 has high potential avoided costs that start soon, build steadily, and affect an increasingly broad range of hours. These potentially avoidable costs also shift from summer-based to winter-based over the study period. On this type of feeder, DERs will have the greatest value if they can provide broad relief in the summer and winter (focused on the late afternoon and evening hours) and shaped to offset potential emerging pressures.

Feeder 2: Very High Pressure, Summer-Peaking, Needle

For Feeder 2, the maximum pressure scenario is projected to add 2.4 MW to the baseline peak load on the feeder by 2030, at an incremental annualized cost of $913,600 in modeled infrastructure upgrades required, increasing to 4.8 MW and an annualized cost of $1.86M by 2045. As with Feeder 1, the Main Relief measures completely eliminates the pressure above normal rating on this feeder.

Figure 17 shows the same heat map styling as above, showing total avoided costs by hour and month. In this figure, we can see, similar to Feeder 1, that nearly all of the potential avoided costs are in the evening, with the highest concentration between 6pm and 11pm. A slightly longer duration of high value hours can be seen in July, where peak value starts around 4pm. The highest value by a significant margin is at 5 to 9pm in July. The total avoided costs are $25.8M in cumulative (undiscounted) dollars and $16.9M in present value.

Figure 17. Feeder 2, Total Distribution Capacity, O&M, and Voltage Avoided Costs ($000s) by Hour and Month, All Years

Hour	F2 | Total Avoided Distribution Costs (Thousand $) By Hour and Month, ALL Years											
Month	1	2	3	4	5	6	7	8	9	10	11	12
1	4	-	-	-	-	-	-	-	-	-	-	-
2	-	-	-	-	-	-	-	-	-	-	-	-
3	-	-	-	-	-	-	-	-	-	-	-	-
4	-	-	-	-	-	-	-	-	-	-	-	-
5	-	-	-	-	-	-	-	-	-	-	-	-
6	-	-	-	-	-	-	-	-	-	-	-	-
7	-	-	-	-	-	-	-	-	-	-	-	-
8	13	-	-	-	-	-	-	-	-	-	-	-
9	8	-	-	-	-	-	-	-	-	-	-	-
10	-	-	-	-	-	-	-	-	-	-	-	-
11	-	-	-	-	-	-	-	-	-	-	-	-
12	-	-	-	-	-	-	-	-	-	-	-	-
13	-	-	-	-	-	-	-	-	-	-	-	-
14	-	-	-	-	-	-	-	-	-	-	-	-
15	-	-	-	-	-	-	-	-	-	-	-	-
16	-	-	-	-	-	-	1	-	-	-	-	-
17	5	-	-	-	-	-	1,159	1	-	-	-	-
18	77	-	-	-	-	16	2,765	84	2	-	-	4
19	744	32	-	-	-	204	4,406	396	39	-	1	284
20	1,096	73	7	-	1	280	3,413	545	80	-	3	405
21	1,038	50	1	-	-	115	3,355	284	21	-	-	236
22	841	37	1	-	-	41	1,879	111	5	-	-	163
23	429	12	-	-	-	0	989	6	-	-	-	52
24	16	-	-	-	-	-	-	-	-	-	-	-
											$	25,828

Figure 18 and Figure 19 show the same seasonal, by-year-and-hour heat maps as above, illustrating how costs build over time by season. As before, the total dollar value in the two heatmaps below sum to the same total as the heatmap above. In these figures, we can see the summer value is greater than on Feeder 1, with an early spike and then gradual development, while the winter value is much lower than on Feeder 1, and it builds steadily and relatively evenly across seasons, with concentration 6-10pm.

Figure 18. Feeder 2, Total Summer Distribution Capacity, O&M, and Voltage Avoided Costs ($000s) by Hour and Year

Hour	F2 | Total Avoided Distribution Costs (Thousand $) SUMMER Only																						
Year	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
13	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
14	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
16	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	1
17	-	-	-	26	60	78	89	98	100	100	96	86	73	59	47	40	35	32	29	28	28	27	28
18	-	206	166	152	151	156	162	169	163	156	149	144	130	114	101	94	88	88	92	94	96	97	100
19	-	74	137	142	145	153	161	170	209	236	251	272	293	298	293	293	287	284	279	276	271	264	258
20	-	-	-	73	97	112	121	131	149	172	180	196	230	262	282	291	293	298	296	293	287	281	275
21	-	44	125	134	138	146	154	161	165	180	187	182	183	184	184	186	191	195	201	206	209	210	210
22	-	-	-	39	70	87	97	106	107	107	115	118	112	101	96	93	95	99	106	113	120	125	130
23	-	-	-	-	33	55	68	79	83	85	84	76	66	54	44	37	33	31	30	31	32	35	39
24	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
																						$	20,194

Figure 19. Feeder 2, Total Winter Distribution Capacity, O&M, and Voltage Avoided Costs by ($000s) Hour and Year

Hour	F2 | Total Avoided Distribution Costs (Thousand $) WINTER Only																						
Year	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1	2
2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	2	3	4	4
9	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	2	2	3
10	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
13	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
14	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
16	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
17	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	2	2
18	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	4	6	8	10	11	12	14	16
19	-	-	-	-	-	-	-	-	-	-	14	26	32	35	46	62	81	97	108	119	133	148	161
20	-	-	-	-	-	-	-	-	-	-	16	28	43	66	89	115	135	148	161	174	189	202	216
21	-	-	-	-	-	-	-	-	-	-	11	25	45	67	87	95	110	124	133	140	151	162	177
22	-	-	-	-	-	-	-	-	-	-	-	11	20	44	63	79	86	96	108	119	129	138	149
23	-	-	-	-	-	-	-	-	-	-	-	-	-	10	19	30	40	47	53	63	71	78	84
24	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	3	6	8
																						$	5,633

In Figure 20, we see the average hourly avoided cost value for each year in the study period for Feeder 2. As before, because this view highlights the average value and the denominator is small in the initial period and increases year by year, we can see the relevance of taking action early. In this figure, we can see a high relative value of intervention in a few hours in 2024, then a rapid drop off in the value of addressing individual hours, with high hourly values returning in 2035, then dissipating on an hourly basis as the pressure becomes broader, with more hours increasing the total value of addressing the pressure, while reducing the per hour value.

Figure 20. Feeder 2, Average Distribution Capacity, O&M, and Voltage Avoided Costs by Hour and Year

Hour	F2 | Average Avoided Distribution Costs ($) ALL Months																					
Year	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	13	11	9
2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	21	17	27	22	18
9	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	17	13	11	18
10	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
13	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
14	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
16	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11	9
17	-	-	-	541	375	318	294	277	244	217	186	151	118	88	127	141	105	107	105	134	135	133	138
18	-	4,033	1,106	541	375	318	294	277	244	217	372	453	353	351	510	422	420	561	523	501	459	465	489
19	-	4,033	1,106	541	375	318	294	554	977	866	1,117	1,509	1,646	1,844	1,720	1,828	1,785	1,630	1,443	1,469	1,417	1,284	1,199
20	-	-	-	541	375	318	294	277	733	650	744	1,358	1,998	2,195	2,293	2,249	1,960	1,924	1,735	1,619	1,606	1,494	1,393
21	-	4,033	1,106	541	375	318	294	277	488	650	744	905	1,293	1,581	1,465	1,406	1,540	1,497	1,422	1,319	1,322	1,339	1,273
22	-	-	-	541	375	318	294	277	244	217	558	604	470	703	892	890	875	989	1,024	1,051	998	1,018	1,024
23	-	-	-	-	375	318	294	277	244	217	186	151	118	263	319	375	315	374	418	451	445	498	526
24	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	17	40	55	46

In summary, Feeder 2 has less potential value than Feeder 1, but still a value far above zero. There is some merit in an early intervention here, but in general it is a feeder that comes under pressure more gradually and later than Feeder 1. Summer interventions may be favored here, though both seasons require pressure relief. Feeder 2 shows a needle peak behavior, with costs caused by loads during noticeably fewer number of hours than for Feeder 1. In 2030, Feeder 1 has 810 hours with load above the normal rating, while Feeder 2 has just 51 hours. Interventions therefore could be designed to target a smaller number of hours to deliver their value.

Feeder 3: Very High Pressure, Winter-Peaking, Following

For Feeder 3, the Maximum Pressure scenario is projected to add 5.1 MW to the baseline peak load on the feeder by 2030, at an incremental annualized carrying cost of $1.98M in modeled infrastructure upgrades required, increasing to 10.0 MW and $3.86M in annualized upgrade cost by 2045. Unlike Feeders 1 and 2, the Main Relief measures do not completely eliminate the pressure above normal rating on this feeder.

Figure 21 shows the same heat map as above, showing total avoided costs by hour and month. In this figure, we can see, similar to Feeders 1 and 2, that there is a concentration and the highest values of potential avoided costs in the evening, again 6pm and 11pm; however, the pressure on this feeder is broader, with relevant value in the afternoons and for much of the month of January, including a second hot spot in the morning (from 7 to 10am), and with modest values December–March in all hours. The longest duration of very high value hours can be seen in July and January, from the late afternoon to midnight.

The total avoided costs from the Main Relief are $47.1M in cumulative (undiscounted) dollars and $30.5M in present value. This value does not reflect the total value of avoiding all potentially avoidable costs on this feeder because the Main Relief scenario does not entirely relieve the pressure. Load flexibility in addition to load shaping has the potential to resolve the remaining pressure, as shown below.

Figure 21. Feeder 3, Total Distribution Capacity, O&M, and Voltage Avoided Costs ($000s) by Hour and Month, All Years

Hour	F3 | Total Avoided Distribution Costs (Thousand $) By Hour and Month, ALL Years										
Month	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**
1	374	154	67	-	0	0	19	5	1	0	22	92
2	215	65	18	-	-	-	1	-	-	-	2	27
3	146	42	9	-	-	-	-	-	-	-	0	8
4	96	23	3	-	-	-	-	-	-	-	-	5
5	81	14	4	-	-	-	-	-	-	-	-	2
6	128	23	10	-	-	-	-	-	-	-	-	4
7	173	26	18	-	-	-	-	-	-	-	-	6
8	371	63	56	1	-	-	-	-	-	-	7	26
9	539	116	81	0	-	-	1	0	-	-	13	78
10	383	114	46	-	-	-	5	0	-	-	5	45
11	252	85	30	-	-	0	8	0	-	-	3	17
12	181	71	13	-	-	1	15	2	-	-	4	7
13	158	66	9	-	-	4	39	7	-	-	6	7
14	152	78	17	-	3	27	104	43	4	-	14	16
15	175	79	22	-	5	51	172	110	17	1	18	23
16	200	78	25	-	17	97	272	202	47	6	23	33
17	280	121	53	1	49	182	457	369	130	20	41	86
18	628	252	146	22	124	331	753	643	294	56	141	278
19	1,356	592	413	135	295	572	1,169	985	581	219	395	662
20	1,689	693	613	205	315	574	1,118	941	695	270	466	788
21	1,773	666	580	168	267	485	977	831	539	189	444	767
22	1,378	568	525	134	188	361	745	620	372	124	341	624
23	1,178	462	421	66	85	206	481	374	177	51	238	497
24	548	156	108	1	1	5	57	25	3	0	35	125
											$	**47,111**

Figure 22 and Figure 23 show the same by-year-and-hour heat maps as above, illustrating how costs build over time by season. As before, the total dollar value in the two heatmaps below sum to the same total as the heatmap above. In these figures, we can see summer value is similar in aggregate to Feeder 1 and becomes substantial in 2027, while winter value is much greater than on Feeder 1, and, as with Feeder 2 it builds steadily and eventually exceeds summer value. On this feeder winter has greater value, 1.6x that of summer, and in both seasons many hours have a broad spread of moderate value hours, with higher value 5-11pm in both seasons.

Figure 22. Feeder 3, Total Summer Distribution Capacity, O&M, and Voltage Avoided Costs ($000s) by Hour and Year

Hour	F3 | Total Avoided Distribution Costs (Thousand $) SUMMER Only																					
Year	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
1	-	-	-	-	-	-	-	-	0	0	0	0	0	1	1	1	1	2	2	3	4	5	6
2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	0	0	0	0	0
3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	0	0	0	0	0
10	-	-	-	-	-	-	-	-	-	-	-	0	0	0	0	0	0	0	0	1	1	1	1
11	-	-	-	-	-	-	-	-	0	0	0	0	0	0	0	0	1	1	1	1	1	1	1
12	-	-	-	-	-	-	0	0	0	0	1	1	1	1	1	1	1	1	1	2	2	2	3
13	-	-	-	-	-	-	1	1	1	2	2	2	2	2	2	2	3	3	4	5	5	6	7
14	-	-	-	-	-	1	3	4	5	6	7	7	8	9	10	11	12	13	14	15	16	17	18
15	-	-	-	-	-	2	9	10	12	13	14	16	17	19	20	22	23	25	26	28	29	31	33
16	-	-	-	-	0	6	18	21	24	27	29	32	34	36	38	40	41	43	44	45	47	49	51
17	-	-	-	-	9	31	47	51	54	57	59	61	63	65	66	68	69	71	73	75	77	79	82
18	-	-	-	-	38	85	102	104	105	105	107	109	111	112	114	116	117	120	122	124	126	129	132
19	-	-	-	6	160	196	177	177	177	178	179	180	182	183	185	187	189	191	192	195	196	199	200
20	-	-	-	1	134	186	176	178	181	182	184	187	189	191	193	195	197	199	201	203	205	207	208
21	-	-	-	-	79	132	138	143	147	151	154	157	160	163	166	169	172	175	178	181	183	186	188
22	-	-	-	-	20	61	83	91	97	103	109	114	119	124	128	132	137	141	145	149	153	156	160
23	-	-	-	-	1	13	27	34	41	48	55	61	67	72	77	82	87	92	97	102	107	112	116
24	-	-	-	-	-	-	0	0	1	1	1	1	2	3	3	4	6	7	9	10	12	14	16
																						$	18,242

Figure 23. Feeder 3, Total Winter Distribution Capacity, O&M, and Voltage Avoided Costs ($000s) by Hour and Year

Hour	F3 | Total Avoided Distribution Costs ($) WINTER Only																					
Year	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
1	-	-	-	-	13	15	17	18	20	22	24	27	31	34	38	42	46	49	54	58	62	67	71
2	-	-	-	-	7	6	7	8	9	11	12	13	14	15	17	18	20	22	24	27	29	32	34
3	-	-	-	-	6	5	5	5	6	6	7	8	8	10	11	12	13	14	15	16	18	19	21
4	-	-	-	-	2	3	3	3	3	3	4	5	6	6	7	7	8	9	10	10	11	12	13
5	-	-	-	-	2	3	3	3	3	3	3	4	4	5	5	6	6	7	7	8	9	9	10
6	-	-	-	-	6	7	6	6	5	6	6	7	7	8	9	9	10	11	11	12	12	13	14
7	-	-	-	-	10	9	7	7	7	8	9	10	11	11	12	13	13	14	15	16	17	18	19
8	-	-	-	39	22	17	18	18	19	20	21	22	22	23	24	26	27	29	31	33	35	37	39
9	-	-	-	66	30	28	29	29	30	31	32	33	35	37	39	41	44	47	50	53	55	58	61
10	-	-	-	19	19	20	21	21	22	22	23	24	25	27	29	31	34	36	39	41	44	46	49
11	-	-	-	-	11	12	12	13	13	14	15	16	17	18	19	21	23	25	27	29	31	33	36
12	-	-	-	-	2	8	9	9	9	10	10	11	12	13	14	15	17	18	20	21	23	25	27
13	-	-	-	-	-	5	7	7	7	7	8	9	10	11	13	14	16	18	19	21	23	25	27
14	-	-	-	-	-	5	7	7	7	7	8	9	11	13	15	17	19	21	23	24	26	29	31
15	-	-	-	-	-	4	7	7	8	9	10	11	13	15	17	19	21	23	26	28	31	35	38
16	-	-	-	-	-	4	7	7	8	10	11	13	14	16	19	21	24	27	31	35	39	43	47
17	-	-	-	-	2	6	9	11	12	15	18	21	25	29	33	37	43	48	54	59	64	70	75
18	-	-	-	-	21	27	30	36	42	48	56	65	75	84	92	100	108	116	123	131	138	145	153
19	-	-	-	70	109	119	125	140	153	165	178	189	199	208	217	225	232	239	245	251	257	262	267
20	-	-	62	146	157	172	171	186	201	212	223	233	242	250	257	263	270	276	281	286	290	294	298
21	-	-	163	158	151	160	162	176	189	201	211	221	229	237	244	251	257	264	269	274	279	283	287
22	-	-	7	87	104	112	119	132	146	160	173	184	193	202	210	217	225	233	239	246	251	257	262
23	-	-	-	78	76	80	83	94	105	115	127	138	149	158	166	173	180	187	194	201	208	215	221
24	-	-	-	13	19	23	25	27	29	31	35	39	43	48	52	56	61	66	71	77	82	87	91
																						$	28,868

In Figure 24 we see the average hourly avoided cost value for each year in the study period for Feeder 3. On this feeder, as before the highest hourly value is when the pressure is on fewer hours, but on this feeder that hourly value doesn't have the same degree of spikiness as the prior feeders.

Figure 24. Feeder 3, Average Distribution Capacity, O&M, and Voltage Avoided Costs by Hour and Year

Hour	F3 | Average Avoided Distribution Costs ($) ALL Months																					
Year	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
1	-	-	-	-	32	70	64	58	73	84	82	102	101	115	122	120	124	137	145	160	165	173	179
2	-	-	-	-	32	23	41	39	41	38	43	40	46	45	51	52	58	63	69	77	80	79	83
3	-	-	-	-	32	12	17	24	28	24	24	24	31	35	35	36	33	34	36	47	51	55	59
4	-	-	-	-	32	12	12	10	8	14	24	22	22	22	22	22	26	28	26	24	27	31	35
5	-	-	-	-	32	12	12	10	8	7	9	13	19	19	20	22	20	18	21	23	24	24	27
6	-	-	-	-	32	23	12	14	12	21	27	24	24	28	29	27	26	26	26	28	27	27	32
7	-	-	-	-	32	23	17	29	28	28	40	40	36	35	35	32	31	32	36	38	40	44	49
8	-	-	-	190	63	82	64	63	69	63	58	54	55	65	67	70	71	75	77	82	85	85	86
9	-	-	-	190	95	117	93	87	81	87	79	92	96	106	110	108	119	118	116	118	117	117	118
10	-	-	-	190	63	105	76	72	65	59	64	70	75	87	88	100	101	100	99	101	100	108	110
11	-	-	-	-	63	47	47	43	53	56	52	51	48	50	61	79	81	80	79	83	87	90	96
12	-	-	-	-	32	47	35	29	37	38	43	43	43	48	51	54	56	61	70	77	80	88	101
13	-	-	-	-	-	47	41	34	37	35	43	46	53	54	65	68	78	81	87	99	97	108	111
14	-	-	-	-	-	58	47	63	61	70	82	89	111	115	114	109	112	111	116	119	129	131	136
15	-	-	-	-	-	93	116	111	106	115	125	135	147	145	147	151	155	160	166	177	181	185	188
16	-	-	-	-	32	117	186	202	191	192	186	194	195	201	198	201	198	200	213	211	225	227	230
17	-	-	-	-	158	257	297	299	292	293	290	275	279	277	275	283	294	293	298	297	297	291	295
18	-	-	-	-	539	642	512	487	467	457	476	501	498	474	455	439	432	418	417	403	410	403	396
19	-	-	-	760	1,553	1,214	942	915	849	803	759	721	707	666	626	588	556	528	505	478	458	435	412
20	-	-	893	760	1,711	1,424	1,093	1,041	955	866	830	797	738	690	657	624	581	550	517	489	460	435	412
21	-	-	893	570	1,267	1,261	1,000	973	918	834	793	746	704	677	643	622	584	547	517	485	458	435	412
22	-	-	893	380	760	829	814	756	784	758	702	676	651	619	583	574	556	530	505	478	456	431	411
23	-	-	-	380	380	444	512	559	561	576	573	563	550	519	498	488	473	462	459	455	444	428	409
24	-	-	-	190	95	105	99	96	97	108	131	151	159	167	165	183	198	212	220	232	231	229	233

In summary, Feeder 3 has greater potential value than Feeder 1 or 2 from load shaping and has additional potential value addressable by load flexibility on top of load shaping. There is merit in an early intervention here because pressure is substantial in both seasons before 2030. Also, as an additional layer of intervention, this feeder would benefit from load flexibility on top of load shaping. Load flexibility is valuable on all feeders in every scenario; however, on this feeder it is essential to avoid exceeding feeder limits and to capture all potential distribution capacity, O&M, and voltage avoided costs. Although Feeder 3 has more than 4,000 hours that exceed the normal rating in the Maximum Pressure case, only 54 hours of load over the normal rating remain after the Main Relief measures are applied. This means load flexibility must address only a few targeted hours. This additional relief will be illustrated in the following section.

Feeder 4: Low Pressure, Summer-Peaking, Minimal Load Throughout

Feeder 4 never exceeds its normal rating in any modeled scenario and therefore there is no value to potentially avoidable distribution system costs. Feeder 4 is a part of Pepco's LVAC network that serves the central business district.

6.3. Avoided Distribution Cost Detail - Load Flexibility

The Study Team expects that in general load shaping measures will be less expensive to implement per MW and MWh. As load flexibility is not able to achieve the same magnitude of results as load shaping, the Study Team modeled the load shaping measures first and applied load flexibility measures to the remaining load.

On Feeder 3, load shaping relief does not fully relieve the modeled pressure on the feeder. Load flexibility shows potential to address the remaining pressure. As previously described, load flexibility was modeled as a reduction of 30 percent on the top 266 hours. This additional relief brings the feeder below the normal rating and yields an additional $4.5M in avoided costs. After the Main Relief measures were applied, the remaining hours are few where the feeder still exceeds the normal rating, but in these hours the normal rating is frequently exceeded for many years, such that the accumulated value from load flexibility is substantial, approximately 10 percent of the value of load shaping when applied after load shaping. If the same curtailment approach was applied before load shaping, or if the modeled flexibility is greater in number of hours or percentage reduction, then the values for load flexibility would be substantially higher.

Figure 25, Figure 26, and Figure 27 illustrate the opportunity for load flexibility to provide relief value on Feeder 3 by hour and month for all the years of the study period, by hour and year in the summer, and by hour and year in the winter. In Figure 25, we can see most of the value is in January, July, and August, with peaks from 7-10pm across these months and with a smaller peak, about half the magnitude in January at 9am. In Figure 26, we see the residual value of unrelieved pressures (after load shaping) starts in 2029 and more than doubles by 2045.

Figure 25. Feeder 3, Load Flexibility Total Distribution Capacity, O&M, and Voltage Avoided Costs ($000s) by Hour and Month for All Years

Hour	F3 | Total Avoided Distribution Costs (Thousand $) By Hour and Month, ALL Years											
Month	1	2	3	4	5	6	7	8	9	10	11	12
1	41	-	-	-	-	-	16	-	-	-	-	-
2	16	-	-	-	-	-	-	-	-	-	-	-
3	-	-	-	-	-	-	-	-	-	-	-	-
4	16	-	-	-	-	-	-	-	-	-	-	-
5	-	-	-	-	-	-	-	-	-	-	-	-
6	61	-	-	-	-	-	-	-	-	-	-	-
7	56	-	-	-	-	-	-	-	-	-	-	-
8	182	-	-	-	-	-	-	-	-	-	-	-
9	316	-	-	-	-	-	-	-	-	-	-	-
10	96	-	-	-	-	-	-	-	-	-	-	-
11	46	-	-	-	-	-	-	-	-	-	-	-
12	-	-	-	-	-	-	-	-	-	-	-	-
13	-	-	-	-	-	-	-	-	-	-	-	-
14	-	-	-	-	-	-	-	-	-	-	-	-
15	-	-	-	-	-	-	-	-	-	-	-	-
16	-	-	-	-	-	-	-	-	-	-	-	-
17	-	-	-	-	-	96	-	8	-	-	-	-
18	-	-	-	-	-	-	-	-	-	-	-	-
19	325	81	-	-	16	-	382	298	-	-	-	-
20	646	46	-	-	-	-	556	182	61	-	-	-
21	489	-	-	-	-	-	243	23	-	-	-	-
22	169	-	-	-	-	-	25	-	-	-	-	-
23	-	-	-	-	-	-	8	8	-	-	-	-
24	-	-	-	-	-	-	-	-	-	-	-	-
											$	4,505

Figure 26. Feeder 3, Load Flexibility Total Summer Distribution Capacity, O&M, and Voltage Avoided Costs ($000s) by Hour and Year

Hour	F3 | Total Avoided Distribution Costs (Thousand $) SUMMER Only																					
Year	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8	8
2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
13	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
14	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
16	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
17	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15	13	12	11	10	10	10	8	15
18	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
19	-	-	-	-	-	-	24	26	28	20	35	32	31	33	30	38	59	54	51	50	57	57	53
20	-	-	-	-	-	-	24	26	28	41	35	32	47	50	60	50	47	54	61	61	57	65	61
21	-	-	-	-	-	-	-	-	-	-	-	16	16	17	15	13	12	22	20	30	29	33	46
22	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	8	8
23	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15
24	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
																						$	1,904

Figure 27. Feeder 3, Load Flexibility Total Winter Distribution Capacity, O&M, and Voltage Avoided Costs ($000s) by Hour and Year

Hour	F3 | Total Avoided Distribution Costs (Thousand $) WINTER Only																					
Year	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	16	15
2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8	8
3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8	8
5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	19	16	15
7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11	10	10	10	8	8
8	-	-	-	-	-	-	-	-	-	20	18	16	16	17	15	13	12	11	10	10	10	8	8
9	-	-	-	-	-	-	24	26	28	20	18	16	16	17	15	13	12	22	20	20	19	16	15
10	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15	13	12	11	10	10	10	8	8
11	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10	10	8	8
12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
13	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
14	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
16	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
17	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
18	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
19	-	-	-	-	-	-	-	-	-	20	18	32	31	33	30	38	35	33	30	30	29	33	30
20	-	-	-	-	-	-	48	52	57	41	35	32	31	33	30	38	35	33	51	50	48	41	38
21	-	-	-	-	-	-	24	26	28	20	35	32	31	33	30	25	35	33	30	30	29	24	23
22	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	25	24	22	20	20	19	16	23
23	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
24	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
																						$	2,601

7. ROADMAP

The results of this analysis indicate that DER compensation mechanisms, particularly those designed to relieve the pressures expected from growth in electricity peak demand at the local level, can provide considerable benefits to residents of the District of Columbia. To harness the potential of DERs to provide these benefits in the near term, the District should review and update existing DER compensation mechanisms while also considering the development of new ones. This section outlines the recommended roadmap for the implementation of DER compensation mechanisms including incentive/rebate programs, rate designs, VDER tariffs, and contracts with DER providers.

Before delving into the roadmap, the following section outlines financial, technical/administrative, customer, and policy principles of DER compensation. It then integrates these principles into the roadmap discussion. Next, we identify enhancements to distribution system planning to support the development of DER compensation mechanisms. We conclude with a discussion of additional research and activities that are likely needed to support the roadmap over the longer term.

7.1. Principles for Compensating DERs

Table 8 below outlines financial, technical/administrative, customer, and policy principles for compensating DERs. These principles should be considered when designing compensation mechanisms to facilitate deployment of DERs.

Table 8. Principles for Compensating DERs

Principles and Examples for Application
1. Financial: Set appropriate compensation levels
• Ensure economic levels of compensation needed to attract program participants (while ensuring that the DERs are still cost-effective). The objective of the design of the DER compensation mechanism should be to pay enough to get the societally beneficial actions to happen, but less than the traditional solutions or other competing solutions (thereby achieving net savings). To enable sufficient participation in a solution, it is important to understand the benefits and costs realized by the host customer or developer and ensure that the value of participating is evident to that customer or developer.
• To maximize benefits to all ratepayers, compensation levels for DERs should be set at a just and reasonable level that reflects the availability, reliability, dispatchability, and location of the DER, while still procuring the necessary quantity of cost-effective DER resources. It is important to ensure that the compensation for DERs does not outweigh benefits to society. If the costs exceed the benefits, ratepayers are paying more than the traditional solution, and the DER solution is not cost-effective and should not be pursued.
• Consider whether the compensation mechanism is resource-specific or resource-agnostic and determine how the mechanism will be applied. On the one hand, resource-specific compensation mechanisms may more clearly indicate the desired customer behavior and the value proposition may be more transparent to the customer. On the other hand, resource-agnostic efforts provide for more flexibility and create more opportunity for diverse solutions, which may ultimately be more cost-effective.
• Where the cost of resources is not known, Pepco can leverage RFPs to reveal the range of current resource costs.
• Tiered compensation can be used to provide greater rewards for DERs with higher temporal and spatial value or greater response certainty (i.e., for firm, semi-firm, and non-firm resources).[23,24]

[23] Pepco's Annual Consolidated Report states, "To be considered as a planning resource, a DER must be firm. In other words, it must be available at the time of peak load. Pepco's system planning criteria dictate that a DER is considered firm and is thus a dependable resource for peak planning purposes, if it is available (or coincides) 95% of the time with the peak on whichever component of the distribution system is being evaluated (feeder, substation transformer, or substation" (Pepco. *2023 Annual Consolidated Report*. April 18, 2023. Page 11. Available at: https://edocket.dcpsc.org/apis/api/Filing/download?attachId=188799&guidFileName=682ed2e8-d4ff-4df2-a071-ec01e26b73b5.pdf)

[24] Pepco asserts that energy efficiency is considered a firm DER resource. Pepco also asserts that backup generators and solar are not firm DER resources. Battery storage, when dispatched to meet generation and transmission peaks, is also not a firm DER resource. Electric vehicles are not discussed in the ACR. (Id. At 11.)

Principles and Examples for Application
2. Technical/ Administrative: Consider the complexity of the DER compensation mechanisms
• Establish simple, transparent, and intuitive mechanisms as these will appeal to more customers, at least at the outset. Residential customers may respond better to relatively simple tariff structures. As such, a simple TOU rate or EV tariff may be more appropriate for these customers than a complex VDER tariff.
• Avoid developing overly complex new DER compensation mechanisms if existing mechanisms are adequate. The District currently has multiple mechanisms for supporting the development of DERs (including energy efficiency and demand response programs, solar PV incentives, EV tariffs, rate designs such as net energy metering, and third-party DER contracting such as for non-wires alternatives). The refinement or expansion of existing programs and compensation mechanisms may be the most efficient means of encouraging the development of additional DERs, particularly if compensation through these existing programs is aligned with the values identified in a VDER study and resources are targeted to the highest-value locations. Development of an entirely new tariff (e.g., a VDER tariff) can require considerable regulatory and administrative resources and may not be necessary. If a new VDER tariff is undertaken, it can be beneficial to keep the design simple.
• Mitigate risk associated with the certainty of resource availability. Some DER compensation mechanisms produce outcomes that are more certain than others. For example, if resources are procured through a contract with non-performance penalties, this provides a greater level of certainty that a specific quantity of relief will be available by a certain date. Other mechanisms, such as rate designs, rely more on voluntary efforts, which can fluctuate over time due to many factors.
• Address data requirements and ownership changes in program designs. Some tariffs and market settlement mechanisms require robust data systems that reliably track performance through sophisticated metering. Those data systems can come with increased cost and complexity. Where additional equipment is needed, incentives for any additional equipment should be considered to support customer/developer interest. Customers may have concerns about data privacy. It is important to balance the need for data with the willingness of customers to install the equipment needed to monitor and share that data.
• Consider that certain DERs could cease to be available if ownership changes. The District should plan for the transition of DERs to a new customer if the customer who originally enrolled moves. For example, what happens to a battery system when a new customer moves in? In many cases, it may make sense to leave any equipment in place and reach out to the new customer with information about the opportunities associated with their new property. The new customer may need to re-enroll in the DER compensation mechanisms, which will likely require further outreach and education.
• Advanced inverters, controls, and communications may be needed to unlock potential. Specifically, DERs need to be dispatched in an intelligent and coordinated way, and this means there needs to be reliable communications systems designed to support signaling directly to DERs. And DERs for load flexibility depend on the ability to monitor the status of both distribution circuits and the status of resources on those circuits to coordinate DER operations. In addition, the relative value of signaling and communications managed by the utility should be considered in contrast with a scenario where DER owners or third-party aggregators are responsible for dispatch. Advanced communications networks may be necessary to assure high reliability; these come with additional cost and affect market participation and development for DER operations that should be evaluated.

Principles and Examples for Application
3. Customer: Consider predictability of the DER compensation mechanisms
• Develop programs that are stable and predictable over time. Establish programs with the intention of keeping the structure and pricing in place for some time so customers and developers can more accurately estimate the value and experience it. Set up clear start and end dates for the programs and address grandfathering in the terms to provide greater certainty if the mechanism changes. Stability of compensation mechanisms is particularly important for commercial DER providers to obtain financing for their projects. It also gives customers the chance to spread the word about the program to others who may be interested, such as neighbors, friends, and family.
• Provide options for more sophisticated customers or for novice customers to grow into over time. Understanding of and willingness of some customers to participate in more complex structures with greater risk and greater reward may grow with experience.
4. Policy goals: Consider all the important goals of DER efforts such as public health, resilience, environmental protection, and equity
• Some DER efforts may contribute more to certain policy goals, such as District decarbonization goals. A comparison of the benefit-cost analyses for several different proposed efforts will demonstrate the magnitude of these types of benefits. While one effort may be less cost-effective, it may offer more of a benefit that is a higher priority.

7.2. DER Compensation Mechanisms

Far from being monolithic, each type of DER has its own financial, technical, participant, and policy considerations, which determine the way it can and will be utilized. Because of this, the Study Team does not recommend adopting a one-size-fits-all approach to compensating DERs in the District. Instead, various forms of DER compensation mechanisms can be employed which, taken together, maximize the beneficial deployment of DERs. These DER compensation mechanisms include:

- Incentive or rebate programs;
- Rate designs;
- VDER tariffs; and
- Contracts with DER providers.

Many District-wide DER compensation mechanisms already exist (such as incentive or rebate programs for energy efficiency, demand response, and solar and rate designs for electric vehicles), some of which have a timing and locational component. However, there are many untapped opportunities to further deploy more temporally and locationally targeted DER compensation mechanisms. Such mechanisms will provide the most value where the utility has identified a future distribution system pressure that can be addressed by DERs.

The DC PSC has a number of open formal cases which may be informed by the conclusions and recommendations in this study. They include:

- Formal Case No. 1050 - In the Matter of the Investigation of the Implementation of Interconnection Standards in the District of Columbia.
- Formal Case No. 1086 - In the Matter of the Investigation into the Potomac Electric Power Company's Residential Air Conditioner Direct Load Control Program.
- Formal Case No. 1130 - In the Matter of the Investigation into Modernizing the Energy Delivery System for Increased Sustainability.
- Formal Case No. 1155 - Potomac Electric Power Company’s Application for Approval of its Transportation Electrification Program.
- Formal Case No. 1160 - In the Matter of the Development of Metrics for Electric Company and Gas Company Energy Efficiency and Demand Response Programs Pursuant to Section 201 (b) of the Clean Energy DC Omnibus Amendment Act of 2018.
- Formal Case No. 1163: In the Matter of the Investigation into the Regulatory Framework of Microgrids in the District of Columbia.
- Formal Case No. 1166: In the Matter of the Investigation Into Energy Storage And Distributed Energy Resources In The District Of Columbia.

- Formal Case No. 1167: In the Matter of the Implementation of Electric And Natural Gas Climate Change Proposals.
- Formal Case No. 1172: In the Matter of the Consideration of Federal Funding under the Infrastructure Investment and Jobs Act and Inflation Reduction Act.
- Formal Case No. GD2019-01-M In the Matter of the Implementation of the 2019 Clean Energy DC Omnibus Act Compliance Requirements.

We recommend next steps focused on the deferral and avoidance of more expensive utility solutions and new efforts (efforts that are not already underway) that can be taken towards the goal of a cost-effective and reliable electric system as part of a low emissions energy system approaching net zero. To cost-effectively address temporal- and feeder-specific pressures, Pepco should continuously examine the extent to which it can address the distribution system pressures through low-cost utility solutions such as load transfers, feeder up-rating, and conservation voltage reduction. In addition to this effort, the District should take the following steps.

1. First, the DC PSC should establish baselines for measuring current performance and identify metrics to track the performance of DER compensation mechanisms going forward. The baselines are a way to continuously monitor feeder-level loads against normal ratings to allow sufficient time to deploy solutions. Metrics can include, but are not limited to, the quantity of DERs procured in a specified time period (e.g., quarterly enrollment levels in a demand response program); the cost to customers, including incentives paid, marketing, and administrative costs; and the performance (e.g., load reduction) of the DERs during peak events.

