BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF HAWAI‘I

In the Matter of	)	
	)	
PUBLIC UTILITIES COMMISSION	)	Docket No. 2018-0165
	)	
Instituting a Proceeding to Investigate Integrated Grid Planning.	)	
	)	
	)	

THE JOINT PARTIES’ COMMENTS ON THE HAWAIIAN ELECTRIC COMPANIES’ AUGUST IGP UPDATE

EXHIBIT A

AND

CERTIFICATE OF SERVICE

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Pursuant to Order No. 37927, filed August 23, 2021, Blue Planet Foundation, Hawai‘i PV Coalition, and Hawai‘i Solar Energy Association (the "Joint Parties") respectfully submit responses to the Public Utilities Commission's questions on the Hawaiian Electric Companies' ("Hawaiian Electric's") August IGP Update filed August 3, 2021 and revised on August 19, 2021 ("August IGP Update").

Although Hawaiian Electric has made some recent progress in incorporating stakeholder feedback, the IGP process continues to pose challenges and frustrations. The Joint Parties have proposed numerous sensitivities and analyses that Hawaiian Electric has ultimately rejected.[1] Hawaiian Electric has also made last-minute changes to the sensitivities under consideration without adequate vetting and over the stakeholders' objections.[2]

Further, no amount of stakeholder meetings can change the fact that, under the current IGP process, Hawaiian Electric has sole access to much of the underlying data and formulas for

[1] *See, e.g.*, Joint Parties' Comments on the HECO Companies' First Review Point, filed Feb. 25, 2021, at 11-12.

[2] *See infra*, Joint Parties' Response to PUC Question No. 3.

the inputs and assumptions (such as the DER adoption rate and sales forecasts), which inform the IGP process. This limits stakeholders' ability to meaningfully opine on the reasonableness of the proposed inputs and assumptions except at a high level or where Hawaiian Electric adopts public inputs.

While the broad bookends proposed by Hawaiian Electric will likely provide useful information, a key for the future success of the IGP docket will be how this information is used and, if necessary, how the inputs and assumptions will be updated. If the intent is simply to tweak the existing base case, then this exercise will be futile. Instead, the bookends and future sensitivities should inform a series of preferred options that accelerate progress towards Hawai'i's clean energy mandate.

For example, the Brattle Electrification study for Pepco's climate plan estimates significant load growth as a result of rising levels of electrification.[3] Nonetheless, Pepco anticipates energy efficiency and load flexibility (including residential behind the meter storage) will reduce peak demand growth by 40% between now and 2050 (*see* **Fig. 1**).[4] Pepco also states it believes it can manage this peak demand growth at the distribution system level.[5] It is hoped that Hawaiian Electric is viewing the current bookends with the intent to examine the feasibility and likelihood of a similar result and accelerated RPS coming out of the IGP process.

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[3] *See* Exhibit A: Pepco Electrification Study, D.C. Pub. Serv. Comm'n Formal Case No. 1167, filed Aug. 27, 2021, at 3, *available at* https://www.pepco.com/Documents/1167%20%20Pepco%27s%20Electrification%20Study%20%20082721.pdf (last visited Sept. 9, 2021).

[4] *Id.* at 4, 17, 35-39.

[5] *Id.* at 4.

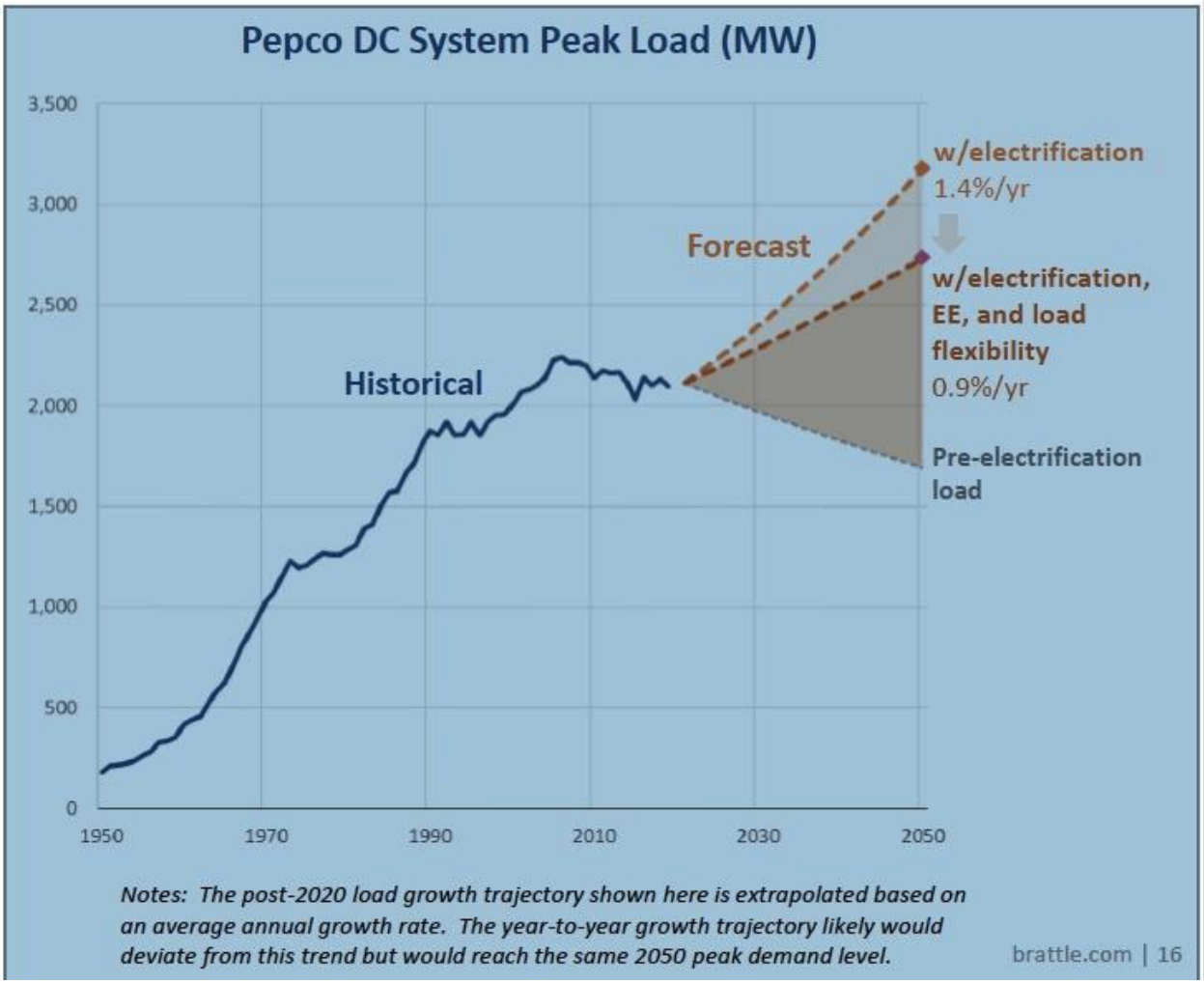

Fig. 1. Pepco Electrification Study, D.C. Pub. Serv. Comm'n Formal Case No. 1167, filed Aug. 27, 2021

Finally, the Joint Parties encourage continued access and availability to Hawaiian Electric's grid planning,[6] such as requiring updates and continued access to Hawaiian Electric's

[6] As a case in point, Ulupono Initiative LLC, through its consultant, has access to a resource planning modeling tool that has allowed the organization to successfully advocate for removing land constraints on grid-scale PV. *See* Ulupono Presentation to the IGP Stakeholder Council on June 18, 2021, *available at* https://www.hawaiianelectric.com/documents/clean_energy_hawaii/integrated_grid_planning/igp_meetings/20210618_igp_stakeholder_council_switch_analysis_slides.pdf (last visited Sept. 8, 2021).

RESOLVE model.[7] The Joint Parties reiterate that to enhance transparency, flexibility, quality, and overall confidence in the utility planning process, the Commission should require all utilities to open up the modeling process, as California has already done.[8]

The Joint Parties' further specific comments on the August IGP Update, including answers to some of the Commission's questions posed in Order No. 37927, are as follows:

PUC QUESTION 1

> Does the August IGP Update thoroughly address every Commission concern articulated in Order No. 37730? If not, please explain what concerns remain.

Joint Parties' Response

No. For example, the August IGP Update does not adequately address the Commission's concerns stated in Order No. 37730 regarding Hawaiian Electric's thermal generating unit retirement plans.[9] Although Hawaiian Electric has included a retirement plan in its August IGP Update, this one-page plan lacks any rationale for the timing of and units selected for retirement.[10] By comparison, Hawaiian Electric's retirement plan in its December 23, 2016 Power Supply Improvement Plan Update Report included more than one dozen pages of

[7] Currently, the DER Parties access to RESOLVE is limited to the existing base case for use in the DER investigative docket (Dkt. No. 2019-0323) and it is unclear, based on the existing confidentiality provisions, if access or material information can be provided to other interested stakeholders. Expressly encouraging such access—assuming other stakeholders agree to the confidentiality provisions—could provide meaningful benefits to the IGP process.

[8] Joint Parties' Comments on the HECO Companies' First Review Point, filed Feb. 25, 2021, at 3-4.

[9] *See* Order No. 37730 at 32-35.

[10] *See* August IGP Update at 152.

explanation.[11] In its Inputs and Assumptions—or at the very least in its forthcoming Grid Needs Assessment—Hawaiian Electric should thoroughly explain its rationale for the proposed retirement plan and must also comply with the Commission's directives to:

(1) "analyze how using a retirement plan in the base case changes the optimization of new renewable and storage resources outside of incremental compliance needs for O'ahu"; and

(2) "thoroughly analyze and clearly explain why the model selects such large amounts of biomass and biofuel resources, including what cost assumptions (e.g., fuel prices) in the modeling contribute to this selection."[12]

Without this information or analyses, the Commission lacks any basis for approving Hawaiian Electric's proposed retirement plan.

PUC QUESTION 3

Is Hawaiian Electric's proposed high electric vehicle forecast sensitivity reasonable, including the underlying assumptions? If not, please explain why not, and what modifications are necessary.

Joint Parties' Response

No. As stated in Blue Planet Foundation's letter filed on August 18, 2021, Hawaiian Electric's approach of modeling high EV adoption *without* managed charging is unreasonable.[13] At the June 17, 2021, Stakeholder Technical Working Group, Hawaiian Electric proposed including a sensitivity titled "Faster Customer Technology Adoption," which assumed high

[11] *See In re Pub. Utils. Comm'n*, Docket No. 2014-0183, Hawaiian Electric Companies' PSIPs Update Report, filed Dec. 23, 2016, at M-1 – M-13.

[12] Order No. 37730, filed Apr. 14, 2021, at 34-35.

[13] *See* August IGP Update at 110-11, tbl. 6-3.

uptake of rooftop solar, EVs, and energy efficiency measures, along with managed EV charging (*see* **Fig. 2**).[14]

Proposed Bookend Sensitivity

- What is the appropriate uptake to assume for higher or lower levels of EV and EE?
- What are the policy drivers that would affect DER, EE, and EV? Do the bookends create a reasonable envelope around the potential for each of these layers?

Assumption	Slower Customer Technology Adoption	Base	Faster Customer Technology Adoption	High Load
DER	Market Forecast	HE Company Proposal	DER Parties Proposal	Market Forecast
Electric Vehicles	EV--	Market Forecast	EV++	EV++
Energy Efficiency	EE--	Market Forecast	EE++	EE--
Time-of-Use	None	Managed EV	Managed EV	None

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Fig. 2. HECO 6/17/2021 STWG Presentation, Slide 48

Based on the understanding that Hawaiian Electric would consider high EV uptake both with and without managed charging, Blue Planet Foundation supported including a high EV forecast of 100% ZEV by 2045. Hawaiian Electric's August IGP Update, however, omits the "Faster Customer Technology Adoption" sensitivity or any scenario or sensitivity that pairs high EV uptake with managed charging. This omission prevents any valuation or comparison of managed versus unmanaged charging in a high-EV environment. Without this analysis, the

[14] Hawaiian Electric's June 17, 2021 presentation to the Stakeholder Technical Working Group is available at https://www.hawaiianelectric.com/documents/clean_energy_hawaii/integrated_grid_planning/20210617_presentation_slides_igp_stakeholder.pdf (last visited Sept. 8, 2021).

Commission, Hawaiian Electric, and stakeholders lack critical information to inform near-term planning and managed charging policies as Hawai‘i pursues its goals to electrify transportation.[15]

Although evaluating high EV adoption alongside unmanaged charging may be appropriate for a high bookend scenario, there is no valid reason for refusing to assess "Faster Customer Technology Adoption" as a standalone sensitivity, along with the several other standalone sensitivities proposed. Hawaiian Electric has already layered the underlying data for this sensitivity and presented this analysis at the September 7, 2021 Stakeholder Technical Working Group meeting.[16] These layers show that high EV uptake along with managed charging, high rooftop solar uptake, and high energy efficiency (*see* "High Adoption" (teal line) in **Figs. 3 & 4**) significantly reduces O‘ahu's near-term GWh sales and near-term MW peak below the "High Load" (dark orange line) scenario, in which high EV uptake along with unmanaged charging, low rooftop solar uptake, and low energy efficiency is assumed. This information should be incorporated and modeled as a standalone sensitivity in the IGP process to inform planning, procurements, programs, and pricing going forward.

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[15] For example, a study by the Citizens Utility Board found that optimized EV charging in Illinois could produce up to $2.6 billion in consumer savings through 2030 from lower wholesale market energy prices ($2 billion), capacity cost reductions ($124 million), and reduced volumetric components of the residential distribution rates ($193 million). The study further concludes that "deep EV penetration without effective charge-management could lead to costly delivery system upgrades." Citizens Utility Board, Charging Ahead, Deriving Value from Electric Vehicles for All Electricity Customers, at 4 (2019), *available at* https://www.citizensutilityboard.org/wp-content/uploads/2019/03/Charging-Ahead-Deriving-Value-from-Electric-Vehicles-for-All-Electricity-Customers-v6-031419.pdf (last visited Sept. 10, 2021).

[16] Hawaiian Electric's September 7, 2021 presentation to the Stakeholder Technical Working Group is available at https://www.hawaiianelectric.com/documents/clean_energy_hawaii/integrated_grid_planning/stakeholder_engagement/working_groups/stakeholder_technical/20210907_stwg_meeting_presentation_materials.pdf.pdf (last visited Sept. 8, 2021).

We strongly urge the Commission to require Hawaiian Electric to include the "Faster Customer Technology Adoption" sensitivity in its IGP analysis.

