Smart Electric Power Alliance

Demonstration of Utility Smart Charge Management for Multiple Benefit Streams

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The Smart Electric Power Alliance (SEPA), a 501(c)(3) organization with over 1,000 members, accelerates the transition to a clean, affordable, and resilient electricity system for all. SEPA engages with its diverse membership—which includes utilities, policymakers, and regulators—through education, collaboration and convening, and the search for innovative policy, regulatory, and technology solutions. For more information, please visit www.sepapower.org.

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EVmatch

EVmatch is a software company advancing electric vehicle adoption by making charging reliable and accessible to all. Founded in 2016, the company operates a two-sided platform that connects EV drivers with property owners, utilities, and businesses that host and manage shared EV charging stations. With partnerships across the public and private sectors and integration with Level 2 smart chargers and patented adapter technology, EVmatch delivers a flexible, scalable solution for today's evolving mobility needs. For more information, visit www.evmatch.com.

exelon℠

Exelon is the nation's largest utility company, serving more than 10 million customers through six fully regulated transmission and distribution utilities—Atlantic City Electric (ACE), Baltimore Gas and Electric (BGE), Commonwealth Edison (ComEd), Delmarva Power & Light (DPL), PECO Energy Company (PECO), and Potomac Electric Power Company (Pepco).

Headquartered in Los Angeles with projects across the globe, Shell Recharge Solutions plays an important role in Shell's broader commitment to achieving net-zero emissions by 2050, in step with society, and to helping our customers achieve their own sustainability targets. For more information, visit https://www.shell.us/business/mobility/shell-recharge-for-businesses-and-communities.

Sunrun Inc. is a leading residential solar, battery storage, and energy services company accelerating the transition to a clean energy future. Since 2007, Sunrun has generated more than 25 billion kilowatt-hours of clean electricity, helping avoid over 14 million metric tons of carbon emissions. Sunrun designs, installs, owns, and maintains solar and battery systems for homeowners across the United States, and provides energy solutions for multifamily and new home developments. For more information, visit www.sunrun.com.

WeaveGrid is a software company building data products to enable the electric transportation transition. The SaaS company's platform connects a growing wave of electric vehicles to an electric grid that was not designed to support the high-power needs of widespread charging. WeaveGrid uses cutting-edge data science and optimization to bring value to all stakeholders in this transition, including utilities, automakers, and drivers. For more information, visit www.weavegrid.com.

Executive Summary

In the summer of 2020, the U.S. Department of Energy (DOE) awarded funding to Exelon's Maryland utilities—Baltimore Gas and Electric (BGE), Delmarva Power & Light (DPL), and Potomac Electric Power Company (Pepco)—to implement the Smart Charge Management (SCM) pilot. This initiative aimed to design and implement managed electric vehicle (EV) charging strategies, evaluate the grid impacts of EV charging, and assess the utilities' ability to control EV load based on real-time grid conditions.

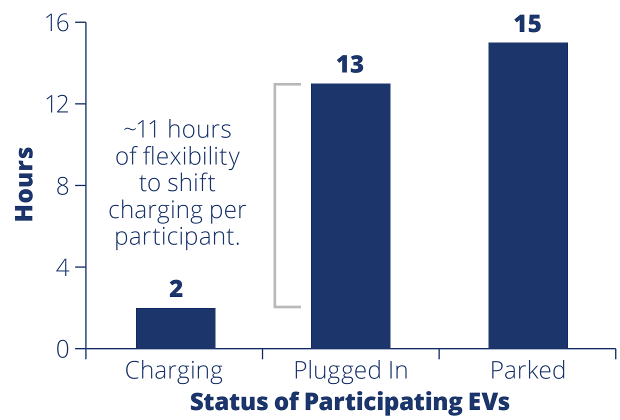
The SCM pilot explored four aspects for continued improvement:

1. Cybersecurity and managed charging functionality testing of two vendor platforms—WeaveGrid (telematics-based) and Shell Recharge Solutions (network-based)—which pursued charge scheduling and optimization through distinct approaches.
2. An analysis by Argonne National Laboratory (ANL) modeling team of three potential SCM enrollment scenarios within BGE and Pepco service territories over the next decade to assess future scalability.
3. Employing customer engagement strategies, including surveys and a responsive pricing approach.
4. The launch and implementation of pilots in Exelon's Maryland territories in collaboration with WeaveGrid.