2. Second, Pepco and other stakeholders (including DCSEU) can recommend whether to evolve existing mechanisms to address time- and location-specific pressures. It is likely to be more efficient to refine or expand existing programs and compensation mechanisms than to develop new mechanisms. The DC PSC could refine existing mechanisms to ensure that they reflect the values identified in this VDER study and that resources are targeted to the highest-value locations and hours of day.

3. As an optional third step, the DC PSC, Pepco, and/or other stakeholders may determine that existing mechanisms are insufficient and that new DER compensation mechanisms are needed. Some DER compensation mechanisms that could be effective at providing relief, such as certain rate designs and VDER tariffs, may not be in use by the District. Benefit cost analysis can be conducted on proposed designs for new DER compensation mechanisms.

4. Lastly, the District should repeat this roadmap process periodically to evaluate the performance of all DER compensation mechanisms and update them as needed. The District can require a more significant set of study updates every five years to the avoided costs and other major inputs.

Figure 28 below illustrates this recommended roadmap.

Figure 28. Roadmap for Establishing DER Compensation Mechanisms

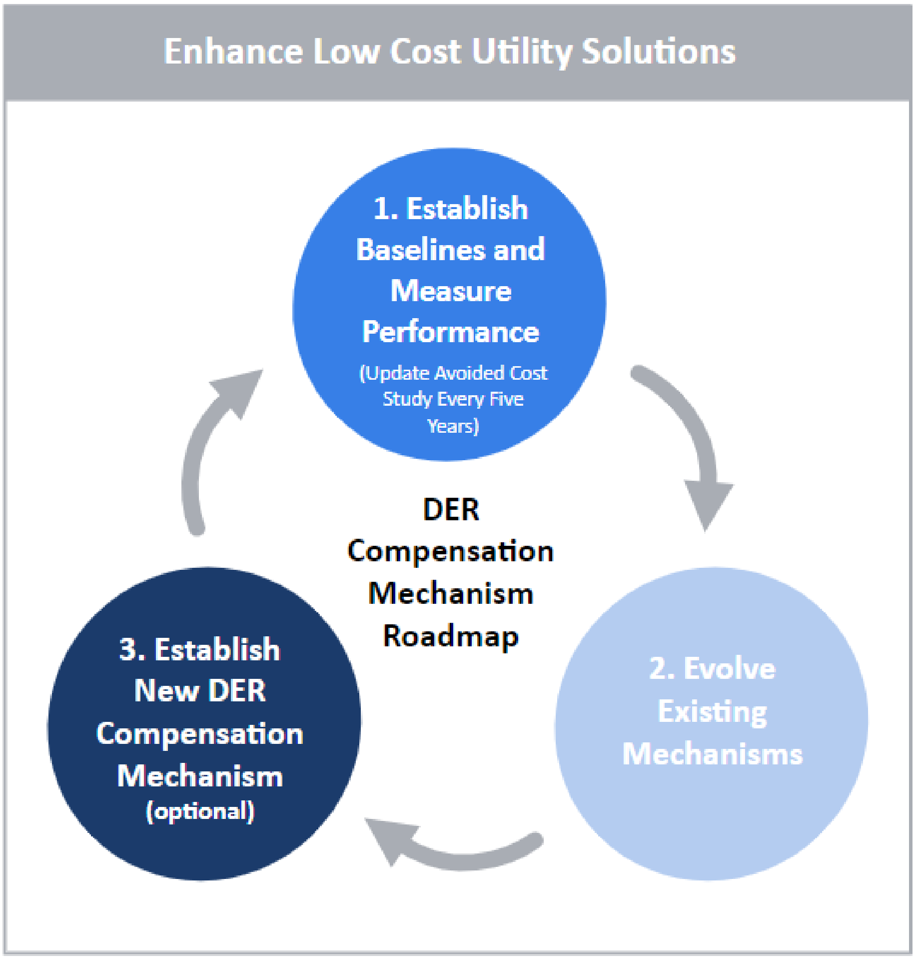


Table 9 below summarizes the different DER compensation mechanisms that can be considered, along with a brief overview of the key financial, technical/administrative, participant, and policy considerations for each. A more detailed discussion of each mechanism appears below the table.

Table 9. Summary of DER Compensation Mechanisms and Key Considerations

Compensation Mechanism	Financial Considerations	Technical/Administrative Considerations	Participant Considerations	Policy Considerations
Incentive/ Rebate Programs	• Additional costs depend on whether existing programs can be leveraged to target certain timing and locations • Typically resource-specific (with differing incentives by resource)	• Pepco, DC SEU, or other third parties can administer • No guarantee that sufficient DERs will materialize in the timeframe needed	• Available to RES and C&I customers and third parties • Focused on rewards	• Can be designed to address policy priorities • EE offers high GHG emission reduction benefits due to reducing load, rather than simply shifting load to other hours
Rate Designs	• Low additional cost • Can be resource-specific (with differing costs by resource) or resource-agnostic	• Pepco is the administrator; third parties can help customers manage load • Needs to consider which rate components should be included – customer charge, distribution rate, transmission rate, and generation rate • Data limitations may hamper efforts to reach new customers or target specific customer types • No guarantee that sufficient resources will materialize in the timeframe needed	• Available to RES and C&I customers • Can include penalties in addition to rewards • Need to balance differentiation in rates with the risk of higher costs for participants • Requires a higher degree of participant education and more spending on marketing	• Can be designed to address policy priorities

Compensation Mechanism	Financial Considerations	Technical/Administrative Considerations	Participant Considerations	Policy Considerations
VDER Tariffs	• Can add cost, depending on the design of the tariff • Can be resource-specific (with differing costs by resource) or resource-agnostic	• Pepco is the administrator • No guarantee that sufficient resources will materialize in the timeframe needed	• Available to RES and C&I customers and third parties • Focused on rewards • Requires a higher degree of participant education	• Can be designed to address policy priorities
Contracts with DER Providers	• Additional cost • Typically resource-specific (with differing costs by resource) • RFPs can help with price discovery	• Pepco is the administrator • Useful for solutions that need to be implemented relatively quickly and with greater certainty	• Available to third-party providers • Can include penalties for non-performance • Requires sophisticated DER providers to participate	• Can indicate policy priorities in RFP and rank responses accordingly

Incentive/Rebate Programs

Financial Considerations

Incentive and rebate programs tend to be resource-specific, meaning a program is designed to increase customer investment in certain measures or resource types and differing incentives are designed to encourage participation in each measure or resource type. Energy efficiency, demand response, and solar programs are examples of incentive/rebate programs that are currently active in the District.

To the extent that these existing incentive/rebate programs can be leveraged to better address future distribution-system pressures in specific locations and during particular hours, these programs may require little additional cost. If existing programs must be expanded or higher-cost measures implemented, then the overall cost may be significantly higher. Thus, the Study Team recommends that existing energy efficiency and demand response programs be examined to determine whether they can effectively address future grid needs through program modifications.

Over the next decade, building electrification is expected to add considerable additional load through fuel switching, which increases peak demand and necessitates additional infrastructure investments. The pace and magnitude of building electrification's impact will in large part depend on (1) the District's policies and incentives, (2) the efficiency of the building envelope and appliances adopted at the time of electrification, and (3) the way that the appliances are operated moving forward. Coupling energy efficiency and demand response with electrification is likely to be the most cost-effective means of mitigating the impacts of building electrification on the grid.

Our analysis indicates that the timing of solar generation is generally not well-aligned with future distribution system needs. However, solar programs could be more cost-effective if paired with batteries or if new loads from building and vehicle electrification are shifted to the mid-day hours to better utilize solar. In addition, more west-facing solar may have benefits in providing greater benefits later in the day. For example, if PV could generate until 8pm in the summer, it could potentially help address evening capacity constraints on the distribution system. Further study is needed to assess the feasibility and incentives required for such deployment, as the incentives would have to be sufficiently high to offset the reduction in total energy generation from west-facing systems compared to south-facing systems.

Technical/Administrative Considerations

A range of entities can administer incentive and rebate programs, including Pepco, the DCSEU, or third parties. Participation in energy efficiency, demand response, and solar programs is voluntary, so there is no guarantee that goals can be met in the timeframe needed with these programs. Voluntary demand response programs (such as Pepco's direct load control programs) allow customers to opt out with no penalty, which reduces the certainty of load reductions. Incentive levels can be adjusted to increase or decrease customer response. However, demand response programs can also be designed to be contractual. Alternative demand response program designs require customers to respond with a preset magnitude of load reduction or face penalties, which yields far more reliable load reductions.

Participant Considerations

Numerous types of customers can participate in incentive and rebate programs. Incentives and rebates represent different types of rewards, which means that there are additional costs to implement these programs.

Policy Considerations

Incentive and rebate programs can be designed to address policy priorities. In particular, energy efficiency has low net cost due to the significant environmental benefits (as valued through the social cost of carbon) associated with reducing energy consumption, rather than simply shifting load to other hours.

Recommendation #1: Proactively address future electrification pressure through modification or expansion of existing energy efficiency and demand response incentive/rebate programs to the extent doing so is cost-effective.

The most cost-effective way to deploy additional energy efficiency and demand response will likely be through updates to existing Pepco and DCSEU programs. The Study Team recommends the following actions:

a. Reexamine incentive levels for weatherization and building envelope upgrades, investment in high efficiency HVAC systems, and improvements in controls systems and grid responsive equipment and appliances that can engage in demand response. Determine what incentive level would reflect the load shaping and load shedding value that these measures support.

b. Reassess programs to ensure they account for the value of load flexibility and the breadth of emerging technologies that can support load flexibility, including ongoing assessment of the state-of-the-art in advanced commercial HVAC controls, water cooling and heating, space cooling and heating, and refrigeration measures. As a starting point, all energy efficiency programs should also consider how grid responsiveness can be enabled concurrently with efficiency measures.

c. Add an incentive tier for those who weatherize their home, adopt controls, and/or enroll in a demand response program at the same time as, or within a specific number of months after, electrification.

d. Include a new incentive tier for those who can reduce or shift load if they live in areas with potential distribution system pressures, to properly capture the feeder-specific value they offer.

e. Add another program type to the demand response programs for those customers who are interested in higher rewards in exchange for taking on more risk, for example more events, events that occur year-round, less predictable timing of events, or penalties for non-performance.

Recommendation #2: Amend solar incentives to include storage and account for temporal- and feeder-specific values.

The District can augment the existing solar incentive/rebate program to provide temporal value by adjusting incentives to reflect the times at which distributed generation is most valuable. In addition, the incentive could be expanded to provide incentives for independent battery energy storage systems and those co-located with solar. Coordination of the dispatch of these systems is important and should be based on grid needs. Also, it is important to account for third-party aggregators that may manage battery dispatch.

Rate Designs

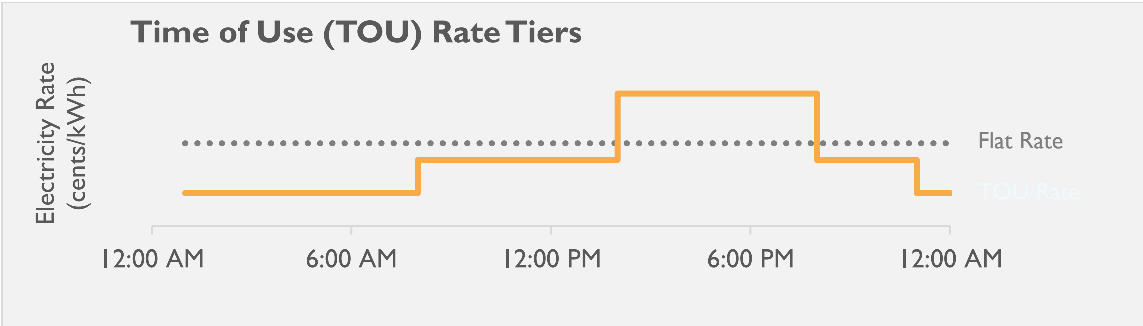
Financial Considerations

Rate design can help make the actual hourly cost of energy more transparent to customers, which encourages customers to shift electricity usage (including from building electrification and electric vehicles) to lower-cost times, thereby reducing system-wide costs. By designing rates that more accurately reflect costs on the grid, rate designs can function as a compensation mechanism for DERs by reducing electricity prices during certain hours. This approach is also a low-cost, no-regrets measure, as it simply improves the efficiency of price signals for all customers on a rate. Further, rates are typically designed to be revenue-neutral; thus, the implementation of new rates reallocates existing costs and does not create any additional costs (other than administrative and customer education/outreach costs). Rate designs can be resource-specific, such as an EV TOU rate, or resource-agnostic.

Technical/Administrative Considerations

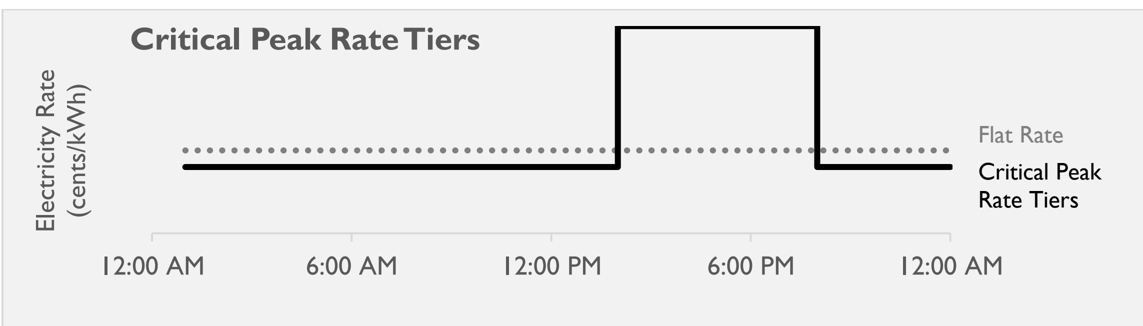
Rate design can vary from extremely simple rates (such as flat volumetric rates which charge the same amount per kWh regardless of when electricity is consumed), to locational pricing in which rates differ by location on the distribution system, to locational, dynamic pricing in which the rates also fluctuate every 15 minutes or hourly based on wholesale market prices. While rate designs can be complex, there are numerous rate designs which may appeal to a wide range of customers in the District and can be implemented relatively easily. These include TOU rates and critical peak pricing (CPP) rates, as described below:

- *Time-of-Use Rates:* TOU rates have two or more rate tiers, based on pre-set time periods. Electricity rates are higher during hours when costs on the system are highest, and lower during hours when costs tend to be low. While this rate structure can be attractive to customers because the rates and peak hours are known ahead of time, it generally represents only a rough approximation of actual system costs.



- *Critical Peak Pricing:* This rate structure imposes a very high price (typically in the range of \$0.50–\$2.00/kWh) that is only triggered for a limited number of specific events, such as system reliability or peak electricity market prices.[25] These events generally last for only 2–6 hours, and customers will not know whether an event will be called until a day in advance (or less). The maximum number of CPP events in a year is limited, often in the range of 10–20 events. In exchange for high prices during CPP event hours, customers receive lower rates during other hours.[26]

  Notably, utilities can implement CPP on a system-wide basis to address periods when the distribution grid as a whole is peaking, or they can implement CPP on a circuit-by-circuit basis to reflect different hours when various locations on the distribution grid experience peak demand.



Pepco and third-party energy suppliers administer rates, and any entity can help to manage the load.

Participant Considerations

Rate designs can be implemented for all customer types but are not available to non-customers such as third-party DER developers. For rate design to be effective, greater customer education is required, and the design will need to balance the need to differentiate rates for different time periods and locations

[25] Hledik, R. et al., 2016.

[26] Alternately, Peak Time Rebates can be implemented. While Peak Time Rebates may be more attractive to customers, Peak Time Rebates are more administratively burdensome because it requires the establishment of a counterfactual baseline level of usage. Evidence also indicates that Peak Time Rebates are less effective in reducing load than CPP.

with customer risk tolerance and potential of incurring higher bills. Also, the penetration and location of EVs are generally not well known to Pepco, and without changes to EV tracking and reporting, it will be challenging for Pepco to reach new customers with any EV-specific rate design.[27] Rate designs that require customers to opt-in can make it challenging to reach critical mass, which may be needed to reach timing and locational-related goals. In general, rate designs that require customers to proactively sign up have much lower enrollment levels than rates onto which customers are defaulted (i.e., "opt-out" rates).

Policy Considerations

Rates can be designed to address policy priorities, such as adoption of EVs or reduction of electricity use during hours when emissions are highest.

Recommendation #3: Implement additional time- and location-varying rates to appeal to customers with various types of DERs, including solar and batteries.

The Study Team recommends that the results of this Value of DER study be used to guide the development of rates that reflect costs to supply electricity service across time and location. Rates of varying complexity can be offered to customers with different levels of sophistication, allowing customers to opt into the rate that best aligns with their preferences. Rate development can include calculations of the value of relief offered by different types of resources at different times; the District can apply this data to better inform the EV TOU rate design or help develop additional rates. For example, whole-house TOU rates can be offered alongside locational CPP rates (where the timing of peak events varies by location according to local distribution needs.) Further, EV customers could be allowed to separately meter their EV load, which may encourage more customers to sign up for the rate.

The DC PSC may also wish to consider gradually requiring net metering customers to take service on a time-varying rate to reflect the value of solar and encourage customers to install solar in a direction (e.g., west-facing) that maximizes the value to the grid.

VDER Tariffs

Financial Considerations

VDER tariffs can present an additional cost, depending on the design. Rate designs can be resource-specific or resource-agnostic.

[27] Some utilities offer incentives (e.g., $50 gift cards) for EV customers to notify the utility that they own an EV. This enables the utility to more easily identify EV owners, market rate design information to the customer, and potentially identify the need for future grid upgrades on a circuit.

Technical/Administrative Considerations

Utilities are typically the administrators. Participation is usually voluntary, which means that sufficient resources may or may not materialize in the timeframe needed.

Participant Considerations

VDER tariffs can be applied broadly to customers, such as Residential and Commercial customers, and third parties. They are a newer type of compensation mechanism, so they may require more customer education to enable participation.

Policy Considerations

Like incentives and rebates and rate designs, VDER tariffs can be designed to address policy priorities.

Recommendation #4: Develop VDER tariffs for technologies that can export to the grid.

VDER retail tariffs can provide a highly granular price signal that is capable of much more accurately compensating resources than traditional net metering tariffs or other rate designs. These tariffs may have a locational component wherein resources installed in a certain area are compensated more highly (perhaps up to a MW cap).

To date, VDER tariffs have only been applied to technologies that export energy to the grid, rather than to consumption from the grid or DERs such as energy efficiency and demand response. In New York, the VDER tariff (which reflects the "value stack") was designed primarily to replace the net metering tariff with a more accurate and efficient compensation model. In its 2017 order on the value of DER, the New York Public Service Commission determined it was appropriate to exclude energy efficiency and demand response from eligibility for the VDER tariff, noting that such resources "are eligible for participation in other existing tariffs and programs that reflect cost-benefit principles" and that allowing such resources to participate in the VDER tariff "could lead to overlapping compensation, opportunities for uneconomic arbitrage, and market confusion."[28]

A similar situation could materialize in the District, whereby energy efficiency and demand response resources are currently deployed through ratepayer-funded programs that use a benefit-cost analysis framework. Although these resources could conceivably be funded through a VDER tariff, there are multiple benefits to having utilities or third-party program administrators continue to provide these resources through incentive/rebate programs, rather than through a VDER tariff. One of the chief advantages of incentive/rebate programs over VDER tariffs is that utilities or third-party program administrators can use programs to achieve wider policy goals and overcome market failures, such as ensuring that low-income customers are not left out, and addressing split incentives (for example, where a landlord controls the efficiency of building appliances, but a renter pays the utility bills).

[28] New York Public Service Commission. Order on Net Energy Metering Transition, Phase One of Value of Distributed Energy Resources, and Related Matters. Cases 15-E-0751 and 15-E-0082. March 9, 2017, at 45.

It is important to note that the District's current definition of DER does not exclude fossil fuel generation. As a result, the District will need to decide whether fossil fuel generation should be eligible for VDER tariffs.[29]

Recommendation #5: Consider implementing various complexity levels in a VDER tariff, or pairing VDER tariff options with other compensation options to appeal to customers with different preferences.

The more complex a VDER tariff is, the narrower its appeal is likely to be to different types of customers. New York's VDER tariff is quite complex, with compensation for energy based on day-ahead locational marginal prices, three options for compensation for generation capacity, and a locational component. While a large company with battery storage and a dedicated energy manager may be able to easily shift load throughout the day in order to discharge energy from its storage system when market prices are high or when it would be compensated for generation capacity contributions, a residential customer with a small home battery is less likely to participate in such a complex mechanism unless the customer subscribes to a service to manage such transactions for them. While this level of complexity may be a barrier for some, it also reflects the complexity of the actual market. It may be beneficial for some highly interested and responsive consumers to have the option to be market responsive, as is sometimes facilitated by relatively complex tariffs.

To address differing customer preferences, the District could implement different tiers of complexity of VDER tariffs, or it could offer a VDER tariff alongside other compensation mechanisms such as more sophisticated rate designs. For example, New York's VDER tariff offers three different options for compensation for wholesale market generation capacity. The first option provides a levelized credit (in $/kWh) for resources based on the expected coincidence of solar PV generation with the system peak hour. The second option provides resources with a $/kWh credit for generation during pre-set windows in the summer when the peak is most likely to occur. The third option, which is mandatory for dispatchable generation, is based on the actual output of the resource during the peak hour.[30] The District can design a VDER tariff based on the wholesale market and distribution system values. Alternatively, the District could rely on more sophisticated rate designs (such as feeder-specific critical peak pricing) to compensate customers who do not wish to participate in a VDER tariff.

[29] District of Columbia Municipal Regulations at 15 DCMR § 999 provide the following definition: "Distributed energy resource" or "DER" – A resource sited close to the customer's load that can provide all or some of the customer's energy needs, can also be used by the system to either reduce demand (such as demand response) or increase supply to satisfy the energy, capacity, and/or ancillary service needs of the distribution or transmission system. Types of DER include, but are not limited to: photovoltaic solar, wind, cogeneration, energy storage, demand response, electric vehicles, microturbines, biomass, waste-to-energy, generating facilities, and energy efficiency.

[30] ConEdison. Components and Eligibility for the VDER Value Stack. Available at https://www.coned.com/-/media/files/coned/documents/save-energy-money/using-private-generation/specs-and-tariffs/components-value-stack.pdf?la=en.

Contracts with DER Providers

Financial Considerations

Contracts with DER providers are typically resource-specific and impose an additional cost. Contracts can be useful for revealing the range of current pricing for new DER measures, or resources for which costs have recently changed.

Technical/Administrative Considerations

Utilities are typically the administrators and will prepare and release an RFP for service and evaluate responses to that RFP. This mechanism can be useful for procuring a certain amount of one or more specific resources in a specific timeframe.

Participant Considerations

Third parties respond to RFPs issued by the utility and, when the pool of respondents is competitive, these parties need to be relatively well established and sophisticated to be selected. This mechanism can include penalties for non-performance.

Policy Considerations

The DC PSC can encourage the administrator to include one or more policy considerations in its RFP and prioritize certain policy considerations in its evaluation of the responses.

Recommendation #6: Use RFPs and contracts with DER providers where specific solutions are required to address feeder-specific pressures. Pursue RFPs after other low-cost mechanisms (such as energy efficiency programs and rate design) are employed.

Utilities frequently use competitive solicitations through RFPs to procure DERs for specific non-wires solutions projects. For example, in New York, the utilities have issued multiple RFPs to procure DERs for non-wires solutions. In the District, Pepco has also begun to use this approach to procure DERs where it is cost-effective. In 2020 and 2021, Pepco issued an RFP that sought DERs to address a locational pressure at the Waterfront Substation. Pepco received 12 responses from diverse resources, including solar, storage, and demand response; but those that were deemed viable did not provide positive net benefits after application of Pepco's benefit-cost analysis.[31]

Although Pepco's initial non-wires solutions procurement process has yet to bear fruit, this model will potentially identify cost-effective DERs in the future. Competitive solicitations are useful for identifying solutions that need to be implemented relatively quickly and with certainty, as the contract can require that the resources are installed and operable by a certain date and can assess penalties for non-performance. In contrast, utility rate designs and VDER tariffs provide no guarantee that sufficient

[31] Pepco. FC 1130. Update to its DSP/NWA Process. December 10, 2021.

resources will materialize, or that the resources will show up when needed. On the other hand, contracts for DERs may require sophisticated DER providers (although these providers may aggregate multiple types of customers) which may limit the number of customers reached.

In the future, DER providers and aggregators will likely use a variety of resources when responding to RFPs, including battery storage, demand response, and potentially energy from EV batteries (using vehicle to grid, V2G, technology). The District should continue to rely on RFPs to enter into contracts with DER providers for specific non-wires solutions where timing and dispatchability of the resource are paramount. RFPs can help with price discovery, especially for third-party solutions. However, this mechanism may be higher cost than the others and it requires numerous responses to provide competition and choice. Prior to issuing RFPs, the DC PSC should pursue other forms of DER compensation as this is likely to address many pressures more cost-effectively.

7.3. Distribution System Planning Enhancements

Pepco initiates planning for a distribution capacity upgrade when its 10-year forecasting process identifies a capacity need (i.e., when expected peak load exceeds the capacity of existing distribution equipment). Currently, Pepco conducts a short-range peak load forecast (for future years 1–3) for distribution feeders, substation transformers, and substations, as well as a long-range peak load forecast for years 4–10. The short-range peak load forecasts include estimated impacts from DERs and expected new load growth, as well as low-cost mitigation strategies such as load transfers. Pepco summarizes these forecasts at the substation level in its Annual Consolidated Report.[32]

The next step in Pepco's planning process is to model each feeder using power flow analysis software to identify potential violations (e.g., thermal overloads or low voltage) and determine whether each distribution system component can reliably serve the forecasted peak loads. Once it identifies potential violations, Pepco considers mitigation options, including:

1) Operational measures: Resetting relay limits, conducting phase balancing, or other measures;

2) Load transfers: Conducting field switching to transfer load from a higher-loaded feeder to a lower-loaded feeder;

3) Short-range construction projects: Implementing feeder extensions, installation of capacitors or voltage regulators, reconductoring, and NWA solutions; and

[32] The 2023 Annual Consolidated Report noted that COVID-19 has had significant effects on load in the District of Columbia, especially commercial load. The cause of this is thought to be a continuation of hybrid work schedules. Whether, and how rapidly, load returns to pre-COVID "normal" cannot be determined with any certainty at this time. This adds a degree of uncertainty to load forecasting in the District.

4) Long-range construction projects: Implementing new feeder extensions, new substation transformers or entirely new substations, and NWA solutions.

Increased investment in firm DER resources can reduce the need for all four types of mitigation. However, this report focuses on DER promotion measures intended to address the fourth category of mitigation options (long-range distribution utility construction projects) with the aim of deferring such projects when deferral is cost-effective. Targeted DER intiatives to address this category of mitigation require time to develop and implement.

There are several areas where Pepco could enhance its distribution system planning to support the development of cost-effective DERs through greater information sharing. For example, Pepco could improve the availability of information regarding potential long-term future distribution-system needs that do not rise to the level at which they would be identified in Pepco's Locational Constraints Report and addressed through a formal RFP through Pepco's existing NWA process. Additional examples are addressed below.

Data Regarding Distribution System Needs

Pepco's Annual Consolidated Report summarizes long-term peak load forecasts at the substation level. More granular information regarding the forecasted hourly demand of individual feeders or substation transformers would enable stakeholders to better understand what types of DERs might best address future grid needs.

Currently, granular information including projected grid pressures (e.g., feeders projected to be within 70 percent of normal rating within the planning horizon) is not available to stakeholders.[33] Additional information that would improve transparency and facilitate the deployment of DERs includes:

- Normal and emergency ratings for all feeders and current and projected proximity to such ratings;
- Full 8,760 load curves for multiple years for feeders currently or projected to exceed 70 percent of normal ratings;
- Estimated residential, commercial, and industrial percentages of load on each feeder;
- Details on the assumptions about expected electrification, both vehicles and buildings, for each feeder;
- Assessment of the likelihood of future violations; and

[33] Although the Locational Constraints Report highlights distribution-system constraints that have a high likelihood of occurring and resulting in the need for a potential upgrade, there may be missed opportunities in identifying locations with potential needs but less certainty. The recommendations regarding greater information availability would help address this.

- An accounting of capacity constraints that Pepco is addressing, or plans to address, through low-cost mitigation measures, such as load transfers or other operational measures, so that stakeholders understand which pressures will likely be resolved through such measures and would not require DER solutions.

It would also be beneficial for a standard data transfer protocol to exist for all of the above data, and for exported power flow models to exist so that these data are available to DC PSC and any authorized stakeholders in a consistent, accessible format.

DER Forecasting

In addition to the enhanced data transparency recommendations above, it is critical that stakeholders understand the underlying assumptions regarding DERs that underpin Pepco's load forecasts and projected grid needs. In particular, the identification of grid needs will require clarification of the extent to which both short- and long-term load forecasts reflect building electrification load growth, vehicle electrification load growth, energy efficiency, demand response, solar programs, and new technologies such as smart inverters. The Study Team recommends greater coordination among stakeholders regarding the load forecasts used in Pepco's planning process (including impacts of existing energy efficiency, demand response, solar, and EV programs). With regard to vehicle electrification growth, Pepco should ensure that circuit-level load growth is monitored on an on-going basis. This should include tracking of the location and capacity of new high-powered EV chargers.

In addition, Pepco, the DC SEU, and third-party providers should apply the VDER framework and values to evaluate the economic and available potential of DER solutions to address future distribution system constraints for the District and adjust program designs or develop new programs to access this potential. Program designs should address temporal and spatial characteristics of the capacity pressures. In addition, this avoided cost study should be refreshed regularly (e.g., every three to five years). Also, it would be beneficial to establish well-defined annual data updates to be provided by Pepco to DC PSC that can be loaded into a framework that automatically updates the load profile of emerging constraints.

When evaluating the economic potential and cost-effectiveness of DERs, it would also be advantageous to understand the avoided costs of traditional utility solutions. Although the Annual Consolidated Report provides total project costs and annual budgets for approved distribution projects, these values are not presented on a unit basis (e.g., $/kW-year), which would enable comparison across various solutions. Further, the cost information in the Annual Consolidated Report appears to only cover near-term projects that are unlikely to be avoided by DERs due to timing, rather than long-term grid upgrades that have a greater potential for deferral or avoidance through DER deployments. While long-term utility upgrade costs may be difficult to develop, even a ballpark or range of costs would facilitate the identification of potentially cost-effective DERs.

7.4. Other Considerations

These recommendations exist in a complex market context that includes the following important factors which also ought to be considered when designing solutions:

- Complex Distributed Systems: DERs are part of a complex system and require whole system design, which may include standards, communications, and coordinated operations. In the future, DERs may require more coordinated dispatch that is aligned with the needs of the grid in real time. The grid is one of the few systems that operates at near the speed of light. Active DERs need to fit into this system via a communications layer that has low latency and high reliability and must send and receive data in standardized ways to facilitate interoperability. Centralized modeling and control systems will also be helpful, including smart systems that can rapidly determine emerging needs and evaluate how to balance needs across the grid. One important challenge to bear in mind is balancing needs of the distribution system while accounting for the regional situation upstream. While we do not discuss these systems in detail in this report, these kinds of broader systems will need to be considered to support appropriate coordination and interoperability across distributed energy resources and ensure resources across these complex systems are optimized.

- Increasing Resilience Risks: Energy distribution systems are facing greater risks from what once were considered "once-in-a-hundred year" events. From superstorms to the risk of cyber and physical attacks, to out-of-season or extreme heat and cold, the operating environment is changing, and it is more necessary than ever to ask "what if" questions in regard to systems designs, asking whether the system will be able to function when these kinds of events occur, as well as thinking about (likely inevitable) restoration efforts. In addition, there are some endogenous risks arising from the emerging distributed systems themselves; specifically, as loads become more flexible, designs will need to consider the impact of coincident demand on various circuits. Time-of-use rates in particular should be studied to avoid a situation where all EVs, battery banks, precooling systems, etc. are set to begin operations at the same time creating a potentially unmanageable coincident demand when a low-cost rate period begins. While time-of-use rates provide strong static price signals, those signals may not reflect the high variability and dynamic nature of tomorrow's high DER environment. For these systems, intentionally designed asynchronous timing will be required to support efficient use of grid resources. While we do include a value for solutions designed to provide resilience in this report, we do not discuss the types of measures that may provide resilience in detail. DC PSC may want to assess whether a combination of feeder-specific, dynamic pricing or control signals would provide the essential flexibility for coordinating both utility and consumer resources for optimal operation of the grid during resilience events, along with other potential resilience measures.

- Beneficial Loads: Load flexibility will likely increase in value as renewable generation increases and more atypical events occur across the energy delivery supply chain, as may be anticipated because of climate change and simply as a function of the energy systems transition itself. To provide load flexibility, targeted programming may be needed for major systems like the water utility, streetlights, public transit, and any similar large and broad loads that are centrally managed. If these loads can become more flexible, they can potentially provide similarly large and broad benefits to the rest of the system during either normal or emergency operation. In addition, as buildings electrify, we suggest bearing in mind that with proper systems in place buildings can be supply (rooftop PV, back up generation), storage (battery, EV, thermal), and flexible load (pre-cooling, variable lighting). Coordination of all these resources will be essential to maximize benefits to consumers.

- Infrastructure Capital Cycles: The distribution system is a collection of many thousands of assets that each have a lifecycle and an investment logic. Investment decisions often represent long-term plans and the costs of the current system reflect all prior investment decisions. Accordingly, there are more and less opportune times to intervene in the system. For example, DER solutions cannot defer or avoid an infrastructure investment that has already occurred. Similarly, if an infrastructure investment will be required because of aging equipment reaching the end of its useful life or to address reliability concerns, that investment may not be possible to defer or avoid. These kinds of issues will be feeder specific and are relevant considerations when developing guidance for the utility or designing programs and market mechanisms aimed at engaging third-party solutions. Though both have value, DER compensation must reflect whether an investment can actually be avoided or merely deferred. Longer-term planning horizons and annual monitoring of feeder pressures can help identify upcoming pressures as early as possible, giving cost competitive DERs the greatest opportunity to respond.

- Price Uncertainty: When modeling future prices in wholesale markets and when pricing compensation for greenhouse gas curtailment, there is a high level of uncertainty. For example, it is unclear whether PJM, the regional system operator, will continue to rely on generation and transmission capacity markets in the future in the same way as they are currently employed, and if these markets continue to exist it is unclear when the peak times will be and how many hours will be required of capacity-supporting resources. Because the market for regional capacity is evolving, it will be beneficial to track these developments and ensure that the local market designs align with these evolving conditions.

7.5. Additional Research and Activities

This study reveals additional opportunities for research and activities to support the development and implementation of DER compensation mechanisms. A summary of these opportunities follows.

1. The Study Team used a system-level average value of avoided distribution cost from Pepco of $385,500 per MW-year in 2020 dollars and applied it to all additional distribution capacity requirements. Further analysis could provide more precise estimates for avoided distribution costs for the feeder types analyzed in this study. Also, it would be more accurate to have an avoided distribution cost that is more targeted to instances when the pressure on feeders exceeds some threshold (i.e., the normal rating). This value would be higher than $385,500 per MW-year but applied to fewer MWh as the analysis would only focus on the instances when the pressures exceed the normal rating of the feeder.
2. Monitoring and management options for needle peaks merits further analysis because the value of better targeting and remediating these peaks is high. On feeders where a few hours are driving infrastructure investment, further research into the causes and potential remedies may elucidate high value solutions for these few hours with such high costs.
3. Many of the feeders in this study were radial feeders with evening peaks, indicating a probable prevalence of residential load. The assumptions for EVs and building electrification relied on data sets focused on residential consumers, personal vehicles and electrification, and relief of residential loads. While these findings are likely applicable with some margin of error to a commercial context, more detailed modeling of specific commercial building and vehicle scenarios would be beneficial. Similarly, additional value for DERs may be discovered in specific industrial or campus scenarios, though these are likely to be somewhat idiosyncratic.
4. There is a significant and likely cost-effective opportunity to couple electrification with energy efficiency and grid-responsiveness. Demonstration projects showing grid responsiveness at site and at community scale would be beneficial to demonstrate economic and technical feasibility for grid responsive buildings and clarifying the incremental costs of these measures on top of standard electrification (and efficiency) measures. The development of grid-interactive building codes for new and substantially renovated older buildings may also be beneficial.
5. Better data on the penetration and location of EVs and EV chargers is needed. Required reporting for high power EV chargers and/or other substantial new loads that might impact distribution circuit reliability may be beneficial.
6. Synthetic feeder modeling is a way of managing feeder data that provides anonymized data on feeders that can support scenario simulation and research on specific feeder situations without disclosing sensitive information about actual feeders. Further

investigation of the potential to apply this approach to Pepco feeder data could yield extensive, easily accessible, and usable information for many stakeholders to be able to engage in VDER conversations as discussions of pressure and relief situations become more common.