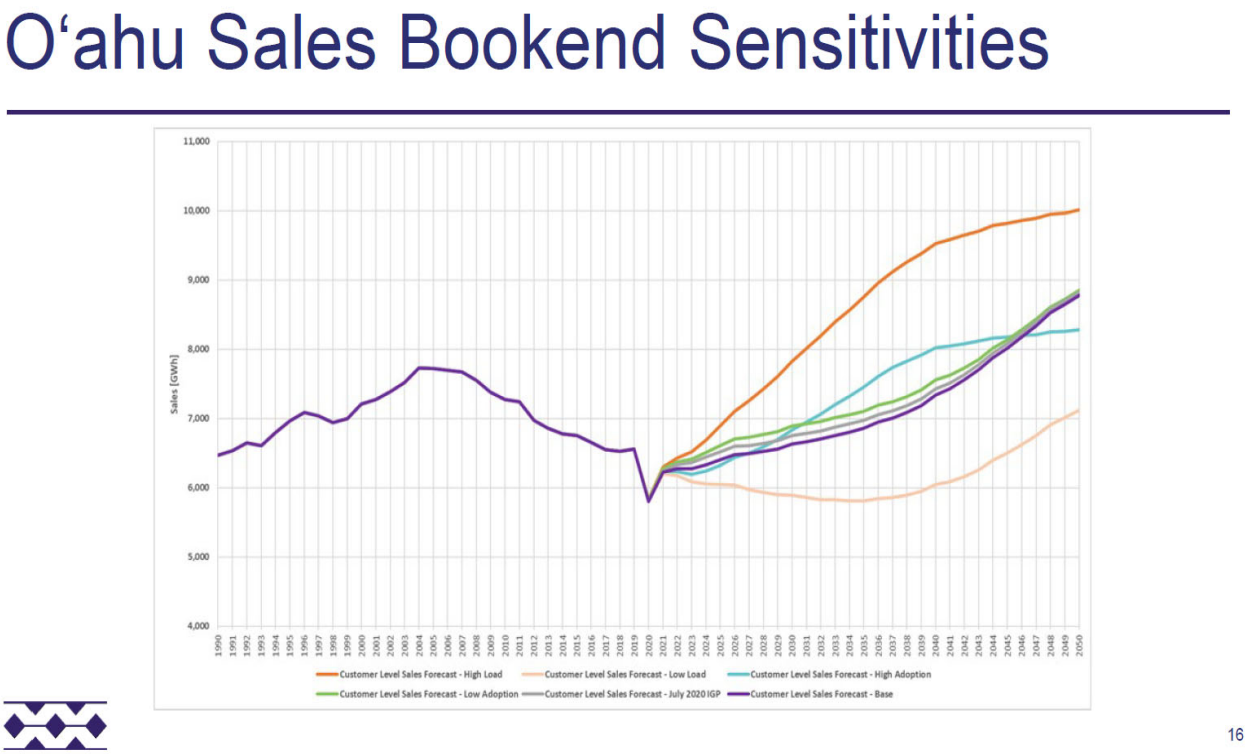

Fig. 3. HECO 9/7/2021 STWG Presentation, Slide 16

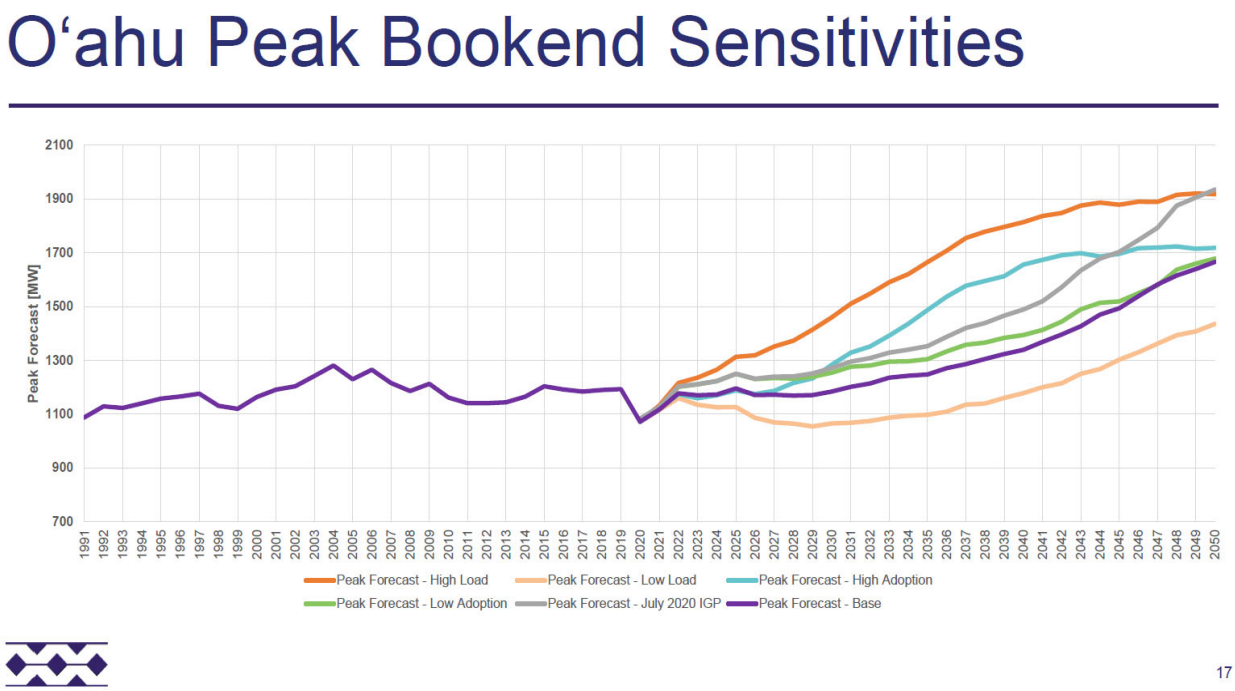

Fig. 4. HECO 9/7/2021 STWG Presentation, Slide 17

PUC QUESTION 7

Do the assumptions regarding future DER programs represent a reasonable best estimate for this round of IGP? If not, please suggest alternative assumptions.

Joint Parties' Response

While there have been significant improvements to the DER forecast assumptions, several baseline assumptions regarding current and potential incentive programs may inappropriately impact the bookend cases.

First, it is unclear whether Hawaiian Electric is appropriately accounting for federal and state tax incentives. Hawaiian Electric indicated it would apply a $5,000 cap on residential PV-only systems for "Federal and State investment tax credits" and a cap on residential PV+storage systems of $10,000 beginning in 2022.[17] However, no such "cap" for the federal investment tax credit ("ITC"), and applying this cap would significantly reduce the incentive amount available to most clean energy projects.

It is further unclear whether Hawaiian Electric is correctly applying the cap applicable to Hawai'i's renewable energy income tax credit, as it applies to each "5kW system" installed. As an example, a 20 kW system could be eligible for $20,000 in state tax credits.

Similarly, it is uncertain what federal ITC assumptions are being utilized in Hawaiian Electric's high-end DER bookend. The August IGP Update indicates an extension of ten years but does not clarify at what percentage the ITC is maintained.[18] Congress's and the Biden Administration's infrastructure and budget reconciliation packages, *i.e.*, the "Build Back Better" plan, potentially increases the ITC back to 30% and keeps it at that higher level for ten years.

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[17] August IGP Update at 46-47.

[18] *Id.* at 47, tbl. 4-3.

Yes, the August IGP Update shows the federal ITC stepping down and being reduced to zero beginning in 2024.[19]

Second, the lower bookend case should realistically take into account the impact of Hawaiian Electric's rate design proposals. Hawaiian Electric assumes a 3.336 kW "peak" for an average residential customer.[20] This seems unlikely. A typical, modern electric clothing dryer can consume 4-5 kW. In conjunction with any other electricity usage typically found at a home, such as a refrigerator, lights, rice cooker, etc., the average residential customer would likely see a higher peak demand charge (over a 15 minute period) than what Hawaiian Electric proposes.

Further, demand charges would greatly impact current and future electrification efforts. The new electric Ford F-150—a vehicle that currently represents 1 in 16 cars driven in the United States today—will charge at a peak rate of 18 kW. With a $3 a kW proposed demand charge, a new Ford F-150 owner could anticipate at least a $54 a month new "charge" as a condition of electrification. Hawaiian Electric's rate design proposals, based on a 15 minute interval "peak," would likely result in significantly increased residential charges on customers seeking to modernize and electrify their homes. While DERs could help defer the impact of some of these demand charges—and keep load off the grid—the lack of visibility or transparency surrounding a demand charge would likely depress overall market adoption.

PUC QUESTION 8

> In the August IGP Update, Hawaiian Electric proposed a modification to the bookend scenarios, replacing the higher and lower customer technology adoption bookends with high and low load bookends. Do these high and low load bookend scenarios provide a reasonable and valuable structure for assessing future grid needs and solutions?

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[19] *Id.*

[20] *Id.* at 51.

Joint Parties' Response

While this may be a matter of semantics, there are differences between conducting a high and low load analysis versus understanding the ability of technologies to support the grid and reduce overall system peaks. For example, a high DER adoption rate may mask future load growth from overall electrification (for example, a high DER and high EV adoption scenario). Much of the time, increased EV load growth may be served from behind the meter solar and storage. As such, Hawaiian Electric would likely treat this scenario as a "low load" scenario. Nonetheless, such a scenario could also show occasional large system peaks, that is, large amounts of load suddenly appearing a small number of times over the year when DERs do not serve demand. This could trigger the need for substantial utility investment to meet the few times a year where DERs are not otherwise addressing the increased load. Nonetheless, understanding the impacts of high technology adoption—and the ability to create flexible loads—should help a reasonable utility system planner to design an appropriate program, procurement, or pricing option that could adequately address these outlier circumstances.

DATED: Honolulu, Hawai'i, September 10, 2021.

/s/ Melissa Miyashiro
Melissa Miyashiro
Blue Planet Foundation

/s/ Kylie W. Wager Cruz
Isaac H. Moriwake, Esq.
Kylie W. Wager Cruz
Earthjustice
Counsel for Blue Planet Foundation

/s/ Robert Harris
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Hawai'i PV Coalition

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Robert R. Mould
Hawai'i Solar Energy Association

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August 27, 2021

Ms. Brinda Westbrook-Sedgwick
Commission Secretary
Public Service Commission
of the District of Columbia
1325 G Street, NW
Suite 800
Washington, DC 20005

Re: Formal Case No. 1167

Dear Ms. Westbrook-Sedgwick:

Pursuant to Order No. 20754, Potomac Electric Power Company ("Pepco") submits to the Public Service Commission of the District of Columbia ("Commission") its electrification study. The purpose of this study is to assess the impact of electrification on the Pepco DC system by using average growth in system peak demand between 2021 and 2050 as a proxy for the overall impact on the Pepco DC distribution system. The study demonstrates the potential role of energy efficiency ("EE") and load flexibility in moderating the load impacts of electrification on the Pepco DC power grid. Through Clean Energy DC, the District has established the pathway to meeting its decarbonization goals involves an emphasis on energy efficiency and conservation, followed by decarbonizing the electric supply, including expanding local solar, and, finally, using decarbonized electricity to electrify as much as possible. Pepco, through its Climate Solutions Plan, will execute a multi-faceted strategy that will advance a smarter, stronger and cleaner energy system to help the District of Columbia achieve its leading climate goals and to achieve carbon neutrality by 2050.

The study found that future growth in the Pepco DC distribution system will remain well within the rate of system growth that Pepco DC has successfully managed and operated historically, even under the assumption that the District's landmark decarbonization goals are met largely through new electrification initiatives across all sectors. As shown on page 3 of the study, under certain assumptions Pepco's study estimates that peak demand will grow at an average annual rate of 1.4% between 2021 and 2050. Between 1950 and 2020, Pepco managed annual peak demand growth rates on its DC system well in excess of 2%.

The District's decarbonization and supporting goals extend over a 30-year period, allowing the load growth associated with electrification to be addressed at a manageable pace spanning three decades. Moreover, EE and load flexibility can significantly reduce future increases in peak demand and can be scaled up as electrification initiatives gain traction. Indeed, with an achievable

EXHIBIT A

portfolio of EE and load flexibility measures, the annual peak demand growth rate can be reduced from a projected 1.4% down to 0.9% between 2021 and 2050. Finally, heating electrification is expected to shift the Pepco DC system peak to the winter season, which is currently lower than its summer peak demand. As a result, heating load will have "room to grow" before it begins to contribute to new capacity needs.

While this study focuses on system-wide impacts, it is anticipated that load growth would be location specific and based on localized grid conditions and trends. Pepco does anticipate local capacity needs and enhancements associated with broad electrification, yet these investments could be moderated, as discussed above.

Pepco will remain a key partner to the Commission and the District in their efforts to achieve District climate goals and looks forward to continuing to work with the Commission, the District government and other stakeholders to successfully combat the effects of climate change.

Please contact me if you have any further questions.

Sincerely,

s/Andrea H. Harper
Andrea H. Harper

Enclosures

An Assessment of Electrification Impacts on the Pepco DC System

PRESENTED BY

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Sanem Sergici

Michael Hagerty

Julia Olszewski

PREPARED FOR

pepco

An Exelon Company

AUGUST 2021

Brattle

Disclaimer

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Purpose of this study

Electrification is expected to play a key role in achieving DC's landmark climate goals

- The Mayor's Office has established a goal of carbon neutrality by 2050
- The electrification of heating and transportation are important opportunities for achieving these goals, along with decarbonizing the power supply

The purpose of this study is to assess the impact of electrification on the Pepco DC system

- Brattle's DEEP model is used to simulate load growth due to meeting District's climate goals through electrification
- Growth in system peak demand is used as a proxy for the overall impact on the Pepco DC distribution system
- We focus on the average rate of load growth between 2021 and 2050, when climate goals are intended to be met

The study explores the potential role of energy efficiency (EE) and load flexibility in managing growth

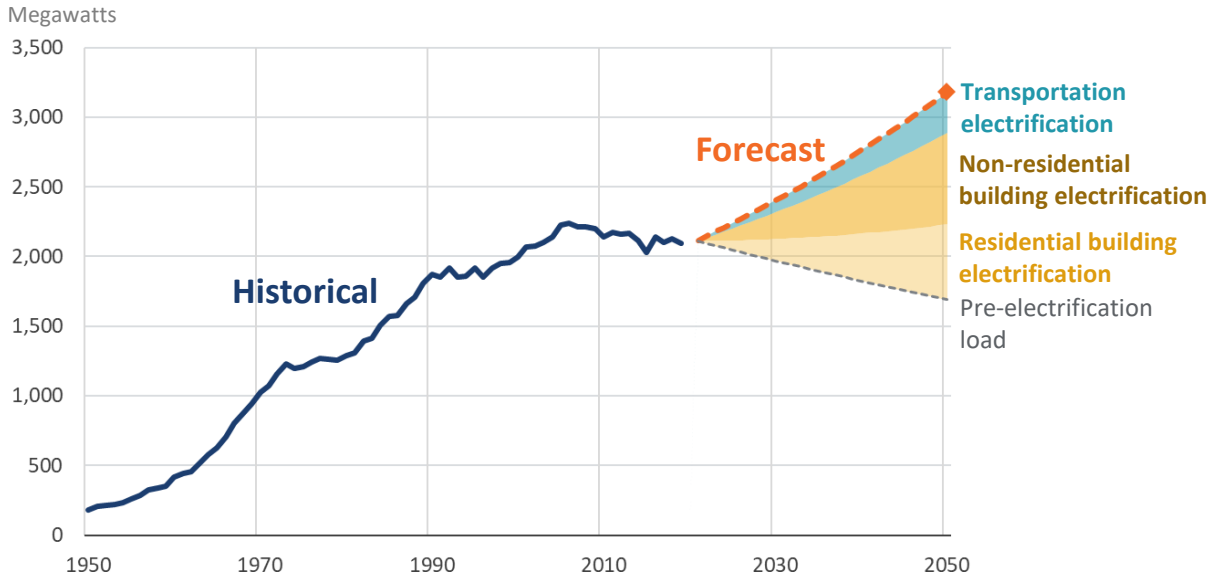
- EE and load flexibility could moderate the load impacts of electrification on the Pepco DC power grid
- Brattle's LoadFlex model is used to simulate achievable levels of future peak demand reduction due to load flexibility