This SCM pilot was developed to explore how EV charging flexibility can minimize grid costs associated with EV load growth on the distribution grid while maintaining customer satisfaction. Compared to other types of electricity load, EV charging is uniquely flexible. As shown in Figure 1, residential participants, who park their vehicles at home for an average of 15 hours per day but only charge for 2 hours, provided an 11-hour daily flexibility window. This presented a significant opportunity to shift charging away from peak demand periods.

As illustrated in Figure 2, SCM was designed to test increasingly sophisticated ways to leverage charging flexibility to align home charging requirements with the distribution grid while still meeting customer preferences.

Figure 1. Median Hours in Each Status at Home

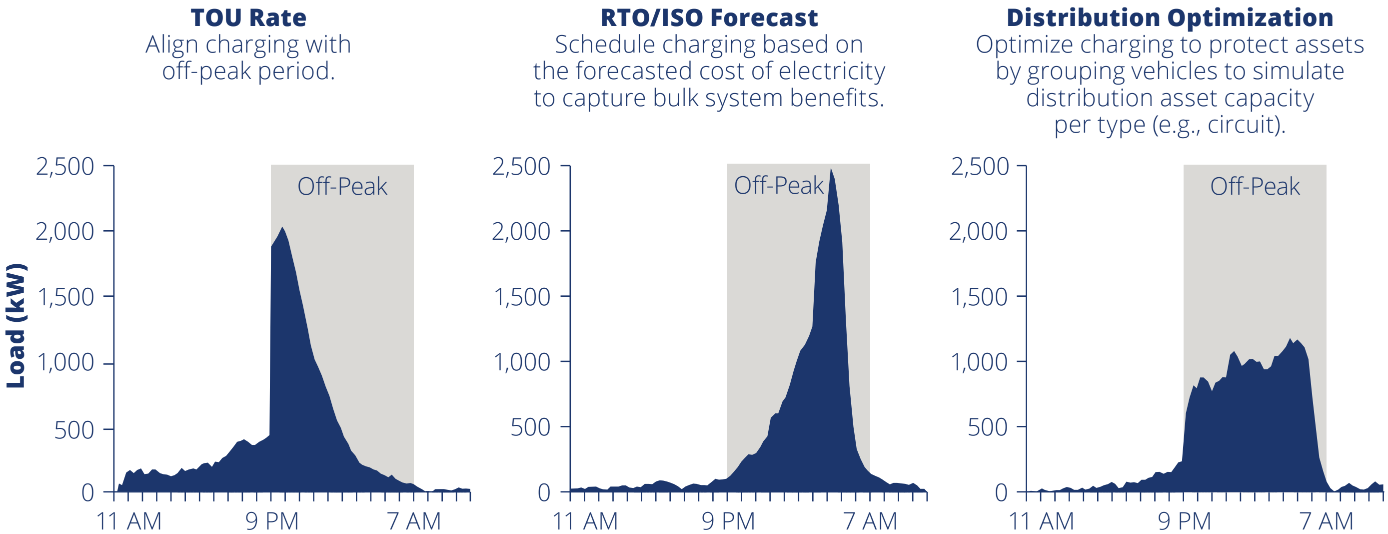


Source: WeaveGrid (2024).

- **Static Off-Peak Charging:** Initially, charging was shifted to off-peak hours to reduce grid strain, though it lacked real-time adaptability. This approach did not dynamically adjust based on weather conditions, real-time usage patterns, generator outages, or grid congestion.
- **Price-Optimized Charging:** To enhance grid responsiveness and cost-effectiveness, charging was scheduled in response to PJM's day-ahead energy market prices. By leveraging an API-driven system[1] to optimize costs and charging requirements, 1,716 EV drivers received financial benefits while utilities further alleviated grid stress.
- **Distribution Load Balancing:** Using WeaveGrid's Distribution Integrated Smart Charging Orchestration (DISCO) technology, charging loads were actively balanced among 3,000 vehicles in 19 geographic groups, reducing non-coincident peaks and flattening the overall EV charging load curve.

1 An API (Application Programming Interface) is a set of rules and protocols that allows different software applications to communicate and interact with each other, enabling them to exchange data and functionality, without needing to know how the other application is implemented.

Figure 2. Time-of-Use and Demand Response Distribution Impacts are Mitigated Through Distribution Optimization



Source: WeaveGrid (2024). Recreated by SEPA.