7. Data availability limited the Study Team's ability to conduct power flow modeling of LVAC feeders for this study. It may be worthwhile to resolve the data access, delivery, and modeling challenges for a variety of reasons, as well as to close the loop on evaluating how DERs show up on these feeders in greater detail.
8. The modeling of building energy efficiency retrofits in this report considered an aggregated energy efficiency retrofit package containing multiple measures. It may be possible to identify a hierarchy of impact values for specific measures of the retrofit package. For example, determining if envelope upgrades, a more efficient heat pump, or a grid-responsive hot water heater would be most valuable on specific feeders would facilitate prioritization of the highest value measures.
9. This study included load shaping and load flexibility. It may be valuable to also assess the potential for short-term periodic load shifting in response to specific events, especially for EVs. This kind of demand response measure represents a short-to-medium-term and market-oriented load responsiveness that would lead to avoidance of charging during the hours when the wholesale market is likely to peak (July and August weekdays, 2-7 pm in this study). This value is somewhat captured in the load flexibility scenario, but in terms of the actual planning and behavior it may represent an additional scenario worth separate consideration; In this case, analysis might entail implementing load shaping, load shifting, and load flexibility as sequential layers to achieve an even more optimized relief scenario.

Appendix A. Detailed Description of VDER Framework and Impacts

The purpose of this section is to provide a more detailed description of a framework for appropriately valuing the services provided by DERs in the District of Columbia. In developing this framework, the Study Team reviewed and considered methodologies and guidance from numerous sources, including:

- VDER methodologies from other jurisdictions (as described in Appendix B);
- The *National Standard Practice Manual for Benefit-Cost Analysis for Distributed Energy Resources* (NSPM for DERs);[34]
- The recommendations of the Clean Energy Act Implementation (CEAI) Working Group;[35]
- Pepco's 2020 *Benefit-to-Cost Analysis Handbook for Locational Constraint Solutions;*[36]and
- Current practices for assessing cost-effectiveness analysis of District energy efficiency and demand response programs, including those operated by the DCSEU.[37,38]

In developing a framework, the Study Team sought to leverage the methodologies and practices that were (1) most applicable to the District of Columbia and consistent with its policy goals, and (2) reasonably accurate while avoiding excessive effort and cost.

This description starts with a discussion of the relevant study period and discount rate. It discusses the utility system impacts, including (1) a description of the impact, (2) the method by which the impact should be valued, and (3) the estimated value from our analysis. It then does the same for the societal impacts, using the same structure for the discussion. The estimated DER values use District-specific data; a variety of electricity market, emissions, and customer interruption models; and, where necessary, proxy values from other jurisdictions. Where an impact tends to apply to certain types of DERs more than others, the Study Team has noted the applicability of the impact.

[34] National Energy Screening Project. 2020. *National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources*. Edition 1. Available at: https://www.nationalenergyscreeningproject.org/national-standard-practice-manual/.

[35] Clean Energy Act Implementation Working Group. 2021. Framework for Compliance with the Clean Energy Omnibus Amendment Act of 2018 (the CEDC Act) of the District of Columbia. Case No. GD-2019-04-M.

[36] Pepco. 2020. *Benefit-to-Cost Analysis Handbook for Locational Constraint Solutions.*

[37] NMR Group, Inc. 2021. *DCSEU FY2020 Performance Benchmarks Report*. Submitted to the District of Columbia Department of Energy and Environment.

[38] Synapse also reviewed FC1160 and understands that Pepco plans to use the DCSEU BCA inputs to assess the cost-effectiveness of its energy efficiency and demand response programs.

A.1. Choice of Study Discount Rate and Study Period

Discount Rate

A discount rate is used to convert future dollars into present value dollars. The choice of a study discount rate reflects a time preference, where a higher discount rate gives more value to short-term impacts and a lower discount rate places more emphasis on the long term. Thus, a higher study discount rate values benefits occurring in the near term much more than benefits occurring in the future, while a lower study discount rate values benefits in the near term and future more equally.

The choice of study discount rate for a VDER analysis is primarily a policy decision about the weight given future ratepayers versus ratepayers today. A jurisdiction's policy goals should inform the choice of discount rate. [39] For example, where a jurisdiction prioritizes addressing long-term societal impacts such as climate change, a lower study discount rate may be most appropriate. The purpose of the societal cost test is to indicate whether the benefits of an energy efficiency resource will exceed its costs from the perspective of society as a whole.[40]

This study explores the full range of discount rate options, along with a range of values for the social cost of carbon, to illustrate the impact of changes to these two factors on net present value benefits.

- A low benefits case applies a real discount rate of 7 percent and a low cost of carbon.
- A high benefits case uses a real discount rate of 2 percent and a high cost of carbon.
- A mid benefits case includes a real discount rate of 3 percent and a cost of carbon that is between the low and high carbon costs.

The low, mid, and high carbon costs selected for these cases are explained in the section further along in this appendix titled "Greenhouse Gas Emissions: Generation."

It is important to note that we discuss two discount rates and that these two discount rates can be different. This section discusses the study discount rate. There is also a carbon cost discount rate used in the carbon cost calculations. The section on Greenhouse Gas Emissions: Generation documents the discount rates used to calculate low, mid, and high carbon costs. A social discount rate (typically a lower discount rate) is used as the carbon cost discount rate as it reflects the rate at which society is willing to

[39] National Energy Screening Project. 2020. *National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources.* Edition 1. Available at: https://www.nationalenergyscreeningproject.org/national-standard-practice-manual/. At pg. 5-16 to 5-17.

[40] This test provides the most comprehensive picture of the total impacts of an energy efficiency resource and is useful for identifying the total universe of economic impacts of investment in energy efficiency resources. It is particularly apt for jurisdictions that have particular interest in a range of societal considerations, such as environmental or economic development concerns, in addition to an interest in minimizing utility system and efficiency program participant costs. The societal cost test includes all costs described above for the total resource cost test, plus any costs incurred by society, including environmental costs and reduced economic development.

trade off a value received today with a value received in the future. A social discount rate is more appropriate for decisions regarding public safety and welfare, such as global climate change.[41]

Study Period

The study period refers to the number of years over which the analysis assesses the benefits and costs. The study period should be long enough to capture the full stream of costs and benefits associated with the life of the suite of DERs under consideration. The Study Team chose a study period of 2023–2045, as this period approximates the expected lifespan of distributed solar[42] and is long enough to capture the lifespan of multiple other DERs, including many energy efficiency measures and batteries.[43]

A.2. Utility System Impacts

The avoided costs to the utility system (including wholesale markets) are the most apparent and quantifiable benefits provided by DERs, and in many cases are regularly quantified in energy efficiency cost-effectiveness analyses. Many of these impacts have direct implications for rates paid by all utility customers, such as through the avoidance of generation capacity procurement. Others have indirect impacts on ratepayers, such as through enhancement of reliability. Table 10 lists the key utility system impacts and provides a short description of each. The following sections then discuss these impacts in more detail.

[41] New York State Department of Environmental Conservation. 2022. *Value of Carbon Guidance 2022 Update*. Pages 17-20. Available at: https://www.dec.ny.gov/docs/administration_pdf/vocguid22.pdf.

[42] Solar panel manufacturers warrantees typically last 25 years. *See:* Kurtz, et al. *Photovoltaic Module Qualification Plus Testing*. National Renewable Energy Laboratory. NREL/TP-5200-60950. December 2013. Available at https://www.nrel.gov/docs/fy14osti/60950.pdf.

[43] For example, lithium-ion batteries generally have warrantees for about 7 years. *See:* National Rural Electric Cooperative Association, National Rural Utilities Cooperative Finance Corporation, CoBank, and NRTC. Battery Energy Storage Overview. Business & Technology Report, April 2019. Available at: https://www.cooperative.com/programs-services/bts/documents/reports/battery-energy-storage-overview-report-update-april-2019.pdf.

Table 10. Overview of Utility System Impacts

Type of Impact		Impact Description
Energy	Energy Generation	Cost of producing or procuring energy from generation resources on behalf of customers
	Energy Demand Reduction Induced Price Effects (DRIPE)	Price effect in the wholesale markets caused by a reduction or increase in demand
	Environmental Compliance	Costs to comply with environmental regulations
	Renewable Portfolio Standard Compliance	Increase or decrease in cost of compliance with renewable portfolio standards (RPS)
	Ancillary Services	Services required to maintain electric grid stability and power quality (i.e., frequency regulation, voltage regulation, spinning reserves, and operating reserves)
	Market Price Risk Reduction	Risk of fuel price volatility
Generation Capacity		Cost of generation capacity required to meet the forecasted system peak load
Transmission	Transmission Capacity	Cost to construct and maintain the high-voltage transmission system to transport electricity safely and reliably
	System Losses	Cost associated with electricity lost through the transmission system
Distribution	Distribution Capacity	Cost of substation and distribution line infrastructure to meet customer electricity demand
	System Losses	Cost associated with electricity lost through the distribution system
	Operations and Maintenance (O&M)	Expenses to maintain safe and reliable operation of distribution facilities
	Voltage	Cost of voltage regulation needed to ensure reliable and continuous electricity flow across the power grid
Other	Utility DER Procurement and Program Administration Costs	Cost of utility procurement and administration of DERs, through utility ownership, financial incentives to host customers, or developer contracts; may also include administrative costs such as outreach to trade allies, technical training, marketing, payments to third-party consultants, and other administrative costs
	Utility Performance Incentives	Cost of incentives offered to the utility to encourage successful, effective implementation of DER programs
	Credit and Collections	Changes in utility costs associated with arrearages and bad debt
	Construction and Procurement Cost Risk	Risks associated with construction and procurement cost volatility
	Reliability	Value of maintaining generation, transmission, and distribution system to withstand instability, uncontrolled events, cascading failures, or unanticipated loss of system components; this category reflects the value above that which is already included in standard system design and operation

Energy Generation, Generation Capacity, and Ancillary Services Costs

Description

Avoided energy costs are the costs associated with producing the energy that would have been consumed were it not for the DER under consideration. The value of the avoided energy costs depends on the conditions of the broader electric power grid. The specific physical infrastructure, system load, time of day, congestion on the transmission system, and several other factors determine which electric resource operates on the margin and would therefore be displaced due to the DER. That marginal generator's avoided fuel costs and avoided variable operations and maintenance costs represent the avoided energy benefit within that hour. For the District of Columbia, the operation of the PJM wholesale market determines this value.

Generation capacity costs reflect the cost of meeting peak load for each year, plus a reserve to account for planned and unplanned outages in generation or transmission, as well as any forecast errors due to unseasonable weather or other factors. As a member of PJM, Pepco and other electricity suppliers procure generation capacity through the PJM Reliability Pricing Model (RPM) capacity auction, proportional to the District's expected load at the hour of PJM's coincident peak load, which typically occurs during summer afternoons.

Ancillary services help to maintain reliability of the transmission system and support the transmission of electric power from sellers to purchasers. Electricity suppliers in the District must procure regulation and reserves through PJM's ancillary services market. These costs are generally a small fraction of energy and generation capacity costs.

Method

The methodology and key assumptions for determining these avoided costs are described in Appendix C.

Value

Table 11 below shows the average annual avoided energy generation, generation capacity, and ancillary service costs in 2020$/MWh. The marginal energy costs represent the wholesale market clearing price for energy production in each hour. At an annual level, these are weighted by hourly generation to reflect variation in the quantity of energy purchased in each hour. In general, costs are expected to decline in the near-to mid-term, before beginning to rise again by the end of the decade.

The marginal generation capacity costs represent the market clearing price in the PJM capacity market. A unit's bid into the generation capacity market is the levelized capital and fixed cost of the unit less the profits that the unit could earn from the energy and ancillary service markets. The quantity of generation capacity that load-serving entities in PJM are required to procure from the market is based on annual peak demands. Because the exact time and date of the peak demand is unknown in advance, the Study Team analyzed the expected timing of the top 100 load hours in each year over the study period. This analysis revealed that approximately 84 percent of these top 100 load hours occur between the hours of 1 pm and 7 pm during the months of July and August. Thus, the Study Team apportioned the generation capacity costs for each year over weekday hours in July and August from 1 pm to 7 pm (a total of 266 hours each year).

EnCompass modeling of ancillary services includes regulation (up and down), spinning and non-spinning reserves, and supplemental reserves (up and down). For the PEPCO zone, the supplemental reserve prices and regulation down price were zero. The spin and non-spin prices were identical.

Table 11. Annual Avoided Energy Generation, Generation Capacity, and Ancillary Services Costs

Year	Avoided Energy Generation Cost (2020$/MWh)	Avoided Generation Capacity Cost (2020$/kW-year)	Avoided Ancillary Services Cost (2020$/MWh)
2023	26	26	2
2024	24	33	2
2025	23	42	2
2026	23	39	2
2027	23	44	2
2028	24	57	3
2029	25	57	4
2030	26	57	5
2031	25	59	4
2032	26	51	5
2033	26	48	6
2034	26	47	6
2035	26	48	6
2036	27	51	6
2037	27	53	6
2038	27	56	7
2039	27	58	7
2040	27	61	8
2041	27	64	8
2042	28	47	9
2043	28	70	10
2044	28	74	10
2045	28	77	11

Application

The energy, generation capacity, and ancillary services value provided by each resource can be estimated by multiplying the DER's load reduction or generation profile by the modeled hourly energy, generation capacity, and ancillary services prices. However, the timing of when generation capacity benefits are realized depends on whether peak demand reductions are bid into the capacity market, as described below:

- Any resource that is bid into and clears PJM's capacity auction provides direct benefits. These benefits are equal to the cleared generation capacity multiplied by the applicable market clearing price. Note that if the generation capacity contribution is bid into the market by a customer or third-party DER owner, then the bulk of the benefits will be captured by the DER owner, rather than flowing to all customers.

- Resources that are not bid into the market indirectly reduce generation capacity requirements and supply costs over time by impacting PJM's load forecast. As load reductions from uncleared resources appear in the historical data, forecasts of peak demand (and thus generation capacity requirements, including reserve margins) are reduced. Thus, if the reserve margin is 16 percent, a 1 MW peak demand reduction results in a 1.16 MW reduction in capacity obligation. However, the impacts do not occur immediately. Because each annual generation capacity auction is performed three years in advance of a commitment period, and because there is a lag in terms of when changes to peak demand appear in the load forecast used for a capacity auction, this study assumes that benefits from uncleared generation capacity do not start until five years after they occur. Once the load reductions begin to impact the capacity requirement, they do so gradually, ramping up to 100 percent over approximately five years. If the load reductions cease, then the impact also phases out over time. Initially, the reduction in generation capacity obligations will likely be captured primarily by energy suppliers and will not flow through to customers. Over time, however, energy suppliers will likely reduce their prices to reflect the lower capacity procurement costs.

The cleared and uncleared generation capacity values for 2021–2035 are in Table 12 below. The uncleared capacity phase-in schedule is based on a resource installed in 2021 that continues to provide peak demand reductions through the study period. The modeling assumed a 16 percent target reserve margin for each year, based on PJM's approximate target reserve margins for the past decade for each capacity auction.[44]

[44] PJM. *2020 PJM Reserve Requirement Study. 11-year Planning Horizon: June 1st 2020 - May 31st 2031*. Analysis Performed by PJM Staff Reviewed by Resource Adequacy Analysis Subcommittee. October 6, 2020. Table I3: Historical RRS Parameters. Page 12. Available at: https://www.pjm.com/-/media/committees-groups/committees/pc/2020/20201006/20201006-item-05b-2020-pjm-reserve-requirement-study-draft.ashx.

Table 12. Cleared and Uncleared Generation Capacity Values

Year	Cleared Generation Capacity	Uncleared Generation Capacity			
	Generation Capacity (2020$/MWh, 266 hours)	*PJM Target Reserve Margin*	*Uncleared Generation Capacity Phase-In*	*Uncleared Generation Capacity (2020$/kW-yr)*	*Uncleared Generation Capacity (2020$/MWh, 266 hours)*
2023	97	16%	0%	0	0
2024	125	16%	0%	0	0
2025	156	16%	0%	0	0
2026	146	16%	30%	14	0
2027	166	16%	50%	26	0
2028	215	16%	70%	46	0
2029	216	16%	90%	60	0
2030	216	16%	100%	67	0
2031	220	16%	100%	68	0
2032	191	16%	100%	59	0
2033	180	16%	100%	55	0
2034	176	16%	100%	54	0
2035	182	16%	100%	56	0
2036	191	16%	100%	59	0
2037	200	16%	100%	62	0
2038	209	16%	100%	65	0
2039	219	16%	100%	68	0
2040	230	16%	100%	71	0
2041	241	16%	100%	74	0
2042	253	16%	100%	78	0
2043	265	16%	100%	82	0
2044	277	16%	100%	86	0
2045	291	16%	100%	90	0

Energy Demand Reduction Induced Price Effects (DRIPE)

Description

The Demand Reduction Induced Price Effect (DRIPE) is the price suppression that occurs in a competitive wholesale energy or generation capacity market when reduced demand results in a lower clearing price of energy or generation capacity, indirectly reducing the costs for all consumers. While the price reductions may be quite small, the total savings across all megawatt-hours (MWh) of energy or megawatts (MW) of generation capacity, expressed in dollars, can be substantial.[45] This study, however,

[45] Chernick, Paul and John J. Plunkett. 2014. "Price Effects as a Benefit of Energy-Efficiency Programs." Page 1. Available at: http://aceee.org/files/proceedings/2014/data/papers/5-1047.pdf.

focuses on the benefits that accrue to customers in the District of Columbia, which amounts to approximately 1.5 percent of PJM's total load and thus a similar proportion of the price reduction benefits. In addition, the benefits of DRIPE tend to be temporary—they may dissipate over a few years as the marketplace re-equilibrates to the lower level of demand. For example, if energy revenues decline, generation owners may invest less in the maintenance of their units, resulting in more frequent outages and higher energy prices. Further, customers may respond to lower energy prices by increasing consumption, pushing prices upward.

Method

This study modeled the change in wholesale market prices due to a hypothetical reduction in District energy consumption and peak demand of approximately 9 percent and 4.5 percent, respectively. The change in prices due to the reduction in energy consumption and peak demand is the price effect due to DERs that reduce load or peak demand. This can be expressed as an elasticity:

$$\varepsilon = \frac{\%\ \Delta\ Price}{\%\ \Delta\ Demand}$$

This can then be expressed on a $/MWh or $/MW basis. Because the market clearing price is reduced for all load in the District, the value is then multiplied by the energy or generation capacity needs of the District to determine the total impact.

Value

The modeling indicated an energy market elasticity of approximately 0.11 percent, meaning that a reduction in zonal load of 1 percent leads to a reduction in the zonal energy market clearing price of 0.11 percent. While this is a relatively small change, the impacts are felt across the total quantity of energy purchased in each hour, resulting in a considerable impact per MWh of load reduction. Over the study period, the Study Team estimated that reducing load by one MWh would provide benefits to customers in the District of Columbia of approximately $1.50 for the energy market. However, no beneficial price effect was observed for the capacity market.

Due to the relatively minor reduction in the energy market clearing price, a material change in behavior from generating unit owners or customers that would cause the price effect to significantly dissipate is unlikely. This study therefore assumed that the price effect would remain for the entirety of the study period.

Table 13. Avoided Energy and Generation Capacity Demand Reduction Induced Price Effects (DRIPE)

Year	Avoided Energy DRIPE (2020$/MWh)	Avoided Generation Capacity DRIPE (2020$/kW-yr)
2023	2	0
2024	1	0
2025	1	0
2026	1	0
2027	1	0
2028	1	0
2029	1	0
2030	1	0
2031	1	0
2032	1	0
2033	1	0
2034	1	0
2035	1	0
2036	1	0
2037	1	0
2038	1	0
2039	1	0
2040	2	0
2041	2	0
2042	2	0
2043	2	0
2044	2	0
2045	2	0

Application

Any DER that reduces wholesale energy and generation capacity purchases will theoretically lower the market clearing price.

Environmental Compliance

Description

Electric generation units are subject to a variety of federal and state regulations related to criteria pollutants. Compliance with these regulations typically involves the purchase and retirement of criteria pollutant or carbon emissions allowances. Therefore, renewable or load reducing DERs can help avoid compliance costs associated with criteria pollutants or carbon allowances.

Similarly, the Regional Greenhouse Gas Initiative (RGGI), a regional carbon trading scheme, includes the PJM states of Maryland and Delaware. Every ton of carbon emissions from generators in those states comes with an additional cost ultimately passed on to energy purchasers. In hours when DERs result in less generation from fossil-fired generators located in Maryland and Delaware, those generators avoid RGGI compliance costs.

Method

The U.S. Environmental Protection Agency (EPA) regulates sulfur dioxide (SO_2), nitrogen oxides (NO_X) from power plants through cap-and trade programs. The cost of complying with the SO_2 and NO_X regulations is reflected in allowance prices for emissions covered under the Cross-State Air Pollution Rule (CSAPR) and the Acid Rain Program (ARP). Marginal reductions in criteria pollutants are calculated using the EnCompass model and are reflected in the modeled energy prices.

Similarly, the cost of compliance with RGGI is included in the energy market bids for generators in RGGI states, and thus is represented in the marginal energy prices produced by the EnCompass model.

Value

SO_2 prices have declined dramatically over the past decade and have hovered around $0.01/ton for the past several years. In 2021, the SO_2 spot auction cleared at a weighted average price of $0.013/ton, while the seven-year advance auction allowances cleared at $0.01/ton. The modeling assumed these prices will remain constant for the study period due to their stability in recent years and seven-year advance prices.

In 2021, EPA released an updated Cross-State Air Pollution Rule (CSAPR), which requires further ozone season NO_X emissions reductions for Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, New Jersey, New York, Ohio, Pennsylvania, Virginia, and West Virginia.[46] The marginal cost of mitigation using selective catalytic reduction to reduce NO_X was estimated to be $1,600/ton in 2021. Although prices spiked to $3,000/ton in March 2021,[47] the prices are expected to fall to the marginal cost of compliance (i.e., $1,600/ton).

Because the cost of compliance with NO_X, SO_X, and RGGI regulations are reflected in energy market prices, these values are not separately reported.

Renewable Portfolio Standard Compliance

Description

The District of Columbia's RPS includes a Tier I obligation that grows from 9.5 percent of sales in 2015 to 100 percent of sales in 2032 and thereafter. It contains a solar carve-out requirement that grows from 0.7 percent in 2015 to 5.5 percent in 2032, increasing by 0.65–0.7 percent annually until it reaches 15

[46] 86 FR 23054 (April 30, 2021 Final Rule), available at https://www.federalregister.gov/documents/2021/04/30/2021-05705/revised-cross-state-air-pollution-rule-update-for-the-2008-ozone-naaqs. Summary available at https://www.epa.gov/csapr/revised-cross-state-air-pollution-rule-update.

[47] ESAI Power, *Emissions Watch Blog*, Pennsylvania RGGI CO2 Limits, Illinois Energy Bill, and CSAPR Update, May 24, 2021, available at https://www.esaipower.com/pennsylvania-rggi-co2-limits/.

percent in 2041.[48] Every MWh of electricity generated by distributed solar avoids the purchase of a fraction of a Tier I Renewable Energy Credit (REC) and the fraction of a solar renewable energy credit (SREC) associated with that year. Currently, the District RPS allows Pepco DC to comply with the RPS using Tier I RECs purchased within PJM, or within an adjacent control area. SRECs, on the other hand, are only eligible if located in the District or if connected to a distribution feeder that feeds the District. Therefore, there is an ample quantity of RECs for use in RPS compliance in the District, but the supply of SRECs is much tighter.

Method

The Study Team developed the value of RPS compliance costs using the following two-step process.

> Step 1: Identify the annual RPS requirement (as percent of retail electric sales) over the study period by requirement (Tier 1 and Solar RECs).
>
> Step 2: Multiply the REC price forecast by the percentage of electric retail load that the supplier must meet from renewable energy under the RPS. For example, in a year where the REC price is $10 per MWh and the RPS target is 10 percent, the avoided RPS cost is $10 per MWh x 10 percent = $1.00 per MWh.

Value

For the Tier 1 REC price forecast, the Study Team recommends the use of the 2020 ICF REC price forecast developed for Dominion in Virginia.[49] The ICF REC price forecast is appropriate for use in DC because it is based on a comprehensive assessment of state-level RPS targets in PJM to forecast supply and demand for RECs across these states. The Study Team recommends use of the ICF moderate case REC price forecast because it accounts for likely policy changes in the near- and mid-term. Table 14 shows the Tier 1 REC price forecast, Tier 1 RPS requirement, and avoided Tier 1 REC costs derived by multiplying the REC price forecast by the Tier 1 RPS requirement.

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[48] Law Number L24-0314 went into effect on March 10, 2023; it increased the Solar Renewable Energy Portfolio Standard target increased from 10 percent to 15 percent by 2041. The Alternative Compliance Payment (ACP) schedule was also adjusted.

[49] ICF Resources, LLC. 2020. *Overview of PJM REC Price Forecasting*. Prepared for Dominion Energy Virginia. Virginia State Corporation Commission, Case Number PUR-2020-00035.

Table 14. Avoided Tier 1 REC Costs

Year	Tier 1 REC Price Forecast (2020$/MWh)	Tier 1 RPS Requirement (inclusive of Solar Carve-Out)	Avoided Tier 1 REC Costs (2020$/MWh)
2023	8	39%	3
2024	9	45%	4
2025	11	52%	5
2026	13	59%	7
2027	11	66%	7
2028	10	73%	7
2029	9	80%	6
2030	3	87%	3
2031	10	94%	9
2032	6	100%	6
2033	5	100%	4
2034	6	100%	6
2035	6	100%	5
2036	6	100%	5
2037	6	100%	5
2038	5	100%	5
2039	5	100%	4
2040	5	100%	4
2041	5	100%	4
2042	4	100%	4
2043	4	100%	4
2044	4	100%	3
2045	4	100%	3

For the SREC price forecast, this study used the same method as applied in the DCSEU's calculation for avoided costs for resources that modify load. Under the DCSEU methodology, the value is based on the difference between the SREC price and the RPS Alternative Compliance Payment (ACP).[50] This represents the savings from complying with the solar carve-out through SRECs as opposed to through the ACP. Only the difference between the SREC price and the ACP is counted as an avoided cost, however, since the SREC payment would likely flow to a DC resident and is therefore not a true cost to ratepayers. The SREC price should be based on the most recent year's average SREC trading price for the DC market and decreases in relation to the ACP over time. Table 15 shows the DCSEU Avoided Solar RPS Compliance Costs, local solar carve-out, and avoided SREC costs derived by multiplying the DCSEU Avoided Solar RPS Compliance Costs by the local solar carve-out.

[50] NMR Group, Inc. 2021. Appendix C.

Table 15. Avoided SREC Costs

Year	DCSEU Avoided Solar RPS Compliance Costs (2020$/MWh)	Local Solar Carve-Out	Avoided SREC Costs (2020$/MWh)
2023	110	3.00%	3
2024	90	3.65%	3
2025	90	4.30%	4
2026	90	5.00%	5
2027	90	5.65%	5
2028	90	6.30%	6
2029	70	7.00%	5
2030	70	7.65%	5
2031	70	8.30%	6
2032	70	9.00%	6
2033	0	9.65%	0
2034	0	10.30%	0
2035	0	11.00%	0
2036	0	11.65%	0
2037	0	12.30%	0
2038	0	13.00%	0
2039	0	13.65%	0
2040	0	14.30%	0
2041	0	15.00%	0
2042	0	15.00%	0
2043	0	15.00%	0
2044	0	15.00%	0
2045	0	15.00%	0

Application

DERs can impact the cost of compliance with RPS requirements by reducing or increasing retail electric load. A reduction in electric load from energy efficiency, solar, and other DERs can reduce RPS Tier 1 and Solar RPS obligations and the associated compliance costs. Solar DERs explicitly avoid the additional cost of the ACP above the SREC price. Conversely, DERs such as batteries that increase electric load will increase compliance costs.

This framework treats the reduction or increase in RPS compliance costs as a separate monetized value from the societal cost of carbon (SCC). The cost of RPS compliance is based in part on the projected value of a REC, which represents one MWh of energy produced by a qualifying resource (including the associated emissions, economic, and other societal non-energy attributes of renewable electricity generation). However, the monetary value of these RECs is not based on those societal attributes; it is based upon market supply and demand for renewable resources, where the demand is created by the RPS target and demand for RECs in other PJM states. Furthermore, the value of RPS compliance cost does not equal the value of a REC. The RPS compliance cost equals the REC price multiplied by the RPS target in any given year.

While a primary goal of the RPS is to contribute to carbon reduction goals, it is not possible to determine how much of the REC value is related to carbon emissions versus other societal attributes of the renewable generation. Additionally, the societal benefits represented by RECs, including the SCC, public health, and economic benefits, are valued through different methods. For example, the SCC is based on the damage cost to society from carbon emissions and public health impacts are calculated by determining marginal emissions rates and societal values from EPA. Therefore, while it is possible the value of a REC may account for some societal benefits it is not possible to understand the exact magnitude. To avoid double-counting, the REC value should be excluded from the value stack if the SCC and other avoided emissions benefits are included. The Societal Impacts section provides more discussion on this topic.

Market Price Risk

Description

DERs reduce customer exposure to fluctuations in the energy market associated with supply and demand imbalances or fuel price fluctuations. For example, batteries or traditional demand response can shift load to off-peak hours, thereby avoiding temporary spikes in energy prices. Energy efficiency reduces the quantity of energy purchased in the market, thereby reducing exposure to fluctuations in the price of natural gas or other fossil fuels, or to interim energy price spikes. Because they reduce the probability and severity of rare but especially costly circumstances, DERs provide a hedge to the utility system.

Method

This study used the wholesale risk premium from the *Avoided Energy Supply Components in New England* (AESC) 2021 study.[51] The AESC value is likely to be a reasonable proxy for DC, given that it includes supplier costs from Maryland as well as New England.

Value

The wholesale risk premium is estimated to be 8 percent and applies to the unhedged portion of energy purchases. As of 2021, retail suppliers provided 70 percent of electricity supply in the District, while Pepco provided 30 percent.[52] Retail suppliers frequently mitigate their exposure to commodity price fluctuations through the use of financial hedges.[53] Based on a review of the District's second-largest

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[51] Synapse Energy Economics, Resource Insight, Les Deman Consulting, North Side Energy, and Sustainable Energy Advantage. *Avoided Energy Supply Components in New England: 2021 Report.* Prepared for AESC 2021 Study Group. Released March 15, 2021. Amended May 14, 2021. Available at: https://www.synapse-energy.com/avoided-energy-supply-costs-new-england-aesc.

[52] U.S. Energy Information Administration (EIA) Form 861, 2021.

[53] For example, Constellation Energy, one of the largest retail suppliers in the District, hedges between 97 percent and 100 percent of its generation and notes that it is "exposed to market fluctuations in the prices of electricity, natural gas and oil, and other commodities" and uses "a variety of derivative and non-derivative instruments to manage the commodity price risk of our electric generation facilities, including power and gas sales, fuel and power purchases, natural gas transportation and pipeline capacity agreements, and other energy-related products marketed and purchased. To manage these risks, we

retail supplier's hedging practices, an estimated 90 percent of retail supply is hedged.[54] Thus, an estimated total of 63 percent of energy in the District is hedged, with 37 percent unhedged.

Transmission Capacity

Description

To the extent that DERs reduce a utility's peak load, they may reduce the need for new transmission expenditures.

Method

The avoided transmission cost is based on Pepco's most recent Formula Rate Annual Update to the Federal Energy Regulatory Commission. This study assumed that this value would increase at the rate of inflation over the study period.

Value

Pepco's current transmission charge is $30.30/kW-year.[55] This value was then distributed over the 266 hours most likely to represent the annual peak for the PEPCO zone, which the Study Team estimated to occur during weekdays in July and August from 1 pm to 7 pm.

may enter into fixed-price derivative or non-derivative contracts to hedge the variability in future cash flows from expected sales of power and gas and purchases of power and fuel." Constellation Energy, Form 10-Q, Filed November 28, 2022. Available at https://investors.constellationenergy.com/static-files/b15e9ade-dcda-4924-a628-c99de0e4661b

[54] Ibid.

[55] PJM 2022 Network Integration Transmission Service Rate, available at https://www.pjm.com/-/media/markets-ops/settlements/network-integration-trans-service-january-2022.ashx

Table 16. Avoided Transmission Capacity Costs

Year	Avoided Transmission Capacity Costs (2020$/kW-yr)	Avoided Transmission Capacity Costs (2020$/MWh, 266 hours)
2023	30	114
2024	30	114
2025	30	114
2026	30	114
2027	30	114
2028	30	114
2029	30	114
2030	30	114
2031	30	114
2032	30	114
2033	30	114
2034	30	114
2035	30	114
2036	30	114
2037	30	114
2038	30	114
2039	30	114
2040	30	114
2041	30	114
2042	30	114
2043	30	114
2044	30	114
2045	30	114

Transmission System Losses

Description

Electricity produced at large generation stations must be transmitted to the local distribution grid on high voltage transmission lines. Due to resistance, some of that power is lost, resulting in less power available at load than was generated. DERs can avoid transmission losses by reducing the power that is sent along transmission lines. Because losses on the transmission system grow with the square of the current on the line, hours with high use incur substantially more losses than hours with low use.

Method

Transmission losses are included in the locational marginal price produced by EnCompass for each year.

Distribution Capacity, O&M, and Voltage

Description

To the extent that DERs reduce a utility's peak load, they may reduce the need for new substation and distribution line infrastructure, operation and maintenance expenses, and costs of voltage regulation.

Method & Value

The method for determining this avoided cost is described in Section 5 and the values are provided in Section 6.

Distribution System Losses

Description

Similar to transmission losses, some power flowing on a distribution circuit is lost to resistance. DERs that reduce power flow on the distribution grid avoid distribution losses. As with transmission losses, distribution losses grow with the square of the current, and are therefore much higher when the circuit is at peak use. Marginal distribution losses are roughly 1.5 times the average loss at that time interval.

Method

Analysts typically measure distribution losses using load flow models. This study used Pepco's reported default loss factors for the purposes of this study, except where the Study Team conducted additional modeling to determine more precise loss values.

Value

Pepco reports its default distribution loss factors for most rate tariff schedules to be between 5.7 percent and 6.2 percent for energy.[56] This study took the average of these values and multiplied it by 1.5 to account for marginal losses.

[56] Pepco. 2015. *District of Columbia's Rate Tariffs, Rate Codes, Load Profiles and Loss Factors Matrix*. Available at: https://www.pepco.com/DoingBusinessWithUs/Documents/DCRateCodeLossFactorMatrix-2-26-18%20(003).pdf.

Table 17. Avoided Distribution Losses

Year	Avoided Distribution Losses (2020$/MWh)
2023	3
2024	3
2025	2
2026	2
2027	2
2028	3
2029	3
2030	3
2031	3
2032	3
2033	3
2034	3
2035	3
2036	3
2037	3
2038	3
2039	3
2040	3
2041	3
2042	3
2043	3
2044	3
2045	3

Utility DER Procurement and Program Administration Costs and Utility Performance Incentives

Description

Utility program expenditures include any incentives provided to customers to purchase or install DERs, as well as the administrative costs of running programs (overhead costs) and any utility performance incentives.

When analyzed from the perspective of all utility customers, incentives provided to customers for DERs are not considered a cost but are simply a zero net transfer. However, under a program administrator cost test, incentives are considered a cost, while from the perspective of a host customer, incentives are a benefit.

Utility administrative costs are considered a cost to customers (except under the host customer's perspective) as utility administrative costs will ultimately be recovered from all customers. Similarly, utility performance incentives are a cost to customers and will be recovered from all customers.

Method

Utility program expenditures should be reported by the utility for each DER program.

Value

These costs vary by program and should be included in cost-effectiveness analyses for specific programs. This analysis does not include values specific to each program in this study.

Credit and Collections

Description

The credit and collections category includes reduced costs associated with arrearages, bad-debt write-offs, terminations and reconnections, customer calls and collections, notices, rate discounts, and price hedging.

Method

Pepco reports its arrearages and uncollectible expenses (also referred to as "bad debt") on a monthly basis, pursuant to Order Nos. 14293 and 15134. For 2019 (prior to pandemic-related policies regarding disconnections) Pepco reported a total of $3.8 million in bad debt. Although it is difficult to determine the extent to which DERs reduce bad debt, a simplifying assumption can be made that bad-debt reductions occur in proportion to total revenue. For 2019, bad debt represented 1.4 percent of Pepco's total residential revenue of $264 million. However, the value of reducing credit and collections expenses should also include the administrative costs associated with customer service and collections. Thus, the bad-debt value should be increased to account for these benefits.