Summary of findings

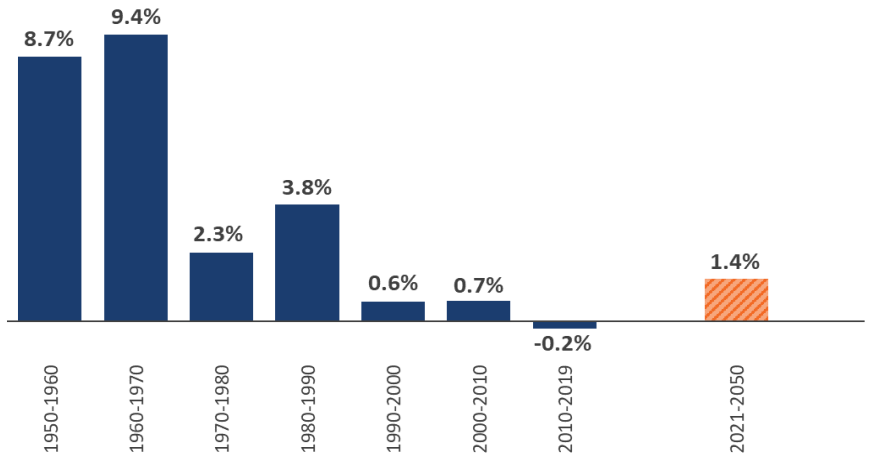
With electrification, Pepco DC's future rate of load growth will remain within recent historical ranges

- Historically, Pepco has reliably managed annual peak demand growth rates **well in excess of 2%**
- If electrification is the primary pathway for achieving the District's decarbonization goals, we estimate that peak demand will grow at an **average annual rate of 1.4% to 1.7%** between 2021 and 2050
- On average, the system will grow at a rate that is higher than recent observed growth but well below growth rates that Pepco has reliably managed in the past

Pepco DC System Peak Demand
Before EE and Load Flexibility



Compound Annual Growth Rate
by Decade



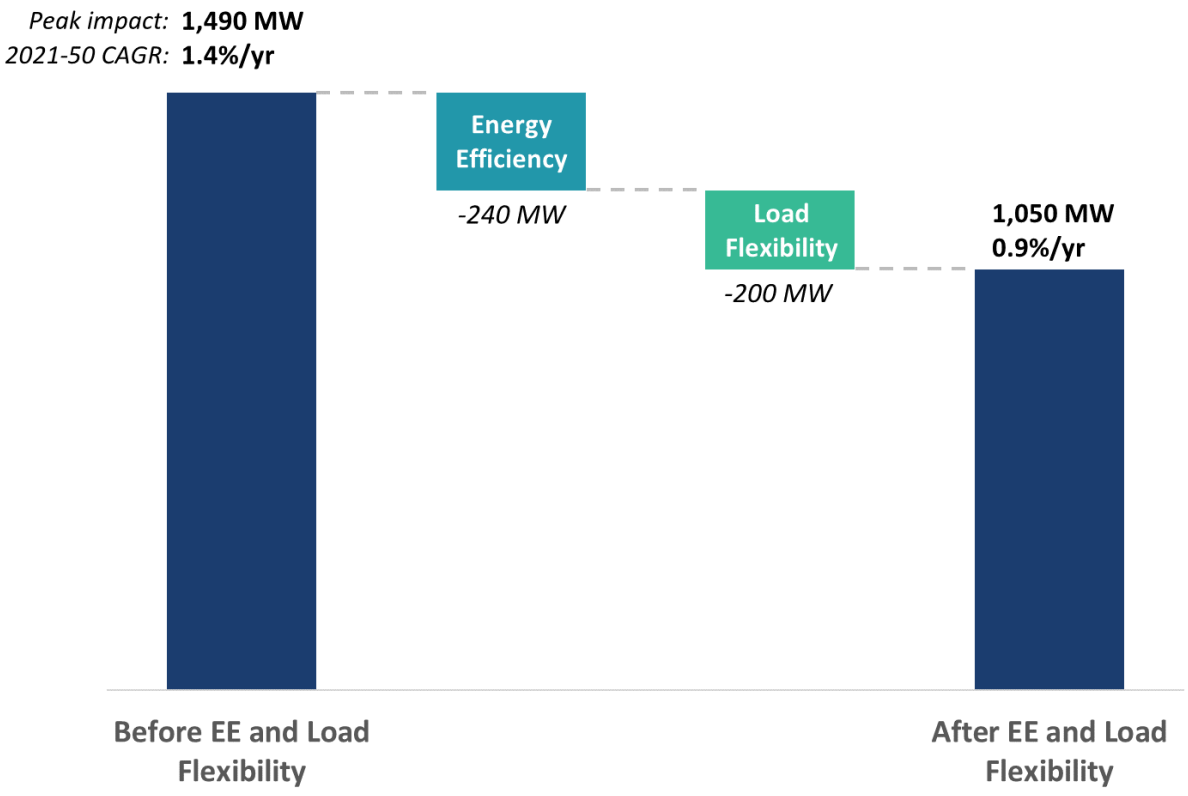
Summary of findings (cont'd)

EE and load flexibility could reduce Pepco DC's future load growth rate to less than 1% per year

- The robust portfolio of EE and load flexibility options considered in this study would reduce total 2050 peak demand by 14%, eliminating roughly 40% of the load growth that otherwise would occur between 2021 and 2050
- This highlights the value of EE and load flexibility in an economy that is increasingly electricity dependent

While these findings suggest that the Pepco DC distribution system can support electrification as a pathway for achieving the District's decarbonization goals, this study is not intended to be a substitute for a detailed distribution plan, which would include location-specific analysis of load growth and capacity needs on the distribution system as well as the costs and benefits of various approaches to addressing that growth

Incremental Contribution of Electrification to Pepco DC System Peak Demand, 2021-2050



Contents

The District’s Climate Goals

The District has established landmark energy decarbonization goals

The DC Mayor's Office has established a long-term goal of **carbon neutrality by 2050**

CleanEnergy DC established a goal to **reduce 2032 GHG emissions by 50%** relative to 2006 levels

Electrification is expected to play a key role in achieving the CleanEnergy DC goals

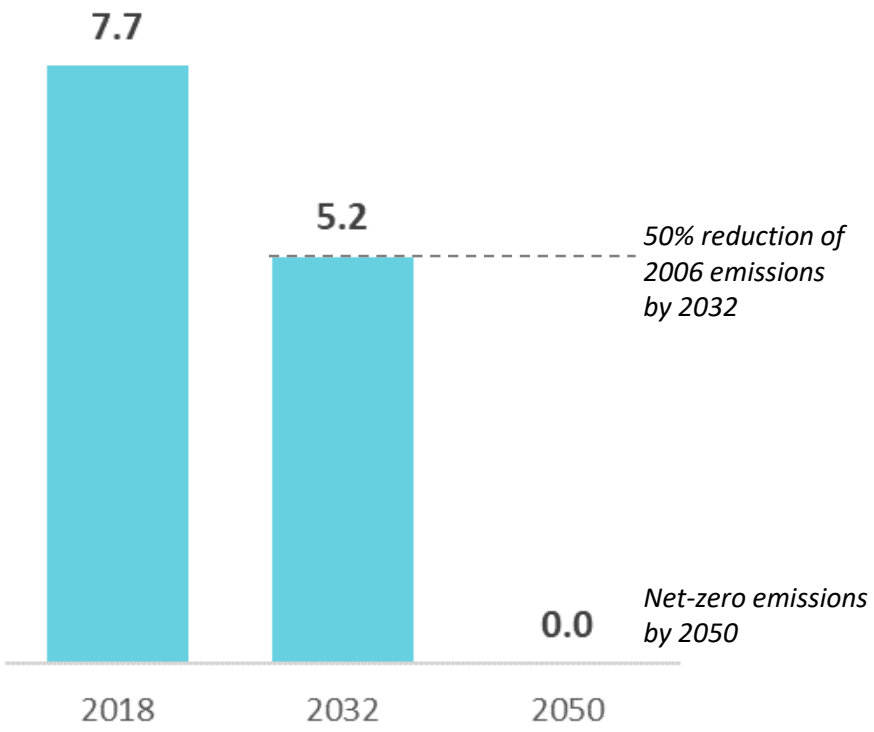
CleanEnergy DC includes the following **objectives for 2032**:

- Electricity as the primary clean fuel source for the District, with 100% of all energy derived from renewable sources
- Several transportation electrification initiatives
- A goal of reducing building energy consumption by 50%, which could be addressed by widespread adoption of electric heating

The goals of CleanEnergy DC will need to be expanded to ultimately satisfy the District's 2050 carbon neutrality objective

The District's Economy-Wide Decarbonization Goals

Million $MTCO_2e$ Emissions per year



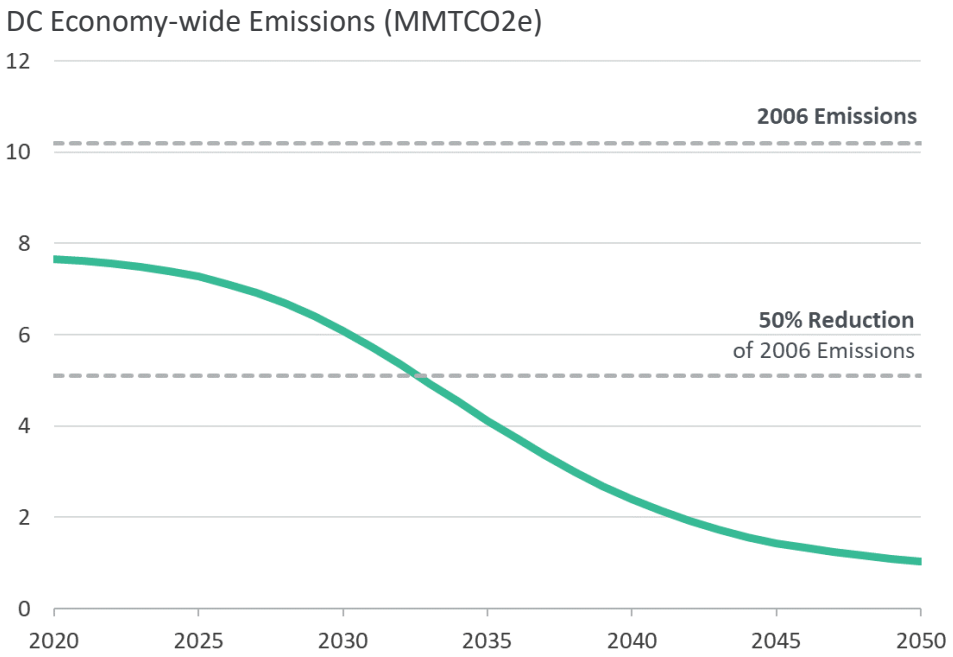
Source: 2018 DC GHG Inventory, available at: https://doee.dc.gov/service/greenhouse-gas-inventories.

Electrification could drive achievement of carbon neutrality by 2050

We assume 100% of light-duty vehicles and 95% of buildings will be fully electrified to meet the 2050 climate goals. These decarbonization initiatives will contribute to load growth.

The Carbon Impacts of Electrification

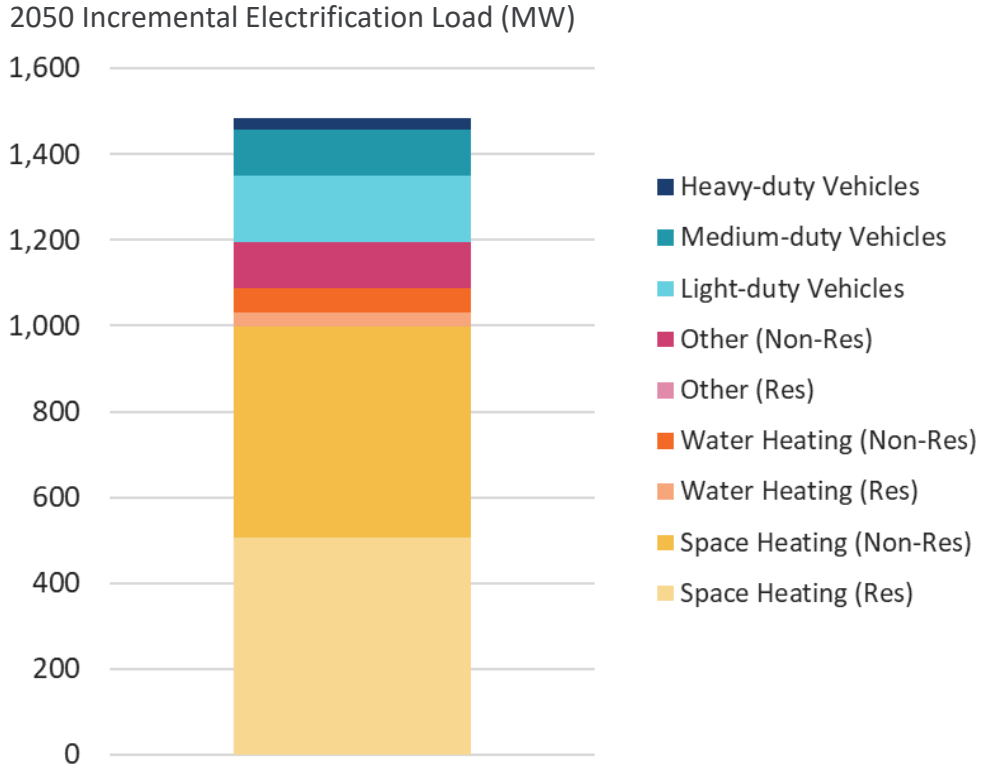
with Decarbonized Power Supply



Notes: The year-to-year trajectory of emissions decline is illustrative. By 2050, the modeling assumptions lead to approximately 90% of DC economy-wide emissions being eliminated through electrification and fully decarbonized power supply. The remaining 10% is assumed to be addressed through other means. Transportation and building electrification levels are based on a review of other public decarbonization studies and Brattle modeling. with See Appendix B for further details of the decarbonization modeling.