Pre-Launch Cybersecurity Assessment

Prior to the deployment of the SCM pilot, ANL conducted a comprehensive cybersecurity assessment of the EVSE and telematics software used by Shell Recharge Solutions (SRS) and WeaveGrid. Using industry-standard methodologies, including STRIDE and MITRE ATT&CK, the evaluation identified and mitigated potential cyber threats related to internal, physical, and remote access points. By proactively addressing security risks, ANL certified the readiness of both platforms and provided general cybersecurity insights to help utilities and software providers strengthen managed charging program security.

Trade-offs Between Vendor Platforms

The two vendor platforms are capable of charge scheduling and optimization through curtailment, but they leverage distinct approaches: **WeaveGrid (Telematics-Based)** and **Shell Recharge Solutions (Network-Based)**.

WeaveGrid's telematics-based approach enabled personalized charging strategies tailored to individual vehicle owners and relied on accurate telematics data and strong network connections. In contrast, Shell Recharge Solutions' (SRS) network-based approach provided a broader view of the charging ecosystem, allowing for resource management across multiple vehicles and stations, though it lacked individual vehicle-level optimization.

At the time of testing, each platform had trade-offs. Teslas offered the most robust API for charge scheduling and optimization, but broader participation in active managed charging required direct integration with automaker software—a process that takes time. As EV ownership expands, bridging these approaches through deeper integration and broader participation from automakers will be key to optimizing managed charging for both efficiency and user-specific requirements.

Analysis of Potential SCM Enrollment Scenarios

The ANL modeling team evaluated three possible scenarios for SCM enrollment within BGE and Pepco service areas through 2035. Their analysis aimed to assess the program's potential for future expansion. As part of this analysis, ANL modeled EV load growth on selected representative feeders to evaluate the distributional system upgrade costs required to accommodate new EV load under these different enrollment scenarios, providing insights into potential grid impacts and necessary infrastructure investments.

- **Scenario 1: No Enrollment** (unmanaged charging)
- **Scenario 2: Minimum Enrollment** (11% by 2035)
- **Scenario 3: Steady Growth** (2% to 8% enrollment from 2023-2029, reaching 38% by 2035)

In addition, ANL evaluated two smart charging strategies: **Time-of-Use (TOU)** and **Load Balancing**. EV managed charging strategies play a pivotal role in minimizing and deferring infrastructure upgrade costs. Across all scenarios, the smart charging strategies studied effectively managed increased EV charging load with minimal adverse effects on distribution system assets and power quality.

- **Time-of-Use (TOU):** Successfully shifted EV charging to off-peak hours, but occasionally created a secondary peak at the start of the off-peak period, causing additional grid strain as EV adoption grows.
- **Load Balancing (LB):** Distributed EV charging more evenly over time, preventing sharp peaks and optimizing grid performance while reducing grid strain and deferring feeder upgrade costs compared to unmanaged charging.

ANL concluded that at **higher enrollment levels, load balancing generated greater cost savings than TOU.** By dynamically distributing demand across different times, load balancing reduces stress on distribution assets (e.g., transformers, circuits, and feeders), ultimately delaying the need for infrastructure upgrades. **At lower EV penetration and participation levels, TOU rates are more effective.** However, **as enrollment increases, the overall benefits of load balancing surpass those of TOU.** Therefore, focus should be placed on increasing participation to at least a minimal threshold where the advantages of load balancing outweigh those of TOU.

ANL concluded that over the study period, the net present value of savings for load balancing across both utilities was $215M under Scenario 3: Steady Growth. Dividing by the cumulative enrollment for both utilities results in savings of $297 per vehicle per year. It is important to note that these savings are only at the feeder and secondary transformer level. Managed charging creates additional benefits, including generation capacity, transmission capacity, generation energy, carbon reduction and other distribution-system benefits that were not analyzed as part of the ANL scope of work. These benefits would be in addition to the $297 in benefits per vehicle per year that ANL found. As the all-in cost of running a load balancing managed charging program, including incentives, should be comfortably below $300 per vehicle per year, the ANL study enables an assessment of cost effectiveness when benchmarked against per-vehicle program costs at scale which have the potential to place downward pressure on rates.

Smart charging strategies based on load balancing and TOU effectively shift charging loads to off-peak periods, reducing the burden on the existing grid infrastructure. When it comes to reducing or deferring infrastructure investment, the load balancing-based charging strategy proved more effective than the TOU-based strategy for both the BGE and Pepco feeders at higher levels of enrollment.