Value

In 2019, bad debt totaled 1.4 percent of Pepco's revenues. Assuming bad debt declines in proportion to revenues, a $100 reduction in customer bills due to DERs would result in a reduction in bad debt of $1.40. The Study Team then assumed that the value of avoided administrative costs and customer service costs increases the value by 50 percent. The total estimated value is thus 2.14 percent of the retail rate, or approximately $0.002/kWh in 2022.[57] The Study Team then adjusted this value over time for inflation and converted it from 2022 to 2020 dollars.

[57] This value is based on the marginal price of electricity for Pepco's residential customers of approximately $0.10/kWh. This reflects Pepco's current winter 2022 supply rate of $0.066/kWh, transmission rate of $0.011/kWh, and average annual distribution rate for consumption above 400 kWh of approximately $0.021/kWh. Available at: https://www.pepco.com/SiteCollectionDocuments/1.DC%20Rates%20Update%2012.1.21%20%20R.pdf.

Table 18. Avoided Credit and Collections Costs

Year	Avoided Credit and Collections Costs (2020$/MWh)
2023	0.002
2024	0.002
2025	0.002
2026	0.002
2027	0.002
2028	0.002
2029	0.002
2030	0.002
2031	0.002
2032	0.002
2033	0.002
2034	0.002
2035	0.002
2036	0.002
2037	0.002
2038	0.002
2039	0.002
2040	0.002
2041	0.002
2042	0.002
2043	0.002
2044	0.002
2045	0.002

Application

Applicable to any DER that reduces customer bills.

Construction and Procurement Cost Risk

Description

To the extent that DERs can reduce the need for new electric system infrastructure and are not owned by the utility, DERs reduce the construction cost risk associated with generation capacity, transmission capacity, and distribution capacity.

Method

For distribution system construction cost risk, the Study Team developed a generic contingency value based on Pepco's contingency factors for Pepco's Second Biennial Underground Infrastructure Improvement Projects Plan, which the Commission approved in Order No. 20285.

Value

This study assumed a construction cost contingency factor of 15 percent, based on a simple average of Pepco's 10 percent contingency factor for electrical cost and 20 percent for civil costs.[58] This risk factor can be applied to specific avoided distribution system capital investments going forward. The Study Team did not apply it to the avoided distribution costs in this study because we relied on Pepco's estimates of generic marginal distribution costs, rather than costs for specific projects.

Reliability

Description

The modeled avoided wholesale market costs and avoided transmission and distribution capacity costs will capture most reliability benefits from DERs. To the extent that the DER contributes to reliability above and beyond minimum reliability standards, there may be incremental societal benefits.

Method

One method of estimating the value of reduced interruptions (also referred to as the "value of lost load" or "VoLL") is to use the Interruption Cost Estimator (ICE) developed by Lawrence Berkeley National Laboratory and Nexant, Inc. The ICE model estimates the benefits associated with reducing lost load in the United States. The ICE model has multiple limitations, however. For large commercial and industrial (C&I) customers, the VoLL is based on GDP/kWh by state, while for small C&I customers and residential customers, it uses survey data from surveys conducted by 10 utilities in certain parts of the country. No surveys were performed in the Mid-Atlantic region, and much of the survey data is quite outdated (ranging from 1989 to 2012). Finally, the data is focused on relatively short outages (less than 24 hours) and is not intended to be used for outage durations exceeding eight hours.[59]

Another option for estimating the VoLL is to look to Europe, as was done for the 2021 AESC study.[60] The AESC study sourced additional residential and non-residential VoLL values from a 2018 report by Cambridge Economic Policy Associates (CEPA) titled *Study on the Estimation of the Value of Lost Load of Electricity Supply in Europe*.[61] The CEPA study developed its residential VoLL estimates by calculating the value of leisure time for individuals in each member country, and calculating the proportion of that leisure value that is dependent on electricity. The value of leisure is estimated using the assumption that, at the margin, an hour of leisure is valued the same as the income generated from an additional

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[58] Formal Case No. 1159, Order No. 20285, January 24, 2020, ordering paragraph 209.

[59] Sullivan, M.J., J. Schellenberg, and M. Blundell, Nexant, Inc. *Updated Value of Service Reliability Estimates for Electric Utility Customers in the United States*. January 2015. Available at https://eta-publications.lbl.gov/sites/default/files/lbnl-6941e.pdf

[60] Synapse Energy Economics. 2021. *Avoided Energy Supply Components in New England* (AESC 2021). Available at https://www.synapse-energy.com/project/avoided-energy-supply-costs-new-england-aesc. pp. 281–284.

[61] Cambridge Economic Policy Associates Ltd. "Study on the Estimation of the Value of Lost Load of Electricity Supply in Europe." July 2018. Available at https://www.acer.europa.eu/en/Electricity/Infrastructure_and_network%20 development/Infrastructure/Documents/CEPA%20study%20on%20the%20Value%20of%20Lost%20Load%20in%20the%20electricity%20supply.pdf.

hour of work.[62] The CEPA study also estimated the VoLL for nine industrial sectors, construction, transportation, services, and a combination of agriculture, forestry, and fishing. For these uses, the VoLL was calculated using the correlation of electricity use to the actual value of output (Gross Value Added, or GVA).

The VoLLs developed in the CEPA study are strongly correlated with the wealth of each country. To increase comparability with New England, the AESC study used VoLLs from countries with gross domestic products of at least half of New England's. For residential customers, this resulted in an average VoLL of $12.56/kWh. This is approximately four times higher than the estimates from the ICE calculator. However, the estimate for the services sector from the CEPA study is $10.40/kWh, which is much lower than the Small C&I value from the ICE calculator.

This study monetized the reliability benefits of DERs using the average of the CEPA values for higher-income European countries and the LBNL values from the ICE calculator. Given the lack of data specific to the District of Columbia, these estimates represent rough approximations only.

Value

The value of increased reliability will depend upon the extent to which outages are reduced (i.e., the kWh of unserved energy avoided) multiplied by the average VoLL calculated from the ICE calculator and CEPA study, which is $57.31/kWh (2020$). The feeder analysis in this study did not identify particular improvements in reliability related to implementing DERs, and thus the Study Team did not apply this value. However, it could be applied in the future to specific projects.

A.3. Societal Impacts

In addition to impacts on customers through the utility system, DERs may also impact customers in the District in other ways. These "societal impacts" include values such as the SCC, public health impacts from avoided pollution at the local level, resilience, and equity. Table 19 provides an overview of the types of societal impacts and a short description of each. The following sections then discuss these impacts in more detail.

[62] Cambridge Economic Policy Associates Ltd. "Study on the Estimation of the Value of Lost Load of Electricity Supply in Europe." July 2018, p. 84.

Table 19. Overview of Societal Impacts

Type of Impact		Impact Description
Greenhouse Gas Emissions		Non-embedded societal cost of greenhouse gas emissions (i.e., the social cost of carbon from electricity generation and methane leakage)
Other Environmental		Externalities associated with liquid and solid waste emissions, land use, and water use
Public Health		Costs borne by society associated with pollution health impacts such as from NO_x and $PM_{2.5}$. These costs include medical costs and reduction in productivity.
Other	Resilience	Value associated with the ability to anticipate, prepare for, and adapt to changing conditions and withstand, respond to, and recover rapidly from disruptions
	Equity	Value of fair treatment, advancement, opportunity, and access for all individuals (low-income customers in disadvantaged communities only)

Greenhouse Gas Emissions: Combustion

Description

Fuel combustion at power plants releases GHG emissions into the atmosphere. Reductions in electricity consumption resulting from DERs can therefore result in reductions in GHG emissions by avoiding fuel combustion.

Method

The GHG emissions from power plant fossil fuel combustion are based on hourly emissions rates throughout the study period. A reduction of load in any one hour reduces emissions equivalent to the emissions rate associated with the marginal generator. Theoretically, EnCompass or another economic dispatch model can model this by observing changes in zonal emissions due to a small decrease in load at the zonal level. However, imports and exports into a zone complicate the analysis. In the hours in which the PEPCO zone is exporting to other regions, a reduction in local demand may lead to no change in emissions in the zone, but rather an increase in exported electricity. In the hours in which the PEPCO zone is importing electricity, a change of demand in the zone may reduce the electricity imported but not the emissions from local generation.

Due to significant hourly imports and exports to and from the PEPCO zone, this study could not estimate marginal emissions rates with precision. Instead, the Study Team developed average hourly emissions rates for a 24-hour period for each month in five-year intervals. Hourly greenhouse gas emissions were modeled in EnCompass for each PJM zone for the years 2021, 2025, 2030, and 2035. The hourly emissions account for GHG emissions produced from generators in the PEPCO zone, as well emissions imported into the zone from other regions. The hourly emissions rates for each modeled year were then applied to the two years prior to and following the modeled year for the years 2023 through 2035. For example, the hourly emissions rates for 2030 were applied to the years 2028 through 2032. Because of this step change in emissions rates, the change in emissions in some years (particularly 2028) is substantial. The average hourly emissions rate for 2030 and 2035 is very similar, although small differences exist in the hourly emissions profiles. For the years 2036 through 2045, we used the compound annual growth rate of the linear trend in emissions from 2021 to 2035.

The estimated average hourly CO_2 emissions rates (tons/MWh) for each month and hour 2021–2035 are shown in Table 20 below. The highest emissions tend to be in the winter and summer overnight hours, while the lowest emissions fall in the shoulder seasons during the middle of the day.

Table 20. Average Hourly CO_2 Emissions Rates (tons/MWh, 2021–2035)

	Hour Ending																							
Month	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**
Jan	0.45	0.45	0.45	0.45	0.44	0.43	0.41	0.41	0.39	0.38	0.38	0.38	0.39	0.39	0.40	0.41	0.43	0.43	0.43	0.43	0.43	0.44	0.45	0.45
Feb	0.42	0.43	0.43	0.43	0.42	0.42	0.40	0.39	0.37	0.35	0.34	0.34	0.34	0.35	0.35	0.37	0.39	0.41	0.41	0.41	0.41	0.41	0.42	0.43
Mar	0.36	0.38	0.38	0.38	0.37	0.36	0.35	0.33	0.31	0.29	0.28	0.27	0.26	0.26	0.27	0.28	0.29	0.33	0.35	0.35	0.36	0.36	0.38	0.37
Apr	0.37	0.38	0.38	0.38	0.36	0.34	0.33	0.28	0.25	0.26	0.25	0.25	0.25	0.25	0.26	0.27	0.29	0.33	0.34	0.33	0.34	0.33	0.34	0.35
May	0.38	0.38	0.38	0.37	0.37	0.35	0.33	0.28	0.27	0.27	0.27	0.27	0.27	0.28	0.29	0.29	0.30	0.33	0.34	0.35	0.36	0.36	0.35	0.36
Jun	0.41	0.43	0.43	0.42	0.42	0.38	0.38	0.32	0.32	0.31	0.31	0.31	0.31	0.32	0.32	0.32	0.34	0.36	0.37	0.39	0.38	0.38	0.39	0.40
Jul	0.43	0.44	0.45	0.45	0.45	0.43	0.40	0.34	0.34	0.34	0.34	0.35	0.35	0.36	0.36	0.36	0.37	0.39	0.40	0.41	0.41	0.41	0.40	0.42
Aug	0.43	0.44	0.45	0.45	0.45	0.42	0.40	0.36	0.34	0.33	0.33	0.34	0.36	0.36	0.37	0.37	0.37	0.39	0.40	0.41	0.40	0.40	0.41	0.42
Sep	0.40	0.41	0.41	0.42	0.40	0.39	0.37	0.33	0.31	0.31	0.31	0.31	0.32	0.33	0.33	0.34	0.35	0.37	0.38	0.38	0.38	0.38	0.39	0.39
Oct	0.35	0.36	0.35	0.36	0.35	0.33	0.32	0.28	0.25	0.25	0.23	0.24	0.24	0.25	0.26	0.28	0.31	0.35	0.35	0.35	0.34	0.34	0.32	0.34
Nov	0.38	0.40	0.40	0.40	0.40	0.39	0.39	0.36	0.34	0.32	0.31	0.31	0.30	0.30	0.32	0.34	0.37	0.38	0.39	0.38	0.38	0.38	0.39	0.38
Dec	0.42	0.42	0.42	0.42	0.42	0.41	0.39	0.38	0.36	0.36	0.35	0.35	0.35	0.36	0.37	0.38	0.40	0.40	0.40	0.39	0.40	0.40	0.41	0.42

Source: Synapse EnCompass modeling.

The next section explains how the Study Team used these values to calculate the low, mid, and high avoided GHG cases.

Greenhouse Gas Emissions: Generation

Description

The social cost of carbon (SCC) is a commonly accepted means for representing the societal damages resulting from greenhouse gas emissions which are not embedded in current costs. The SCC plays a large role in the overall value of DER and is subject to considerable debate. Below is a description of the three cases modeled for the avoided generation GHG costs (low, mid, and high) and the SCC inputs for these cases.

Method and Value: Low Avoided Generation GHG Cost

The current SCC was initially developed under the Obama Administration's Interagency Working Group (IWG) for use in federal decision-making. The 2016 IWG SCC is the most recent set of values released by the federal IWG. It has been endorsed or otherwise supported by the National Academies of Science and the Government Accountability Office and has been upheld in court as a reasonable set of values to use. The 2016 published technical support document that emerged from this analysis recommended a 2023 value of $54 per metric ton in 2020$, which is derived using a 3 percent discount rate.[63] The Study Team multiplied the stream of values from this case by 1.10231 to convert from dollars per metric ton to dollars per short ton, which are the units used in this study. The Study Team then multiplied this stream of values by the average hourly CO2 emissions to arrive at the low avoided generation GHG cost. Table

[63] Interagency Working Group on Social Cost of Greenhouse Gases. August 2016. *Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis – Under Executive Order 12866.* Available at https://obamawhitehouse.archives.gov/sites/default/files/omb/inforeg/scc_tsd_final_clean_8_26_16.pdf.

21 below illustrates the stream of values applied as the generation component (methane leakage is the other component) of the low GHG case (in 2020$ per short ton).

Table 21. Low GHG Cost Case: Avoided Generation GHG Cost

Year	2016 IWG SCC (2020$/metric ton, 3% Discount Rate)	2016 IWG SCC (2020$/short ton, 3% Discount Rate)	Average Hourly CO2 Emissions (short tons/MWh)	Low Avoided Generation GHG Cost (2020$/MWh)
2023	54	60	0.42	25
2024	55	61	0.42	26
2025	56	62	0.42	26
2026	57	63	0.42	27
2027	58	64	0.42	27
2028	59	65	0.30	19
2029	60	66	0.30	20
2030	61	67	0.30	20
2031	62	68	0.30	20
2032	63	69	0.30	21
2033	64	71	0.30	21
2034	65	72	0.30	21
2035	66	73	0.30	22
2036	68	74	0.29	21
2037	69	75	0.28	21
2038	70	76	0.26	20
2039	71	77	0.25	20
2040	72	79	0.24	19
2041	73	80	0.23	19
2042	74	81	0.22	18
2043	75	83	0.21	18
2044	76	84	0.21	17
2045	77	85	0.20	17

As there has been considerable debate regarding the SCC and the appropriate discount rate to use, this study also considered mid and high cases.

Method and Value: Mid Avoided Generation GHG Cost

This SCC is based on a December 2020 guideline document titled *Establishing a Value of Carbon* from the New York State Department of Environmental Conservation (the 2020 NYS SCC Guideline).[64] The 2020 NYS SCC Guideline recommends using the values identified as an interim SCC by the Biden Administration in February 2021 (and previously issued by the Obama Administration in 2016), but with a different range of discount rates. While the federal IWG provides SCC values using discount rates of

[64] New York State Department of Environmental Conservation. 2020. *Establishing a Value of Carbon: Guidelines for Use by State Agencies.* Available at: https://www.dec.ny.gov/docs/administration_pdf/vocfguid.pdf.

2.5 percent, 3 percent, and 5 percent (with a central identified value of 3 percent), the 2020 NYS SCC Guideline recommends calculating the SCC at a discount rate of 1 percent, 2 percent, and 3 percent to better reflect the range of potential SCC values. In particular, the 2020 NYS SCC Guideline also recommends using a central discount rate of no more than 2 percent for decision-making. This SCC was recommended for use in the *2021 New England Avoided Energy Supply Cost* study[65] and recently endorsed again in the *Value of Carbon Guidance: 2022 Update* (2022 NYS SCC Update).[66]

The 2023 value for this SCC is $126 per metric ton in 2020$, which is derived using a 2 percent discount rate. To convert from metric tons to short tons, the Study Team multiplied the stream of values from this case by 1.10231. It then multiplied this stream of values by the average hourly CO2 emissions to arrive at the mid avoided generation GHG cost. Table 22 below illustrates the stream of values which is the generation component (methane leakage is the other component) of the mid GHG case (in 2020$ per short ton).

[65] Synapse Energy Economics, Resource Insight, Les Deman Consulting, North Side Energy, and Sustainable Energy Advantage. *Avoided Energy Supply Components in New England: 2021 Report*. Prepared for AESC 2021 Study Group. Released March 15, 2021 Amended May 14, 2021. Available at: https://www.synapse-energy.com/sites/default/files/AESC%202021_20-068.pdf.

[66] New York State Department of Environmental Conservation. 2022. *Value of Carbon Guidance 2022 Update*. Page 34. Available at: https://www.dec.ny.gov/docs/administration_pdf/vocguid22.pdf.

Table 22. Mid GHG Cost Case: Avoided Generation GHG Cost

Year	2020 NYS SCC (2020$/metric ton, 2% Discount Rate)	2020 NYS SCC (2020$/short ton, 2% Discount Rate)	Average Hourly CO2 Emissions (short tons/MWh)	Mid Avoided Generation GHG Cost (2020$/MWh)
2023	126	139	0.42	59
2024	128	141	0.42	60
2025	129	142	0.42	60
2026	131	144	0.42	61
2027	132	146	0.42	61
2028	134	148	0.30	44
2029	136	150	0.30	45
2030	137	151	0.30	45
2031	139	153	0.30	46
2032	141	155	0.30	46
2033	142	157	0.30	47
2034	144	159	0.30	47
2035	146	161	0.30	48
2036	147	163	0.29	47
2037	149	165	0.28	45
2038	151	167	0.26	44
2039	152	169	0.25	43
2040	154	171	0.24	42
2041	156	173	0.23	40
2042	158	175	0.22	39
2043	160	178	0.21	38
2044	162	180	0.21	37
2045	164	182	0.20	36

Method and Value: High Avoided Generation GHG Cost

The high avoided generation GHG cost case includes the SCC proposed by the EPA last year. In September 2022, the EPA (a member of the IWG) released its updated estimates of the SCC (and other GHGs) that incorporate numerous updates to the 2016 IWG SCC methodology, as recommended by the National Academies of Science, Engineering, and Medicine.[67] EPA quantified the cost of carbon using:

- Three different analyses: (1) one using the Data-driven Spatial Climate Impact Model (DSCIM) model, (2) one using the Greenhouse Gas Impact Value Estimator (GIVE) model, and (3) one using a meta-analysis of existing estimates; and
- Three different discount rates: 1.5, 2.0, and 2.5 percent.

[67] U.S. Environmental Protection Agency. *Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances*. September 2022. Table 4.2.1: Unrounded SC-CO_2, SC-CH_4, and SC-N_2O Values, 2020-2080. Page 120. Available here: https://www.epa.gov/system/files/documents/2022-11/epa_scghg_report_draft_0.pdf.

This SCC represents an average of the three different analyses and is discounted by 2 percent. The 2023 value for this SCC is $204 per metric ton in 2020$, derived using a 2 percent discount rate. To convert from metric tons to short tons, the Study Team multiplied the stream of values by the 1.10231 conversion factor. It then multiplied this stream of values by the average hourly CO_2 emissions to arrive at the high avoided generation GHG cost. Table 23 below illustrates the stream of values which is the generation component (methane leakage is the other component) of the high GHG case (in 2020$ per short ton).

Table 23. High GHG Cost Case: Avoided Generation GHG Cost

Year	2022 EPA Proposed SCC (2020$/metric ton, 2% Discount Rate)	2022 EPA Proposed SCC (2020$/short ton, 2% Discount Rate)	Average Hourly CO2 Emissions (short tons/MWh)	High Avoided Generation GHG Cost (2020$/MWh)
2023	204	225	0.42	95
2024	208	229	0.42	97
2025	212	234	0.42	99
2026	215	237	0.42	100
2027	219	241	0.42	102
2028	223	246	0.30	73
2029	226	249	0.30	74
2030	230	254	0.30	75
2031	234	258	0.30	77
2032	237	261	0.30	78
2033	241	266	0.30	79
2034	245	270	0.30	81
2035	248	273	0.30	82
2036	252	278	0.29	80
2037	256	282	0.28	78
2038	259	286	0.26	75
2039	263	290	0.25	74
2040	267	295	0.24	72
2041	271	299	0.23	70
2042	275	304	0.22	68
2043	279	309	0.21	66
2044	283	313	0.21	64
2045	287	318	0.20	63

Greenhouse Gas Emissions: Methane Leakage

The transport of natural gas to power plants releases methane into the atmosphere through equipment leakages all throughout the system. Thus, reducing energy consumption also avoids methane leakage from transport of natural gas to power plants.

To calculate the quantity of methane leaked during transport, the Study Team used an emissions leakage rate of 1.73 percent based on a 2018 study by Alvarez et. Al., adjusted for the leakage from gas wells to power generation (instead of the leakage from wells to buildings).[68,69] This estimate excludes leaks at the natural gas distribution level (since power plants are not served by the natural gas distribution system). This study assumed that approximately 75 percent of the leaks occur from wells to power generation based on a 2020 EPA study.[70]

The calculation to estimate GHG emissions impacts from methane losses associated with natural gas deliveries to power plants involves the following steps:[71]

1. Estimate the natural gas lost during transport per MWh of electricity from natural gas generation: Natural gas power plants have a heat rate of 7,732 btu/kWh on average.[72] At the leakage rate of 1.73 percent, fugitive methane accounts for 134 btu/kWh or 0.134 MMBtu lost during transport per MWh of generation associated with natural gas power plants.

2. Calculate methane weights in tons/MMBtu: There are 42 pounds of methane/MMBtu or 0.021 tons/MMBtu.[73]

3. Convert methane emissions to tons of CO_2 equivalents: Methane has a substantially larger Global Warming Potential (GWP) than CO_2. One ton of methane is estimated

[68] Alvarez et. al. 2018. "Assessment of methane emissions from the U.S. oil and gas supply chain." *Science* 361, 186-188. DOI:10.1126/science.aar7204. Available at: https://science.sciencemag.org/content/361/6398/186; Guglielmi, G. 2018. "Methane leaks from US gas fields dwarf government estimates." *Nature*. Available at https://www.nature.com/articles/d41586-018-05517-y.

[69] This study was one of the most comprehensive studies of fugitive methane using ground-based, facility-scale measurements and validated with aircraft observations in areas accounting for about 30 percent of U.S. gas production. However, the leakage estimate from this study is still potentially a conservative estimate as recent detailed field studies are finding even higher leakage rates. For example, a new study released in 2022 conducted a basin-wide airborne survey of fugitive methane in the New Mexico Permian Basin and found the total leak rate is 9.4 percent of the total production. *See:* Chen et al. 2022. "Quantifying Regional Methane Emissions in the New Mexico Permian Basin with a Comprehensive Aerial Survey." *Environ. Sci. Technol*. 2022, 56, 7, 4317–4323. Available at: https://pubs.acs.org/doi/10.1021/acs.est.1c06458.

[70] Kirchgessner, D.A., Lott, R.A., Michael Cowgill, R., Harrison, M.R., Shires, T.M., 1997. "Estimate of methane emissions from the U.S. natural gas industry." *Chemosphere*. Vol 35, 1365–1390. https://doi.org/10.1016/S0045-6535(97)00236-1; available at https://www.epa.gov/sites/default/files/2020-11/documents/methane.pdf.

[71] For valuing avoided GHG emissions, this study uses a widely accepted methodology for the conversion of methane into an amount of carbon-dioxide that is considered equivalent in terms of social damages. However, the Study Team recognizes that other studies use a "social cost of methane" which takes account of methane's distinct chemical properties. For example, see Table 34 in the *Preliminary Regulatory Impact Analysis for U.S. Department of Transportation's Proposed Rule on Pipeline Safety: Gas Leak Detection and Repair* (April 2023).

[72] U.S. EIA. "Table 8.1. Average Operating Heat Rate for Selected Energy." Available at: https://www.eia.gov/electricity/annual/html/epa_08_01.html.

[73] This analysis uses short tons. 1 short ton equals 2,000 pounds.

to have about 30 times greater GWP than one ton of CO_2 over a 100-year timeframe and about 83 times greater GWP over a 20-year timeframe.[74]

Based on these GWP impacts, methane emits 0.62 tons of CO_2e /MMBtu for a 100-year timeframe (calculated as 0.021 short tons/MMBtu * 30 GWP). If measured over a 20-year timeframe instead, methane emits 1.73 tons of CO_2e /MMBtu (calculated as 0.021 short tons/MMBtu * 83 GWP).

4. Calculate GHG emissions in tons of CO_2e /MWh for methane lost during transport to natural gas power plants: Each MWh of natural gas plant generation is associated with a leakage rate of 0.134 MMBtu from upstream pipeline transportation. Thus, fugitive methane emits 0.084 tons of CO_2e /MWh (0.62 tons of CO_2e/MMBtu * 0.134 MMBtu/MWh) over a 100-year timeframe. When measured over a 20-year timeframe, the emissions rate is 0.23 tons of CO_2e /MWh (calculated as 1.73 tons of CO_2e/MMBtu * 0.134 MMBtu/MWh).

5. Account for percentage of natural gas on margin: We multiplied the marginal emission factors above by the percentage of time that natural gas plants are on the margin in each year (as modeled in EnCompass), which is approximately 78 percent of the time for the PEPCO zone.

The Study Team then developed three cases for avoided methane leakage costs, based on the timeframe utilized (20-years or 100-years) and the low, mid, and high SCC costs. Table 24 below illustrates these three cases.

[74] IPCC. 2021. *Climate Change 2021 – The Physical Science Basis*. Table 7.15, pp.7-125. Available at: https://www.ipcc.ch/report/ar6/wg1/downloads/report/IPCC_AR6_WGI_Full_Report.pdf. The CEAI Working Group Recommendation A.3.1 states "GWP time scale reference should follow the latest IPCC guidance, at present AR5 (IPCC's technical guide) and updated as the IPCC releases new guidance. Specifically, GWP values should follow IPCC guidelines for 100-year potentials (as opposed to 20- or 500-year). Methane GWP should also be based on a 100-year value following the EPA protocol and GHG Protocol."

Table 24. Low, Mid, and High Avoided Methane Leakage Costs

		Low Methane Leakage Cost		Mid Methane Leakage Cost		High Methane Leakage Cost	
Year	NG Unit on Margin	100-yr Methane CO_2e (tons/MWh)	2016 IWG SCC (2020$/MWh, 3% Discount Rate)	100-yr Methane CO_2e (tons/MWh)	2020 NYS SCC (2020$/MWh, 2% Discount Rate)	20-yr Methane CO_2e (tons/MWh)	2022 EPA Proposed SCC (2020$/MWh, 2% Discount Rate)
2023	83%	0.084	4	0.084	10	0.23	43
2024	79%	0.084	4	0.084	9	0.23	41
2025	80%	0.084	4	0.084	10	0.23	43
2026	78%	0.084	4	0.084	10	0.23	43
2027	77%	0.084	4	0.084	9	0.23	43
2028	78%	0.084	4	0.084	10	0.23	44
2029	76%	0.084	4	0.084	10	0.23	43
2030	79%	0.084	4	0.084	10	0.23	46
2031	79%	0.084	5	0.084	10	0.23	47
2032	80%	0.084	5	0.084	10	0.23	48
2033	81%	0.084	5	0.084	11	0.23	49
2034	77%	0.084	5	0.084	10	0.23	48
2035	78%	0.084	5	0.084	11	0.23	49
2036	78%	0.084	5	0.084	11	0.23	50
2037	78%	0.084	5	0.084	11	0.23	50
2038	78%	0.084	5	0.084	11	0.23	51
2039	77%	0.084	5	0.084	11	0.23	52
2040	77%	0.084	5	0.084	11	0.23	52
2041	77%	0.084	5	0.084	11	0.23	53
2042	76%	0.084	5	0.084	11	0.23	53
2043	76%	0.084	5	0.084	11	0.23	54
2044	76%	0.084	5	0.084	11	0.23	55
2045	75%	0.084	5	0.084	12	0.23	55

Avoided Generation and Methane Leakage GHG Cost

Lastly, the Study Team summed the avoided generation and methane leakage GHG costs into an avoided GHG cost for each case. Table 25 shows the calculation of the low GHG cost case.

Table 25. Low GHG Cost Case: Low Avoided Generation and Methane Leakage GHG Cost

Year	Low Avoided Generation GHG Cost (2020$/MWh)	Low Methane Leakage Cost (2020$/MWh)	Low GHG Cost Case (2020$/MWh)
2023	25	4	29
2024	26	4	30
2025	26	4	30
2026	27	4	31
2027	27	4	31
2028	19	4	24
2029	20	4	24
2030	20	4	24
2031	20	5	25
2032	21	5	25
2033	21	5	26
2034	21	5	26
2035	22	5	27
2036	21	5	26
2037	21	5	26
2038	20	5	25
2039	20	5	25
2040	19	5	24
2041	19	5	24
2042	18	5	23
2043	18	5	23
2044	17	5	23
2045	17	5	22

Table 26 shows the calculation of the mid GHG cost case.

Table 26. Mid GHG Cost Case: Mid Avoided Generation and Methane Leakage GHG Cost

Year	Mid Avoided Generation GHG Cost (2020$/MWh)	Mid Methane Leakage Cost (2020$/MWh)	Mid GHG Cost Case (2020$/MWh)
2023	59	10	68
2024	60	9	69
2025	60	10	70
2026	61	10	71
2027	61	9	71
2028	44	10	54
2029	45	10	54
2030	45	10	55
2031	46	10	56
2032	46	10	57
2033	47	11	57
2034	47	10	58
2035	48	11	59
2036	47	11	57
2037	45	11	56
2038	44	11	55
2039	43	11	54
2040	42	11	53
2041	40	11	52
2042	39	11	50
2043	38	11	49
2044	37	11	48
2045	36	12	47

Table 27 shows the calculation of the high GHG cost case.

Table 27. High GHG Cost Case: High Avoided Generation and Methane Leakage GHG Cost

Year	High Avoided Generation GHG Cost (2020$/MWh)	High Methane Leakage Cost (2020$/MWh)	High GHG Cost Case (2020$/MWh)
2023	95	43	138
2024	97	41	138
2025	99	43	142
2026	100	43	143
2027	102	43	145
2028	73	44	117
2029	74	43	118
2030	75	46	122
2031	77	47	124
2032	78	48	126
2033	79	49	129
2034	81	48	129
2035	82	49	131
2036	80	50	129
2037	78	50	128
2038	75	51	126
2039	74	52	125
2040	72	52	124
2041	70	53	123
2042	68	53	121
2043	66	54	120
2044	64	55	119
2045	63	55	118

Other Environmental

Changes in electricity consumption can result in other environmental impacts, such as water and land-use impacts. This study did not quantify these values.

Public Health

Description

The production and consumption of energy can result in a variety of pollutants that impact public health, including air emissions linked to premature death, chronic and accute bronchitis, asthma, and increased hospital visits. DERs can either increase or decrease air emissions depending on whether they increase or decrease electricity generation.

Method

For this analysis, the Study Team analyzed the health impacts of NO_X and particular matter ($PM_{2.5}$). The Study Team determined the monetized health impacts using the societal value from the EPA's CO-Benefits Risk Assessment Health Impacts Screening and Mapping Tool (COBRA). COBRA estimates and monetizes numerous health impacts, including adult mortality, infant mortality, non-fatal heart attacks, respiratory hospital admissions, cardiovascular-related hospital admissions, acute bronchitis, upper respiratory symptoms, lower respiratory symptoms, asthma exacerbations, asthma emergency room visits, minor restricted activity days, and work loss days due to illness due to changes in emissions.

Table 28 below shows the estimated range of monetary values from COBRA associated with a change in emissions for the District of Columbia. This analysis used the average value.

Table 28. COBRA Health Impacts

	Low (2020$/ton)	Average (2020$/ton)	High (2020$/ton)
$PM_{2.5}$	180,927	294,183	407,439
SO2	22,031	35,822	49,613
NO_X	5,689	9,250	12,811

The study then estimated emissions rates using data reported by PJM for NO_X and by the EPA for $PM_{2.5}$. Although EnCompass also reports these emissions, the imports and exports across regional boundaries hampered the ability to detect changes in emissions at the zonal level. For NO_X, The Study Team used the trend in marginal NO_X emissions rates reported by PJM from 2017–2021[75] to estimate future NO_X emissions.

EPA reported the emissions rate for this area to be 0.0481lbs/MWh.[76] The point estimate did not allow the Study Team to estimate a trend in $PM_{2.5}$ emissions, and thus the analysis held the rate constant.

Value

Table 29 below shows the estimated avoided public health impacts associated with NO_x and $PM_{2.5}$.

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[75] PJM. 2022. *2017–2021 CO_2, SO_2 and NOx Emission Rates*. Available at https://www.pjm.com/-/media/library/reports-notices/special-reports/2021/2021-emissions-report.ashx.

[76] U.S. EPA. 2020. *Estimating Particulate Matter Emissions for eGRID*. Available at https://www.epa.gov/sites/default/files/2020-07/documents/draft_egrid_pm_white_paper_7-20-20.pdf.

Table 29. Avoided Public Health Impacts, NO_X and $PM_{2.5}$

Year	NO_x (lbs/MWh)	Non-Embedded NO_x (2020$/lb)	Avoided NO_x (2020$/MWh)	$PM_{2.5}$ (lbs/MWh)	Non-Embedded $PM_{2.5}$ (2020$/lb)	Avoided $PM_{2.5}$ (2020$/MWh)
2023	0.280	4.63	1.30	0.048	147	7
2024	0.241	4.63	1.11	0.048	147	7
2025	0.207	4.63	0.96	0.048	147	7
2026	0.178	4.63	0.82	0.048	147	7
2027	0.153	4.63	0.71	0.048	147	7
2028	0.131	4.63	0.61	0.048	147	7
2029	0.113	4.63	0.52	0.048	147	7
2030	0.097	4.63	0.45	0.048	147	7
2031	0.083	4.63	0.38	0.048	147	7
2032	0.071	4.63	0.33	0.048	147	7
2033	0.061	4.63	0.28	0.048	147	7
2034	0.053	4.63	0.24	0.048	147	7
2035	0.045	4.63	0.21	0.048	147	7
2036	0.039	4.63	0.18	0.048	147	7
2037	0.033	4.63	0.15	0.048	147	7
2038	0.029	4.63	0.13	0.048	147	7
2039	0.025	4.63	0.11	0.048	147	7
2040	0.021	4.63	0.10	0.048	147	7
2041	0.018	4.63	0.08	0.048	147	7
2042	0.016	4.63	0.07	0.048	147	7
2043	0.013	4.63	0.06	0.048	147	7
2044	0.012	4.63	0.05	0.048	147	7
2045	0.010	4.63	0.05	0.048	147	7

The ownership of RECs generated by a DER will have a direct impact on the total benefits it creates to society and should be assessed when calculating the overall value of a DER.

As described within the RPS Compliance section, a REC represents one MWh of energy produced by a qualifying resource, and it includes the associated environmental, economic, and other societal non-energy attributes of renewable electricity generation. However, when a DER host retains the value of a REC produced, the District may not necessarily receive the full societal impact resulting from that DER. This is because the REC may be sold to another state or retired for the benefit of the DER host, thereby removing the societal attributes of that REC from the District.

For this reason, if the DER host retains ownership of a REC generated, it is important to subtract the value of the associated REC revenues from the total societal benefits to account for the fact the District will not receive the full societal benefits associated with that DER. Within the VDER framework, the societal benefits of the REC overlap with impacts of SCC and public health (NO_X and $PM_{2.5}$ emissions). Since it is impossible to determine how much of the REC value is related to SCC and public health, analysts should subtract the total value of the REC from the sum of the SCC and public health to ensure there is no double-counting.

Resilience

Description

Resilience is an important consideration separate from and in addition to reliability. Resilience is "The ability to prepare for and adapt to changing conditions and withstand and recover rapidly from disruptions."[77] It is generally recognized that reducing *long-duration outages* and reducing outages for *critical customers* are key components to enhancing resilience.