The Peak Demand Impacts of Electrification

2050, without EE and Load Flexibility

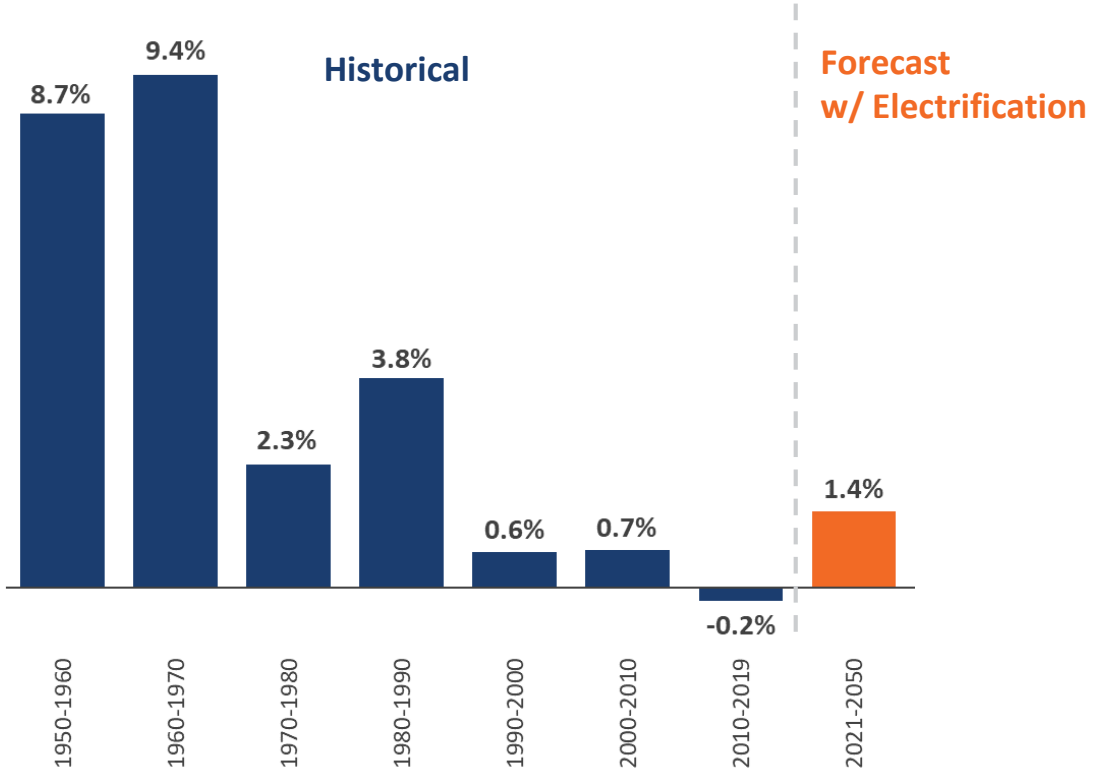


Putting the Load Impacts of Electrification into Context

After electrification, future growth will remain within historical growth rates

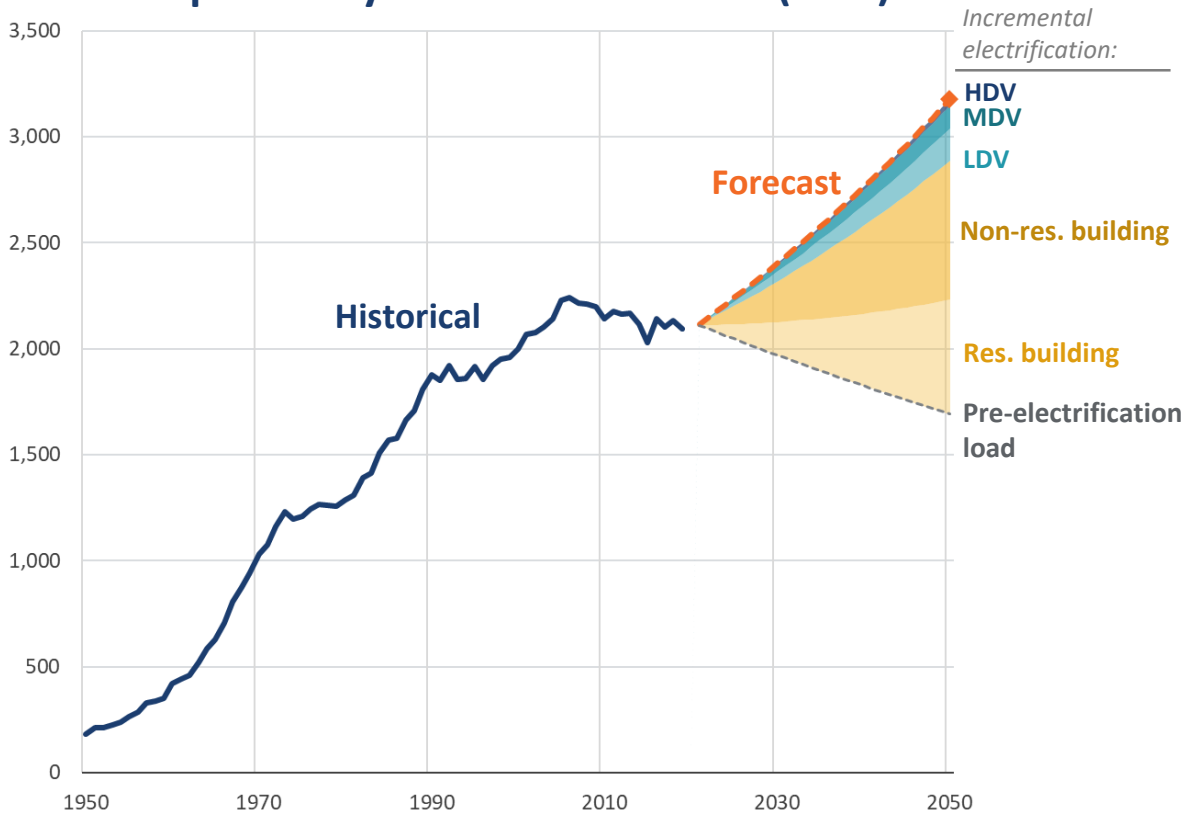
Forecasted load growth with electrification will exceed recent growth rates, but will remain significantly below historical rates of growth that have been reliably managed by Pepco for decades

Average Annual Growth in Pepco DC System Peak Demand



Source: Brattle analysis of 2020 PHI Annual Consolidated Report.

Pepco DC System Peak Demand (MW)



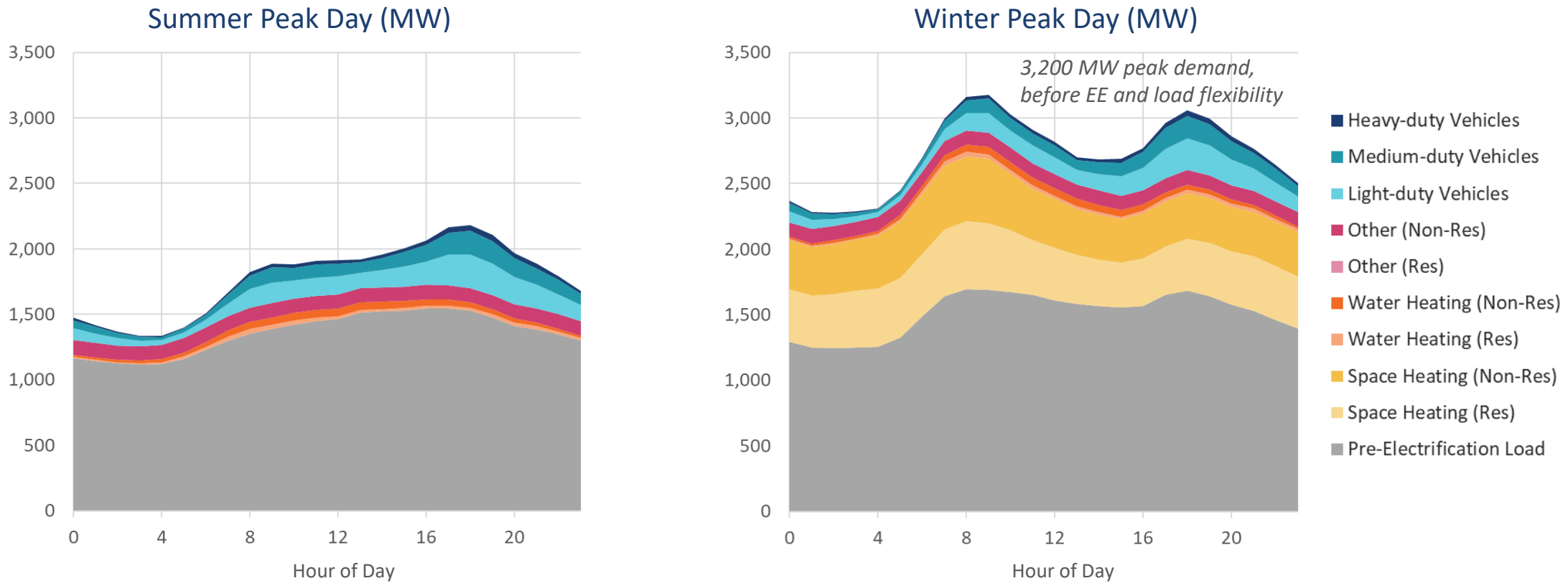
Notes: The post-2020 load growth trajectory shown here is extrapolated based on an average annual growth rate. The year-to-year growth trajectory likely would deviate from this trend, but would reach the same 2050 peak demand level. Peak load decreased significantly in 2020 due to COVID-19. This short-term load reduction does not directly influence the longer-term load forecast given that the analysis is focused on year 2050 outcomes.

With electrification, Pepco DC's system would peak in the winter morning

The increase in heating load is anticipated to result in a winter morning peak of roughly 3,200 MW in 2050

2050 Pepco DC Load Profile with Electrification

Before EE and Load Flexibility



Note: Incremental space heating demand is based on a long-term annual projection of heating gas demand and heating efficiencies. Total annual demand is allocated across days and hours of the year based on Brattle analysis of heating degree days and hourly heat output profiles, which vary with average daily temperature. The analysis assumes all heating system replacements use air-source heat pumps. The space heating efficiency is a function of hourly outdoor temperature for the 90/10 proxy year.

The Role of Energy Efficiency and Load Flexibility

EE and load flexibility are natural complements to electrification

A focus on demand-side initiatives will ensure that future load growth is efficient and flexible

In this study, we have considered a portfolio of options for reducing load growth due to electrification

Load flexibility is an extension of conventional demand response, allowing the load of various electric end-uses to be managed to provide a range of grid services, such as daily load shifting and load building during times of excess power supply

Energy efficiency initiatives can be expanded beyond business-as-usual efforts, to target energy savings during seasons and times of day when those savings are most valuable to the power grid

We modeled achievable participation for one possible portfolio of EE and load flexibility options

- Achievable participation estimates are derived from analysis of participation rates that have been achieved by successful utility demand response offerings across the U.S. and from a review of applicable EE potential studies
- The modeled portfolio is one representative set of possible customer offerings. Other demand-side options could be considered, and enrollment will vary depending on factors such as program design, incentives, and marketing

EE and load flexibility initiatives could target winter electricity demand

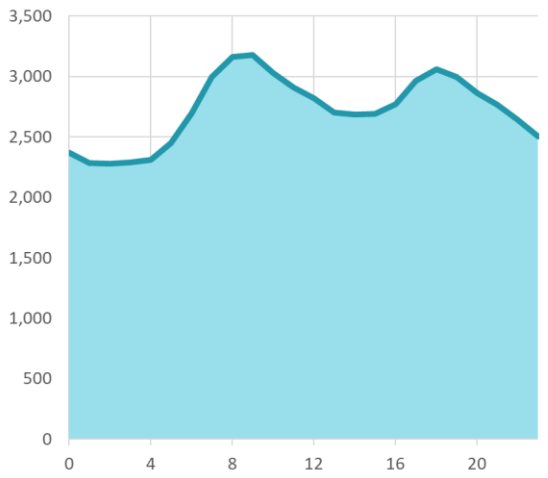
Modeled impacts of the options are based on achievable levels of customer enrollment

	EE / Load Flexibility Options	Description	Modeled 2050 peak reduction potential
Energy Efficiency	High efficiency heat pumps	Higher efficiency heat pumps are adopted when converting building space heating to electricity	3.5% (110 MW)
	Expanded EE initiatives	New EE initiatives would exceed business-as-usual efforts that are embedded in the baseline load forecast (e.g., focused improvements in building thermal envelope)	4.2% (135 MW)
Residential Load Flexibility	Dynamic pricing	Opt-in critical peak pricing (CPP) rate, with critical peak price that is 10x higher than the off-peak price.	1.5% (45 MW)
	Smart thermostat pre-heating	Homes are pre-heated before the morning peak period in order to reduce heating needs during the peak period.	0.9% (30 MW)
	Home EV charging TOU	TOU rates shift evening home EV charging load later in the night.	4.7% (140 MW)
	Behind-the-meter (BTM) storage	Customers with BTM batteries are eligible to participate in a storage load flexibility program, in which Pepco can discharge the battery on a limited number of days per year.	2.4% (75 MW)
Non-residential Load Flexibility	Interruptible tariff	Large commercial customers agree to curtail usage during the morning peak period for a limited number of events per year.	3.7% (115 MW)
	Dynamic pricing	A CPP rate with a critical peak price during the winter morning peak period.	1.8% (60 MW)
	Pre-heating	Similar to the residential program, commercial heating load is shifted from the morning peak period to earlier in the day by pre-heating the building.	0.4% (15 MW)

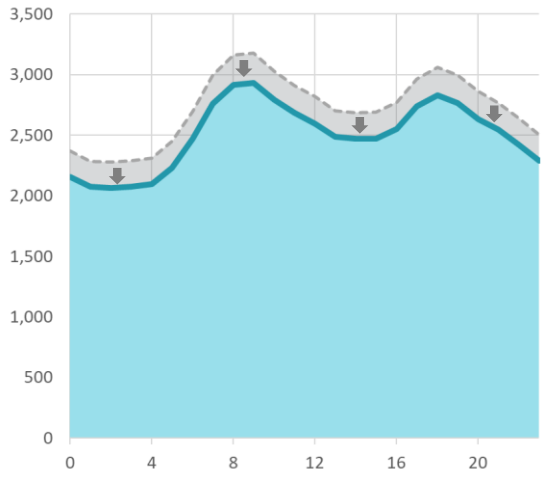
Notes: Peak demand reduction potential is if programs were deployed in isolation. The impacts shown here are not strictly additive when creating a portfolio of programs. See Appendix C for detailed modeling assumptions. Peak reduction potential for all measures is reported as a percentage of the winter morning peak, except for Home EV charging TOU, which is reported as a percentage of the evening peak.

EE and load flexibility could reduce 2050 system peak demand by 14%

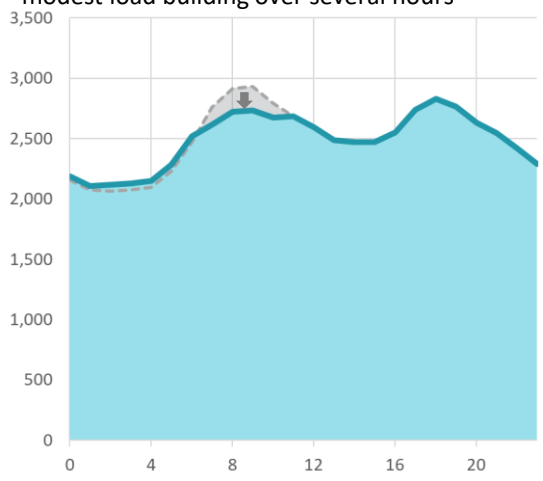
1 Unmitigated 2050 Pepco DC load on winter peak day



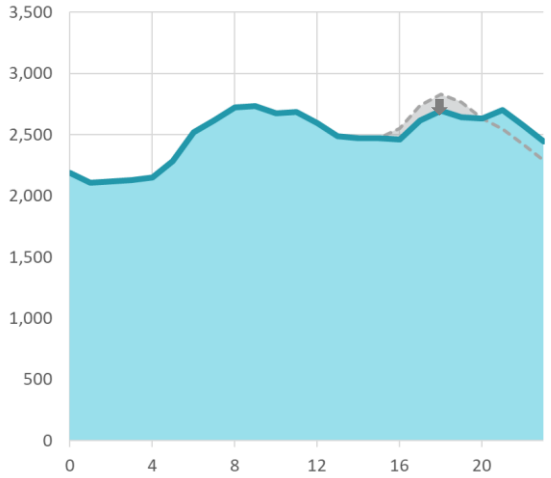
2 Energy efficiency reduces load during all hours



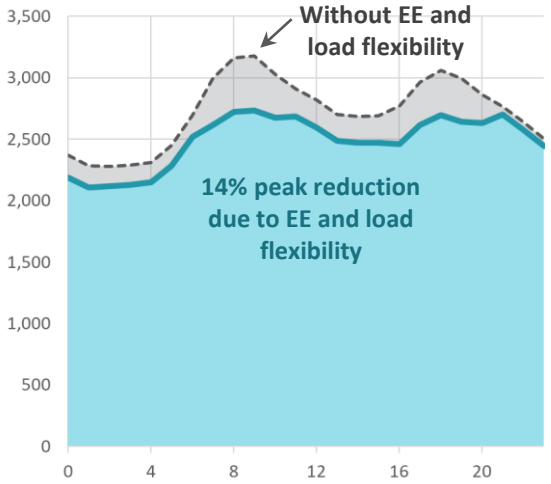
3 Dynamic pricing, interruptible tariffs, pre-heating, and BTM storage clip the morning peak with modest load building over several hours