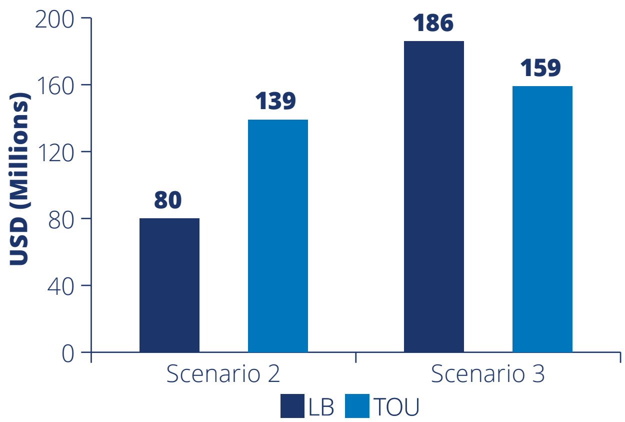
ANL's analysis found that transformers are the most critical asset impacted by increasing EV adoption, making them the primary focus for future grid upgrades. As smart charging enrollment increases, transformer overloading decreases, extending equipment life and deferring the immediate need for costly infrastructure investments. Prioritizing smart charging, especially load balancing, allows existing infrastructure to support high EV adoption rates efficiently and sustainably. **ANL's analysis illustrated that managed charging is a scalable, adaptable solution that defers infrastructure costs—ensuring a smoother transition to mass EV adoption.**

Figure 3 and Figure 4 illustrate the distribution system upgrade cost deferrals for Scenario 2: Minimum Enrollment and Scenario 3: Steady Growth compared to Scenario 1: No Enrollment for BGE and Pepco.

ANL conducted a cost analysis to assess the deferred distribution grid system upgrade costs. Using 19 representative feeders, ANL observed a clear reduction in peak load and a reduction in upgrade costs from both smart charging strategies (TOU and load balancing), varying by enrollment scenarios.

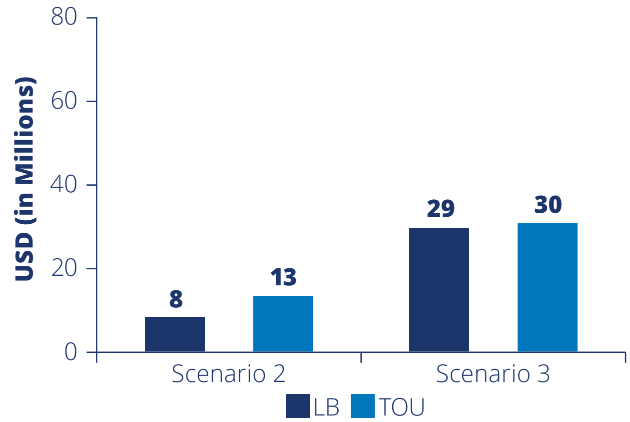
Demonstration of Utility Smart Charge Management for Multiple Benefit Streams

Figure 3. Comparison of Upgrade Cost Deferrals for BGE Feeders



Source: Argonne National Laboratory (2025). Recreated by SEPA.

Figure 4. Comparison of Upgrade Cost Deferrals for Pepco Feeders



Source: Argonne National Laboratory (2025). Recreated by SEPA.

Key Findings

Throughout the four-year pilot, the project team derived key findings that other utilities and software providers may benefit from incorporating into their managed charging program development:

Residential Customers

Presenting Multiple Managed Charging Options Maximizes Enrollment and Satisfaction

- **Customers with the greatest potential savings—those participating in both the SCM pilot and EV-TOU Rate—report the highest satisfaction.** This combination creates the most value for both customers and the electric grid.
- Providing customers with **flexible choices**—such as whether to participate in SCM, EV-TOU rates, and personalized charging settings—improves engagement and satisfaction.
- Program requirements should **account for mobility needs**, ensuring customers can override scheduled charging when necessary.