Method

An approach similar to that used for reliability is to quantify the willingness of customers to pay for increased resilience. While customers frequently use back-up generators to ride through shorter-term outages, microgrids using renewable generation (e.g., solar plus batteries) have the potential to continue delivering power even when fuel supplies are interrupted. The cost of installing a microgrid represents a floor for the value of resilience to customers, as customers would not install a microgrid if they did not value continued electric service at least as much as the cost of the microgrid.

This study drew from the Montclair, New Jersey microgrid feasibility study. The Montclair town center microgrid was proposed to serve a hospital, fire headquarters, regional emergency management office, a school capable of serving as an emergency public shelter, and a mass transit facility.[78] This microgrid is particularly relevant for estimating the value of resilience, as it targets resilience services to the wider community, rather than a private host customer.

Funding for the Montclair microgrid as proposed comes through a public[79]-private partnership in which an investor provides equity capital to finance the project, provided that the investor receives a 10 percent after-tax return. The study then calculated the additional societal contribution needed to provide the allocated investor return.

Value

The Montclair microgrid would require a societal contribution of between 32 percent and 37 percent of the total cost, depending on the depreciation treatment. When the societal contribution is divided over the microgrid's expected 10-year generation, the resulting value is $22.41/MWh in 2020 dollars.[80]

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[77] U.S. Office of the Press Secretary. *Presidential Policy Directive/PPD-21 -- Critical Infrastructure Security and Resilience.* February 12, 2013. Accessed April 28, 2023. Available at: https://obamawhitehouse.archives.gov/the-press-office/2013/02/12/presidential-policydirective-critical-infrastructure-security-and-resil.

[78] Integrated CHP Systems Corp. 2018. *Township of Montclair Microgrid Study Report*. Available at https://nj.gov/bpu/pdf/energy/Montclair%20Microgrid%20Feasibility%20Study%20+%20Attachments.pdf

[79] The New Jersey Board of Public Utilities authorized public grant funds for the project.

[80] *Id.* at 96.

Table 30. Avoided Cost of Resilience

Year	Avoided Cost of Resilience (2020$/MWh)
2023	22
2024	22
2025	22
2026	22
2027	22
2028	22
2029	22
2030	22
2031	22
2032	22
2033	22
2034	22
2035	22
2036	22
2037	22
2038	22
2039	22
2040	22
2041	22
2042	22
2043	22
2044	22
2045	22

Equity

Description

The DC Comprehensive Plan defines environmental justice as “the fair treatment of people of all races, cultures, national origins, and incomes, with respect to the development, implementation, and enforcement of environmental laws, regulations, and policies. A just community is one in which all people experience protection from environmental and health hazards and have equal access to the decision-making process for having a healthy environment.”[81] This study considered improvements in environmental justice as improvements in equity. In addition, it considered positive impacts on disadvantaged customers, including low-income customers, as having a positive impact on equity.

[81] DC Comprehensive Plan, Section 628 E-6.7, pages 338-339, https://lims.dccouncil.us/downloads/LIMS/46201/Meeting3/Enrollment/B24-0001-Enrollment3.pdf.

Method

The DC Comprehensive Plan[82] notes that certain District neighborhoods have been adversely impacted by pollution-generating uses and other forms of environmental degradation, particularly in Wards 5, 6, 7, and 8. These wards are in the eastern portion of the District and have some of the lowest income levels. DERs that reduce energy bills, help avoid new electrical equipment construction in disadvantaged areas of the city (including substations, transmission lines, and fossil-fueled power plants), could be provided with an equity adder.

Value

Energy efficiency programs in numerous jurisdictions have implemented equity adders. Examples of adders to account for low-income benefits from other jurisdictions include the following:

- Nevada applies a non-energy benefits adder of 25 percent to low-income programs.
- New Hampshire applies a 20 percent adder for non-energy benefits to the Home Energy Assistance Program.
- New Jersey applies a 10 percent low-income benefits adder to non-energy benefits.[83]
- DCSEU applies a 5 percent adder for non-energy benefits (other than CO2 emissions) as a proxy value to recognize tangible benefits that are challenging to directly quantify.[84]

As noted in the descriptions, these examples of low-income adders in other jurisdictions typically apply to non-energy benefits from energy efficiency. Because the non-energy benefits for other DERs are more difficult to quantify, such adders are less directly applicable in a VDER analysis. Instead, the Study Team recommends the adoption of a 5 percent adder to all benefits for DERs that benefit customers in Wards 5, 6, 7, and 8. The Study Team calculated the equity adder for each of the four feeders and each GHG case (for a total of twelve equity cost streams) by multiplying the sum of all avoided costs in each hour by 5 percent.

[82] DC.gov. Office of Planning. Comprehensive Plan. Available at: https://planning.dc.gov/comprehensive-plan.

[83] American Council for an Energy-Efficient Economy. Updated April 2017. "Guidelines for Low Income Energy Efficiency Programs." *State and Local Policy Database*. Available at https://database.aceee.org/state/guidelines-low-income-programs.

[84] NMR Group, Inc. 2022. *DCSEU FY2021 Performance Benchmarks Report*. Submitted to the District of Columbia Department of Energy and Environment. August 11, 2022. Available at: https://doee.dc.gov/sites/default/files/dc/sites/ddoe/publication/attachments/DCSEU%20FY2021%20Performance%20Benchmarks%20Report%20FINAL%2008.11.2022.pdf

Appendix B. Summary of DER Compensation Methodologies

This Appendix summarizes the approaches that selected jurisdictions use to value DERs, in order to inform the valuation of DERs in the District of Columbia. Table 31 below summarizes the DER compensation framework development in other jurisdictions and the avoided costs for the highest value impacts. The sections that follow provide more detail on each jurisdiction and study. We provide two detailed summaries of solar-focused studies, one for Maine and one for the District. However, we do not provide a detailed summary of the other solar-focused studies (including Pennsylvania, New Jersey, and Maryland) as they are less relevant than studies that are technology-agnostic.

Table 31. Summary of DER Compensation Framework Development in Other Jurisdictions

State	DE	MD	PA	NJ	NH	Avoided Energy Supply Components (AESC) Study		NY	HI	CA	ME
						ME	NH RI VT CT MA				
Conducted VDER Study?	No	Yes (2018)	Yes (2012)		Yes (2020)	Yes (2018 and 2021)		Yes (2021)			Yes (2015)
Who Contracted the Study?	n/a	Maryland PSC	Solar Industry Advocates		Comm-ission	AESC Study Group		NYSERDA and utilities	HI Division of Consumer Advocate	CPUC	Comm-ission
Technology Assumed?	n/a	Solar			No technology assumed						Solar
Values Vary By	n/a	Utility and year	Location (city)		Vary by location (distribution infrastructure)	Season and on- vs. off-peak period; year; ability to provide firm capacity		Technology, time and year, and DRV & LSRV zone	Time and month	Utility, location (climate zone), time, and month	n/a; Transmission values vary by utility
Has Commission Adopted VDER Compensation Framework?	No – state uses net metering	Proceeding is ongoing	No	Proceed-ing ongoing. Current compensation structure embedded with policy incentive	Proceeding ongoing; full report released	Most recent order opted for an alternative study (ME)	Yes, for determining cost-effectiveness of EE and demand-side resources (NH, RI, VT, CT and MA)	Adopted	Proceeding ongoing	Adopted	No – state currently uses modified net metering based on utility costs

State	DE	MD	PA	NJ	NH	Avoided Energy Supply Components (AESC) Study						NY	HI	CA	ME
						ME	NH	RI	VT	CT	MA				
All-In Avoided Costs	n/a	$0.15 - $0.42/ kWh, depend-ing on utility	$0.26 - $0.32/ kWh, by location		Not eval-uated	n/a						Depend-ent on project, location, utility, and DRV/ LSRV area.	$0.05- $0.24/ kWh, varying by hour of day and month	Depend-ent on project, location, utility, and output profile.	$0.17- $0.18/ kWh
Avoided Energy Costs	n/a	$0.04- $0.06/ kWh, depend-ing on utility and year	$0.056 - $0.063/ kWh by location		Not eval-uated	$0.043- $0.063/ kWh [1]	$0.044- $0.064/ kWh [1]	$0.051- $0.071/ kWh [1]	$0.039- $0.059/ kWh [1]	$0.044- $0.064/ kWh [1]	$0.030- $0.047/ kWh [1]	Varies by project, time, and location. All hours (annual average): $0.018- $0.035/ kWh	Com-bined into all-in rate below, varying by hour and month.	Range of hour-of-day averages: $0.014- $0.10/ kWh	$0.06/ kWh
Avoided Gener-ation Capacity Costs	n/a	$0.004 - $0.01/ kWh, depend-ing on utility and year	$0.016 - $0.22/ kWh by location		No level-ized value	$16.2- $42.1/ kW-yr [2]	$20.4-48.8/ kW-yr [2]					Varies by project, time, and location. $0.00- $0.06/ kWh [3] $0.06- $0.15/ kWh [4]	Com-bined into all-in rate below, varying by hour and month.	Range of hour-of-day averages: $0.00 - $0.10/ kWh	$0.015/ kWh, plus $0.002/ kWh (avoided reserve capacity)

State	DE	MD	PA	NJ	NH	Avoided Energy Supply Components (AESC) Study						NY	HI	CA	ME
						ME	NH	RI	VT	CT	MA				
Avoided Distri-bution System Costs	n/a	No systematic valuation; illustrative example up to $0.114/ kWh	Embedded in transmission capacity		No level-ized value	Not explicitly evaluated						Determined by presence in Distribution Relief Value area. Up to $0.85/ kWh for exports during DRV windows.	Not eval-uated	Range of hour-of-day averages: $0.00 - $0.20/ kWh	Not eval-uated
Avoided Carbon and Criteria Pollut-ants	n/a	Health Benefits: $0.002 - $0.006/ kWh by year Compliance Market Value: De minimis Social Value of CO2: Not monetized	$0.02-$0.05/ kWh, by location		Not eval-uated	GHG: $0.045-$0.054/ kWh [5] Nox: $0.0006-$0.0008/ kWh [1]			GHG: $0.039-$0.046/ kWh [5] Nox: $0.0005-$0.0007/ kWh [1]	GHG: $0.045-$0.054/ kWh [5] Nox: $0.0006-$0.0008/ kWh [1]		Avoided RPS compliance value is greater of REC compliance and/or social cost of carbon. Social cost of carbon not explicitly built into value stack calculator.	Not eval-uated	Range of hour-of-day averages: $0.00 - $0.05/ kWh	Social Cost of Carbon: $0.021/ kWh Social Cost of SO2: $0.051/ kWh Social Cost of Nox: $0.011/ kWh

Notes:

1. *15-year levelized retail value, varies by on- or off-peak period and season*
2. *15-year levelized retail value, varying on uncleared vs. cleared resource*
3. *Levelized over typical solar production curve, varying by month*
4. *Levelized over 240 peak system hours*
5. *5-year levelized retail value, varying by on- or off-peak period and season*

B.1. 2014 Maine Value of Solar Study

Avoided Energy Costs

The avoided energy costs are based on ISO New England hourly real-time locational marginal prices for the Maine load zone. The first year avoided cost calculation used 2013 Locational Marginal Price (LMP) data. For future years, the study escalated the first-year cost using a combination of NYMEX natural gas futures[85] (first 12 years) and EIA's Annual Energy Outlook (AEO 2014) [86] forecast of natural gas prices for electric power.[87]

Avoided Generation Capacity

To estimate avoided generation capacity costs by zone in the ISO New England Forward Capacity Market (FCM),[88] the study used actual data for future years for which auctions had occurred.[89] For future years, the study leveraged prices based on a simulated forecast using data published in the 2014 IRP for Connecticut.[90] The study annualized and adjusted those prices for inflation. To extend the forecast further out, the study escalated prices beyond 10 years at the rate of inflation.[91]

Avoided Transmission and Distribution (T&D) Losses

The study specifies that losses are calculated on an hourly basis for the study period and reflect marginal losses. The marginal avoided losses in each hour reflect the difference between a case in which the PV resource is operating and a case in which the PV resource is not operating. The study recognizes that there is a non-linear relationship between losses and load, as losses are proportional to the square of the load.[92]

The study specifies three different types of losses to be calculated: annual avoided energy losses, Effective Load Carrying Capability (ELCC) losses, and Peak Load Reduction (PLR) losses. The avoided annual energy losses represent the avoided T&D losses for all hours in the analysis period; the ELCC losses represent the avoided T&D losses during the 100 peak hours; and the PLR losses represent avoided distribution losses during peak hours. Each of these loss values requires two calculations: the

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[85] Henry Hub Natural Gas Futures. Available at https://www.cmegroup.com/trading/energy/natural-gas/natural-gas_quotes_globex.html.

[86] U.S. EIA. *Annual Energy Outlook 2014*. Available at http://www.eia.gov/oiaf/aeo/tablebrowser/#release=AEO2014&subject=16-AEO2014&table=3- AEO2014&region=1-1&cases=ref2014-d102413a.

[87] Maine Distributed Solar Valuation Study, p. 29.

[88] Maine Distributed Solar Valuation Study, 30.

[89] Id., p. 30.

[90] Id., p. 30.

[91] Id., p. 30.

[92] Maine Distributed Solar Valuation Study, pp. 26-27.

first time including the effects of avoided marginal losses, and then a second calculation assuming no losses.[93]

Avoided Transmission Capacity

Distributed PV has the potential to avoid or defer transmission investments if it is installed for the purpose of providing transmission capacity and has production that is coincident with the peak. However, it can be difficult to determine the cost of future transmission that is avoidable or deferrable with distributed PV. The Maine study applies transmission tariffs used to recover historical costs as a proxy for this price.[94]

Transmission system charges for ISO New England are assessed as a function of monthly system peaks and are divided into charges for recovering the cost of Pool Transmission Facilities (PTF) that provide Regional Network Service (RNS) plus the cost of local transmission facilities not recovered under the RNS rate. The Maine study quantified the savings that result from the reduction of the cost on the RNS portion due to distributed PV.

Specifically, the study used a generation profile for PV to estimate the expected reduction in monthly peak demand for each month. It then used the reduced monthly peak demands to recalculate the RNS rate (ISO-NE Schedule 9 RNS rates).[95] The result is expressed in kW of average annual network load reduction per kW-AC of rated PV capacity. After estimating the first-year savings per kW of PV capacity, the study escalates these savings at a general inflation rate for each year of the study and then levelizes them.[96]

The Maine study did not include local transmission facility savings from non-transmission alternatives.

Distribution System Costs

As peak demand grows, distribution circuits and substations can approach their normal rating. This necessitates distribution system capital investments, which distributed PV can potentially defer or avoid. Since forecasted peak loads in Maine have generally been flat, however, the study assumed no impact on distribution system capacity investments.[97]

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[93] Maine Distributed Solar Valuation Study, p. 26.

[94] Maine Distributed Solar Valuation Study, p. 32.

[95] ISO New England. *Open Access Transmission Tariff (OATT) - Schedule 9 Regional Network Service (RNS).* Accessed April 28, 2023. Available at: https://www.iso-ne.com/markets-operations/settlements/understand-bill/item-descriptions/oatt-schedule9-rns.

[96] Maine Distributed Solar Valuation Study, pp. 32-33.

[97] Maine Distributed Solar Valuation Study, p. 33.

Ancillary Services

Avoided Reserve Capacity Cost

Reducing load also reduces the reserve requirement. To account for this impact, the avoided generation capacity cost calculation (see below) is grossed up to account for the applicable reserve capacity margin. This calculation uses net installed capacity requirements (ICR).[98]

Solar Integration Cost

The solar integration cost includes the additional costs of operating reserves necessary to handle increases and decreases in fleet power output corresponding to solar variability. The modeling of variability and the calculation of reserve requirements were beyond the scope of this study. Instead, the study relied on the New England Wind Integration Study (NEWIS),[99] which assessed the operational effects of large-scale wind integration in New England. These results may be considered an upper bound on solar integration costs, as wind is typically more variable than solar generation. The approach for calculating the solar integration costs using the results of the NEWIS study is as follows:

1. Sum the reserve requirements provided in the NEWIS study (e.g., 10-minute spinning reserve, 30-minute operating reserve, 10-minute non-spinning reserve) to get the total operating reserve (TOR).

2. Calculate the incremental TOR as a percentage of renewable capacity by dividing the incremental TOR (study scenario less load-only scenario) by the incremental wind capacity.

3. Take the value from Step 2 and apply it to the unit rating of the Marginal PV Resource multiplied by the installed cost of a simple cycle aeroderivative gas turbine.

4. Adjust the value from Step 3 to account for decreased efficiency of the units to address intermittent PV output.[100]

Avoided RPS Compliance Costs

The study assumed no avoided RPS compliance costs, likely because Maine had a surplus of RECs at the time of the study.

[98] Maine Distributed Solar Valuation Study, p. 30.

[99] New England Wind Integration Study. 2010. Available at https://www.iso-ne.com/static-assets/documents/committees/comm_wkgrps/prtcpnts_comm/pac/reports/2010/newis_report.pdf.

[100] Maine Distributed Solar Valuation Study, pp. 31-32.

Avoided Cost of Carbon and Criteria Pollutants

Estimates of avoided environmental costs are calculated by: (1) determining the annual avoided emissions in tons of pollutant per MWh of PV production and (2) applying forecasted market prices and societal costs to the avoided emissions.[101]

The Maine study used EPA's AVoided Emissions and geneRation Tool (AVERT)[102] to estimate the state-specific hourly avoided emissions of carbon dioxide (CO_2), nitrous oxides (NO_x), and sulfur dioxide (SO_2).[103] The avoided emissions associated with a PV generation profile were then multiplied by the value of those emissions, as described below.

Net Social Cost of Carbon

The "net" SCC is determined by: (1) calculating the total Federal SCC and (2) subtracting the embedded carbon allowance costs that are already included in the energy value (through RGGI compliance costs). To forecast RGGI market prices, the study used the Synapse CO_2 Price Report[104] to estimate future compliance costs. Annual avoided emissions calculated from AVERT were multiplied by the Low Case values for each year, adjusted for PV degradation. For each study year, the avoided RGGI allowance costs were subtracted from the SCC value to obtain the annual net SCC value. These values were then levelized using the environmental discount rate.[105]

Net Social Cost of SO_2

The approach for SO_2 accounts for both the social cost and the cost internalized in the New England energy prices. Internalized compliance costs were based on EPA allowance clearing prices,[106] adjusted for inflation and PV degradation, and levelized using the utility discount rate.[107] The study sourced social costs from the EPA Regulatory Impact Analysis,[108] which estimated health co-benefit values under the proposed 111(d) Clean Power Plan.[109] The net social cost of SO_2 was calculated by subtracting the levelized compliance cost from the social cost.

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[101] Id., p. 34.

[102] U.S. Environmental Protection Agency (EPA). *AVoided Emissions and geneRation Tool (AVERT)*. Available at: https://www.epa.gov/avert.

[103] Maine Distributed Solar Valuation Study, p. 32.

[104] Lucklow, P. et al. 2014. *CO2 Price Report, Spring 2014*. Synapse Energy Economics, Inc., See Table 4. Available at http://www.synapse-energy.com.

[105] Id., p. 36.

[106] U.S. Environmental Protection Agency (EPA). *Clean Air Power Sector Programs*. Accessed April 28, 2023. Available at: https://www.epa.gov/airmarkets/2022-so2-allowance-auction.

[107] Maine Distributed Solar Valuation Study, p. 36.

[108] See p. 4-26, Table 4-7, of the Regulatory Impact Analysis. Available at http://www2.epa.gov/sites/production/files/2014-06/documents/20140602ria-clean-power-plan.pdf.

[109] Maine Distributed Solar Valuation Study, p. 36.

Net Social Cost of NO_x

The study assumed a compliance cost of zero for NO_X, since New England is not subject to either the Cross-State Air Pollution Rule (CSAPR)[110] or the Clean Air Interstate Rule (CAIR).[111] The social cost of NO_X was calculated in the manner as described above for SO_x using a 3 percent discount rate.[112]

Energy Demand Reduction Induced Price Effect (DRIPE)

The reduction in market demand from PV results in lower market clearing prices. The Maine study applied the results of the DRIPE methodology described in the 2013 AESC study, which included the state of Maine. That study used a linear regression to estimate the relationship between market prices and demand, while accounting for a lag in the impacts (due to procurements 2–3 years in advance) as well as a decay of the impacts over time as the market adjusts to a new equilibrium.[113] The DRIPE values were estimated for on-peak and off-peak periods in each winter and summer season. The calculation also accounted for the fact that approximately 8.5 percent of sales are hedged through power purchase agreements and long-term contracts.

Generation Capacity Demand Reduction Induced Price Effect (DRIPE)

The calculation for generation capacity DRIPE was similar to that for energy DRIPE. However, since auctions occur three years in advance of the capacity need, generation capacity DRIPE appears after a three-year lag. Further, the study reduced the generation capacity DRIPE to reflect the ELCC of the PV resource and adjusted the value to reflect the PV resource's capacity factor to provide an average DRIPE value per installed kW of capacity.[114]

Risk or Hedge Value

In the Maine study, the methodology quantifies the hedge value associated only with the natural gas displaced by PV. This value is designed to reflect the fact that natural gas is subject to fuel price volatility, while solar generation is not.[115] To compare these two generation alternatives on an equal basis, the study calculated the cost that would be incurred to remove the price uncertainty associated with natural gas. One way to eliminate the fuel price uncertainty for a future year would be to enter into a futures contract for natural gas delivery in that year and invest enough funds today in risk-free securities that mature in that year.[116]

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[110] For more information, see http://www.epa.gov/crossstaterule/.

[111] For more information, see https://www.epa.gov/sites/production/files/2015-08/documents/cair09_ecm_analyses.pdf.

[112] Maine Distributed Solar Valuation Study, p. 36.

[113] Id., p. 38.

[114] Id., p. 38.

[115] Id., p. 39.

[116] Id., p. 39.

The process for completing this avoided fuel uncertainty calculation for a given year is as follows:

> Step 1: Calculate the amount of avoided fuel, based on an assumed heat rate and on the amount of anticipated plant degradation in year i, and the corresponding future cost.
>
> Step 2: Obtain the risk-free interest rate corresponding to maturation in year i.
>
> Step 3: Discount the expense to obtain the present value using the risk-free discount rate.
>
> Step 4: Calculate the energy value by discounting the future expense at the utility discount rate. (Note: this may not be equal to the energy value obtained using electricity market values.)
>
> Step 5: Subtract the energy value result in Step 4 from the result in Step 3. The remaining value is the avoided risk.
>
> Step 6: Levelize the avoided risk value using the risk-free discount rate.
>
> Step 7: Repeat for all remaining years in the study period and sum.[117]

There are a few difficulties with this methodology requiring some simplifying assumptions:

> Using public NYMEX market prices, which extend 12 years into the future, to represent futures prices for contracts is less than the assumed PV system life (20 years on average). Thus, the methodology assumes NYMEX prices for the first 12 years, and then escalates values as described in the Avoided Energy Cost section.
>
> U.S. government securities provide a public source of effectively risk-free returns but are only available for selected terms (e.g., 2, 3, 5, 7, and 10 years) and so linear interpolation may be necessary.
>
> The heat rate selection will be projected based on the declining trend of Locational Marginal Unit (LMU) heat rates.[118]

Reliability Impacts

The study recognizes that advanced inverters may provide additional services in the future, which may reduce the cost associated with voltage regulation. Consequently, no value was assigned in the 2014 study, but the category was kept as a placeholder for future analyses.[119]

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[117] Id., pp. 39–40.
[118] Id., p. 40.
[119] Id., p. 34.

Utility Interconnection and Operational Costs

The Maine Value of Solar Study recognizes that distributed generation can impose additional costs on the grid, such as through impacting line voltages. However, RTO procedures and Commission rules require that such costs be borne by the interconnecting generator. Thus, the study assumes that interconnecting customer-sited solar generators impose no additional costs on the grid beyond those paid by the solar generator.[120]

B.2. 2016 New York BCA Framework and Value Stack

Under its "Reforming the Energy Vision" proceeding the New York Public Service Commission (NY PSC) established a mechanism called the "Value Stack" to compensate DERs based on the value they provide to the system. The Value Stack has thus far primarily been applied to larger solar and battery storage projects. In addition, the NY PSC established a benefit-cost analysis (BCA) framework and required each utility to file a BCA handbook. The BCA framework is intended to be applied to investments in Distributed System Platform capabilities, competitive procurement of DERs, procurement of DERs through tariffs, and energy efficiency programs.[121] The methodologies below are primarily drawn from Consolidated Edison's BCA handbook, with the exception of the discussion of methodologies for quantifying avoided distribution costs. The methodologies for evaluating avoided distribution costs for compensation under the Value Stack have been the subject of continued discussion and evolution.

Avoided Energy Costs

Avoided energy costs are determined by multiplying the change in energy sales at the retail level (grossed up for losses) by the relevant Locational Based Marginal Prices (LBMP). The New York Independent System Operator (NYISO) conducts a biannual Congestion Assessment and Resource Integration Study (CARIS), which projects congestion on the system and forecasts future LBMPs consisting of energy costs, congestion costs, and losses by load zone.

NYISO uses General Electric's Multi Area Production Simulation (MAPS) model to develop 10-year forecasts. MAPS is a production cost model, which simulates the NYISO day-ahead market by simulating hourly security constrained economic commitment and dispatch. [122] Key model inputs include load flow data, unit heat rates, unit capacities, fuel prices, transmission pressures, load forecasts, load shapes, interchange values, O&M costs, and emission costs.[123]

[120] Clean Power Research. 2014. *Maine Distributed Solar Valuation Study. Volume I: Methodology*, p. 34. Available at https://www.maine.gov/mpuc/electricity/elect_generation/documents/MainePUCVOS-VolI-Methodology.pdf

[121] New York Public Service Commission. Case 14-M-0101, Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision, Order Establishing the Benefit Cost Analysis Framework, January 21, 2016.

[122] NYISO (2019) CARIS, Appendix D, p. 22.

[123] NYISO (2019) CARIS, Appendix C, p. 4.

The avoided energy costs (including costs associated with congestion and losses) used in the New York utilities' analyses are based on NYISO's 20-year hourly forecasts of LBMPs by zone. To the extent that LBMPs are required beyond 20 years, the prices are assumed to stay constant in real (inflation-adjusted) dollars per MWh.[124]

Avoided Generation Capacity

This impact is measured by the change in peak load (the project's expected demand reduction capability), grossed up to account for losses. The change in peak load accounts for both the resource's system coincidence factor (i.e., the coincidence of the load impact with actual system peak relative to its nameplate capacity), and a derating factor (which indicates the probability that the resource will be available during system peak hours).[125]

The impact on system peak load is then multiplied by the avoided generation capacity cost, which is based on the New York Department of Public Service (NY DPS) Staff's forecast of spot capacity market prices[126] and takes into account demand and supply forecasts from NYISO's Load and Capacity Data report.[127] The NY DPS Staff create their forecast using the capacity forecasts from the NYISO's Gold Book, together with more recent data on new units or unit retirements. If insufficient generation capacity is forecasted, Staff assumes that new resources will enter at demand curve reference prices, which are based on the Cost of New Entry (CONE).[128]

Avoided Transmission and Distribution Losses

Transmission losses are included in the calculation of LBMPs.[129]

Avoided Transmission Capacity

Short-run avoided transmission congestion costs are captured in LBMPs, but other avoided transmission capacity costs must be modeled separately. Avoided transmission capacity costs measure the change in system peak load (the project's expected demand reduction capability), grossed up to account for losses occurring between the bulk system and the retail customer. The change in peak load accounts for both the resource's transmission coincidence factor (i.e., the coincidence of the load impact with actual

[124] ConEdison (2020) BCA Handbook, p. 18.
[125] ConEdison (2020) BCA Handbook, p. 16.
[126] This input is filed in Case M-0101.
[127] ConEdison (2020) BCA Handbook, p. 17.
[128] NY DPS Staff. 2015. *Staff Whitepaper on Benefit-Cost Analysis in the Reforming the Energy Vision Proceeding*, 14-M-0101.
[129] ConEdison (2020) BCA Handbook, p. 22.

transmission system peak relative to its nameplate capacity), and a derating factor (which indicates the probability that the resource will be available during system peak hours).[130]

The change in peak load is then multiplied by the marginal transmission cost. In some cases, this cost is related to a specific project being avoided, with localized and equipment-specific costs. In other cases, a system-wide average marginal cost is used. ConEdison developed its estimate of system-wide marginal transmission costs in a marginal cost of service study in its 2016 rate case filing.[131]

To develop its system-wide marginal transmission cost estimate, ConEdison used a planning/engineering approach. This methodology identifies components of the system that are driven by load growth and the costs associated with constructing and operating those system components. Specifically, ConEdison used a sample of projects on specific segments of the transmission and distribution system where load-driven expansions were planned, and the cost associated with those projects. ConEdison then converted the project costs to annual marginal costs using carrying charges, O&M, and other applicable loading factors. Transmission costs were developed on a year-by-year basis to reflect the long-term construction schedules for these projects.[132]

Avoided Distribution System Costs

To estimate the avoided distribution system costs associated with DERs, each New York utility conducted its own analysis. Most utilities relied on a marginal cost of service study to estimate the potential avoided distribution costs, but Central Hudson Gas & Electric (CHG&E) conducted a more detailed avoided transmission and distribution cost analysis.

The methodologies varied across utilities, but the marginal cost of service analyses were broadly similar in terms of estimating unit costs associated with load-driven distribution system investments and applying carrying costs and other adders to this value. However, the utilities' marginal cost analyses differed in terms of the types of distribution costs deemed avoidable and included in the analysis, and the extent to which additional investments would be required to serve future load. The utilities that conducted marginal cost of service analyses (rather than an avoided cost analysis) did not remove projections of additional DERs from their load forecasts, thereby underestimating the need for future T&D investments. Some utilities also omitted smaller capital projects (e.g., on the secondary distribution system) from their analysis of potentially avoidable investments.

As an example, ConEdison developed its estimated investment needs separately for (1) transmission, sub transmission, and area substations; and (2) distribution costs (feeders, distribution transformers, secondary wires). For the first category, ConEdison took investment needs, timing, and locations from the Company's Ten-Year Load Relief Program (LRP) investment plan. For the second category, load

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[130] For example, a demand response program may be limited in terms of the number of hours it can be called in a season, thereby limiting its availability during peak hours. ConEdison (2020) BCA Handbook, p. 20.

[131] Consolidated Edison 2016 Rate Case Filing DAC-3, Schedule 1, Case 16-E-0060, January 29, 2016.

[132] Consolidated Edison Demand Analysis and cost of Service Panel Direct Testimony, Case 16-E-0060, January 29, 2016, p. 33.

growth estimates were taken from the LRP, and ConEdison assumed trends in investments from the past three years would continue.[133]

In contrast, New York State Electric & Gas (NYSEG) and Rochester Gas & Electric (RG&E) exclude local primary and secondary lines and transformer costs from their studies. These costs appear to be excluded on the grounds that equipment is sized based on long-term maximum customer demands, rather than based on updated demand data.[134]

Central Hudson Gas & Electric (CHG&E) was the only utility to conduct an avoided T&D cost study. This study removed future DER installations from the forecast in order to construct a counterfactual baseline by which to measure the impacts of additional DERs. CHG&E was also the only utility to conduct a probabilistic load forecast in order to assess the impacts of DERs over a range of possible futures.

Once the utilities identified the marginal costs associated with load growth on their distribution systems, they applied the economic carrying charge associated with traditional investments to calculate an annual deferral value.[135]

Ancillary Services

The New York utilities only account for ancillary service benefits when DERs are able and willing to bid into NYISO's ancillary service markets. When DERs only operate behind the meter as a load modifier, they are assumed to have no impact on ancillary service requirements, as the NYISO procures ancillary services based on available generating resource characteristics. Where DERs bid into the ancillary services markets, the avoided cost is determined by the two-year historical NYISO market clearing prices. Similarly, if DERs increase ancillary service costs, the additional cost is estimated using the two-year historical NYISO market clearing prices.[136]

Avoided RPS Compliance Costs

In addition to participating in RGGI, New York has a Clean Energy Standard (CES). The avoided cost of compliance with the CES is valued as the REC price from the most recently completed NYSERDA RECs solicitation.[137] The BCA handbook does not provide a methodology for forecasting future REC prices.

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[133] Con Edison MCOS 2018, p. iii states "Investment needs are assessed by observing the frequency of upgrades that occurred historically (e.g., on average, an upgrade was performed when peak load was anticipated to increase by 10 MW) and applying that frequency to the estimated future load (using the Load Area forecast load growth from LRP)."

[134] NYSEG and RG&E, Case No. 16-M-0411, Response to Interrogatory/Document Request on NY Utilities MCOS Studies, Request No: DSIP-18-016. Filed November 2018.

[135] CHG&E's Avoided T&D Cost Study, 2018, page. 16, Con Edison MCOS 2018, p. 9 and NYSEG & RG&E DSIP 2018, Appendix D, page D-1.

[136] ConEdison (2020) BCA Handbook, pp. 23, 40.

[137] ConEdison (2020) BCA Handbook, pp. 35-37.

Avoided Cost of Carbon and Criteria Pollutants

In December 2020, the New York State Department of Environmental Conservation released guidelines regarding the SCC. The guidance recommends using the SCC values issued by the Obama Administration in 2016 as interim values, but with a central discount rate of 2 percent.[138] The net SCC (referred to as the net damage costs) are then determined by subtracting the cost of carbon already embedded in the energy price through compliance with RGGI.[139]

The value of avoided compliance with criteria pollutant limits for SO_2 and NO_X are already internalized in the avoided energy cost through allowance prices. These prices are thought to reflect the monetized damages to society.[140]

Energy Demand Reduction Induced Price Effect (DRIPE)

In New York, the wholesale energy market price impact is estimated by DPS Staff using the most recent CARIS database. The impact is estimated for a 1 percent change in load. To calculate the total benefit, the change in LBMP is multiplied by the total energy in a zone for a specific year at the bulk-system level, less the fraction that is hedged via fixed price or multi-year agreements. These impacts are assumed to only persist for one year, as the markets typically respond quickly to the reduced demand, thereby reducing the benefit.

Generation Capacity Demand Reduction Induced Price Effect (DRIPE)

DPS Staff estimates the wholesale generation market price impact by using a spreadsheet model of generation capacity costs. To calculate the total benefit, DPS Staff multiplies the change in generation capacity clearing price by the total generation capacity in a zone for a specific year at the bulk-system level, less the fraction that is hedged via fixed price or multi-year agreements. These impacts are assumed to only persist for one year, as the markets are expected to respond quickly to the reduced demand, thereby reducing the benefit.

Risk or Hedge Value

No risk or hedge value benefit is attributed to DERs.

Reliability Impacts

Enhanced reliability is primarily measured as the avoided load lost (in kWh) due to DERs multiplied by the "Value of Service" (in $/kWh) to the customers who would have been interrupted. The BCA Handbook states that this value should be determined based on the customers' willingness to pay for

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[138] New York State Department of Environmental Conservation. 2020. Establishing a Value of Carbon: Guidelines for Use by State Agencies. Available at: https://www.dec.ny.gov/docs/administration_pdf/vocfguid.pdf.

[139] ConEdison (2020) BCA Handbook, p. 35.

[140] ConEdison (2020) BCA Handbook, p. 38.

reliability but does not provide willingness-to-pay values. Instead, the Handbook notes that the retail rate can be used if willingness-to-pay values are not available. However, the retail rate is clearly a floor for customer willingness-to-pay.[141]

The New York utilities do not discuss exactly how they estimate changes in reliability, other than to identify instances where DERs supply backup power in the event of an outage.[142] Other instances in which DERs could enhance reliability on the distribution system do not appear to be included.

Increased Utility Administration Costs

Actual program administration costs (including incentives such as rebates, program administration costs, measurement and verification, and other costs) are summed and escalated with inflation as needed.

Utility Interconnection and Operational Costs

The New York utilities account for actual incremental investments in the system not borne by host customers (e.g., expanded generation capacity or additional control functionalities) as utility system costs in their cost-effectiveness analyses. The utilities simply sum and escalate these costs with inflation as needed.

B.3. 2017 District of Columbia Value of Solar Study

In 2017, Synapse conducted a value of solar study for the District of Columbia on behalf of the Office of People's Counsel.[143] We summarize that methodology below.

Avoided Energy Costs

To calculate the total avoided energy benefit across each year, each hour's estimated solar generation profile from PVWatts was correlated to a system marginal energy cost, based on historical data for the PJM Interconnect for 2015.[144] The study used 2015 locational marginal prices for the PEPCO zone of PJM and subtracted the congestion and marginal loss portions of the cost, as these costs were accounted for elsewhere in the study.

The cost of avoided fuel is the dominant factor in avoided input costs. For future years, fuel costs were assumed to follow the trajectory of regional electricity generation system prices within EIA's Annual

[141] ConEdison (2020) BCA Handbook, pp. 33-34.