4 EV TOU reduces evening peak, shifting charging load to later hours



5 Mitigated 2050 Pepco DC load on peak day

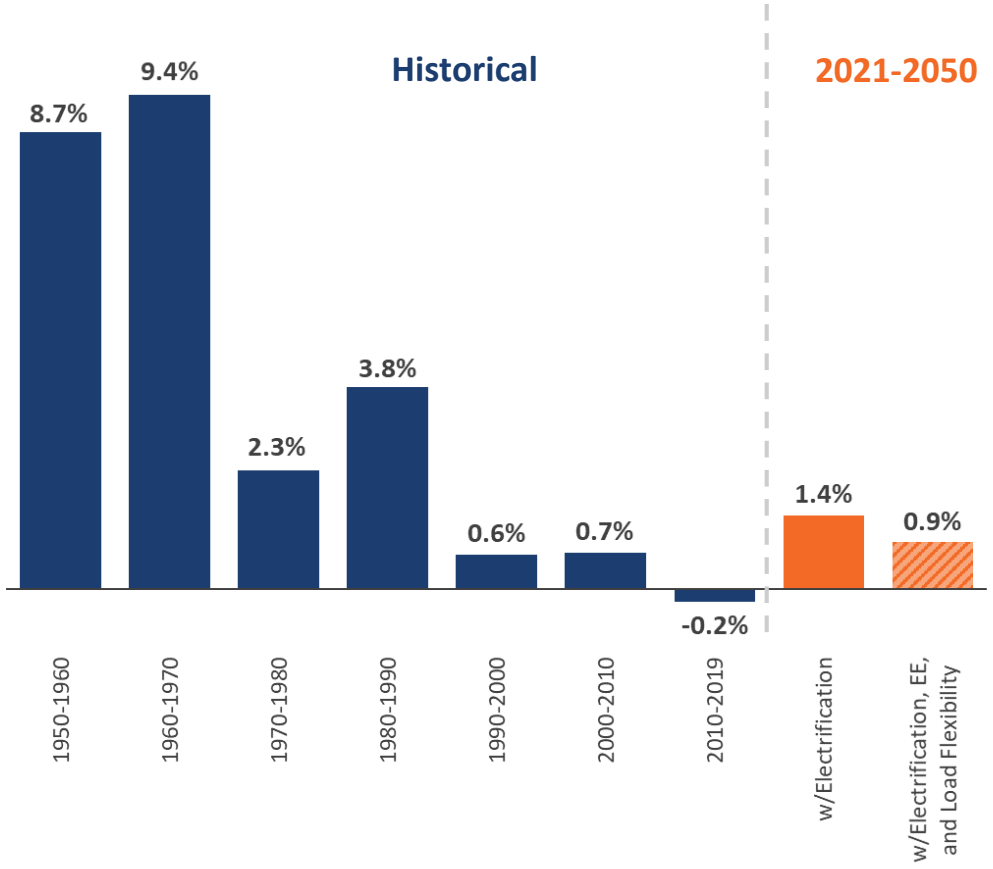


Note: Load impacts are shown for one illustrative portfolio. EE and load flexibility options could be pursued in different combinations, with varying operational strategies and levels of enrollment.

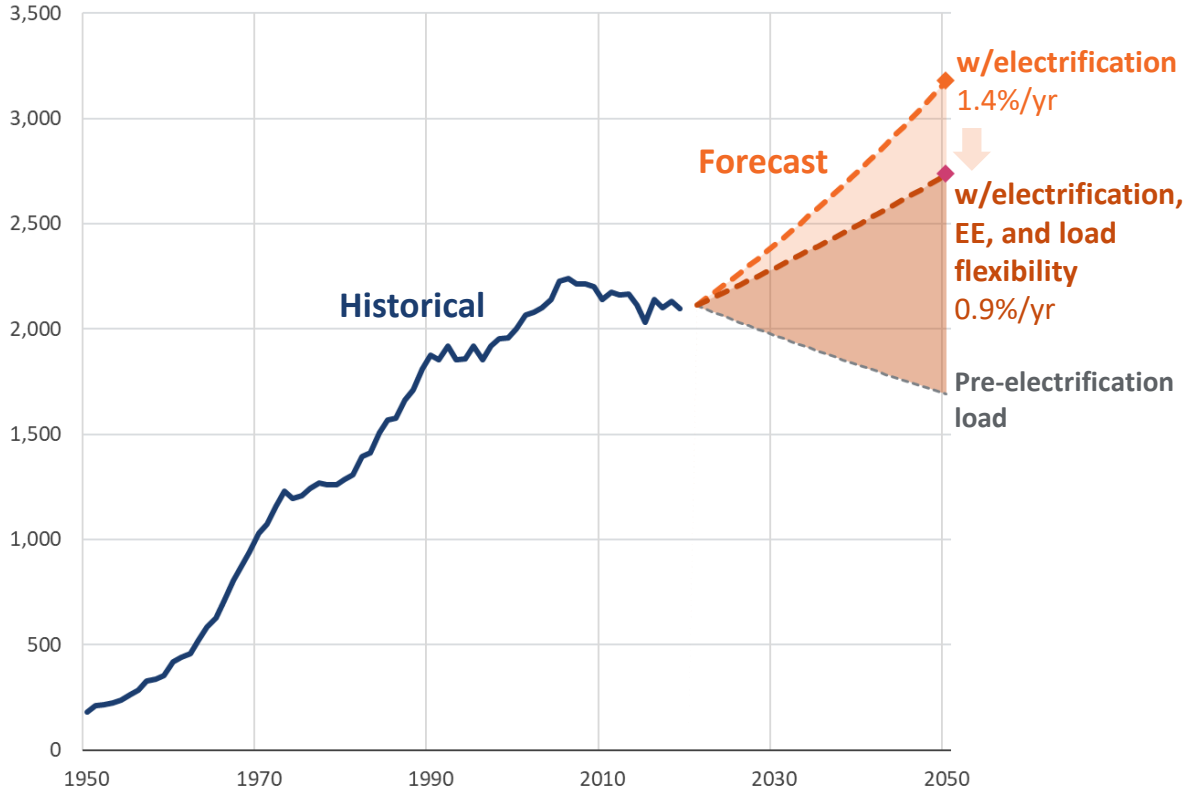
EE and load flexibility reduce the annual peak demand growth rate to 0.9%

Annual load growth below 1% is similar to recent trends over the past few decades

Average Annual Growth in Pepco DC System Peak Demand



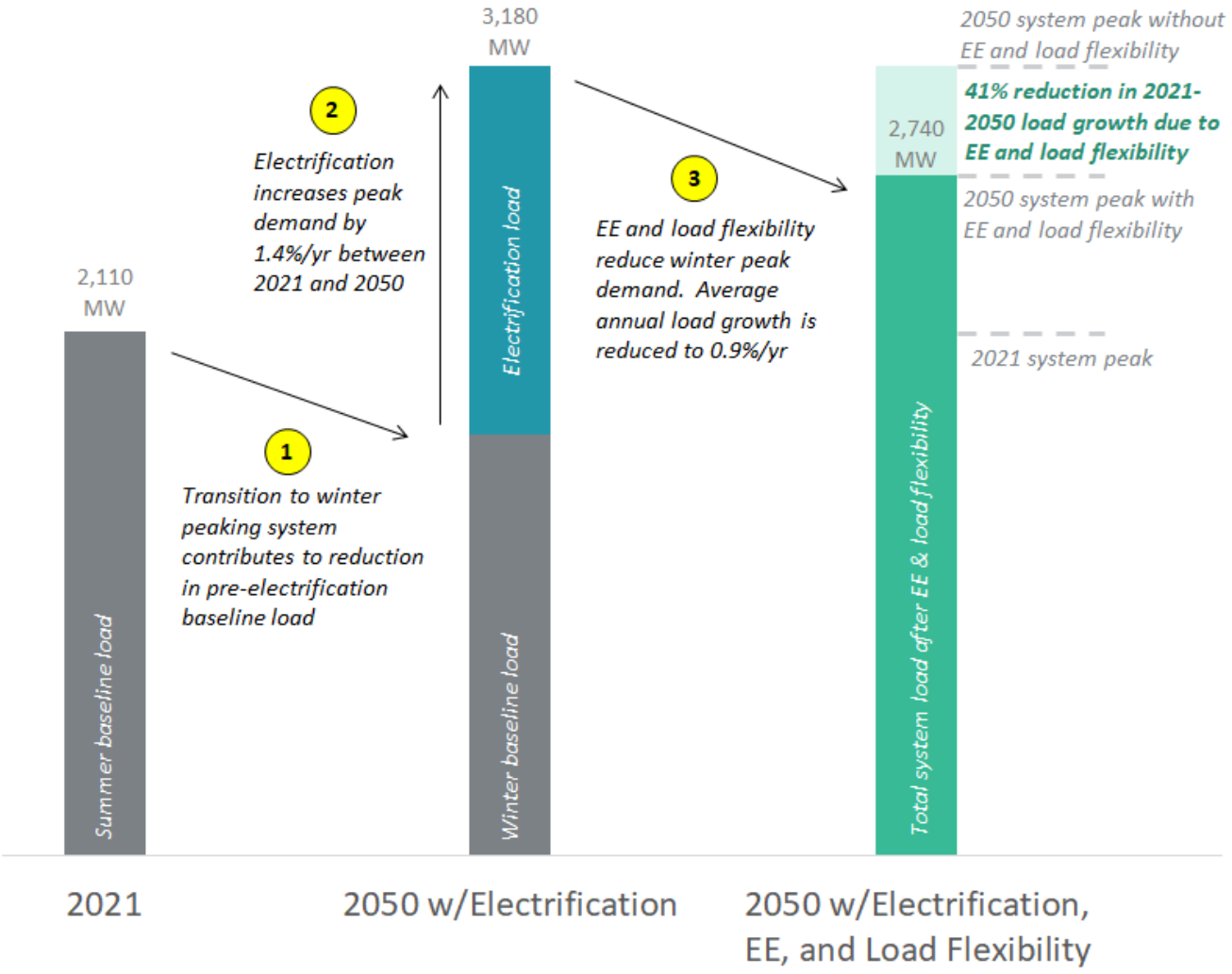
Pepco DC System Peak Load (MW)



Notes: The post-2020 load growth trajectory shown here is extrapolated based on an average annual growth rate. The year-to-year growth trajectory likely would deviate from this trend but would reach the same 2050 peak demand level.

Roughly 40% of 2021 - 2050 load growth is eliminated through EE and load flexibility

- EE and load flexibility reduce 2050 system peak demand from 3,180 MW to 2,740 MW by clipping the morning and evening winter peaks
- Load growth is also mitigated by the transition to a winter peaking system and declining baseline load. Pepco DC's summer load is currently higher than its winter load. This means that **a portion of future electrification-related winter load growth will not contribute to new capacity needs**



Sensitivity Analysis

We tested sensitivity of the findings to an alternative baseline load forecast

To address uncertainty, we considered a case with positive baseline (pre-electrification) load growth

The baseline peak demand forecast presented thus far is based on PJM's projection for the Pepco system

- Pepco DC does not develop a 30-year system load forecast at this time
- Therefore, the baseline forecast was developed by applying compounded annual growth rates from the PJM forecast to Pepco's recent summer and winter peak demand
- This baseline forecast implies declining summer (-1.0%) and winter (-0.2%) annual changes in peak demand across the forecast horizon

As a sensitivity case, we developed a higher alternative baseline forecast

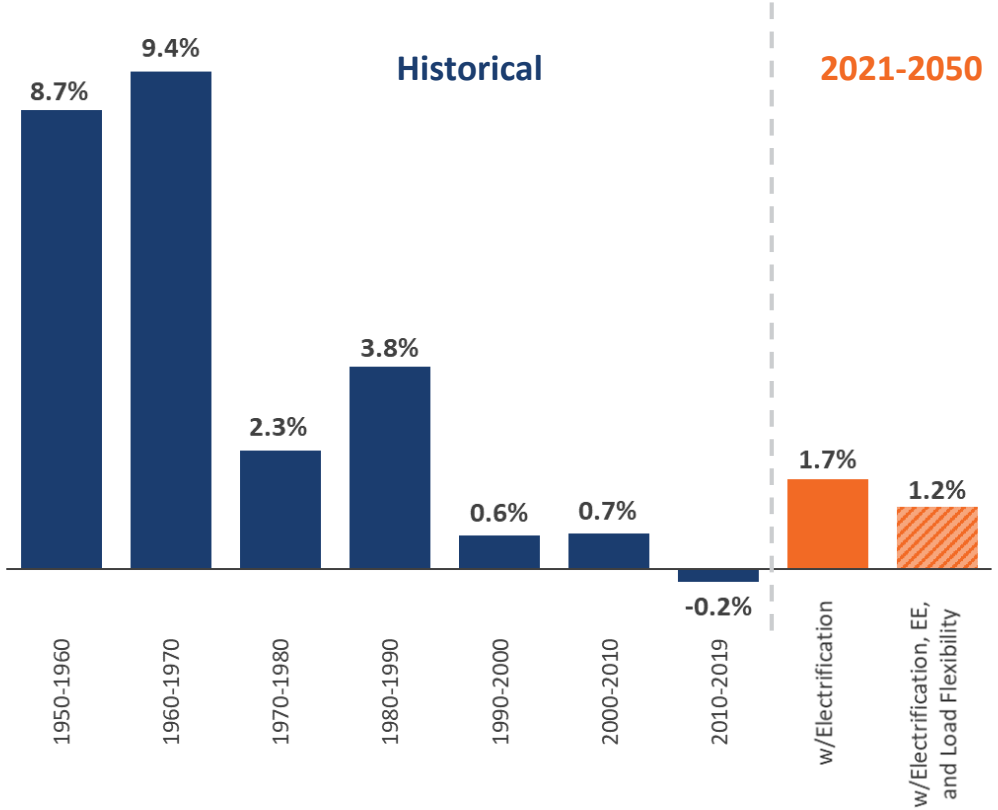
- The alternative baseline forecast is based on a near-term non-coincident peak growth projected by the Pepco distribution planning group
- Under the alternative baseline forecast, both summer and winter peaks are assumed to grow at a compound annual growth rate (CAGR) of 0.4% between 2021-2050