Dynamic Managed Charging Should Be the New Standard for EV Integration

- Utilities should establish optimized managed charging schedules to **proactively mitigate distribution system impacts** before EV adoption begins to cause strain on distribution equipment.
- **Vehicle telematics and EVSE data collection** should be leveraged to avoid costly secondary metering installations.
- Implementing smart charging strategies, in general, shifts EV loads to off-peak periods, redistributing the total load across different times to prevent the overlap of peak base load and peak EV load. This approach minimizes grid strain and optimizes system performance.
- At lower EV penetration and participation levels, TOU rates are more effective. However, as enrollment increases, the overall benefits of load balancing surpass those of TOU.
- The net present value of savings for load balancing across both utilities was $215M under Scenario 3: Steady Growth. Dividing by the cumulative enrollment for both utilities results in savings of $297 per vehicle per year.

Engage Stakeholders Early and Often

- Collaboration with utility IT, distribution planning, and energy acquisition teams is critical for effective SCM implementation.
- Community engagement through EV working groups helps align pilot programs with consumer needs.
- Regulatory alignment is crucial. Utilities should collaborate with public utility commissions throughout the design and implementation of pilot programs to establish a shared understanding of the effectiveness and value of SCM initiatives.

Commercial Fleet Customers

A commercial fleet SCM pilot was planned, but encountered hurdles that limited participation, preventing the pilot from moving forward. However, this effort highlighted key challenges and opportunities for scaling fleet electrification:

- **Fleet Readiness:** Many interested participants lacked EVs in their fleets, creating a "chicken and egg" dilemma where customers were reluctant to purchase EVs without charging infrastructure.
- **Charger Compatibility:** Customers may possess existing hardware and network investments, creating interoperability constraints when considering new equipment.
- **Charging Speed:** Some fleets required faster charging than the units offered by the proposed commercial SCM pilot.

Despite these challenges, key takeaways emerged:

- **Future fleet charging programs should offer flexible and customizable solutions** to accommodate diverse operational needs.
- **Early engagement is critical** to help fleets navigate electrification challenges and identify managed charging benefits.
- **Seamless software and hardware integration should be a top priority** to avoid deployment delays.

Proactive Customer Engagement

The transition from a focus on PJM price optimization to distribution load balancing resulted in later evening charging for many participants, leading to customer confusion. While distribution-level load balancing improved overall grid stability, it introduced a new challenge—ensuring customers understood and accepted the changes in their charging schedules. To address this, Exelon implemented structured engagement strategies, including quarterly retention emails with participation tips and schedule modifications.

This experience underscored the importance of:

- **Clear and transparent communication** before, during, and after major program adjustments;
- **Proactive customer engagement** when making major changes to charging schedules; and
- The recognition that customer participation in managed charging programs is primarily driven by two key factors: **confidence in reliable charging** and **financial incentives.**

The SCM pilot provided valuable insights into the technical, operational, and behavioral aspects of managed charging. By optimizing smart charging strategies, utilities can defer costly infrastructure upgrades, reducing immediate expenditures and freeing up resources to support broader EV adoption.

Introduction

In the summer of 2020, the U.S. Department of Energy (DOE) awarded funding to Exelon for their Maryland operating utilities to carry out their Smart Charge Management (SCM) pilot. The utilities involved include Baltimore Gas and Electric (BGE) as well as Potomac Electric Power Company (Pepco), jointly referred to as Exelon. This project had three total components, with one for each type of customer seeking to charge EVs: residential, fleet, and public.

Figure 5. Project Phase Goals

Phase 1

Cybersecurity Testing & Validation
Demonstrating the integrity of EVSE and in-vehicle telematics systems prior to public deployment through cybersecurity testing and validation at ANL's Smart Energy Plaza.

Platform System Integration & Verification
Integrating and verifying the candidate platform system, including simulating and testing the provision of frequency regulation services, for deployment by the Exelon utilities in the demonstration Phase 2 at the Smart Energy Plaza.

Simulating EV Charging Impact
Simulating the impact of EV charging on the grid through 2035 in Maryland using ANL's Agent-based Transportation Energy Analysis Model (ATEAM) tool. This will include analyzing customer charging behaviors in response to alternative EV charging incentive programs, simulating large-scale co-evolution of EV adoption and charging deployment in study area, and potential load impacts to the grid.

Phase 2

Studying EV Owner Charging Behavior
Understanding EV owner charging behavior in response to a portfolio of utility price signals and incentive structures across various customer categories to maximize future enrollment in utility-led managed charging programs.

Simulating Distribution Utility Operations
Simulating and evaluating the impact of EV charging on local distribution utility operations and evaluate the utilities' ability to actively control EV charging load based on grid conditions at the feeder and transformer level.