[142] ConEdison (2020) BCA Handbook, pp. 34-35.

[143] Whited, et al. 2017. *Distributed Solar in the District of Columbia: Policy Options, Potential, Value of Solar, and Cost-Shifting*. Prepared for the Office of the People's Counsel for the District of Columbia. "2017 DC VoS Study." Available at: https://www.opc-dc.gov/images/pdf/solar/Synapse-DC-Solar-Report-April1217.pdf.

[144] PJM Hourly Integrated Real Time LMP data for 2015. Available at: http://pjm.com/markets-and-operations/energy/real-time/monthlylmp.aspx.

Energy Outlook 2016.[145] Synapse used the AEO Reference Case to scale up the base-year weighted energy cost of $36.35/MWh, based on generation prices in the region applicable to Pepco. Low and high avoided energy scenarios were created using the electric power natural gas prices associated with the High Oil and Gas Resource and Technology and the Low Oil and Gas Resource and Technology AEO 2016 cases.[146]

Avoided Generation Capacity

PJM RPM auction results for the PEPCO zone (in nominal dollars) were used to determine generation capacity prices through the 2019/2020 auction year. For generation capacity price forecasts beyond that, Synapse developed price estimates consistent with the following observations:

1. In years of transmission constraint (2012/2013–2016/2017), the PEPCO zone results were higher than the remainder of PJM, substantially higher in some years.
2. As a percent of PEPCO Net Cost of New Entry (Net CONE), the PEPCO RPM result has declined from 108 percent in 2010/2011 to 41 percent in the 2019/2020 auction.
3. The PEPCO Net CONE value has been less than the PJM-wide Net CONE value since 2012/2013.[147]

The previous five-year net CONE average (adjusted for inflation) was used as the forecasted future value of Net CONE, both for PEPCO and PJM-wide. To calculate a forecast of generation capacity value through 2040, Synapse calculated the historical ratio of RPM results to Net CONE and multiplied that fraction by the forecasted Net CONE. The low forecast used the RTO-wide result assuming no transmission constraints. The high forecast was estimated to be the PEPCO result, a value that embeds historical transmission constraints. A "mid" forecast was created as the mean of the high and low forecasts.[148]

Avoided Transmission and Distribution Losses

To estimate marginal transmission losses, Synapse began by using PJM's published average on-peak loss rate of 3 percent.[149] As discussed by Lazar and Baldwin in a 2011 Regulatory Assistance Project report, marginal losses on a line are typically 1.5 times the average loss on the line at that moment.[150] To convert from average to marginal, the value was multiplied by 1.5.

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[145] EIA. AEO 2016 Final Report. September 15, 2016. Available at: http://www.eia.gov/forecasts/aeo/.

[146] 2017 DC VoS Study, p. 129.

[147] 2017 DC VoS Study, p. 134.

[148] 2017 DC VoS Study, p. 134.

[149] PJM, "Marginal Losses Implementation Training," Winter 2007. Available at: www.pjm.com/~/media/training/new initiatives/ip-ml/marginal-losses-implementation-training.ashx, p. 12 and p. 83.

[150] Lazar, Jim and Xavier Baldwin. 2011. *Valuing the Contribution of Energy Efficiency to Avoided Marginal Line Losses and Reserve Requirements*. Available at: http://www.raponline.org/wp-content/uploads/2016/05/rap-lazar-eeandlinelosses-2011-08-17.pdf.

For distribution losses, Synapse relied on Pepco's 2015 distribution loss study,[151] which reported an average loss value of 6.85 percent. Multiplying the average by 1.5 allows for an estimate of the marginal line losses.[152]

Avoided Transmission Capacity

The study estimated historical transmission capacity expenditures based on data provided by Pepco for the District of Columbia. Transmission capacity spending by Pepco had been increasing annually but leveled off in the three years prior to the study. Rather than project if or how that spending would continue to increase, the transmission capacity expenditures from the most recent year (2015) were simply projected to remain constant. The avoided costs were then divided by the solar effective load carrying contribution to account for solar PV's peak output not being completely aligned with peak load requirements.[153] The solar capacity contribution value used in that analysis was the value established by PJM of 38 percent.[154]

Avoided Distribution System Costs

The study took non-coincident area peak distributional marginal costs from Pepco DC's marginal cost of service study. These costs were based on forecasted marginal primary distribution and secondary distribution capacity, O&M, and voltage costs for the 2015–2019 timeframe, expressed in $/kW. The avoided costs associated with distributed PV were then estimated by multiplying the reduction in non-coincident area peak attributed to distributed solar by the forecasted marginal costs. Similar to transmission costs, solar's effective load carrying contribution for PJM was used to estimate solar's ability to reduce distribution peak demand. The study recognized that although some circuits peak later in the day and will not receive as much distribution system cost avoidance, other circuits peak closer to noontime and will receive more distribution cost avoidance than the solar capacity contribution value allows. Therefore, the average solar coincidence with RTO load was thought to be a reasonable proxy for Pepco's distribution system as a whole. Distribution costs are avoided only once for a distributed PV installation and were thus modeled for only the first year.[155]

Ancillary Services

To account for the impact on ancillary service costs (either positive or negative), Synapse reviewed Pepco DC and PJM documentation related to ancillary service costs as a function of solar PV, as well as a

[151] Pepco response to OPC DR 2-10, Attachment B, Page 1.

[152] 2017 DC VoS Study, p. 132.

[153] 2017 DC VoS Study, p. 132.

[154] PJM. Revision 11, March 5, 2014. "PJM Manual 21 Rules and Procedures for Determination of Generation Capacity." See B.3.j, page 19. Available at: https://www.pjm.com/~/media/documents/manuals/m21.ashx.

[155] 2017 DC VoS Study, pp. 124-125.

review of value of solar studies from around the country.[156] Ultimately no value was assigned for avoided ancillary service costs, since it was unclear whether solar would likely have a positive or negative impact on such costs. In the future, advanced inverters may reduce certain ancillary service costs; but until they become more widely used, the study assumed such value would not be widely realized.[157]

Avoided RPS Compliance Costs

For Tier I RECs, Synapse generated a low, medium, and high REC price forecast. The price of wind RECs in the most recent compliance year was used as the low forecast, as this technology exhibits significant potential growth and was thus expected to represent a significant share of incremental RECs in future years. The high REC price forecast was based on the price paid for wind RECs within PJM at the time of the study.[158]

For SRECs, Synapse also developed three forecasts, each containing three sections to reflect changes in compliance levels over time. The first portion of each forecast pegs the price of an SREC at 96.7 percent of the ACP, which assumes that not enough SRECs are generated to meet the solar carve-out. The second portion of the forecast occurs when the quantity of SRECs is adequate to meet the RPS solar carve-out. Once that parity is achieved, the SREC price is expected to fall to the level of subsidy that is sufficient to stimulate enough solar PV installations annually to maintain pace with the increasing solar carve-out requirements. For the study, this was estimated to be $280/MWh. The third portion of the forecast reflects the later years of compliance in which the ACP is reduced considerably, eventually falling below the subsidy requirement. At that point, the SREC price will shift again, this time back to 96.7 percent of the now much-lower ACP.[159]

The avoided REC cost was calculated as the REC price times the RPS Tier I fraction of sales requirement in that year, as shown in the equation below. The avoided SREC Cost was calculated similarly, using the SREC price and the solar carve-out requirement. Because the solar carve-out requirement represents a portion of the Tier I obligation, the net Tier I REC obligation under the RPS was calculated as the Tier I obligation minus the solar carve-out obligation.[160]

$$Avoided\ REC\ Cost\ = REC\ Price * RPS\ Tier\ I\ Fraction\ of\ Sales\ Requirement$$

[156] See for example Rocky Mountain Institute, "A Review of Solar PV Benefit & Cost Studies," 2nd Edition, September 2013, page 33. Available at: http://www.rmi.org/cms/Download.aspx?id=10793&file=eLab_DERBenefitCostDeck_2nd_Edition&title=A+Review+of+Solar+PV+Benefit+and+Cost+Studies.pdf.

[157] 2017 DC VoS Study, p. 127.

[158] 2017 DC VoS Study, p. 137.

[159] 2017 DC VoS Study, p. 137.

[160] 2017 DC VoS Study, p. 137.

Avoided Carbon and Criteria Pollutants

Criteria air pollutant costs and RGGI compliance costs are embedded in PJM wholesale energy prices and were thus included in the avoided energy costs.[161] To account for the additional societal impacts of carbon, Synapse multiplied the federal SCC (as updated in 2015) by the marginal emissions rate.[162]

To estimate the marginal emissions rate, the study used PJM's forecast of gas and coal capacity to determine the fraction of gas- and coal-fired generation on the margin over the period of the study. The emissions rates for coal and gas[163] were then weighted by the gas and coal capacity forecast to estimate the marginal emissions rate within PJM.[164]

Energy Demand Reduction Induced Price Effect (DRIPE)

The value of solar study relied on an estimate of DRIPE from a 2014 study.[165] The 2014 study estimated a DRIPE energy ratio of 1.17, implying that every 1 percent reduction of energy consumption results in a 1.17 percent reduction in price. Because DRIPE is shared throughout the RTO, customers in the District will only receive roughly 1.57 percent of the benefits. The remaining 98.43 percent of the energy DRIPE benefits flow to other PJM ratepayers and represent a societal benefit. Because there is significant generator build and generator retirement within PJM, Synapse assumed that DRIPE energy benefits dissipate quickly, in a linear manner over a five-year timeframe.[166]

Generation Capacity Demand Reduction Induced Price Effect (DRIPE)

Generation capacity DRIPE was calculated in an avoided cost study performed for Maryland in 2014, including for Pepco.[167] Synapse employed the generation capacity DRIPE price differentials from that study, adjusted for inflation, the Pepco DC fraction of the Pepco zone (of which Pepco DC represents 40.7 percent), and for Synapse's more accelerated decay of DRIPE. Because PJM's RPM capacity auctions

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161 2017 DC VoS Study, p. 141.

162 2017 DC VoS Study, pp. 149-150.

163 EIA, "Table 8.2. Average Tested Heat Rates by Prime Mover and Energy Source, 2007 – 2015." Available at: http://www.eia.gov/electricity/annual/html/epa_08_02.html; and EIA, "Frequently Asked Questions: How much carbon dioxide is produced when different fuels are burned?" June 14, 2016. Available at: https://www.eia.gov/tools/faqs/faq.cfm?id=73&t=11.

164 2017 DC VoS Study, pp. 149-150.

165 Max Neubauer et. al. 2013. "Ohio's Energy Efficiency Standard: Impacts on the Ohio Wholesale Electricity Market and Benefits to the State." Report number E138. Pages 27 and 28. Available at: http://www.ohiomfg.com/legacy/communities/energy/OMA-ACEEE_Study_Ohio_Energy_Efficiency_Standard.pdf.

166 2017 DC VoS Study, p. 142.

167 Exeter Associates. 2014. "Avoided Energy Costs in Maryland." http://webapp.psc.state.md.us/Intranet/casenum/NewIndex3_VOpenFile.cfm?filepath=C:%5CCasenum%5C9100-9199%5C9154%5CItem_525%5C%5CAvoidedEnergyCostsinMaryland.pdf.

procure capacity for future years, the five years of DRIPE for this study year were applied to auction years in which the auction had not yet occurred.[168]

Renewable Energy Certificate Supply Induced Price Effect (SIPE)

The Supply Induced Price Effect (SIPE) exists when additional supply added to the marketplace results in a price reduction effect. If enough distributed solar were to come online to create a surplus of SRECs, the market price for all District compliance SRECs would fall from nearly-ACP to the price necessary to subsidize enough installations each year for Washington, DC to meet its solar carve-out requirement for that year. Synapse used the same REC and SREC price forecasts and District-wide solar adoption rate forecast described earlier, as well as forecasted sales to determine the number of SRECs required by the RPS. Because the sensitivities around solar adoption only result in an acceleration or delay of solar carve-out compliance by one year earlier or later, the SREC SIPE benefit will only occur for one year—the first year when the SREC price falls from nearly ACP to the necessary subsidy value.[169]

Risk or Hedge Value

The study relied on a 10 percent proxy value for risk benefits, in line with a variety of other studies, as there was scant available data by which to estimate the risk benefits of distributed.[170] The risk premium was applied only to categories where market or deployment risk was thought to be present, and only in the years for which there was risk. The categories for which the risk premium was applied are avoided energy, avoided generation capacity, avoided distribution capacity, avoided transmission capacity, avoided environmental compliance, avoided Tier I RPS compliance, avoided solar carve-out RPS compliance, and DER integration. No risk premium was applied to SREC prices until the year in which the solar carve-out was expected to fall below the ACP.[171]

Reliability Impacts

The study did not estimate reliability benefits because smart inverters were not yet widely adopted in the United States, meaning that benefits are not expected to accrue for many years (resulting in low present value due to discounting) and due to a lack of credible forecasts regarding smart inverter benefits.[172]

[168] 2017 DC VoS Study, p. 144.

[169] 2017 DC VoS Study, pp. 145-146.

[170] 2017 DC VoS Study, p. 147.

[171] 2017 DC VoS Study, p. 148.

[172] 2017 DC VoS Study, p. 149.

B.4. 2020 California Avoided Cost Calculator

In 2004, California initiated a proceeding to develop a consistent set of avoided costs across various types of DERs, including energy efficiency, demand response, and distributed generation.[173] In particular, the proceeding sought to coordinate methodologies and input assumptions for the devleopment of avoided costs to be applied to various DERs. The California Public Utilities Commission (CPUC) ultimately adopted the avoided cost forecast methodology and associated spreadsheet model (the Avoided Cost Calculator) prepared by the consulting firm E3. Since then, the assumptions, data, and models used in the avoided cost calculator hasve been regularly updated and are described in Appendix B.

More recently, California has developed a Locational Net Benefits Analysis (LNBA) methodology that expands on the Avoided Cost Calculator by including location-specific values and certain additional avoided cost components. In its 2017 decision on the LNBA, the CPUC adopted several use cases for the values produced by the LNBA: as a heat map showing high-value locations for the installation of DERs, to identify candidate distribution system investments for deferral, and for incorporation into the Avoided Cost Calculator for cost-effectiveness evaluation and for informing DER incentive levels.[174] These use cases have largely been implemented, with each investor-owned utility having developed granular heat maps showing the value of DERs in various locations, and the distribution system avoided by location being identified in competitive solicitations for non-wires alternatives.[175]

Avoided Energy Costs

The SERVM production simulation model is used to generate values for the energy avoided cost component. The SERVM Day-ahead hourly energy prices include the effects of carbon pricing from the cap-and-trade market, which must be removed during the post-processing of the results to leave only fuel costs and power plant operating costs. SERVM model runs only produce energy prices through 2030. To extrapolate energy prices to 2050, hourly implied marginal heat rates (which are proxies for marginal generators) are coupled with projections of fuel costs, power plant O&M costs, and carbon prices.[176]

Avoided Generation Capacity

Marginal generation capacity costs are estimated based on integrated resource planning (IRP) simulations using the RESOLVE model. Currently, the avoided generation capacity cost is based on the

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[173] California Public Utilities Commission, Order Instituting Rulemaking (R.) 04-04-025, April 22,2004.

[174] CPUC Decision 17-09-026, September 28, 2017.

[175] *See*, for example, PG&E's Distribution Investment Deferral Framework Request for Offer here: https://www.pge.com/en_US/for-our-business-partners/energy-supply/electric-rfo/wholesale-electric-power-procurement/2019-didf-rfo.page?WT.mc_id=Vanity_rfo-didf&ctx=large-business

[176] 2020 ACC Documentation, pp. 10-11.

Net Cost of New Entry (Net CONE) of battery storage with a 4-hour duration.[177] The levelized fixed costs of a battery over its useful life are calculated using the cost and performance assumptions and financial pro-forma model from the IRP. The prices for energy and ancillary services are derived from SERVM production simulation and are used to calculate net market revenues for a new battery storage resource. The revenues that the batteries earn, assuming optimal dispatch, are subtracted from the levelized fixed costs to calculate Net CONE.[178]

After adjusting for temperature, losses, and planning reserve margin, the generation capacity values ($/kW-yr) are allocated to the hours of the year with highest system capacity need using the E3 RECAP model. This model uses extensive historical load and generation data to determine the expected unserved energy for each hour of the year, which are then allocated to days of the year for which there is the highest relative system capacity need.[179]

Avoided Transmission and Distribution Losses

The value of deferring transmission and distribution (T&D) investments is adjusted for losses during the peak period using loss factors calculated by the investor-owned utilities.[180] Table 32 shows the loss factors for SCE and SDG&E T&D capacity.

Table 32. Loss Factors for SCE and SDG&E Transmission and Distribution Capacity

	SCE	SDG&E
Transmission	1.054	1.071
Distribution	1.022	1.043

Avoided Transmission Capacity

Transmission avoided costs are developed from general rate case data and data provided by the utilities.[181] Long-term transmission marginal costs ($/kW-yr) are estimated using the Discounted Total Investment Method (DTIM). This method calculates the unit cost of transmission capacity by estimating the present value of peak-demand driven transmission investments divided by peak demand growth. A real economic carrying charge is then applied to this value, as well as other factors such as administrative and general costs and operations and maintenance costs.[182] The annual inflation rate is used to escalate the transmission capacity marginal costs to nominal dollars.[183]

[177] 2020 ACC Documentation, p. 5 and p. 31.
[178] 2020 ACC Documentation, p. 32.
[179] 2020 ACC Documentation, pp. 33-34.
[180] 2020 ACC Documentation, p. 70.
[181] 2020 ACC Documentation, p. 7.
[182] 2020 ACC Documentation, p. 37.
[183] 2020 ACC Documentation, p. 46.

The annual avoided transmission capacity costs are allocated to hours of the year using the peak capacity allocation (PCAF) method to reflect the time-varying need for transmission capacity. The PCAF method "allocates capacity costs to the hours where each utility system is most likely to be constrained and require upgrades—the hours of highest load, with the additional constraint that the peak period contain between 20 and 250 hours for the year."[184]

Distribution System Costs

The 2020 California Avoided Cost Calculator (ACC) recognizes that reducing peak demand can lead to deferring or avoiding investments in distribution infrastructure.[185] Such distribution system avoided costs are developed using information filed in the utilities' Distribution Deferral Opportunity Reports (DDOR) and Grid Needs Assessment, as well as information acquired through data requests.[186]

The ACC identifies two types of avoided distribution capacity costs, referred to as "specified" and "unspecified."[187] Specified deferrals are avoided costs specific to a small number of utility capacity projects that could potentially be deferred via DER adoptions in the project areas.[188] However, specified deferrals are not well-suited to determining the avoided distribution costs because it is difficult to know *a priori* whether there will be a need for a capacity-driven distribution project since the utility load growth forecast may include embedded DER which reduces peak loads and conceals the real need for incremental projects over the five-year planning horizon. The marginal costs of the specified deferrals are not included in the ACC since the ACC cannot currently accommodate the geographic specificity that would be necessary for the specified deferral cases.[189]

Unspecified deferrals estimate the near-term, system-wide marginal distribution capacity costs under the *No New DER* local load or "counterfactual" forecast where new embedded DER are removed from the utility's planning forecast.[190] The near-term distribution marginal costs approach the long-term marginal cost levels after year five.[191]

The calculation for the marginal cost under the counterfactual forecast uses the methodology developed in the Energy Division T&D White Paper:[192]

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[184] 2020 ACC Documentation, p. 47.

[185] 2020 Distributed Energy Resources Avoided Cost Calculator Documentation for the California Public Utilities Commission ("2020 ACC Documentation"). June 24, 2020. p. 48.

[186] 2020 ACC Documentation, p. 7.

[187] 2020 ACC Documentation, p. 49.

[188] 2020 ACC Documentation, p. 49.

[189] 2020 ACC Documentation, pp. 49- 50.

[190] 2020 ACC Documentation, p. 49.

[191] 2020 ACC Documentation, p. 51.

[192] Administrative Law Judge's Amended Ruling Requesting Comments on the Energy Division White Paper on Avoided Costs and Locational Granularity of Transmission and Distribution Deferral Values, June 2019, Attachment A, p. 11.

1. Calculate the counterfactual forecast for each listed circuit, by removing the circuit-level DER forecast from the circuit-level load.

2. Identify potential new distribution capacity projects for all circuits that exceed the facility rating in any year of the counterfactual forecast.

3. Estimate the percentage of distribution capacity overloads that lead to a deferred distribution upgrade by calculating a system-level quantity for deferred distribution capacity using a ratio between capacity overloads to deferrable capacity overloads. The resulting percentage is a proxy for the percentage of distribution capacity upgrades that can be deferred by DER. This percentage is then multiplied by the number of deferrable projects from Step 2 to determine the subset of counterfactual distribution capacity projects that could potentially be deferred by DER.

4. Calculate the average marginal cost ($/kW-yr) of the deferred distribution upgrades. This is done by summing the avoided distribution cost ($/kW-yr) for each project multiplied by its total deficiency need over the planning horizon, divided by the total deficiency need for all projects.

5. Calculate system-level avoided costs by multiplying the average marginal cost found in Step 4 by the total quantity of deferred distribution capacity by DERs for each circuit. The product is divided by the sum of forecasted level of DERs for all areas to obtain a single, system-level distribution deferral value in $/kW-yr.[193]

This method essentially develops a counterfactual distribution capital plan, which is then converted into a system average marginal cost using by applying a Real Economic Carrying Charge annualization factor[194] along with loaders or adders, such as for administrative and general (A&G) and O&M.[195]

These avoided cost estimates are developed using a five-year planning horizon. For Years 8 and beyond, the investment level from the utility's General Rate Case is held constant on a real-dollar basis, while Years 6 and 7 represent an interpolation between Years 5 and 8.[196]

The annual avoided distribution capacity costs are allocated to hours of the year to reflect the time-varying need for distribution capacity.[197]

[193] 2020 ACC Documentation, p. 50.
[194] 2020 ACC Documentation, p. 65.
[195] 2020 ACC Documentation, p. 51.
[196] 2020 ACC Documentation, p. 60.
[197] 2020 ACC Documentation, p. 66.

Ancillary Services

Ancillary service procurements in the day-ahead CAISO market are largely based on the next day load forecasts and reducing load generally decreases the amount of spin and non-spin ancillary services that must be procured to operate the system.[198] Based on the 2018 CAISO Annual Report on Market Issues and Performance,[199] this load dependent ancillary service procurement is approximately 0.9 percent[200] of total wholesale energy costs. The SERVM production simulation model is used to provide forecasted values for ancillary services. The ACC calculates the ratio of spinning reserve to energy prices and applies a 0.9 percent adjustment proportionally to the SERVM results for each year from 2021–2030 to reflect the ancillary services contribution. After 2030, the result is held constant.[201]

Avoided Cost of Carbon and Criteria Pollutants

The avoided costs of GHG emissions are based on both the amount and the value of GHG emissions from the electric grid. This includes both the monetized GHG value (as reflected in the cap-and-trade costs embedded in energy costs) and the non-monetized value, referred to as the "GHG Adder."[202]

The 2020 GHG values are based on the IRP RESOLVE outputs from the No New DER scenario, which provides the shadow price of GHG emission reductions representing the cost of reducing an additional unit of GHGs in each year.

The 2020 ACC uses a two-step approach to estimate GHG emissions impacts from DER measures:

1. Marginal Emissions: Hourly marginal GHG emissions from DERs will be estimated with hourly marginal emissions rates derived from SERVM production simulation of the No New DER case. To derive the hourly marginal emissions for individual types of DERs, the hourly load shapes for each type of DER are multiplied by the hourly marginal emissions rates in tons of CO_2/kWh for each year of the analysis.

2. Portfolio Rebalancing: Rebalancing the supply-side portfolio to achieve the annual GHG emissions intensity targets set in the IRP by making adjustments to the DER portfolio.[203]

Figure 29 conceptually illustrates how this is done and illustrates the net impact of increasing load. The 2020 ACC calculates an estimate of long-run, average annual electric grid GHG emissions intensity

[198] 2020 ACC Documentation, p. 10.

[199] CAISO, 2018 Report on Market Issues and Performance, p. 141-142 and Figure 6.2. May 15, 2019. Available at: http://www.caiso.com/market/Pages/MarketMonitoring/AnnualQuarterlyReports/Default.aspx. Total cost of ancillary services as a percentage of wholesale energy costs is 1.7 percent, and 53 percent of that is estimated to be spin and non-spin, resulting in 0.9 percent.

[200] The total cost of ancillary services as a percentage of wholesale energy costs is 1.7 percent, and 53 percent of that is estimated to be spin and non-spin, resulting in 0.9 percent.

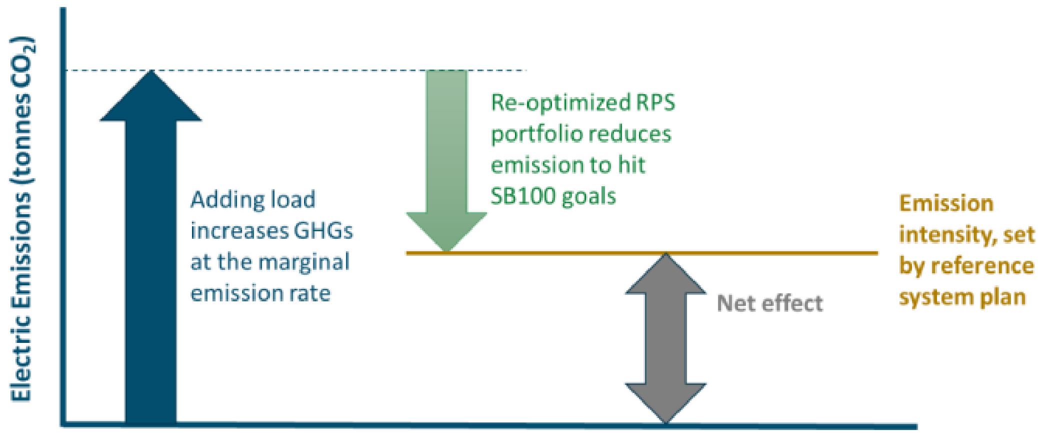
[201] 2020 ACC Documentation, pp. 16-17.

[202] 2020 ACC Documentation, p. 20.

[203] 2020 ACC Documentation, p. 24-25.

aligned with California's GHG reduction target of 100 percent decarbonized electricity (as measured by retail sales) by 2045. The annual emissions intensity values derived from the IRP are used in the RESOLVE capacity expansion modeling to determine the least-cost resource portfolio for meeting electricity sector GHG emission targets. In the long-term, the annual emissions from electricity will decline, and the GHG target will be met, but the portfolio cost will be higher or lower depending on the shape of DER impacts.[204]

Figure 29. Illustrative Long-Run Emissions Calculation



Source: CPUC 2020 ACC Documentation, p. 28.

Energy Demand Reduction Induced Price Effect (DRIPE)

Not estimated.

Generation Capacity Demand Reduction Induced Price Effect (DRIPE)

Not estimated.

Risk or Hedge Value

Not estimated.

Reliability Impacts

Not estimated.

[204] 2020 ACC Documentation, p. 25.

B.5. 2020 New Hampshire Locational Value of Distributed Generation Study

To support the development of tariffs for distributed generation, the New Hampshire Public Utilities Commission engaged a consultant (Guidehouse) to conduct a study regarding the value of distribution-level load reductions potentially achievable on the distribution system. The Locational Value of Distributed Generation (LVDG) study determines the avoidable or deferrable distribution infrastructure investment (capital) costs at a sample of specific distribution system locations in New Hampshire.[205] Because the study was based on a sample of projects with distribution capacity needs, it is not intended to determine a system-wide value of distributed generation and does not attempt to perform a non-wires solution analysis to meet the identified locational distribution capacity need.[206] The study estimates the avoided cost of localized distribution capacity deferral or avoidance, but it does not estimate any other avoided costs associated with distributed energy resources.

Localized Distribution System Avoided Costs

The LVDG study focuses on substantial distribution system capacity investments, such as replacements or upgrades of substations or circuits by analyzing distribution capacity needs over a 15-year planning horizon (5-years historical, and 10-years forward-looking) beginning in the year 2020. The study then analyzes distribution system capacity constraints under base, low, and high load growth scenarios[207] and analyzes the potential value resulting from load reductions.

For each location, the avoided distribution costs are distributed across the years of distribution capacity need within the planning horizon and allocated to the hours with a distribution capacity deficiency to produce hourly distribution capacity avoidance values.[208]

The study methodology can be broken into three steps:

> Step 1: Location Identification – Identify potential locations with expected distribution capacity constraints requiring investments over the study timeframe, including base, low, and high load growth sensitivity analysis.
>
> Step 2: Estimation of Investment Costs for Avoidance – Determine the value of potential avoided distribution capacity investments at the selected locations.
>
> Step 3: Economic Analysis and Mapping of DG Production Profiles with Distribution Capacity Needs – Perform economic analysis to estimate the benefit of distribution

[205] Guidehouse. 2020. *New Hampshire Locational Value of Distributed Generation Study* (NH 2020 LVDG Study). p. iii.

[206] NH 2020 LVDG Study, p. vii.

[207] NH 2020 LVDG Study, p. iii.

[208] NH 2020 LVDG Study, p. 1.

capacity avoidance and map representative DG production profiles with distribution system capacity needs.[209]

The Step 1 analysis reviewed 696 potential locations and identified 122 distribution system substations or lines with distribution capacity deficiencies, where capital investments potentially could be avoided through load reduction under base, low, and high load growth forecast scenarios.[210] From the 122 locations identified, a subset of 16 locations were selected for detailed analysis. To determine the value of potential avoided distribution capacity investments at the 16 selected locations, the study used cost estimates for traditional utility capital investments, using a Real Economic Carrying Charge methodology. As described in the study, the Real Economic Carrying Charge method "creates a stream of annual values over the lifetime of an investment by calculating the total and annual revenue requirements."[211] The annual value is then allocated to the hours in which a distribution capacity deficiency is present, using a weighted average approach.

The results of the study found that the economic value of distribution capacity investment avoidance varies significantly across the locations analyzed, ranging from under $1 per kW per hour to over $4,000 per kW per hour. The sizeable range in values is primarily driven by the number of hours over which the value is spread, which is linked to the hours in which the distribution capacity deficiencies occur at a specific location. Distribution capacity deficiencies that occur over a large number of hours result in a low value per kW per hour, while distribution capacity deficiencies occurring in a small number of hours have a high value.

B.6. 2021 New England Avoided Energy Supply Costs Study

For several decades, New England energy efficiency program administrators (including all major electric and gas utilities and non-utility program administrators), state energy offices, regulators, and advocates have sponsored biannual or triannual studies regarding the avoided costs associated with energy efficiency programs. The primary scenario in this study models the avoided costs under a counterfactual scenario in which no new energy efficiency, active demand management, or building electrification is modeled in future years. The methodology used in the 2021 AESC study is described below.

Avoided Energy Costs

In AESC 2021, the projected level of New England electric system energy levels and prices from 2021 to 2035 were estimated using the EnCompass dispatch model. The model uses system-wide generation capacity, system demand, fuel prices, transmission constraints, unit availability, heat rates, and other

[209] NH 2020 LVDG Study, p. iv.

[210] NH 2020 LVDG Study, p. iv.

[211] NH 2020 LVDG Study, p. vi.

unit attributes to optimize unit commitment and dispatch over time.[212] The energy prices do not include RECs, but they do include modeled environmental regulations that impose a price on traditional generators, including RGGI.[213]

Avoided Generation Capacity

Avoided generation capacity prices begin with the actual results of the Forward Capacity Market (FCM) auction for delivery years 2021/22 through 2024/25. After that, forecast generation capacity prices are based on observations made in recent auctions as well as expected future changes in demand, supply, and market rules. Specifically, the study develops historical supply curves for generation capacity in each historical auction, and then adjusts the supply curve right or left to reflect changes in generation capacity additions and retirements. Similarly, the demand curve is adjusted in each year to reflect expected changes in demand. The point at which the adjusted supply and demand curves meet is the market clearing price for each year.[214]

Generation capacity prices are applied differently for cleared measures (i.e., measures that participate in the capacity market) and uncleared measures (i.e., measures that do not participate in the capacity market).[215] Any load reduction measure that clears the market provides avoided generation capacity costs in the year that the resource participates in the capacity auction. But not all resources are bid into the capacity market. Unlike cleared capacity, the benefit associated with an uncleared resource is not simply the capacity price multiplied by the resource's capacity. Instead, uncleared capacity utilizes a "phase-in" and "phase-out" schedule that approximates how the impacts of these resources are indirectly captured in the development of inputs to ISO New England's FCM.[216] As load reductions from uncleared efficiency programs appear in the model's data, forecasts of generation capacity requirements (i.e., load) are reduced. The study assumes that benefits from uncleared capacity do not start until five years after their installation date, are discounted to some degree, and that the phase-in of these impacts are non-linear, depending on the duration of load reductions and when the reductions occur.[217]

Avoided Transmission and Distribution (T&D) Losses

Marginal line losses for energy

[212] Synapse Energy Economics. 2021. *Avoided Energy Supply Components in New England (AESC): 2021 Report* ("AESC 2021"). Amended May 14, 2021, p. 134. Available at: https://www.synapseenergy.com/sites/default/files/AESC%202021_20-068.pdf.

[213] AESC 2021, p. 136.

[214] AESC 2021, p. 118.

[215] AESC 2021, p. 113.

[216] AESC 2021, p. 124.

[217] AESC 2021, pp. 124-125.

In AESC 2021, a marginal loss factor was applied to any incremental load added in a given year; all other portions of the load (i.e., the quantity that is less than or equal to the total load in the previous year) utilize an average loss factor. The average loss factor was estimated to be 6 percent based on ISO New England estimates.[218] This average factor was multiplied by 1.5 to produce a marginal loss factor, based on the assumption that marginal losses are about 1.5 times average losses.[219]

Marginal line losses for peak demand

To accurately estimate marginal losses associated with peak demand, one would need to know the system utilization factor at peak hours (the degree to which the T&D system is stressed). However, detailed data for system utilization rates for the entire ISO New England grid for peak hours is not readily available. Thus, the study multiplied average losses by 2, based on data showing that factors for marginal losses over average losses range from 1.4 at a 50 percent system utilization to 2.6 at a 92 percent system utilization.[220] For the purposes of calculating the wholesale impact of load components, Synapse applies an average loss factor of 8 percent[221] to any existing demand (e.g., the quantity of demand in a year that is equal to or less than the previous year's demand) and a marginal loss factor of 16 percent (calculated by multiplying 8 percent by a factor of 2.0).[222]

Avoided Transmission and Distribution Costs

The standard approach to estimating generic system-level avoidable transmission or distribution costs in the AESC 2021 report is as follows:

- Step 1: Determine the actual or expected relevant growth in peak demand over a specified historical of future period.
- Step 2: Estimate the load-related investments in dollars incurred to meet that load growth.
- Step 3: Divide the investment by the load growth to determine the cost of load growth ($/MW or $/kW)

[218] Note that 6 percent is the average T&D loss factor assumed by ISO New England for long-term energy forecast. ISO New England. November 18, 2019. Update on the 2020 Transportation Electrification Forecast. Available at https://www.iso-ne.com/static-assets/documents/2019/11/p2_transp_elect_fx_update.pdf.

[219] Valuing the Contribution of Energy Efficiency to Avoided Marginal Line Losses and Reserve Requirements. 2011. Regulatory Assistance Project (RAP). Available at https://www.raponline.org/wpcontent/uploads/2016/05/rap-lazar-eeandlinelosses-2011-08-17.pdf.

[220] AESC 2021, p. 93.

[221] Note that this 8 percent value includes both transmission losses (2.5 percent) and distribution losses (5.5 percent). ISO New England. October 10, 2019. Transmission planning Technical Guide. Available at https://www.iso-ne.com/staticassets/documents/2017/03/transmission_planning_techincal_guide_rev6.pdf.

[222] AESC 2021, p. 93.

- Step 4: Multiply the results of Step 3 by a real-levelized carrying charge to derive an estimate of the avoidable capital cost in $ per kW-year.
- Step 5: Add an allowance for operation and maintenance of the equipment to derive the total avoidable cost in $ per kW-year.[223]

However, the study could not apply this standard approach in all instances. Below we discuss the calculation of avoided T&D costs for specific types of investments.