See Appendix A for further details

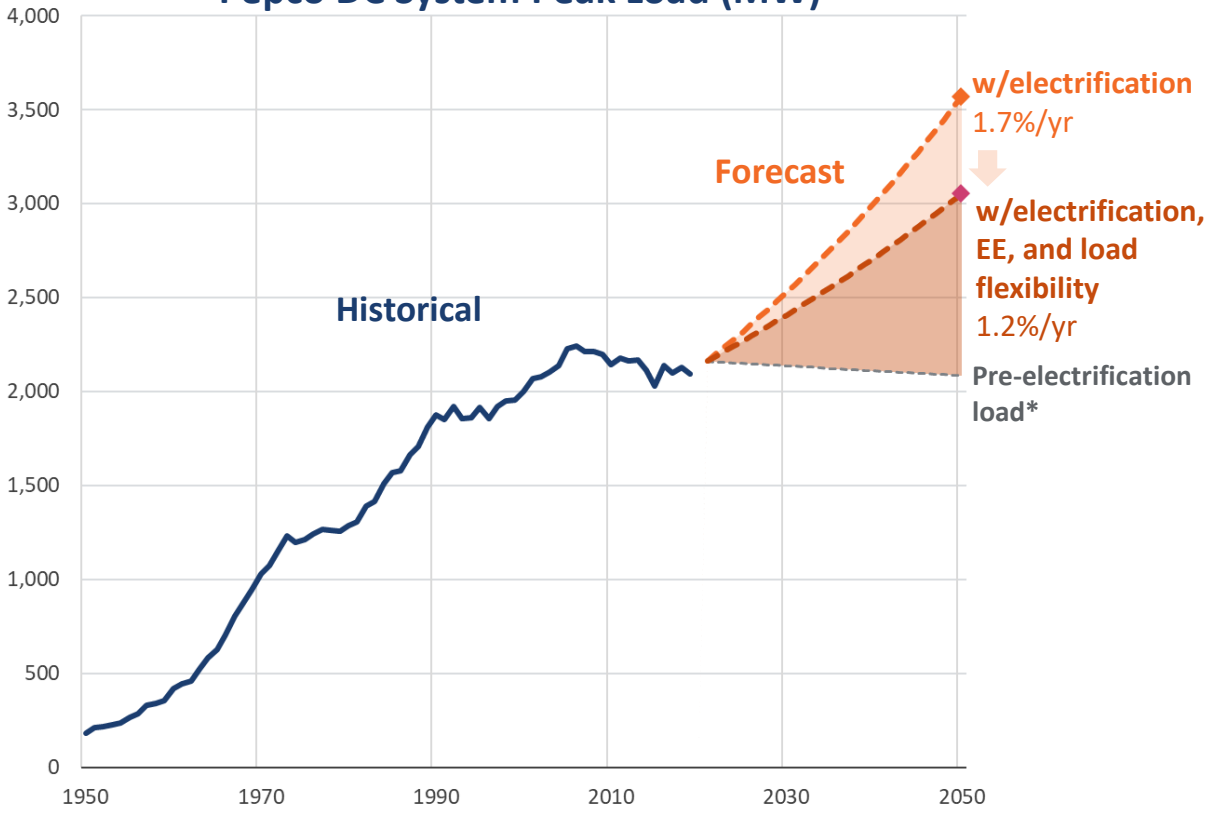
With higher baseline demand, future growth remains within historical bounds

The findings of this study are robust under conditions of positive pre-electrification load growth

Average Annual Growth in Pepco DC System Peak Demand



Pepco DC System Peak Load (MW)



**While the baseline load trajectory is based on summer and winter growth of 0.4% per year, the 2021-2050 rate of change appears negative due to the transition from a summer-peaking system to a winter peaking system. See Appendix B for further discussion. The post-2020 load growth trajectory shown here is extrapolated based on an average annual growth rate. The year-to-year growth trajectory likely would deviate from this trend, but would reach the same 2050 peak demand level.*

Conclusion

What do these results mean for the Pepco DC power system?

In this study, system peak demand growth has been used as a proxy for future impacts on the Pepco DC distribution system

With that focus, we have estimated that future growth in the Pepco DC distribution system will remain well within the rate of system growth that Pepco DC has successfully managed and operated historically, even under the assumption that Pepco DC's landmark decarbonization goals are met largely through new electrification initiatives

Three specific findings support this conclusion:

- **Room to grow:** Heating electrification eventually will shift the Pepco DC system peak to the winter season. Currently, Pepco DC's winter peak demand is lower than its summer peak demand. As a result, heating load will have "room to grow" before it begins to contribute to new capacity needs
- **A long planning horizon:** The District's decarbonization goals extend over a 30-year period, allowing the load growth associated with electrification to be addressed at a manageable pace spanning three decades
- **Demand-side opportunities:** EE and load flexibility can significantly reduce future increases in peak demand and can be scaled up as electrification initiatives gain traction

These findings are not a substitute for a detailed distribution resource plan, which would be conducted to identify capacity investment needs in specific locations on the Pepco DC system

Appendix A:

BASELINE FORECAST

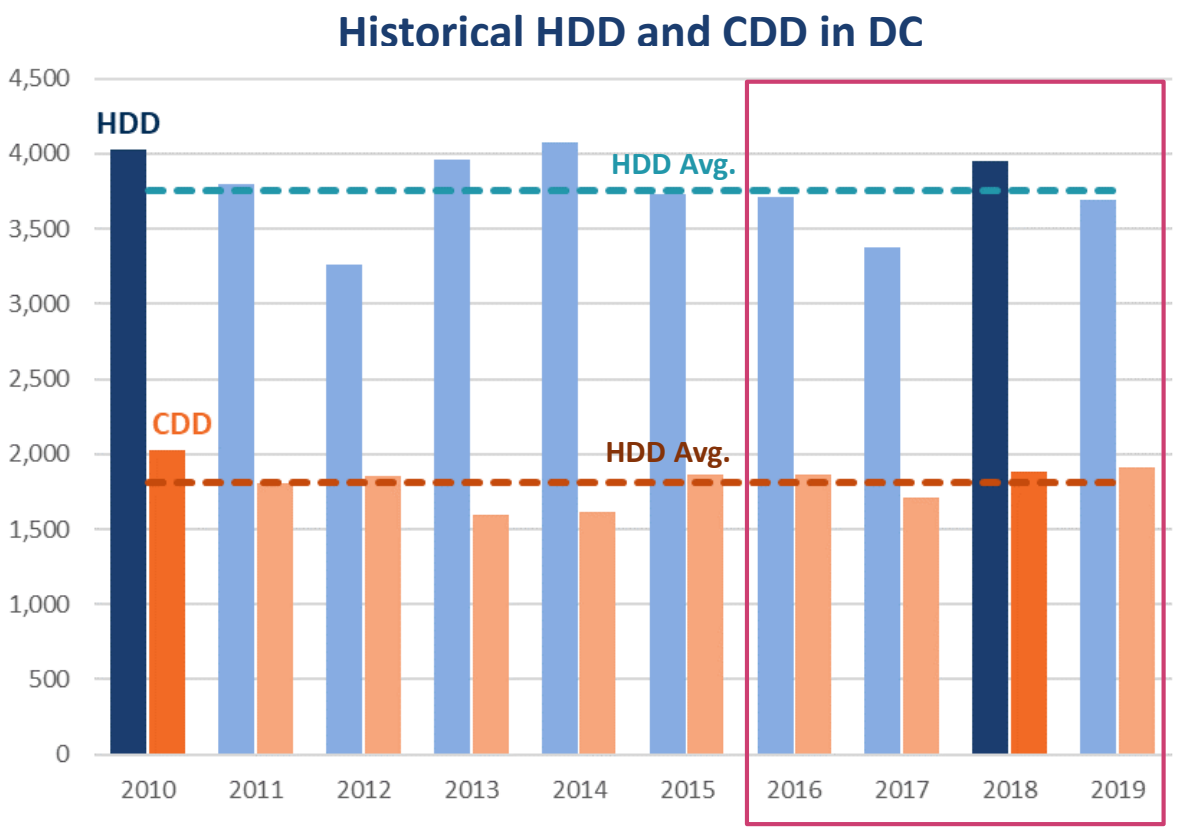
Baseline Demand Forecast Approach

Pepco DC does not develop a 30-year system load forecast at this time; therefore we developed 8760 hourly load forecasts for 2021-2050 following the approach described below

1. **90/10 proxy year selection**
   - Selected year 2018 based on analysis of historical heating and cooling degree days (see next slide)
2. **Annual winter and summer peak forecast**
   - Developed a baseline demand forecast using 2018 summer and winter peak demand as the starting point and the compounded annual growth rates from PJM's Pepco 2020-2036 forecast (net of EV load) for summer and winter peaks
     - For 2020-2036, we use PJM's summer and winter peak load CAGR from 2020-2036
     - For 2036-2050, we use PJM's summer and winter peak load CAGR from 2031-2036
   - Developed a higher "alternative baseline forecast" forecast to anchor to 0.4% non-coincident peak growth forecast provided by the Pepco distribution planning group; we assumed both winter and summer peaks will grow at a CAGR of 0.4% over 2021-2050
3. **8760 hourly demand forecast**
   - Scaled Pepco DC 2018 8760 hourly demand profile so that (1) the summer and winter peak loads from the 8760 hourly profile match with the annual peak forecast and (2) the energy demand of the 8760 is aligned with the energy forecast resulting from applying PJM's energy forecast growth rate (note Pepco DC forecast energy growth rate is consistent with PJM Pepco zone's through 2025)

Forecast Future Demand based on 2018 System Conditions

- Pepco plans around the **hottest year in the last 10 years** to develop its peak loads for each distribution system component in the short-term load forecast
- For our long-term analysis, we selected a year with **both a hot summer and a cold winter**, as over time the summer-peaking system will become winter-peaking
- Based on the **analysis of the District's heating and cooling degree days for the last 10 years**, both 2010 and 2018 have some of the highest HDDs and CDDs
- We selected **2018 as the 90/10 proxy year** based on historical hourly system load data available (2016-2020)



Pepco 8760 hourly system load available for 2016-2019

Estimated Pepco DC Load Growth Rates

The table below summarizes Pepco's historical and forecasted peak growth rates

CAGR for Pepco Demand (%/yr)

	Source	Timeframe	Summer Peak	Winter Peak	Annual Peak
Historical	Pepco DC/MD Weather-Normalized Peak Demand	Summer: 2010-19 Winter: 2010-18	-0.2%	0.3%	-0.1%
Forecast	Pepco DC/MD PJM 2021 (50/50)	2021-2036	-1.2%	-0.2%	-0.4%
	Pepco DC/MD PJM 2021 (90/10)	2021-2036	-0.9%	-0.1%	-0.1%
	Pepco DC Brattle High Alternative (90/10)	2021-2050	0.4%	0.4%	0.4%

Source: Brattle analysis of Pepco data and PJM Load Forecast Report (January 2021).

Baseline Forecast Base Case CAGR

	2021-2036	2037-2050
Winter	-0.2%	-0.3%
Summer	-1.0%	-1.0%

Given that PJM's 2021 accounts for some EV electrification growth, the PJM growth rates used in the Base Case were adjusted to exclude growth in EV electrification.

In addition to the Base Case, we also modeled a higher alternative baseline peak forecast of 0.4% summer and winter baseline peak growth from 2021-2050.

Hourly Baseline Load Forecasts

- We converted the annual winter and summer peak load forecasts into hourly load profiles based on the 90/10 proxy year (2018) historical hourly profile
- For each year in the forecast, we scaled the 2018 hourly load profile to match the winter and summer peak load forecast
- In addition, we scaled the hourly load profile for each year to match with Pepco/PJM's energy projections
  - We compared Pepco DC's 2021-2025 energy forecast to PJM's energy forecast for Pepco for the same time period
  - The two sources consistently projected an annual energy growth of -0.4%/yr
  - We used this assumption to develop the energy forecast used to scale the hourly load profiles for each year
- The 8760 hourly profiles for the higher alternative baseline were developed using the same approach
  - We scaled Pepco's 2018 hourly load profile to match the winter and summer peaks, which were derived this time using a higher growth rate estimate (**0.4%/yr**)
  - We then scaled the profile to match annual energy projections according to a higher rate of annual growth (0.5%/yr).
  - The 0.5%/yr growth assumption falls on the higher end of a range of PJM energy growth assumptions for utilities surrounding Pepco DC/MD

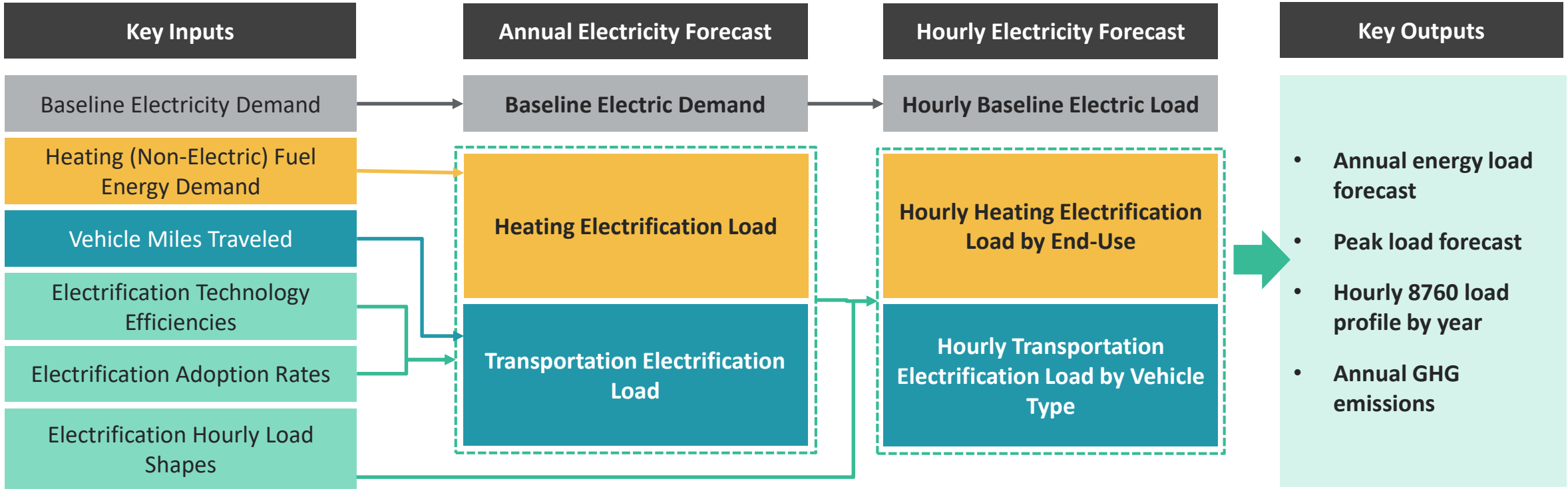
Appendix B:

DECARBONIZATION MODELING

Electrification Modeling Overview

We rely on Brattle's Decarbonization, Electrification & Economic Planning (DEEP) Model to develop the electrification forecast

- The electrification forecast is based on an annual projection of heating fuel energy demand and vehicle miles traveled
- Electric heating and EV adoption rates are used to estimate the fraction of annual demand and miles traveled electrified over time
- Technology efficiency projections and hourly load shapes are used to convert annual demand into hourly outputs



Long-Term District Energy Demand Forecast

This study relies on electrification as the primary means for achieving decarbonization goals: 50% reduction in economy-wide emissions by 2032 and carbon neutrality by 2050

Energy demand in the District is dominated by the non-residential sector

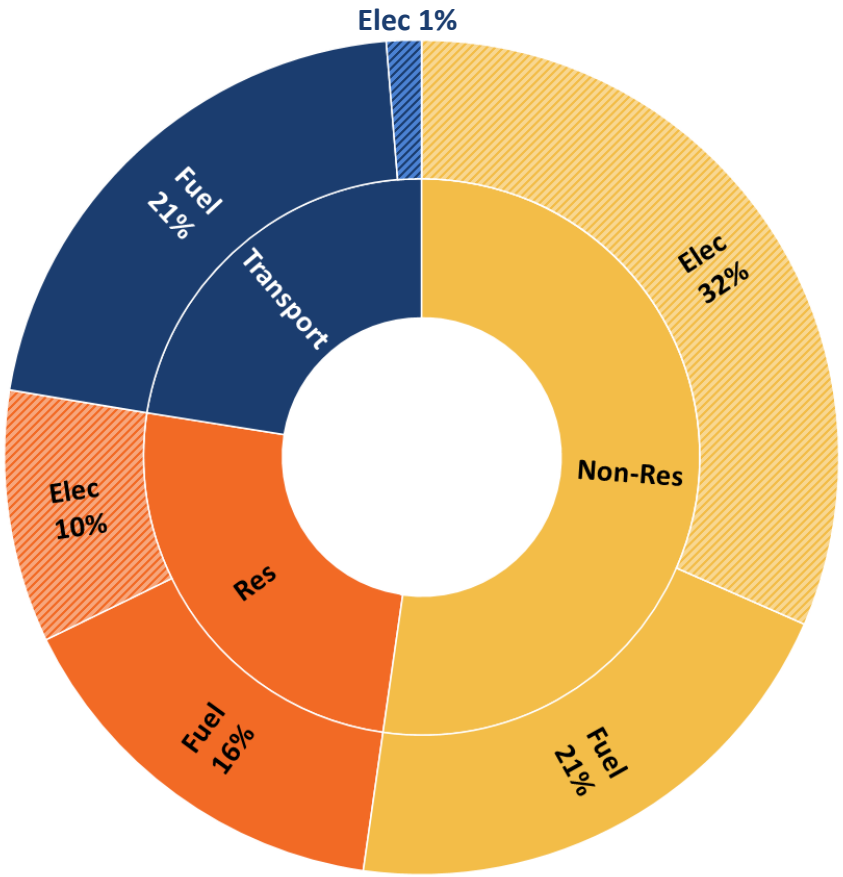
More than 40% of energy demand in the District is already met by electricity

We relied on 2018 fuel demand for heating and transportation vehicle miles traveled (VMTs) to develop current energy demand

- Projected energy demand (2019-2050) is based on AEO South Atlantic trends for transportation, residential and commercial sectors
- Checked AEO projections against projections included in recent District energy policy reports and confirmed that they are generally consistent

We used 2018 as a representative 90/10 year for electricity demand and weather conditions

2018 District Energy Demand Breakdown



Source: 2018 DC GHG Inventory.