Demonstrating Value of Smart Charging
Demonstrating the value streams from utility-managed smart charging to the EV owner, the EVSE partner, and the local electric distribution utility.

EV Charging for Grid Services
Demonstrating the ability for EV charging networks to provide frequency regulation and other electric grid services from EVs.

Source: SEPA (2025).

The objectives of this project were to research, develop, and conduct a wide-scale demonstration to determine optimal managed charging structures for grid value, assess the impact of electric vehicle (EV) charging on local distribution utility operations, and evaluate Exelon's ability to control EV charging load based on grid conditions. The challenges, successes, and lessons learned from this pilot can be shared with other utilities nationwide to inform the development of managed charging programs.

This multi-phased pilot sought to:

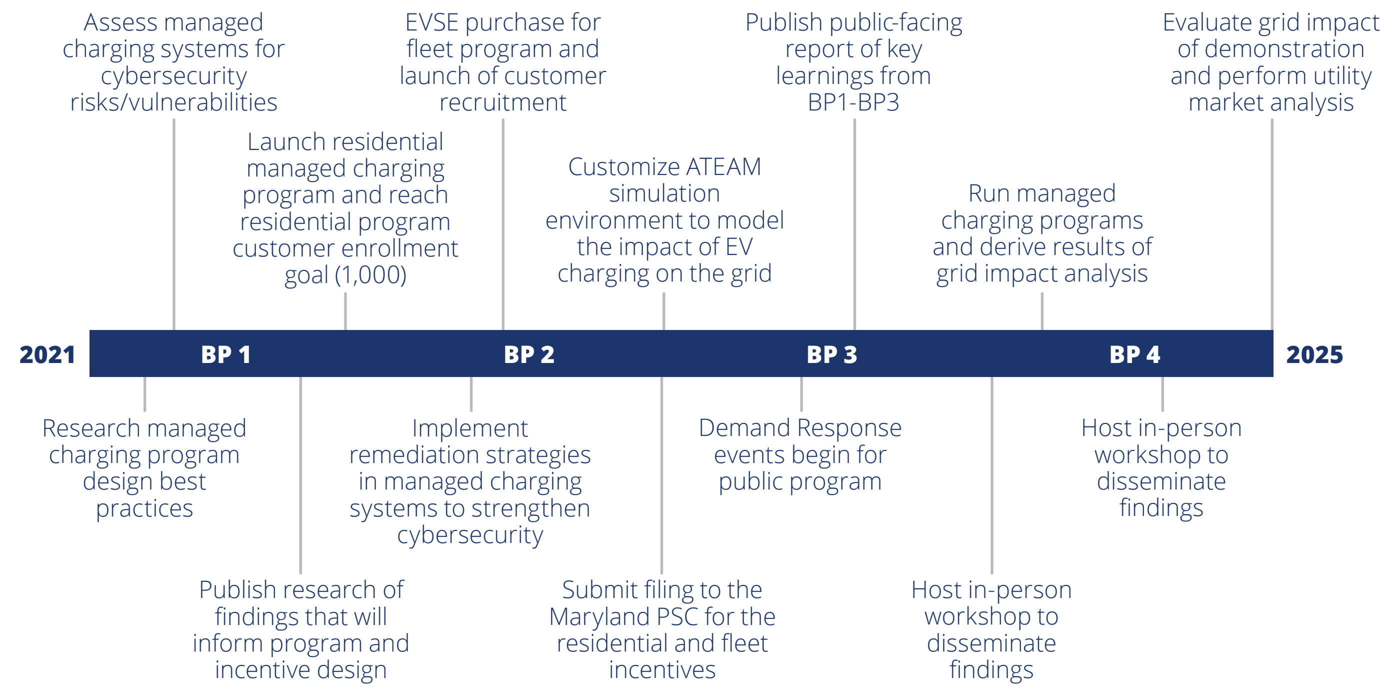
- Understand and reduce grid impacts of EV charging on the utility's distribution and transmission systems.
- Lessen Exelon customers' capital investment required to manage EV charging demand as EV ownership grows.
- Identify potential cybersecurity risks and vulnerabilities of EVSEs and vehicle telematics software.
- Design managed charging plans for residential, commercial, and public customers that can be shared industry-wide.