<u>Pool Transmission Facilities (PTFs)</u>

All load in New England pays for PTFs, in addition to local transmission facilities. In AESC 2021, the avoided costs for PTFs for the 2003–2026 period were calculated using a combination of historical and prospective cost data for load-related investments in substations, new lines, voltage upgrades, and additional capacitors and transformers for completed or planned projects. Lacking detailed data on the forecasted load growth driving the transmission expansion plans, Synapse used the apparent load-related expenditures by year for the historical data as a proxy. More specifically, Synapse determined that projected future annual transmission investments were equal to 85 percent of the historical investment-per-year rate and calculated avoided PTF cost for future years by multiplying the PTF value derived in AESC 2018 ($99 per kW-year in 2021 dollars) by 85 percent, resulting in a PTF value of $84 per kW-year in 2021 dollars.[224]

<u>Utility Approaches to Non-PTF T&D Avoided Costs</u>

AESC 2021 includes a discussion of avoided T&D methods used by several utilities (National Grid, United Illuminating, and Eversource Connecticut). In general, the utilities follow a similar methodology to the standard approach discussed above, except that the investments are often not matched to load-growth years, and assumptions may be made regarding the percentage of investments that are load-growth-related.

<u>Localized Value of Avoided T&D</u>

Localized T&D values can be developed to estimate the value that DERs, namely energy efficiency and demand response, provide to the localized T&D system such as in the case of non-wires alternatives (NWAs) that defer T&D system upgrades. The three-step process developed in the AESC Supplemental Study Part II: *Localized Transmission and Distribution Benefits Methodology* (Supplemental Study) to calculate localized T&D values is as follows:

Step 1: Identify target areas and required load reduction

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[223] *Avoided Energy Supply Components in New England (AESC): 2021 Report*. Synapse Energy Economics. Amended May 14, 2021, p. 236. Available at: https://www.synapseenergy.com/sites/default/files/AESC%202021_20-068.pdf.

[224] AESC 2021, pp. 248-249.

This first step of identifying target projects utilizes a utility's T&D planning processes that identify system contingencies at peak load levels under normal and contingency operations. This may include consideration of the timeline required for procuring the NWA and whether this can be done in time to avoid the identified contingency or violation.[225]

Step 2: Determine benefits of targeted load reductions by identified target area

The present value of deferred expenditures due to an NWA is calculated using the real carrying charge, which is expressed as a percentage. In general, the real carrying charge equals the weighted average cost of capital, plus income tax, property tax, associated insurance, and O&M. The real carrying charge is then used to calculate the present value of the avoided expenditures. In situations where a load reduction defers a specific project by some period of time, the deferral value represents the traditional engineering expenditure reduced by the real carrying charge and then discounted by the real discount rate.[226]

Step 3: Calculate avoided cost ($ per kW)

The final step is to calculate the avoided cost (in $ per kW) for each identified target area by completing the following three steps:

1. Compile the present value of the benefits from the deferral or avoidance of load-related expenditures;
2. Compile the required load reduction, in kWs, required to achieve the deferral or avoidance of said expenditures; and
3. Divide the result from Step 1 by that of Step 2 to arrive at a localized avoided T&D value ($ per kW), by target area.

The average cost of the load reduction strategies used to achieve deferral or avoidance should be less than the calculated localized avoided T&D value, which is the value of the traditional engineering solution. If the average cost per kW is greater than the localized avoided T&D value, then the avoidance or deferral portfolio costs more than the conventional load-related expenditures, and the traditional engineering solution should be pursued.[227]

Ancillary Services

Ancillary services were not modeled separately.

[225] AESC 2021, pp. 261-262.
[226] AESC 2021, pp. 265-266.
[227] AESC 2021, p. 266.

Avoided RPS Compliance Costs

The avoided cost of RPS compliance is a function of both the renewable energy certificate price and the RPS target percentage. REC price forecasts were developed for each RPS sub-category based on expectations regarding eligible supply, annual demand targets, and—where applicable—the long-term cost of entry of renewable energy additions. These forecasts were converted to an avoided cost of RPS compliance on a dollar-per-MWh basis. Voluntary demands for Class 1 RECs (such as a portion of corporate renewable energy purchases and community choice aggregation) were also considered as a factor influencing Class 1 REC prices.[228]

Cost of Carbon and Criteria Pollutants

Environmental regulations not included in the avoided energy costs include SO_2, NO_x, mercury, and federal CO_2 policies.[229]

There are two elements to the cost of carbon in AESC 2021. The first involves compliance with RGGI, and the second calculates incremental social value associated with carbon reductions. RGGI allowances reflect the cost of carbon embedded in energy prices due to state regulations. However, these costs represent only a portion of the total impact of carbon emissions (the "social cost of carbon"). Thus, both costs are calculated for use in different cost-effectiveness tests. When both the RGGI price and the SCC are included, only the net SCC is included (i.e., the difference between the RGGI price and the SCC) in order to avoid double-counting.

The cost of compliance with RGGI is modeled using the EnCompass dispatch model. EnCompass models the RGGI compliance cost as an exogenous price rather than a strict cap on emissions. The RGGI price follows the emissions containment reserve (ECR) price through 2030, and then continues that trajectory to 2035, assuming that reductions in the RGGI cap are continued after the current compliance period ends in 2030.[230]

There are many different options for a SCC. The 2021 AESC report recommends using a value that applies a low discount rate, considers global damages, and considers the impact of high-risk situations. One source for this value is the SCC Guidance published by the State of New York with a 2 percent discount rate.[231] The 15-year levelized SCC was calculated as $128 per short ton in AESC 2021. The federal Interagency Working Group (IWG) is also in the process of updating their SCC recommendations.[232] Environmental Protection Agency, a member of the federal Interagency Working

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[228] AESC 2021, p. 144.

[229] AESC 2021, pp. 110, 112.

[230] AESC 2021, p. 105.

[231] New York State Department of Environmental Conservation. 2021. "Establishing a Value for Carbon: Guidelines for Use by State Agencies." Available at https://www.dec.ny.gov/docs/administration_pdf/vocguidrev.pdf.

[232] Whitehouse.gov. 2021. Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide - Interim Estimates under Executive Order 13990. Available at: https://www.whitehouse.gov/wp-content/uploads/2021/02/TechnicalSupportDocument_SocialCostofCarbonMethaneNitrousOxide.pdf.

Group (IWG), released a guidance document in 2022 that outlined their update to the methodologies of the IWG to be used by the EPA while work on the IWG update is ongoing. In this document they incorporated the latest thinking and research around SCC methodologies to provide an array of SCC values. They used three different damages estimates; one using the DSCIM model, a second using the GIVE model, and a third based on a meta-analysis of existing estimates, and three different short run discount rates; 1.5%, 2.0%, and 2.5%, to come up with a range of Social Cost of Carbon estimates.[233]

Energy Demand Reduction Induced Price Effect (DRIPE)

AESC 2021 estimates Energy DRIPE according to the following steps:

1. A "price shift" is calculated. This shift represents the change in price for a change in demand. Aggregated over many data points, this price shift represents the supply curve of a particular resource. This is calculated using a set of regressions of historical zonal hourly market prices against zonal and regional load.

2. The price shifts are multiplied by total future market demand, so that they may then be applied to any generic change in demand. In other words, the price shift is expressed in terms of price-per-demand. Multiplying the price shift by demand translates it into a price-per-demand value that can then be multiplied by a measure's anticipated savings.

3. The price-per-demand value is adjusted. This includes accounting for hedged demand which has, in theory, already been purchased and is not subject to price shifts and reducing benefits to account for decays in effects, or "phasing in" of effects to describe a lag in the way the market realizes these impacts.

4. After combining the effects of the price shifts, unhedged demand, and decay, one can calculate the energy DRIPE benefits. Assumptions regarding the timing and duration of benefits are based upon the following market realities:

    - The reductions in wholesale prices are assumed to flow through to customers as existing contracts and other resources (legacy resources, renewable contracts, basic-service and other default contracts, direct contracts with marketers) expire.

    - Customers will respond to lower energy prices by using somewhat more energy.

    - The generation market will respond to sustained lower prices by some combination of retiring and de-rating existing generating capacity and delaying new resources

[233] U.S. Environmental Protection Agency. 2022. EPA External Review Draft of Report on the Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances. Available at: https://www.epa.gov/system/files/documents/2022-11/epa_scghg_report_draft_0.pdf.

that reduce market energy prices (such as gas combined-cycle units and high-efficiency combustion turbines).

- Lower loads will tend to result in lower acquisition mandates under renewable and other alternative-energy standards that are stated as a percentage of energy sold.[234]

Energy DRIPE values are presented in two ways: (1) by zone, month, and period; and (2) for the top 100 load or price hours.[235]

Generation Capacity Demand Reduction Induced Price Effect (DRIPE)

AESC 2021 estimates generation capacity DRIPE using the following methodology:

1. A "price shift" is calculated representing the supply curve of a particular resource. This price shift is based on an assumed supply curve since there is not enough information to develop a regression from historical data. Price shifts for future years were estimated using the slope of the most recent capacity market auction, shifted to reflect the change in generation capacity that has occurred since that auction.[236]

2. The price shifts are multiplied by total future market demand, so that they may then be applied to any generic change in demand. However, only the portion of future demand that is unhedged is included.

   AESC uses these values to estimate two varieties of generation capacity DRIPE effects:

   - Cleared DRIPE benefits, which are benefits of measures that clear in the ISO New England FCM.

   - Uncleared DRIPE benefits, which are benefits of measures that are not submitted into or otherwise do not clear in the ISO New England FCM.[237]

3. Finally, the price-per-demand value is adjusted to account for decays in effects. Generation capacity DRIPE for uncleared resources is calculated analogously to that of cleared resources, but the decay schedule and market clearing prices are adjusted to reflect different market features.[238]

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[234] AESC 2021, p. 197.
[235] AESC 2021, p. 197.
[236] AESC 2021, p. 209.
[237] AESC 2021, p. 208.
[238] AESC 2021, p. 213.

Risk or Hedge Value

AESC 2021 accounts for a risk premium on top of the wholesale market price that is designed to account for the risk suppliers assume when setting energy contract prices in advance of delivering the electricity. The risk premium covers the retail supplier's hedging costs (to mitigate wholesale market price fluctuations), as well as the risk associated with procuring too much or too little energy for a particular hour. Imbalances in the quantity of energy procured may be driven by unpredictable variations in weather, economic activity, and customer migration. When retail suppliers hold excess supply, the excess energy is generally sold into the wholesale market at a loss. When retail suppliers have not contracted for sufficient energy, they may need to procure additional energy at premium prices.[239]

For the AESC 2021 study, confidential supplier bids in Massachusetts, Connecticut, and Maryland were analyzed to determine that the risk premium ranges from less than 5 percent to approximately 10 percent. Based on this data, AESC 2021 assumes a wholesale risk premium of 8 percent.[240]

Reliability Impacts

AESC 2021 assigned a reliability benefit to a reduction in electric load. Resources that do not clear the FCM will continue to operate as energy-only resources, increasing reserve margins while reducing the probability of inadequate supply and generation outages.[241] Additionally, the reduction in electric load decreases the thermal wear and tear on transformers and conductors and thereby reduces failures. It also reduces the probability of overloads on T&D equipment that reduce faults.[242]

System Reliability

AESC 2021 calculated the reliability benefit of resources that cleared the capacity market as the product of (a) the VoLL, (b) the change in MWh of reliability benefits per MW of reserve, (c) the net increase in cleared supply, and (d) the decay effect, as discussed below.[243]

Value of Lost Load

AESC 2021 used two studies to calculate the VoLL: the Lawrence Berkeley National Laboratory's (LBNL) 2015 study on *Updated Value of Service Reliability Estimated for Electric Utility Customers in the United States*[244] and a 2018 study titled *Study on the Estimation of the Value of Lost Load of Electricity Supply in*

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[239] AESC 2021, p. 330.

[240] AESC 2021, p. 331.

[241] AESC 2021, p. 284.

[242] AESC 2021, p. 281.

[243] AESC 2021, p. 286.

[244] Lawrence Berkeley National Laboratory. 2015. "Updated Value of Service Reliability Estimates for Electric Utility Customers in the United States." Available at https://eta-publications.lbl.gov/sites/default/files/lbnl-6941e.pdf.

Europe.[245] These values[246] were averaged together for each category of customer in Table 33 below. Then, a weighted average was calculated using share-of-sales data from EIA's form 861.[247] This VoLL is then applied to the calculation of reliability benefits resulting from dynamics in New England's FCM to estimate cleared and uncleared benefits linked to improving generation reliability.

Table 33. Calculation of the Value of Lost Load

	LBNL *2021 $/kWh*	CEPA Ltd. *2021 $/kWh*	Final *2021 $/kWh*	Sales shares *%*
Residential	$2.80	$12.56	$7.68	40%
Small C&I	$290.87	$10.40	$150.64	45%
Large C&I	$19.36	$10.40	$14.88	14%
Weighted Average VoLL			**$73**	

Notes: Sales shares are estimated using 2019 data from EIA Form 861. We assign "commercial" sales from EIA for Small C&I and "industrial" sales to large C&I.

Calculating the Change in MWh of Reliability Benefits per MW of Reserve

ISO New England annually publishes marginal reliability index (MRI) curves, which estimate the loss of energy expectation (LOEE) per MW of additional supply as the reserve margin rises. In AESC 2021, Synapse examined the slope of the MRI curve at each auction's clearing price. The resulting value can be thought of as the estimated change in MWh of reliability benefits per MW of reserve.

Calculating the Net Increase in Cleared Supply

Bidding an additional MW into the capacity market at $0 per kW-month shifts the supply curve to the right. Due to the slope in the demand and supply curves, this results in the quantity of cleared supply increasing by only a fraction of a MW—typically between 0.2 and 0.3 MW.[248]

Calculating the Decay Effect

The impact described above is thought to dissipate over time as customers respond to lower prices by increasing consumption, including during peak hours. In addition, lower generation capacity prices may lead to the retirement of certain resources, or some new proposed resources being withdrawn. The same decay schedule for generation capacity DRIPE was used to estimate the decay in reliability benefits.[249]

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[245] Cambridge Economic Policy Associates Ltd. 2018. "Study on the Estimation of the Value of Lost Load of Electricity Supply in Europe." Available at https://www.acer.europa.eu/en/Electricity/Infrastructure_and_network%20development/Infrastructure/Documents/CEPA %20study%20on%20the%20Value%20of%20Lost%20Load%20in%20the %20electricity%20supply.pdf.

[246] Data from 19 higher-income European countries were selected to increase comparability with New England.

[247] AESC 2021, p. 284.

[248] AESC 2021, p. 285.

[249] AESC 2021, p. 286.

Calculating Uncleared Reliability

The reliability benefit for resources that do not clear the capacity market is estimated in a similar manner to that of cleared generation capacity, except that the impact is much greater because the supply and demand curves are not directly impacted, even though peak demand is reduced. Because uncleared resources are invisible to the market, in the short term this results in the over-procurement of generation capacity until load forecasts are gradually revised downward to account for reduced peak demand.[250] The impact is also grossed up to account for the impact of the reserve margin.

Value of Reliability: T&D Component

Reducing loads (or avoiding rising loads) can also reduce overloads and violations on the T&D system, thereby reducing wear on lines and transformers. The T&D component of the value of reliability estimates the VoLL due to potentially load-related equipment failure. The value of increased T&D reliability is not duplicative of avoided T&D costs, since this value is primarily related to prolonging the expected life of equipment by reducing the frequency of short periods of very high loads or longer periods of high loads that contribute to the breakdown of equipment insulation.[251]

Although AESC 2021 does not calculate a specific value for the benefits associated with enhanced T&D reliability, the study provided an example methodology of how utilities might calculate a value of reliability associated with T&D based on data for National Grid Massachusetts.[252]

The example methodology is as follows:

1. Estimate the percentage of load-related customer outages using outage data from National Grid's "Unplanned Significant Outage Report."

2. Determine distribution-level customer numbers and sales by class to calculate the average annual customer energy usage (e.g., 14 MWh per customer annually or 1.6 kWh per customer-hour).

3. Calculate the product of (a) the number of customer-hours related to load-related outages, (b) the average annual customer energy usage (e.g., 1.6 kWh per customer-hour), and (c) the VoLL to obtain a total annual cost of potential load-related outages.

4. Divide by the total distribution sales in a given year.[253]

The energy delivered in a year will contribute to failures that occur in that year as well as future years. Thus, it may be reasonable to use the load-related cost of lost distribution reliability derived in the

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[250] AESC 2021, pp. 288-289. The impact is estimated at 100 percent for 2021 through 2026, and then decays to zero from 2027 to 2033.

[251] AESC 2021, p. 290

[252] AESC 2021, p. 291.

[253] AESC 2021, pp. 291-292.

present year as a proxy for future years. The distribution reliability cost may vary by time period, with higher costs during peak periods.[254]

B.7. 2021 Hawaii Value of DER Study

To inform the development of compensation rates for DERs in Hawaii, Synapse developed avoided cost estimates for Hawaii Electric Company's system in Docket 2019-0323.

Avoided Energy Costs

To identify the marginal energy value of DERs, Synapse conducted production cost modeling for two load projections: (1) the 2025 Hawaiian Electric load forecast, and (2) an adjusted forecast with a reduced quantity of DERs (assuming DER levels are "fixed" at 2021 levels).[255] Both cases have the same hourly underlying demand, energy efficiency, and electric vehicle load, sourced from the Hawaiian Electric Company's (HECO) Integrated Grid Planning inputs.[256]

To develop marginal costs, Synapse modeled planned generation capacity additions between 2021 and 2025, and then ran the model in economic dispatch mode to develop hourly marginal energy costs for 2025.[257] These marginal energy costs represent the cost of energy production in each hour weighted by hourly generation to reflect variation in the resources committed.[258]

Avoided Generation Capacity

To develop marginal generation capacity costs, Synapse used the EnCompass model to calculate annual carrying costs associated with planned generation capacity additions between 2021 and 2025 on an annual basis. These resources are those that HECO planned to install during that period in compliance with the RPS. Synapse assigned battery energy storage costs to generation capacity. We also assigned a portion of solar PV costs to generation capacity because energy from the solar PV is used to charge the batteries, which are then available to meet evening peaks.[259]

[254] Id., p. 292.

[255] Division of Consumer Advocacy. Program Track Final Proposals. Docket No. 2019-0323. May 7, 2021. Attachment 1. DER Program Design Filing. p.25.

[256] Division of Consumer Advocacy. Program Track Final Proposals. Docket No. 2019-0323. May 7, 2021. Attachment 1. DER Program Design Filing. p.25.

[257] Division of Consumer Advocacy. Advanced Rate Design Final Proposals. Docket No. 2019-0323. March 19, 2021. pp. 8-9.

[258] Whited et al., "Development of Time-of-Use Rate Options for Hawaii", filed in Advanced Rate Design Track, Docket 2019-0323, March 15, 2021, p. 11.

[259] Division of Consumer Advocacy. Program Track Final Proposals. Docket No. 2019-0323. May 7, 2021. Attachment 1. DER Program Design Filing. pp.2-3.

Synapse allocated generation capacity costs driven by peak demands evenly across all hours designated as "on-peak" according to the extent to which the planned generation capacity would serve peak load. Off-peak carrying costs were spread across total load. [260]

Avoided Transmission and Distribution Costs

Since T&D marginal costs were unavailable, Synapse allocated embedded T&D costs according to an approach intended to reflect where marginal changes in load would create or reduce long-term costs.[261] Synapse used the HECO's 2017 Cost of Service Study as the source for the total revenue to be collected from each class and for each grid component system (transmission, substations, etc.). Synapse allocated 10 percent of transmission costs to all hours, to reflect the fact that the transmission topology is designed to address contingencies and allocated the remaining 90 percent of transmission costs to on-peak hours to reflect the fact that the overall capacity of the transmission system is sized to meet peak loads.[262]

A portion of distribution substation costs were assigned to all hours to reflect the role of substations in meeting demand for energy at all times. This portion was calculated by taking the ratio between the lowest and highest load-hour for each class. The remaining portion of substation costs were assigned to either on-peak or off-peak hours using a peak generation capacity allocation factor (PCAF) approach. Average class loads from the Class Load Study were used as a proxy for the load diversification that would occur across different parts of the system due to geographic separation of the customer classes; Synapse assigned a factor to each hour based on whether the typical class load in that hour exceeded 80 percent of the peak load.[263] For distribution line allocation, half of line O&M costs were assigned to all hours to reflect costs that are not load-driven (such as costs associated with vegetation management, inspections, etc.) Synapse added the all-hours share for minimum average class loads (as derived for substations) and assigned the remainder of distribution line costs to the on- and off-peak hours based on the PCAF factors.[264]

Ancillary Services

Synapse used the EnCompass model to estimate the marginal costs of ancillary services. EnCompass modeling of ancillary services includes regulation (up and down), spinning and non-spinning reserves, and supplemental reserves (up and down).

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[260] Whited et al., 2021. "Development of Time-of-Use Rate Options for Hawaii," filed in Advanced Rate Design Track, Docket 2019-0323, p. 12.

[261] Division of Consumer Advocacy. Advanced Rate Design Final Proposals. Docket No. 2019-0323. March 19, 2021. p. 11.

[262] Whited et al., 2021. "Development of Time-of-Use Rate Options for Hawaii," filed in Advanced Rate Design Track, Docket 2019-0323, p. 14.

[263] Whited et al., 2021. "Development of Time-of-Use Rate Options for Hawaii," filed in Advanced Rate Design Track, Docket 2019-0323, pp. 14-15.

[264] Whited et al., 2021. "Development of Time-of-Use Rate Options for Hawaii," filed in Advanced Rate Design Track, Docket 2019-0323, p. 15.

> Synapse modeled ancillary services as a 30-minute minimum reserve requirement, which could be met by both online and offline resources based on the resource capability inputs. The 30-minute response time is a resource's maximum time to ramp up to contribute to total up reserves, and to ramp down to contribute to total down reserves. For this set of model runs, Synapse did not model 1-minute regulation up and down requirements; for future DER-valuation purposes, Synapse intends to more finely model the ancillary service requirement by further including this constraint, in addition to the 30-minute requirement.[265]

In the 2025 system, which has more distributed solar PV and batteries than the 2021 system (low-DER case), utility-scale storage resources were largely able to provide ancillary services and had higher ancillary service costs than those reflected in the 2021 system. Those costs were concentrated in the midday hours. However, the 2025 ancillary service costs were still well under 1 percent of the cost of power supply.[266]

[265] Whited et al., 2021. "Development of Time-of-Use Rate Options for Hawaii," filed in Advanced Rate Design Track, Docket 2019-0323, p. 8.

[266] Division of Consumer Advocacy. Advanced Rate Design Final Proposals. Docket No. 2019-0323. March 19, 2021. p. 26.

Appendix C. EnCompass Energy and Generation Capacity Modeling Methodology and Assumptions

The Study Team used the EnCompass model to develop a forecast of energy, generation capacity, and ancillary services prices for the 2021–2035 planning horizon. Developed by Anchor Power Solutions, EnCompass is a production-cost and capacity-expansion model for the electric sector that covers all facets of power system planning, including:

- Short-term scheduling, including detailed unit commitment and economic dispatch, with modeling of load shaping and shifting capabilities;
- Mid-term energy budgeting analysis, including maintenance scheduling and risk analysis;
- Long-term integrated resource planning, including capital project optimization, economic generating unit retirements, and environmental compliance; and
- Market price forecasting for energy, ancillary services, capacity, and environmental programs.

EnCompass combines inputs and pressures related to load projections, fuel price forecasts, resource cost projections, state legislation and regulations (including renewable portfolio standards), existing and new renewable and conventional resources, and ancillary service requirements.

This analysis entailed a two-step process to develop hourly energy prices and annual generation capacity prices. First, the Study Team ran a capacity-expansion simulation for the planning horizon from 2021–2035. This step reflects planned units that are scheduled to come online or retire, as well as units that are endogenously added or retired to meet demand and other pressures. From this generation capacity expansion run, the Study Team obtained the resource buildout. The second step was to run an hourly (8,760 hours) dispatch simulation for the entire planning horizon. The Study Team calibrated the model to historical PJM prices.

To properly estimate the avoided costs associated with incremental DERs, this study used a hypothetical scenario, referred to as the No Distributed Energy Resource ("No DER") scenario. This scenario includes the impacts from existing DERs but assumes no additional DERs are added in the future. To develop the No DER scenario, the Study Team removed the effects of DERs in the Pepco DC utility territory (e.g., solar PV, energy efficiency, and electric vehicles) from the PEPCO zone annual energy and peak load forecasts.

The Study Team based the energy and peak load forecasts for the No DER scenario on data from the PJM 2021 Load Forecast Report.[267] We then modified the underlying forecast to remove the impacts of incremental energy efficiency, distributed solar, and electric vehicles. The 2021 Load Forecast Report and the PJM 2021 Solar Forecast Data[268] provide assumptions regarding the energy and peak load impacts for future electric vehicles and distributed solar, but not for energy efficiency. To remove the impacts of future energy efficiency programs from the load forecast, the Study Team added back load equal to the energy efficiency savings (on a percentage basis) achieved by the DCSEU in 2019.[269]

Table 34 and Table 35 below show the solar PV, energy efficiency, and electric vehicle load that was added to the underlying PJM forecast to develop the No DER scenario forecast (in column E).

Table 34. Pepco DC No DER Energy Load Forecast (GWh)

Year	Underlying	Solar PV	Energy Efficiency	Electric Vehicles	Energy Load Forecast (No DER Scenario)
	A	B	C	D	E =A + B + C + D
2021	12,690	249	81	(68)	12,952
2022	12,517	292	79	(89)	12,799
2023	12,510	332	79	(113)	12,808
2024	12,554	377	80	(137)	12,874
2025	12,477	424	79	(162)	12,818
2026	12,382	480	79	(187)	12,754
2027	12,286	541	78	(213)	12,692
2028	12,228	607	78	(238)	12,676
2029	12,108	679	77	(263)	12,601
2030	11,969	754	76	(289)	12,510
2031	11,846	836	75	(316)	12,441
2032	11,757	931	75	(343)	12,420
2033	11,606	1,013	74	(371)	12,322
2034	11,497	1,088	73	(400)	12,258
2035	11,429	1,142	73	(428)	12,215
2036	11,406	1,182	72	(458)	12,203

Source: Calculated using the PJM 2021 Load Forecast Data, Table E-PEV and PJM 2021 Solar Forecast Data.

[267] PJM 2021 Load Forecast Data. Available at: https://www.pjm.com/-/media/library/reports-notices/load-forecast/2021-load-report-data.ashx.

[268] PJM 2021 Solar Forecast Data. Available at: https://www.pjm.com/-/media/planning/res-adeq/load-forecast/solar-forecast-data.ashx.

[269] That is, the Study Team assumed the load forecast included the impacts of energy efficiency equal to 2019 annual percentage savings, as reported in EIA Form 861 for the DC Sustainable Energy Utility. These savings totaled 1.27 percent of sales and 0.4 percent of peak demand. These energy efficiency impacts were then removed from the load forecast by adding back in sales equal to the 2019 energy efficiency savings on a percentage basis.

Table 35. Pepco DC No DER Peak Load Forecast (MW)

Year	Underlying	Solar PV	Energy Efficiency	Electric Vehicles	Peak Load Forecast (No DER Scenario)
	A	B	C	D	E =A + B + C + D
2021	2,607	128	5	(7)	2,733
2022	2,558	129	5	(10)	2,683
2023	2,549	149	5	(12)	2,691
2024	2,543	170	5	(16)	2,702
2025	2,520	190	4	(18)	2,695
2026	2,499	220	5	(21)	2,703
2027	2,495	239	5	(24)	2,715
2028	2,495	248	5	(26)	2,721
2029	2,496	274	5	(29)	2,745
2030	2,490	302	5	(32)	2,765
2031	2,484	319	5	(34)	2,773
2032	2,478	343	5	(35)	2,790
2033	2,471	360	5	(37)	2,800
2034	2,463	368	5	(37)	2,799
2035	2,457	392	5	(38)	2,815
2036	2,450	401	5	(39)	2,817

Source: Calculated using the PJM 2021 Load Forecast Data, Table B-8B and PJM 2021 Solar Forecast Data.

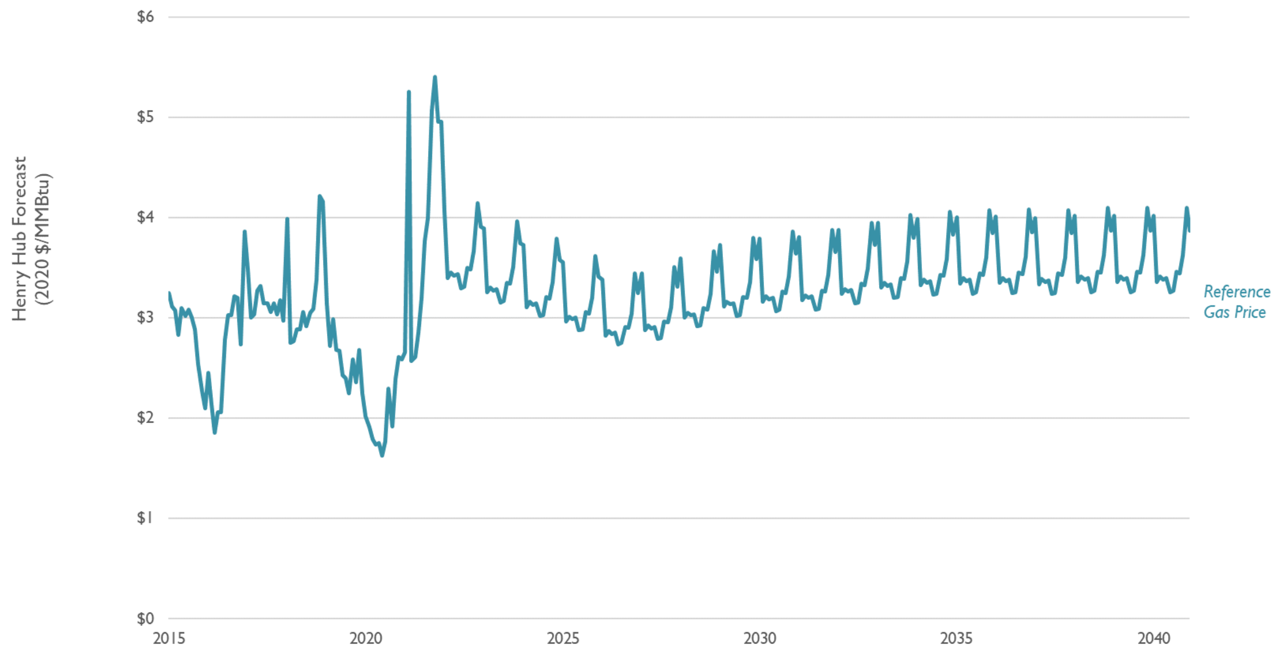
For natural gas prices, this study used a blend between NYMEX Henry Hub price forecasts,[270] AEO 2021 Henry Hub price forecasts[271] for 2022–2025, and AEO 2021 Henry Hub natural gas price forecasts for 2026–2040. After developing the Henry Hub price forecast, the Study Team relied on the EnCompass National Database for region-specific price adders to develop the final delivered price forecasts to electric generators.[272] The natural gas price forecast for Henry Hub is shown in Figure 30 below.

[270] Henry Hub Natural Gas Futures. Available at: https://www.cmegroup.com/trading/energy/natural-gas/natural-gas_quotes_globex.html, Downloaded on 8th December 2021.

[271] U.S. EIA. 2021. Annual Energy Outlook 2021. Available at: https://www.eia.gov/outlooks/aeo/data/browser/#/?id=13-AEO2021&cases=ref2021&sourcekey=0.

[272] Although AEO includes long-term delivered prices to electric generators, these prices are not region-specific. Therefore, we rely on region-specific price adders from NDB to layer on top of the Henry Hub base forecast to account for regional variability and reflect the delivered price to electricity generators in PJM.

Figure 30. Natural Gas Price Forecast – Henry Hub



Source: NYMEX and EIA 2021 Annual Energy Outlook.

The Study Team used the EnCompass National Database for unit-level coal price forecasts. For the PJM region, the EnCompass National Database relies on 21 discrete forecasts, and projects costs for coal sourced from the Northern Appalachia, Central Appalachia, Southern Powder River, International, and Illinois Basin regions. The coal price to the mid-Atlantic region is expected to remain relatively flat throughout the study period, with prices in the range of $75/ton–$78/ton (2020$).

In the modeling environment, EnCompass tracks the quantity and cost of capacity added to the model to serve the peak load. The capacity required also includes additional reserves to meet planning and operating requirements. The model estimates the annual costs associated with carrying the investment required for new capacity, based primarily on the capital cost of the new resource amortized over time. These annual capacity carrying costs are directly available in the model for both the scenarios tested, and for all years of the planning horizon. The model also tracks the fixed costs associated with the existing fossil-fuel fleet, in addition to the operating costs of those resources if or when they are used to generate energy in the model.

EnCompass dispatches the available resources to meet the actual hourly load (inclusive of system losses) in each hour. The model keeps track of the total production costs required to meet the load in each hour. These parameters – annual costs of new capacity, annual fixed costs for existing capacity, and annual production costs for energy dispatched – combined make up the total energy and capacity costs by year for each of the two scenarios modeled. The differential between these two cost streams is the avoided cost.

Renewable Energy Resource Costs

The analysis used NREL 2021 Annual Technology Baseline (ATB) Data[273] for modeling the capital costs (2020$/$kW_{AC}$) of Grid-Scale Solar (Single-Axis Tracking), Grid-Scale Battery Storage (4-hour), Onshore Wind, and Offshore Wind technologies shown in Table 36. The modeling based all resource capital costs on the moderate case.

Table 36. Technology Capital Costs (2020$/kW)

Year	Grid-Scale Solar (Single-Axis Tracking)	Grid-Scale Battery (4-hr)	Onshore Wind	Offshore Wind	PV + Storage
2021	$1,303	$1,296	$1,306	$2,538	$1,898
2022	$1,244	$1,214	$1,263	$2,416	$1,801
2023	$1,184	$1,132	$1,220	$2,312	$1,704
2024	$1,125	$1,049	$1,177	$2,221	$1,607
2025	$1,065	$967	$1,135	$2,137	$1,509
2026	$1,006	$932	$1,092	$2,061	$1,412
2027	$946	$897	$1,049	$1,990	$1,315
2028	$887	$862	$1,006	$1,923	$1,218
2029	$827	$828	$963	$1,860	$1,121
2030	$768	$793	$921	$1,800	$1,024
2031	$761	$783	$911	$1,768	$1,013
2032	$754	$773	$902	$1,739	$1,003
2033	$747	$763	$893	$1,711	$993
2034	$741	$753	$884	$1,685	$983
2035	$734	$734	$875	$1,661	$972

Source: NREL 2021 ATB.

Table 37, Table 38, and Table 39 show heat maps of PEPCO zone energy prices in 2020 dollars for the years 2025, 2030, and all years of the planning horizon (2021–2035) respectively, which can be used to identify the month/hour combinations associated with high/low energy prices for purposes of determining peak/off-peak hours and TOU rates.

[273] NREL 2021 ATB Data. Available at: https://atb.nrel.gov/electricity/2021/data.