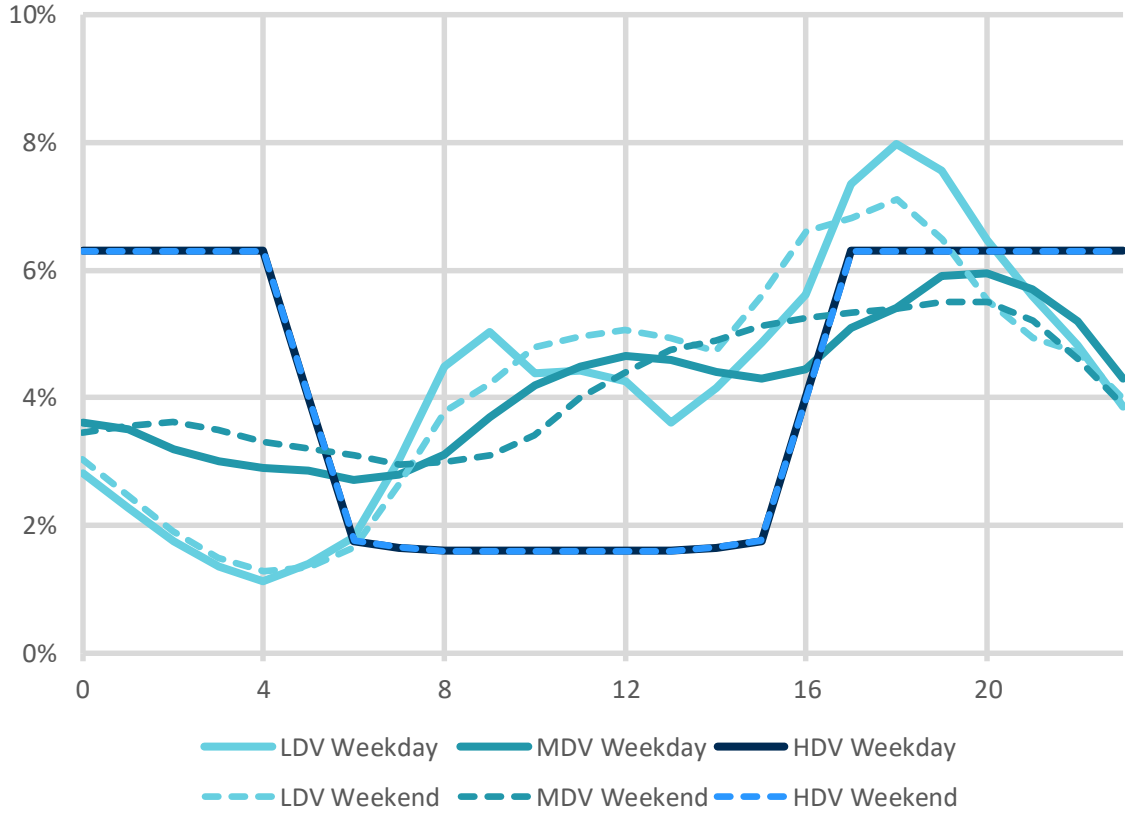
Transportation Electrification Forecast

- Developed **VMT projections** based on recent historical VMTs in the District and AEO VMT forecast for South Atlantic region
- **Vehicle efficiency projections** are based on the Moderate case in the NREL Electrification Futures Study
- Monthly **vehicle efficiencies** are a function of the average **monthly temperature** of the 90/10 proxy year (2018)
- **Light duty vehicle (LDV) hourly profiles** are based on home and work charging data from EVI Pro Lite for the District, and we assume **40% of charging takes place at work**, to reflect that a significant share of the District workforce resides outside of the DC area
- **Medium duty vehicle (MDV) and Heavy duty vehicle (HDV) hourly profiles** are developed using load shapes from SCE, CEC, and NREL studies on MHDV charging patterns
- We assume **100% of light-duty vehicles, over 75% of medium-duty vehicles, and over 50% of heavy-duty vehicles are electrified by 2050**, based on Brattle's review of transportation electrification studies and expert survey of MDV and HDV adoption trends through 2050

Note: LDVs are defined as passenger cars and light trucks, MDVs as class 2-4 vehicles and HDVs as class 6-8 vehicles (single unit and combination trucks).

EV Charging Profiles

(% of daily charging energy demand)



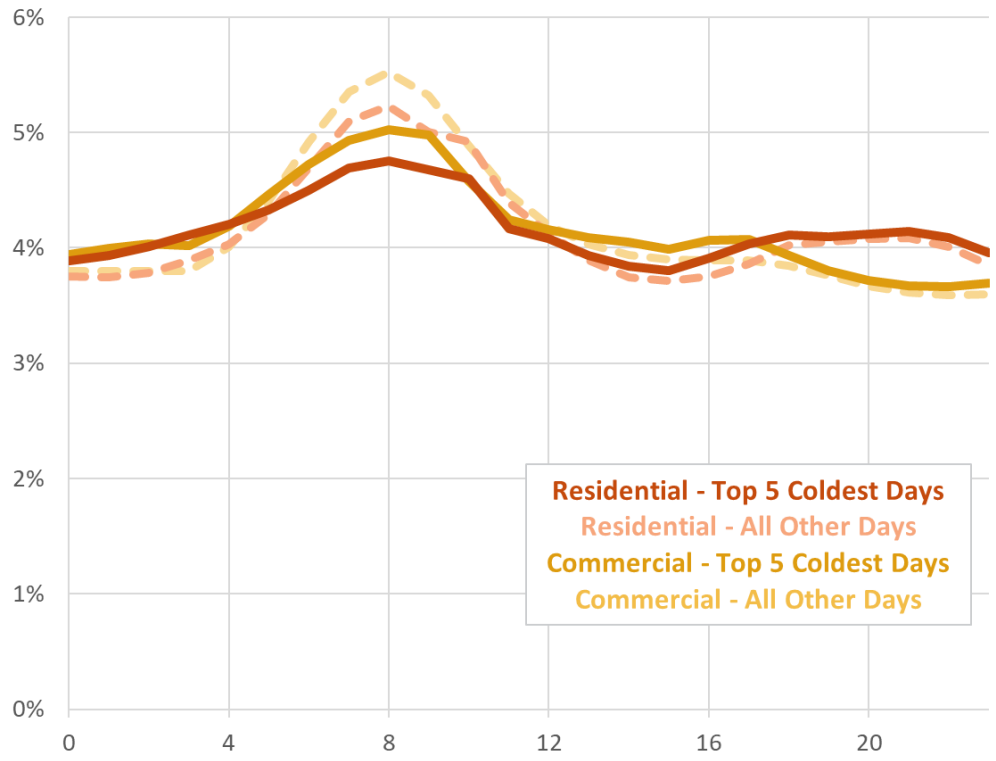
Sources:
Southern California Edison Company's Charge Ready Pilot Quarterly Report. 31 August, 2020.
California Energy Commission Final Project Report: California Investor-Owned Utility Electricity Load Shapes. April 2019.
CEC Assembly Bill 2127 Electric Vehicle Charging Infrastructure Assessment (Staff Report). Docket number 19-AB-2127. 7 January 2021.
NREL Medium-Duty Plug-In Electric Delivery Truck Fleet Evaluation, 27-29 June 2016.

Building Electrification Forecast

- In this study, the **decarbonization of the building sector** is achieved mainly through **heat pump electrification**
  - We assume 95% of building fuel demand is electrified by 2050
- We developed a **heating fuel demand projection** based on 2018 historical data and AEO growth forecasts for the South Atlantic region (we relied on 2018 historical data to reflect 90/10 conditions)
- We used an **efficiency forecast of fuel furnaces** to convert the heating fuel demand projection into annual **heating energy output**
- We allocated the annual heating energy output across days proportionally to the **heating degree days** in 2018
- The **heating hourly profiles** were used to allocate daily heating output across the hours of the day (see chart for *space heating* profiles; *water heating* and *other* profiles can be found in the appendix)
- We used the **heat pump efficiencies** to convert heating output into **electricity demand** for heating
  - Heat pump heating efficiency projections are based on the NREL Electrification Futures Study (Moderate case)
  - Air source heat pump (ASHP) efficiencies were adjusted to reflect 90/10 temperature conditions, based on the ratio of 2018 HDD to the 20-yr historical avg. of annual HDDs
  - ASHP efficiencies are modeled at an hourly-level as a function of outside temperature

Space Heating Profiles

(% of daily energy demand)

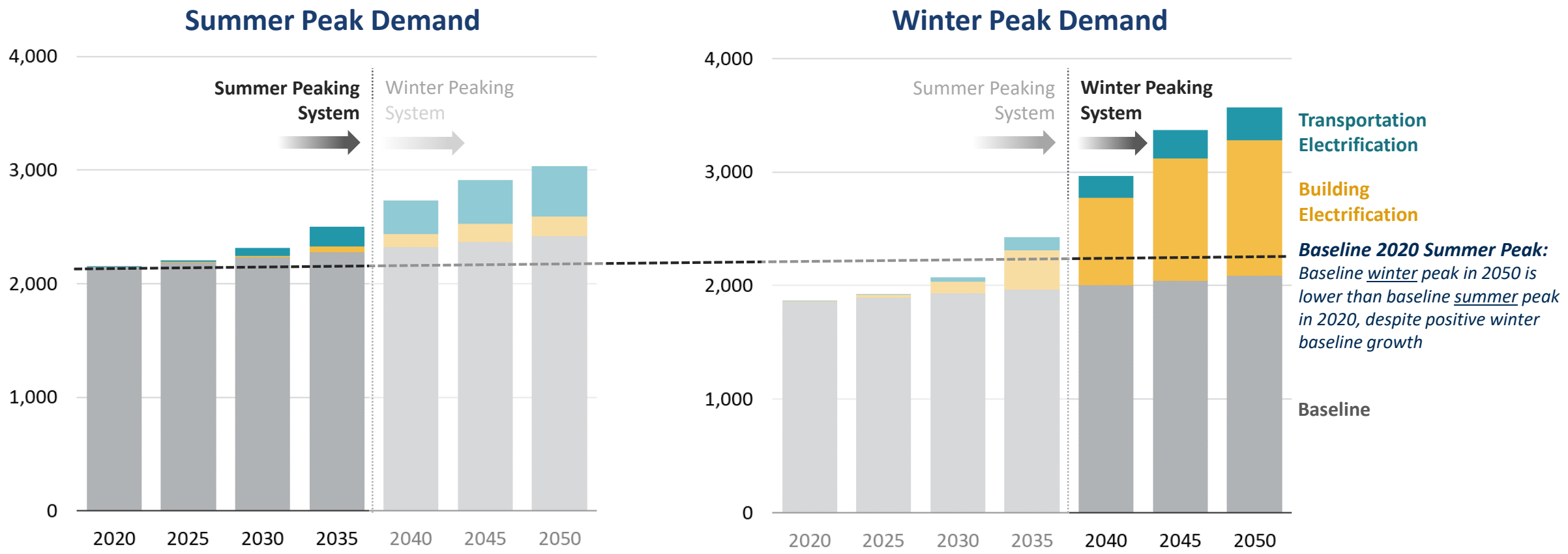


Hour Beginning

Note: The residential profiles are based on the DPL gas data analysis (75% of customers in sample were residential). The commercial profiles were created by scaling the shape of the EPRI load shapes to align with the DPL data.

Baseline Load Growth in Sensitivity Case

While the **baseline load trajectory** is based on **summer and winter growth of 0.4% per year** in the sensitivity case, the **2021-2050 rate of change** for baseline load **appears negative** in figures. This is due to the transition from a summer-peaking system to a winter peaking system with electrification

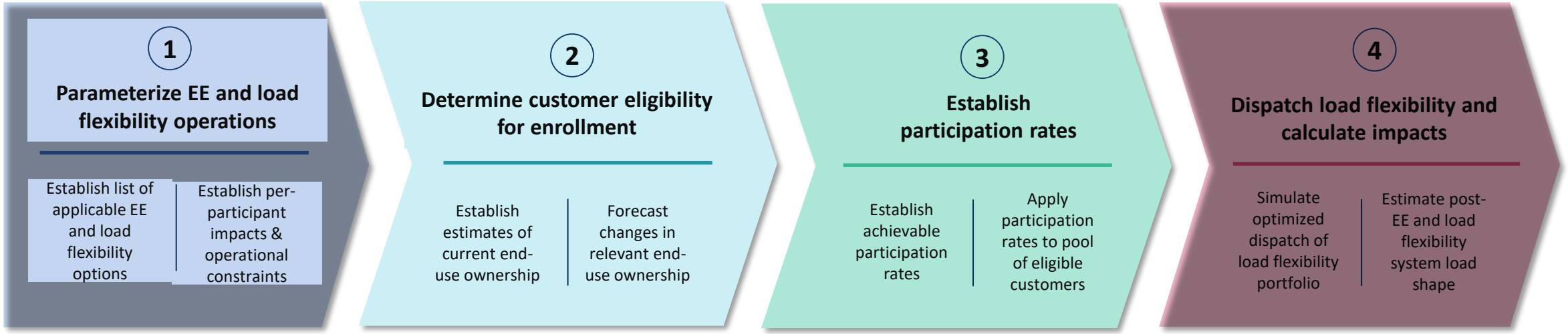


Appendix C:

ENERGY EFFICIENCY AND LOAD FLEXIBILITY MODELING

EE and Load Flexibility Modeling Overview

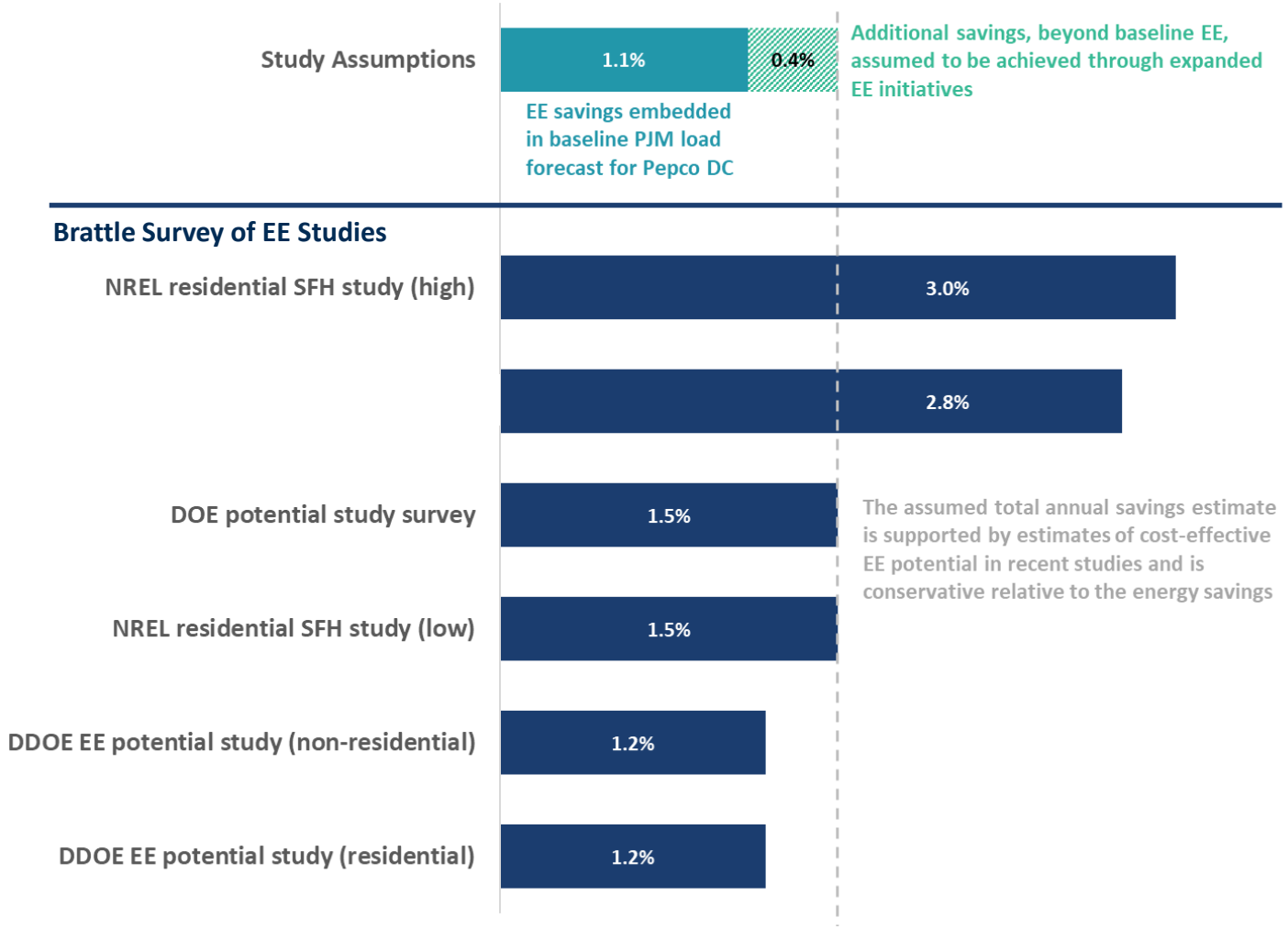
We use Brattle's LoadFlex modeling framework to develop the EE and load flexibility impact estimates



For more information about the LoadFlex model, see *The National Potential for Load Flexibility: Value and Market Potential Through 2030*.

Establishing the Impacts of Expanded EE Initiatives

Annual Pepco DC Energy Savings Due to EE (% of Sales)



Based on a review of EE studies, we assume new, **incremental EE savings of 0.4% per year** from 2021 through 2050.

Those savings are incremental to the 1.1% annual EE savings embedded in the baseline load forecast.

The result is a **5% reduction** in projected 2050 system peak demand (after electrification)

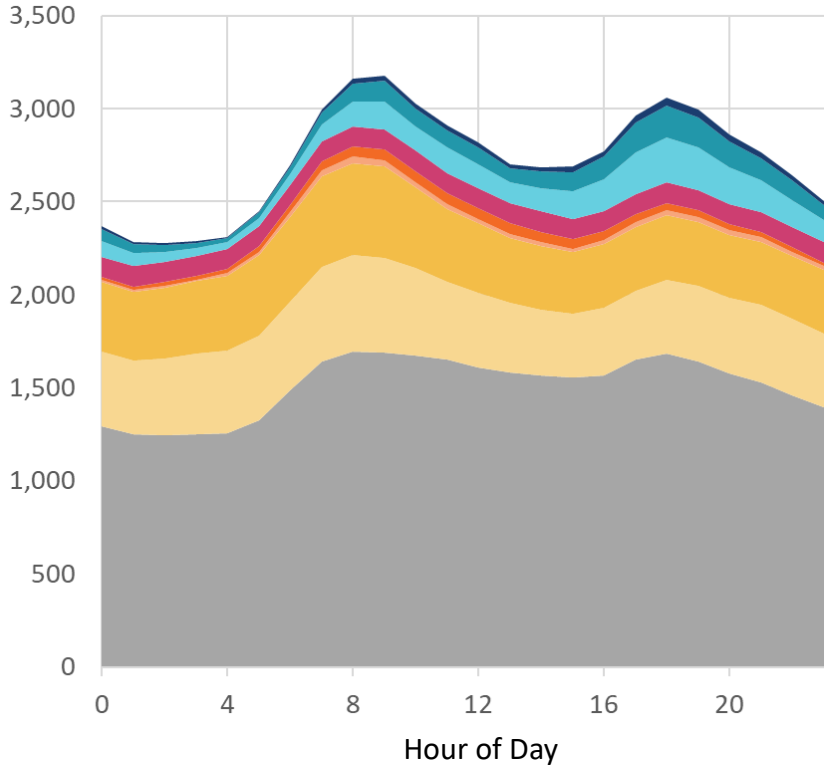
Annual energy savings rates were calculated by Brattle using information in the following sources:

- Department of Energy (DOE), "Energy Efficiency Potential Studies Catalog", available at: https://www.energy.gov/eere/slsc/energy-efficiency-potential-studies-catalog.
- District Department of the Environment (DDOE), "Electric And Natural Gas Energy Efficiency And Demand Response Potential For The District Of Columbia", 2013.
- National Renewable Energy Laboratory (NREL), "Electric End-Use Energy Efficiency Potential in the U.S. Single-Family Housing Stock", January 2017.
- Sustainable DC 2.0 Plan. Based on goal of cutting per capita energy use District-wide by 50% in 2032, current baseline at 30%. Assuming energy reduction is met through energy efficiency measures.

Estimating Energy Savings from High-Efficiency Heat Pumps

Unmitigated 2050 Winter Peak Demand (MW)

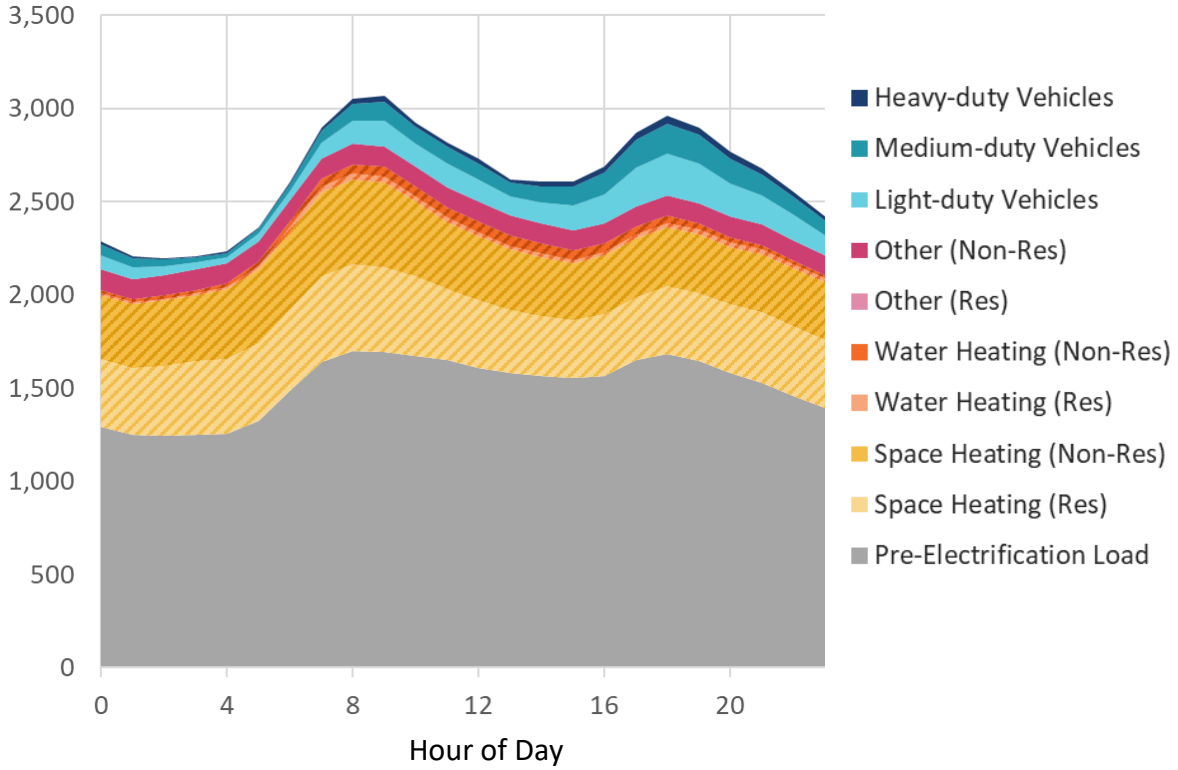
Assumes all new heat pumps have COP of 3.4 to 4.4, based on NREL Electrification Futures "Mid Case" Scenario



3.5% reduction in system peak demand due to 9% reduction in new heating load on peak day, attributable to partial adoption of high-efficiency heat pumps

2050 Winter Peak Demand (MW) with Higher Efficiency Heat Pumps

Assumes half of heat pumps have COP of 3.9 to 5.3, based on NREL Electrification Futures "High Case" Scenario



Load Flexibility Modeling Assumptions (Residential)

Load Flexibility Options	Load Impact per Participant	Eligible load	Participation (% of eligible)
Dynamic pricing	The CPP rate is assumed to have a 10:1 ratio between the critical peak price and the off-peak price. Brattle's database of residential time-varying pricing pilots was used to simulate the load impacts of a rate with this price ratio. The result is a 19% peak reduction per CPP participant. The simulation was tailored to observations from Pepco's recent TOU pilot in Maryland. Consistent with the findings of that pilot, no load increases during non-event hours is assumed to occur.	All residential load	Individual measure: 30% In illustrative portfolio: 15%
Smart thermostat pre-heating	20% of participating heat pump load is assumed to be curtailed during a 4-hour event. Participant comfort is preserved by pre-heating the building. All curtailed heating load is assumed to shift to pre-event hours, plus an incremental 30% increase. Impacts are based on a review of PGE's residential heating DLC pilot, as well as building load simulations conducted by Lawrence Berkeley National Laboratory (LBNL) and National Renewable Energy Laboratory (NREL).	All residential heat pump load	Individual measure: 30% In illustrative portfolio: 15%
Home EV charging TOU	60% of home charging load during the afternoon winter peak hours is assumed to be curtailed and shifted to the hours immediately following the curtailment period. Impacts are based on Brattle review of a recent NREL study in Maryland.	All home EV charging load	100%, assuming TOU rates become the standard for home EV charging by 2050
Behind-the-meter (BTM) storage	Pepco DC is assumed to be able to fully charge and discharge a BTM battery at any time of day during a limited number of events per year. Each participant is assumed to have a 7 kW / 13 kWh battery (similar to a Tesla Powerwall). Similar programs are being offered by Green Mountain Power, Portland General Electric, and Holy Cross Energy, among others.	All BTM batteries (assumed 20% residential adoption by 2050)	Individual measure: 30% In illustrative portfolio: 30% (BTM batteries do not "compete" with end-uses in other load flexibility options)

Note: "Individual measure" participation is an achievable participation rate if the measure were offered in isolation, without "competition" from other residential load flexibility offerings. Participation "in illustrative portfolio" indicates the assumed participation rate in the modeled portfolio of load flexibility options, accounting for cross-measure competition.

Load Flexibility Modeling Assumptions (Non-residential)

Load Flexibility Options	Load Impact per Participant	Eligible load	Participation (% of eligible)
Dynamic pricing	Participants are assumed to reduce usage by 10% during CPP events, based on a review of large commercial and industrial price responsiveness studies. This assumption is similar to that used in FERC's *A National Assessment of Demand Response Potential*.	All load of medium/large commercial customers (demand >25 kW)	Individual measure: 30% In illustrative portfolio: 15%
Interruptible tariff	Participants agree to reduce electricity usage during a limited number of events. Interruptible tariffs are offered by many utilities currently and account for a large share of existing U.S. demand response capability. Due to their relatively infrequent use, participants typically are willing to commit to large load reductions. Based on a review of data on utility interruptible tariff programs, we assume participants will reduce their peak demand by 20% during events, with no load building outside of the events.	All load of medium/large commercial customers (demand >25 kW)	Individual measure: 30% In illustrative portfolio: 15%
Pre-heating	Similar to the residential pre-heating program, commercial heating load would be shifted from a morning event period to the pre-event hours. Data on commercial heat pump load control capabilities is limited, though building load has been demonstrated to provide peak demand reductions through a variety of automated-DR applications. Based on a review of simulations by LBNL and NREL, we have assumed 10% load reduction during peak hours, with all of that load shifted to the pre-event hours.	All commercial heat pump load	Individual measure: 30% In illustrative portfolio: 15%

Note: "Individual measure" participation is an achievable participation rate if the measure were offered in isolation, without "competition" from other residential load flexibility offerings. Participation "in illustrative portfolio" indicates the assumed participation rate in the modeled portfolio of load flexibility options, accounting for cross-measure competition.

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Additional Reading on Electrification and Load Flexibility

- A National Roadmap for Grid-Interactive Efficient Buildings, prepared for U.S. DOE by LBNL and The Brattle Group, May 2021.
- Getting to 20 Million EVs by 2030: Opportunities for the Electricity Industry in Preparing for an EV Future, Brattle report, June 2020.
- Identifying Likely Electric Vehicle Adopters, prepared for EPRI, December 2019.
- Residential Electric Vehicle Time-Varying Rates That Work: Attributes That Increase Enrollment, prepared for SEPA, November 2019.
- Heating Sector Transformation in Rhode Island: Pathways to Decarbonization by 2050, prepared for the Rhode Island Division of Public Utilities and Carriers and the Rhode Island Office of Energy Resources, April 2019.
- Achieving 80% GHG Reduction in New England by 2050: Why the region needs to keep its foot on the clean energy accelerator, prepared for Coalition for Community Solar Access, September 2019.
- The Total Value Test: A Framework for Evaluating the Cost-Effectiveness of Efficient Electrification, prepared with EPRI, July 2019.
- The National Potential for Load Flexibility: Value and Market Potential through 2030, Brattle report, June 2019.
- The Potential for Load Flexibility in Xcel Energy's Northern States Power Service Territory, prepared for Xcel Energy, June 2019.
- The Coming Electrification of the North American Economy: Why We Need a Robust Transmission Grid, prepared for WIRES Group, March 2019
- The Hidden Battery: Opportunities in Electric Water Heating, prepared for NRECA, NRDC, and PLMA, January 2016.
- Valuing Demand Response: International Best Practices, Case Studies, and Applications, prepared for EnerNOC, January 2015.

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CERTIFICATE OF SERVICE

I hereby certify that a copy of Potomac Electric Power Company's Electrification Study has been served this August 27, 2021 on:

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I hereby certify that on the following date a copy of the foregoing document was duly served upon the following parties as follows:

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