Table 37. Projected 2025 Average Hourly Energy Prices by Month (2020$/MWh)

	Hour Ending																							
Month	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
January	32	31	31	31	33	38	46	52	44	39	37	35	34	34	35	36	39	51	55	48	45	41	38	34
February	26	26	26	27	27	31	41	42	37	32	29	29	28	28	28	29	30	36	44	41	36	34	30	27
March	23	23	23	24	25	28	35	32	28	26	25	24	24	23	23	23	24	26	30	31	30	27	25	23
April	21	20	20	20	22	24	25	24	23	22	22	23	23	23	23	24	24	26	27	30	30	26	24	21
May	20	19	19	19	20	21	22	22	22	23	23	24	24	24	26	28	28	30	29	30	30	27	24	21
June	19	19	19	19	19	20	20	21	22	23	24	25	26	28	28	30	32	31	29	30	28	25	23	20
July	21	21	20	21	21	22	22	23	24	26	28	30	33	34	37	39	37	37	34	33	31	28	25	22
August	22	22	21	21	22	22	23	23	23	24	26	28	30	32	35	37	38	36	34	34	31	27	25	23
September	20	19	19	19	19	20	21	22	22	22	22	23	24	25	28	30	33	33	35	34	30	26	24	21
October	21	20	20	20	22	24	24	26	25	25	24	24	23	23	23	24	27	32	35	32	29	26	24	22
November	24	24	24	24	25	28	32	33	30	27	27	26	25	26	26	27	30	38	36	34	33	30	28	25
December	26	26	25	26	26	28	33	37	33	31	30	29	28	28	28	29	32	42	40	37	35	33	31	28

Table 38. Projected 2030 Average Hourly Energy Prices by Month (2020$/MWh)

	Hour Ending																							
Month	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
January	35	33	33	34	35	38	46	53	41	38	37	35	33	34	35	37	41	55	60	53	48	45	41	36
February	28	29	29	29	30	33	44	44	34	32	30	30	30	29	30	31	32	39	47	47	41	37	34	30
March	26	26	26	26	27	31	34	33	29	27	26	25	24	23	25	25	25	28	32	33	32	29	27	26
April	24	24	24	24	25	27	27	27	26	26	26	26	26	26	26	27	28	30	31	33	33	30	28	25
May	23	22	22	22	23	24	24	24	23	24	24	24	24	25	27	28	29	30	30	32	32	30	27	24
June	23	23	22	22	23	23	23	24	24	25	26	28	29	29	30	31	33	34	33	33	32	29	26	24
July	25	24	24	24	24	25	25	26	27	29	31	33	41	45	57	66	59	75	61	59	52	36	31	26
August	25	25	25	24	24	25	25	26	26	27	29	29	30	30	33	42	37	41	40	42	37	32	30	26
September	23	22	22	22	23	24	25	25	25	25	25	25	24	24	25	27	29	35	39	37	34	29	27	24
October	25	24	24	24	25	27	28	29	27	26	25	25	24	24	25	25	29	35	41	35	32	30	28	25
November	27	27	27	27	27	29	32	33	31	29	28	28	27	28	28	29	32	42	40	35	34	32	31	27
December	29	28	28	28	29	30	35	39	34	33	32	30	30	30	30	31	35	45	42	40	37	36	34	30

Table 39. Projected 2021–2035 Average Hourly Energy Prices by Month (2020$/MWh)

	Hour Ending																							
Month	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
January	34	33	33	33	35	38	46	53	42	39	37	36	34	35	35	37	41	54	58	51	47	43	40	35
February	29	29	29	29	30	33	44	47	37	34	32	31	31	30	30	31	33	39	48	47	41	37	34	30
March	25	25	25	25	26	30	35	34	29	27	26	25	24	23	24	25	25	28	31	32	31	28	27	25
April	23	23	23	23	24	26	27	27	26	25	25	25	25	25	26	27	27	29	30	33	32	29	27	24
May	22	21	21	21	22	23	23	23	23	24	24	24	24	25	26	28	29	30	30	31	32	29	26	23
June	22	22	21	21	22	22	23	24	24	25	26	27	29	30	31	33	34	34	32	33	31	28	26	23
July	24	24	23	23	24	24	24	26	27	29	31	33	39	44	47	51	52	56	49	48	45	35	29	25
August	25	24	24	24	24	25	25	26	26	28	29	31	32	34	36	42	40	40	38	40	36	32	29	25
September	23	22	22	22	22	24	24	25	25	25	25	26	25	27	29	31	33	36	38	37	34	30	27	24
October	24	24	24	24	25	27	29	29	28	27	26	26	26	26	26	26	30	35	40	36	32	30	28	25
November	27	27	26	27	27	29	33	34	31	29	29	28	28	28	28	30	32	41	41	36	35	33	31	28
December	29	28	28	28	29	30	35	40	35	34	32	31	31	31	31	32	35	45	42	40	38	36	34	30

Figure 31 through Figure 34 show the average hourly energy prices for the PEPCO zone by season (winter and summer) for the years 2022, 2025, 2030, and 2035. A common trend across the years is that daily energy prices in the winter season tend to peak twice, once between the hours of 6 am–8 am and again between the hours of 5 pm–7 pm. In the summer season, the daily energy prices tend to peak between the hours of 5 pm–7 pm. These energy prices are closely tied to the price of natural gas.

Figure 31. 2022 Average Hourly Energy Prices

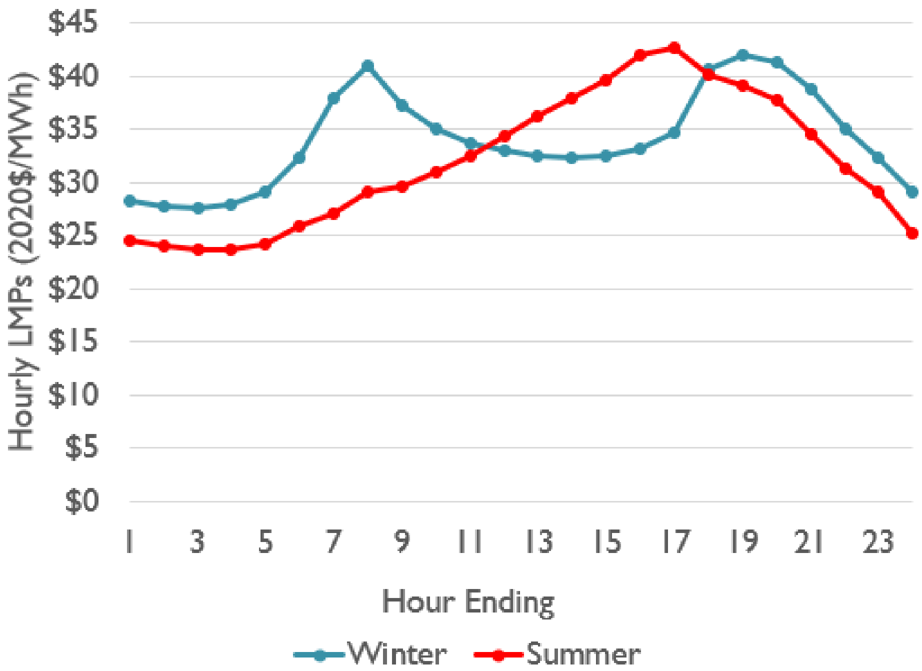


Figure 32. 2025 Average Hourly Energy Prices

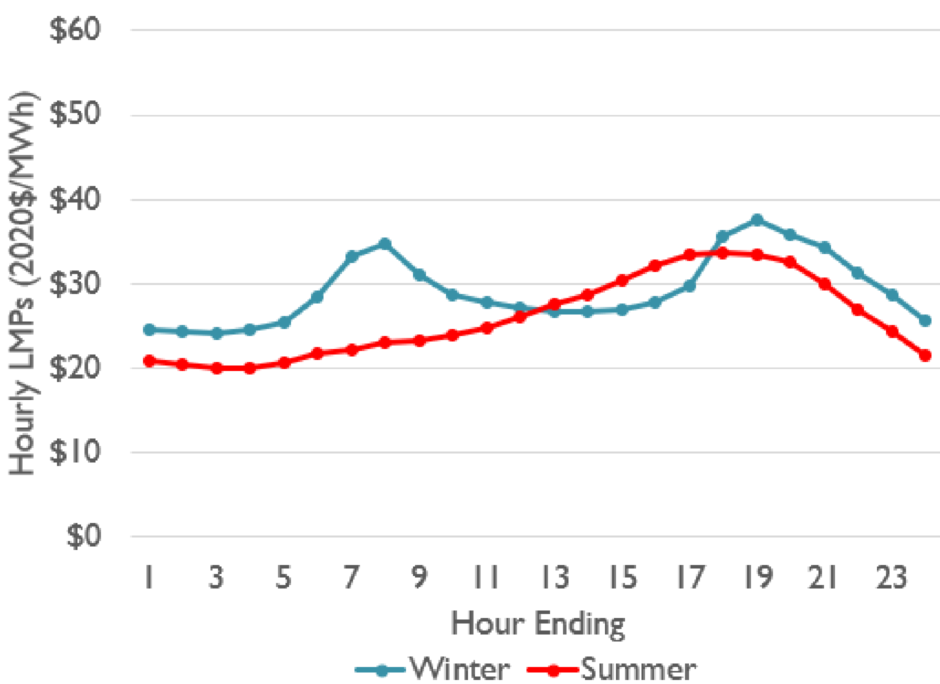


Figure 33. 2030 Average Hourly Energy Prices

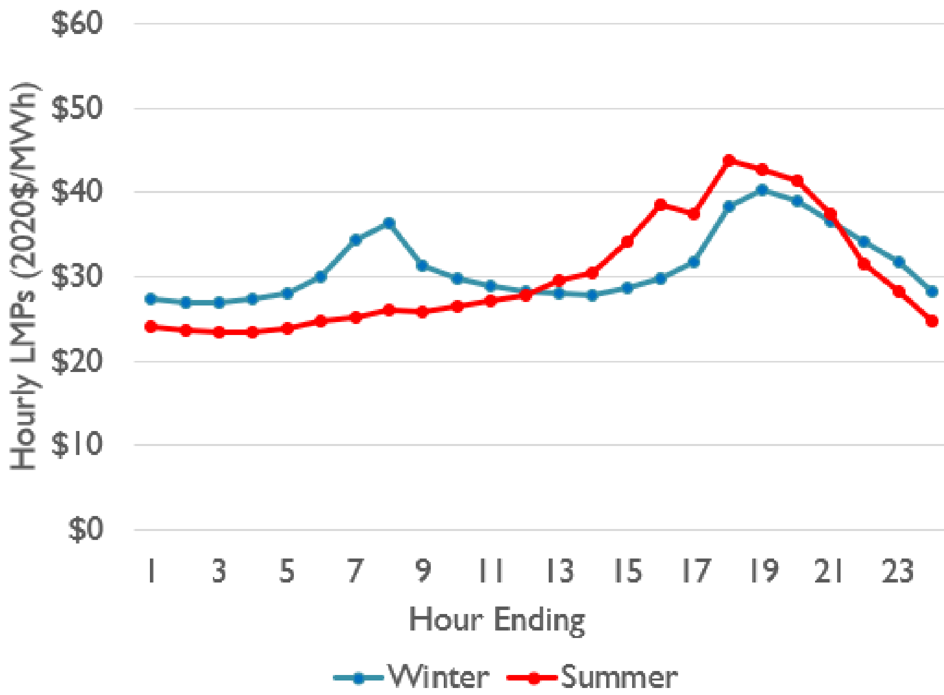
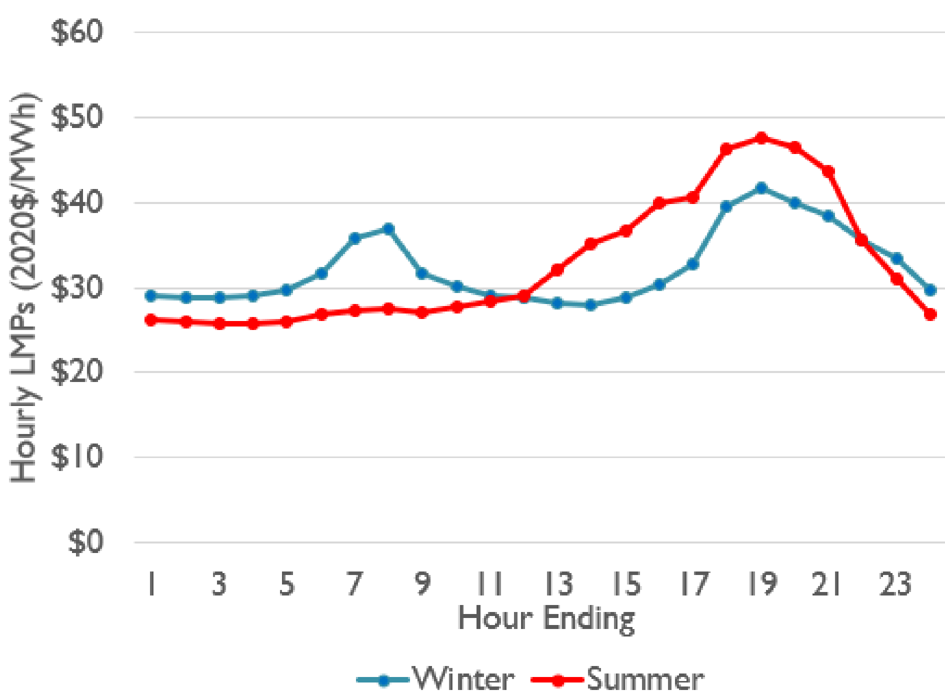


Figure 34. 2035 Average Hourly Energy Prices



Appendix D. Distribution System Analysis Methodology and Key Assumptions

D.1. Distribution Feeder Data Overview

As part of the preliminary work for feeder-level analysis of the distribution system, the Study Team worked collaboratively with Pepco to compile feeder data. Pepco provided data on 32 feeders, including hourly load profiles for three years and peak load projections for 10 years. In addition, the Study Team received information on the normal and emergency ratings for each feeder, planned load transfers, and details of the physical system, including lines transformers, switches, capacitors, breakers, and similar assets. Pepco also provided power flow modeling export files and substation evaluation reports.

These data supported independent power flow analysis performed in OpenDSS and EPRI software for power flow modeling and provided the basis for assessing the impacts of PV and Battery Energy Storage Systems (BESS), both at the loads and as a community resource, and supported assessment of the relevance of advanced inverters, capacitors, and conservation voltage reduction in a broad range of scenarios.

In addition, the Study Team used the provided data to support development of load profile projections with hourly (8,760) data for 25 years. These time series data arrays provided the "Baseline" scenario to which the Study Team added similarly structured 8,760hrs x 25yrs arrays representing a range of scenarios to assess potential pressures from electrification of buildings and vehicles and the potential hourly relief from shaping, shifting, and shedding load.

D.2. Distribution System Baseline Scenario

The distribution system baseline was provided by Pepco and does not appear to include electrification. In all cases, the baseline scenario showed a load that stayed within or almost within the bounds of the Normal Rating of the feeder. In some instances, it was clear that this was achieved through a load transfer to another feeder, and the Study Team strongly supports ongoing evaluation for the potential to relieve emerging loads through this mechanism. Also, the feeders reviewed appear to be well managed with respect to staying ahead of emerging pressures, such that no feeder was projected to significantly exceed its normal rating without a corresponding remedy provisioned. For modeling purposes, management of these feeders led to a baseline scenario where the feeders do not experience significant pressure prior to the arrival of pressure from vehicle and building electrification.

D.3. Vehicle Electrification Pressure

To develop the hourly (8,760) profile of electric vehicle loads, this study used a Department of Energy (DOE) tool, developed by the Alternative Fuels Data Center (AFDC), called the Electric Vehicle Infrastructure Projection Tool (EVI-PRO) Lite. This tool allows a user to select a state and urban area (in our case Washington, DC), plus a set of scenario variables, and then it shows the load profile for six kinds of charging and exports a csv file of the weekday and weekend load profiles given the selected scenario variables. The kinds of charging include Level 1 and 2 charging for home and work and Level 2 and 150kW public fast charging.

The variables allow determination of the mix of these charging types and the timing profile within these kinds of charging. So, for example, a user can select the degree of preference for home charging, and determine whether charging occurs immediately, after a delay, or at a minimal level across the available period.

Using the EVI-PRO tool we initially developed four scenarios:

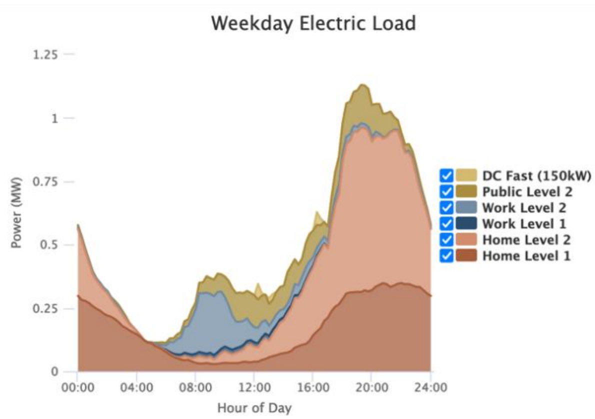
1) Charge primarily at home, immediately, as fast as possible
2) Charge primarily at home, only after midnight
3) Charge primarily at work
4) Balanced charging designed to flattening EV loads

Images of the weekday loads for each EV scenario are shown in Figure 35 below. Please note, these image exports are directly from the EVI-PRO tool, and it was not possible to scale the axes the same. As a result, the magnitudes (and also colors assigned) in each graphic differ. Similarly, and according to the design above, peak load differs in magnitude and timing across the scenarios. Also, the total MWh of charging differs moderately across the scenarios (primarily a result of different efficiencies across the charging types, we assume), and, because the primary intent was to model differences in the timing of charging, the Study Team rescaled the data to ensure a common volume of charging across scenarios, while maintaining the load shapes indicated below.

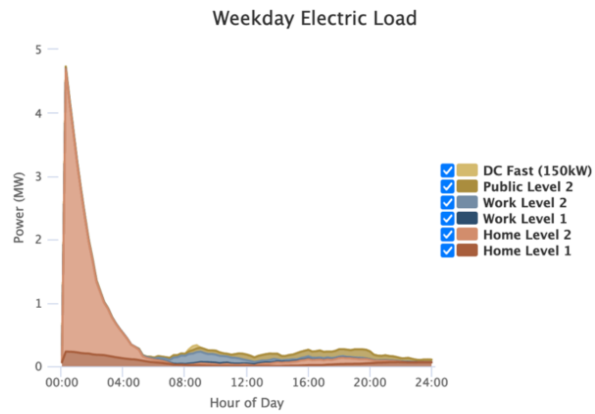
Of these scenarios, Scenarios 1 and 4 had the most explanatory power. Scenario 1 is illustrative in that it would arise without any market intervention or effort to impact the timing of charging—in general, EV owners charge at home and when most convenient, which means immediately restoring batteries to 100 percent. Scenario 2, the night shift scenario, represents a potential intervention to move charging out of the peak evening hours of 7 to 11 pm, but it has the effect of concentrating the load intensely, driving a peak 4 times that of Scenario 1. Scenario 3 shows what can be achieved in terms of moving loads earlier in the day, partially through later home charging and partially through increased charging outside the home. In this scenario, the peak load is slightly below Scenario 1 and the timing is more favorable. Scenario 4 is designed to flatten the load even further and achieves a fairly even distribution of charging, with a peak load approximately half of Scenario 3.

Figure 35. Weekday Loads for EV Scenarios

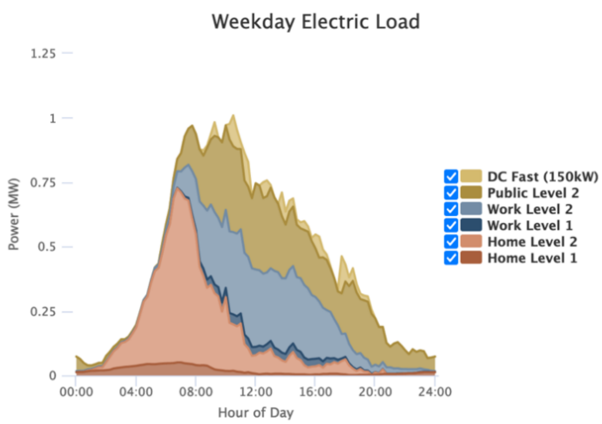
EV Scenario 1



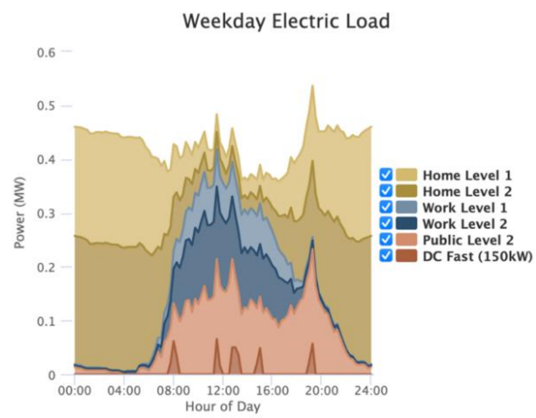
EV Scenario 2



EV Scenario 3



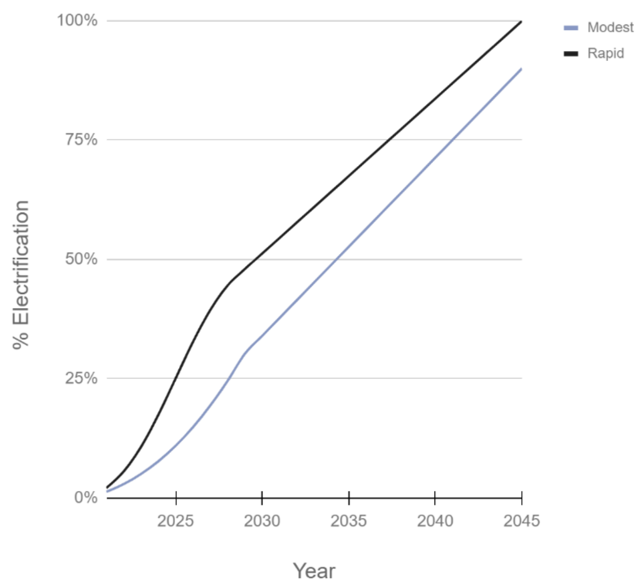
EV Scenario 4



After review of these scenarios, the study moved forward with further modeling of Scenario 1 (representative of the default occurrence of EV charging load shape) and with Scenario 4 (representative of the technical potential for the same volume of load flattened out through load shaping measures).

For these two scenarios, the Study Team also considered the speed of EV adoption, modeling a modest growth and a rapid growth scenario (shown in Figure 36 below). In the rapid growth curve, EVs reach 100 percent by 2045 with relatively rapid initial escalation to 25 percent in 2025 and 50 percent in 2030, and moderate, linear growth from there. While in the next few years this rate of rapid adoption may be unrealistic, it provides an upper bound and shows what the future holds on the way to 100 percent by 2045 which is the official DC Government target. The modest growth scenario reaches 25 percent in 2028, 50 percent in 2034, and 90 percent in 2045. In the early years, this trajectory is more closely aligned to projections and targets in the Transportation Electrification Roadmap produced by the DC Department of Environment & Energy, which aims for more than 25 percent by 2030, though in 2045, it does not quite reach the 100 percent goal.

Figure 36. Modest and Rapid Electrification Load Growth Curves



To complete the development of vehicle electrification scenarios, the Study Team scaled the magnitude of vehicle electrification to each feeder based on each feeder's relative contribution to citywide loads, considered both in terms of MWh and MW. Based on the share of the city's load, EV numbers were assigned to each feeder based on a similar proportion of total number of registered vehicles in the district. These assignments are only intended as illustrative. Actual concentrations of EVs will be higher or lower by feeder, and some feeders will experience relatively more EV workplace charging from commuters coming into the city. As a result, the Rapid EV Growth Scenario may also be reflective of what happens to a feeder in an area with relatively high adoption rates for EVs or where many commuters also charge.

D.4. Building Electrification Pressure

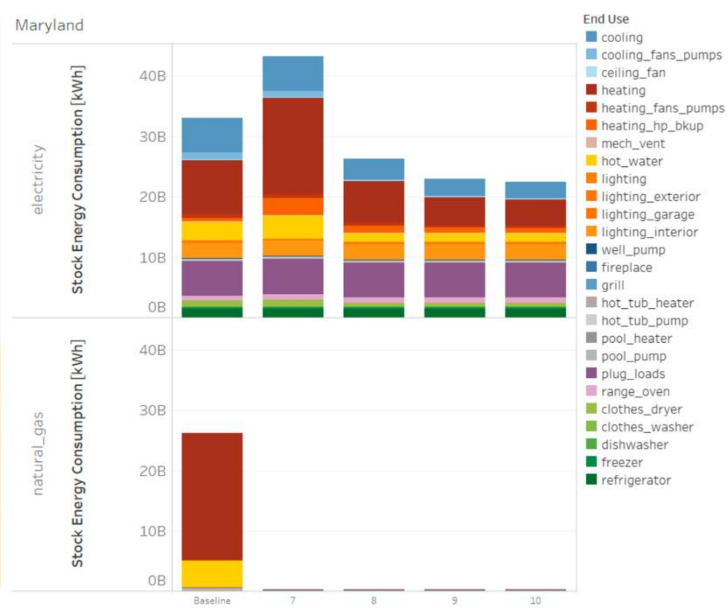
For the building electrification pressure, this study referenced the National Renewable Energy Lab (NREL) studies on End Use Load Profiles (EULP) and End Use Savings Scenarios (EUSS). These studies were designed to support electrification planning, decarbonization analysis, utility integrated resource plans, and policy and rate design. The studies include online tools and data export capabilities. These data were developed for both Residential and Commercial buildings, however only the residential savings scenarios were fully available at the time of this report. Accordingly, it would be relevant to update these findings based on the commercial data once it is available. The impact of basing the analysis on modeling residential scenarios will have some impact on the relief load shaping measures. However, the magnitude of potential savings is expected to be similar in commercial and residential buildings, and the feeders studied all had evening peaks. This indicates a probable prevalence of residential load, such that the modeled pressure and relief may be more accurate for these feeders than if the initial loads were daytime peaking.

The End Use Load Profile data sets provide location-specific, hourly load profiles that are based on sampling of the actual performance of buildings in the selected location, and decomposition of building loads into component parts. For example, there are separate load profiles for refrigeration, lighting, and various types of heating and cooling systems.

The Savings Scenarios expand on the initial load profile data to include impact assessments for 10 scenarios (as shown in Figure 37 below). These 10 scenarios were designed to account for electrification of part or all of a building and potential co-occurring implementation of energy efficiency measures of a few kinds. Of the 10 scenarios, four address 100 percent electrification scenarios (these are Scenarios 7–10 in the image below). In the image below, in the two rows of stacked bar charts, the top section shows electricity consumption, and the bottom section shows gas consumption. Since these are 100 percent electrification scenarios, other than the rightmost column (which is the baseline), there is no gas consumption. The column second to left represents whole building electrification with minimal efficiency measures. The rightmost column shows 100 percent electrification with extensive efficiency measures, including enhanced enclosure/envelope upgrades. This analysis used these two scenarios to represent 100 percent electrification, by default without efficiency, and with maximum efficiency measures, representing the technical potential of retrofits co-occurring with electrification.

Figure 37. Measure Packages in EUSS RES Round 1

1	Basic enclosure
2	Enhanced enclosure
3	Heat pumps, min-efficiency, electric backup
4	Heat pumps, high-efficiency, electric backup
5	Heat pumps, min-efficiency, existing heating as backup
6	Heat pump water heaters
7	Whole-home electrification, min-efficiency
8	Whole-home electrification, high efficiency
9	Whole-home electrification, high efficiency + basic enclosure package
10	Whole-home electrification, high efficiency + enhanced enclosure package



The complete list of efficiency measures included in the high efficiency scenario is below.

- Attic floor insulation
- Air sealing
- Duct sealing
- Drill-and-fill wall insulation

- Foundation wall and rim joist insulation
- Finished attic and cathedral ceiling insulation
- High-efficiency heat pump
- Heat pump water heater
- Ventless heat pump dryer
- Induction range and electric oven

For both building electrification alone and paired with retrofits, the Study Team used the same rapid and modest adoption curves as for EVs, again representing a realistic range and fairly well aligned with DC targets as described in the Clean Energy DC Omnibus Amendment Act of 2018 and DOEE building energy performance programming.

D.5. Compound Electrification Pressure

The Study Team modeled individual pressures, for building and vehicle electrification separately, at two rates of growth, and it then modeled all of the combinations of these scenarios. As one might expect, the Maximum Pressure Scenario was one with simultaneous, rapid electrification of both vehicles and buildings. Notably, this is also the fastest path to decarbonization and realizing DC's stated climate objectives.

Under the Maximum Pressure scenario, many feeders come under pressure, with loads exceeding their normal rating, in the next five years. Further, almost all feeders in the sample set come under pressure within 10 years. As the Maximum Pressure scenario, it is not necessarily the most likely scenario; but it is worth accounting for, because some feeders will likely be on this trajectory. Also, looking long term, this scenario leads to 100 percent electrification of both vehicles and buildings by 2045, which is the stated objective in many DC government policy documents. So, whether the pressure comes on as fast as indicated in the Maximum Pressure scenario, much of the analysis relies primarily on looking at what the system would be like in 2045 with 100 percent electrification, and those views hold merit irrespective of whether the trajectory to get there proves to be rapid or modest in the next decade.

D.6. Load Shaping Measures – Main Relief Scenario

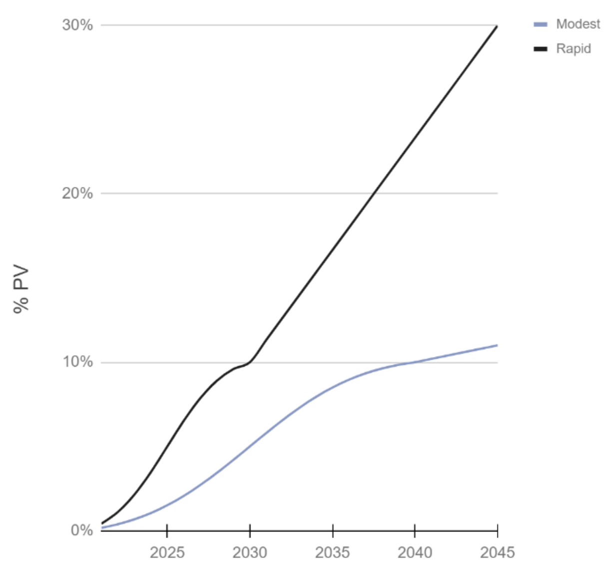
In designing the Main Relief Scenario, the Study Team combined the flattened EVs and the most efficient building electrification loads described above, and then added photovoltaics (PV). In modeling PV, the Study Team reviewed power flow for 1 percent, 10 percent, 20 percent, 30 percent, 50 percent, and 100 percent of the total MWh and then developed rapid and modest adoption curves (as shown in Figure 38 below). In the modest adoption curve, PV reaches 10 percent of total MWh by 2040 (the original target in DC policy), with only a slight increase through 2045. In the Rapid Growth scenario, 10 percent of total

MWh is achieved by 2030 and by 2045, 30 percent is attained, reflecting an approximation of a maximum technical potential.

With power flow modeling, the Study Team assessed the value of local load relief and looked at levels of backflow at the substation when PV generation exceeds load. The team also assessed impacts on voltage and included scenarios with PV located by loads (located at the site of consumption) and community solar installations. The team also modeled the impact of conservation voltage reduction, advanced inverters, and PV collocated with batteries.

Across these scenarios, the modeling found that for the distribution system the Modest PV scenario provided the simplest version of optimization because it reached policy-targeted levels of PV and limited backflows at the substation, which can require infrastructure upgrades of batteries. The Modest PV scenario peaked at approximately 11 percent because PV did not provide meaningful load relief during hours when the feeders we studied exceeded their normal ratings. Also, at the timing of peak loads on most feeders across most scenarios (typically 7 pm and later), PV is not available, so there was little benefit to distribution capacity avoided costs in increasing PV beyond the Modest PV scenario. It may be that some level moderately above the Modest PV scenario is economically optimal on some feeders, both in consideration of the recently updated target of 15 percent which is supported by a generous tariff arrangement and in consideration of the anticipated high future capacity prices in the wholesale market during hours when PV can assist in avoiding these costs. However, for simplicity in managing the effects on potential distribution system impacts, this study anchored the Main Relief scenario on the Modest PV adoption curve.

Figure 38. Modest and Rapid PV Adoption Scenarios



In combination, Building Efficiency, Flattened EVs and Modest PV provide robust relief via load shaping measures.

D.7. Load Flexibility Measures

In evaluating the benefit of load flexibility, the Study Team considered the value of load flexibility at times of peak load and at times of peak pricing. In addition, the team looked at an array of curtailment levels, both in terms of how many hours are addressed and in terms of what percent reduction is assumed. Specifically, the Study Team calculated values for 100–1000 hours targeted, and 15–40 percent curtailment. The team also looked at these levels of curtailment when applied to the Baseline, Maximum Pressure, and Main Relief scenarios and found that the value of targeting peak pricing times far exceeded the value of targeting peak load times (though there may be some circumstances where local load relief is the priority). As might be expected, the value of load flexibility appears greatest in the Maximum Pressure scenario. Because this scenario is unrealistic (in that it will always be avoided by implementation of solutions like those in the Main Relief Scenario or infrastructure upgrades) the Study Team focused on the value of load flexibility after Main Relief load shaping measures have been applied. Notably, though, load flexibility has moderate to high value across all scenarios and at all levels of curtailment. Looking just at wholesale market avoided costs, for example, and assessing the present value of future curtailment renders values ranging from $1M to $9M for Feeder 1 and similar values across the other feeders.

After reviewing the range of potential shedding scenarios, the Study Team decided on a strawman optimal Load flexibility level designed to strike a balance between feasibility, customer convenience, and market value: 266 hours (when wholesale capacity costs are expected) and 30 percent curtailment. This level of load flexibility seems attainable and delivers value in the center of the array of considered scenarios; it also limits the number of hours a customer may be asked to reduce load, and potentially limits the number of months and hours in which such programs would be applied.

Appendix E. DER IMPACTS BY HOUR FOR EACH YEAR AND BY FEEDER TYPE

Where possible, hourly values should be applied in determining the value associated with DERs. For reference, Table 40 below provides a snapshot of a small part of the hourly avoided cost values. The full data set includes all the hourly values from 2023 to 2045 (including 8,760 rows per year for 23 years, removing leap days) in the electronic attachment.

Table 40. Snapshot of Hourly Avoided Cost Values, $2020/MWh

					Avoided Costs: 2020$/MWh												
Timing							Generation Capacity		Distibution Capacity, O&M, and Voltage					GHG			
Month	Day	Hour Ending	Year	Season	PJM Definition Onpeak/Offpeak	Energy	Cleared Generation Capacity	Transmission	F1	F2	F3	F4	Distribution Losses	Low GHG	Mid GHG	High GHG	Public Health
1	1	1	2023	Winter	Offpeak	30.52	0.00	0.00	0.00	0.00	0.00	0.00	2.51	37.44	87.35	168.72	8.37
1	1	2	2023	Winter	Offpeak	30.23	0.00	0.00	0.00	0.00	0.00	0.00	2.49	31.29	73.02	145.52	8.37
1	1	3	2023	Winter	Offpeak	30.18	0.00	0.00	0.00	0.00	0.00	0.00	2.48	32.41	75.62	149.73	8.37
1	1	4	2023	Winter	Offpeak	30.26	0.00	0.00	0.00	0.00	0.00	0.00	2.49	31.53	73.57	146.42	8.37
1	1	5	2023	Winter	Offpeak	30.58	0.00	0.00	0.00	0.00	0.00	0.00	2.52	29.07	67.82	137.11	8.37
1	1	6	2023	Winter	Offpeak	31.79	0.00	0.00	0.00	0.00	0.00	0.00	2.62	32.83	76.59	151.31	8.37
1	1	7	2023	Winter	Offpeak	35.59	0.00	0.00	0.00	0.00	0.00	0.00	2.95	30.89	72.07	143.99	8.37
1	1	8	2023	Winter	Offpeak	38.76	0.00	0.00	0.00	0.00	0.00	0.00	3.23	29.10	67.89	137.22	8.37
1	1	9	2023	Winter	Offpeak	37.66	0.00	0.00	0.00	0.00	0.00	0.00	3.13	29.01	67.68	136.88	8.37
1	1	10	2023	Winter	Offpeak	36.33	0.00	0.00	0.00	0.00	0.00	0.00	3.01	27.85	64.99	132.51	8.37
1	1	11	2023	Winter	Offpeak	35.38	0.00	0.00	0.00	0.00	0.00	0.00	2.93	27.45	64.05	131.01	8.37
1	1	12	2023	Winter	Offpeak	34.37	0.00	0.00	0.00	0.00	0.00	0.00	2.85	27.03	63.06	129.39	8.37
1	1	13	2023	Winter	Offpeak	33.87	0.00	0.00	0.00	0.00	0.00	0.00	2.80	28.33	66.11	134.34	8.37
1	1	14	2023	Winter	Offpeak	33.29	0.00	0.00	0.00	0.00	0.00	0.00	2.75	31.70	73.98	147.07	8.37
1	1	15	2023	Winter	Offpeak	32.15	0.00	0.00	0.00	0.00	0.00	0.00	2.65	32.91	76.79	151.63	8.37
1	1	16	2023	Winter	Offpeak	32.55	0.00	0.00	0.00	0.00	0.00	0.00	2.69	34.18	79.76	156.43	8.37
1	1	17	2023	Winter	Offpeak	35.37	0.00	0.00	0.00	0.00	0.00	0.00	2.93	36.45	85.05	164.99	8.37
1	1	18	2023	Winter	Offpeak	40.68	0.00	0.00	0.00	0.00	0.00	0.00	3.39	35.98	83.96	163.24	8.37
1	1	19	2023	Winter	Offpeak	45.14	0.00	0.00	0.00	0.00	0.00	0.00	3.52	35.45	82.72	161.22	8.37
1	1	20	2023	Winter	Offpeak	39.14	0.00	0.00	0.00	0.00	0.00	0.00	3.26	34.42	80.32	157.34	8.37
1	1	21	2023	Winter	Offpeak	38.29	0.00	0.00	0.00	0.00	0.00	0.00	3.18	35.78	83.48	162.46	8.37
1	1	22	2023	Winter	Offpeak	35.21	0.00	0.00	0.00	0.00	0.00	0.00	2.92	36.07	84.15	163.55	8.37
1	1	23	2023	Winter	Offpeak	33.44	0.00	0.00	0.00	0.00	0.00	0.00	2.76	38.52	89.89	172.84	8.37