Table 1. Partners and Roles

Partner	Role
Exelon (PHI and BGE)	Lead the design and implementation of the managed charging program.
Shell Recharge Solutions (Formally Greenlots)	▪ Implement smart charging technologies to actively manage EV charging sessions for fleet and public customer classes, utilizing EVSE. ▪ Support the operations of smart charge management, performance monitoring, and performance control during the SCM demonstration. ▪ Support customer enrollment and adjust the program for enhanced results.
WeaveGrid	▪ Develop smart charging technologies to actively manage EV charging sessions for residential customers, utilizing vehicle telematics. ▪ Leverage machine learning to identify potential EV owners within Exelon's service territory for program marketing purposes. ▪ Implement EVSE-based managed charging (MC) and other solutions.
Smart Electric Power Alliance	Conduct market research and support Exelon in the design of the managed charging program, and coordinate the dissemination of program learnings.
Argonne National Laboratory	▪ Perform cybersecurity testing on EVSE and SCM platforms. ▪ Perform functional testing of network-based and telematics-based SCM platforms. ▪ Simulate the potential impact of projected EV adoption and managed charging strategies on the Exelon energy system.
EVmatch	Run frequency-regulation demonstration (V1G) with a smart charge adapter.
Sunrun	Run V2H demonstration with a Ford F-150 Lightning.

Source: SEPA (2025).

Figure 6. Timeline of Key Accomplishments



Source: SEPA (2025).

Pilot Program Design

The objectives of the project were to research, develop, and conduct a wide-scale demonstration of a utility Smart Charge Management (SCM) system to develop optimal managed charging structures for grid value, evaluate the impact of EV charging on local distribution utility operations, and evaluate Exelon's ability to control EV charging load based on grid conditions.

Through an assessment of 40 existing managed charging programs and interviews with 20 utilities, the project team recorded raw data, key insights, and lessons learned.[2] Research conducted in 2021 served as the basis for the SCM pilot design. The SCM pilot was consistently assessed via insights derived through implementation as well as SEPA's managed charging program research.[3]

This collection of learnings, summarized in this paper, serves as a guide to all utilities designing or refining their managed charging programs going forward.

Maryland legislation requires increased investment in clean energy and the state has been a leader in reducing greenhouse gas emissions and transitioning to zero emission vehicles (ZEV) since joining the ZEV program in 2007.[4] As of April 30, 2025, Maryland had 135,017 registered EVs, reflecting a significant increase from 92,722 in December 2023. This growth is even more pronounced compared to December 2020, when the state had just 29,268 registered EVs.[5] With a goal of reaching 1.1 million EVs registered by 2030 to support Maryland's 60% GHG reduction goal, there is a significant increase in expected

2 Smart Electric Power Alliance (October 2021). Managed Charging Incentive Design: A Guide to Utility Program Development.

3 Smart Electric Power Alliance (September 2024). The State of Managed Charging in 2024.

4 Maryland Department of Environment (December 2023) Maryland's Climate Pollution Reduction Plan.

5 Maryland Department of Transportation Motor Vehicle Administration (2025). MDOT MVA Electric and Plug-in Hybrid Vehicle Registrations by County (July 2020 – April 2025). Maryland Open Data Portal.

EV charging load on the grid. Left unmanaged, this new load may lead to reliability issues and costly distribution infrastructure upgrades for Maryland's largest electric utilities. For this reason, Exelon embarked on a DOE-supported Smart Charge Management (SCM) pilot from October 2020 to December 2024.

Pilot Preparation: Cybersecurity Testing and Validation

To prepare for the pilot, ANL assessed the cybersecurity of the EVSE and telematics software that would be used by Shell Recharge Solutions (SRS) and WeaveGrid to manage the charging of participants' vehicles. A thorough cybersecurity assessment proactively identified and blocked pathways for unauthorized access to vehicles and data, which prevented issues from surfacing during the pilot. The team used Microsoft's Spoofing, Tampering, Repudiation, Information Disclosure, Denial of Service, Elevation of Privilege (STRIDE) methodology and MITRE's Adversarial Tactics, Techniques, and Common Knowledge (ATT&CK) framework. The team also used an additional suite of cybersecurity attack methods to evaluate the potential for cyberattack through internal network access, physical access to the EVSE and related components, and remote access to EVSE and telematics interfaces, protocols, and services. The ANL team shared the detailed results with SRS and WeaveGrid, and certified EVSE and telematics readiness for the pilot.

Sharing the details of this cybersecurity evaluation publicly would defeat the purpose of such analysis in the first place. Instead, the ANL team has provided more general information about cyberattack pathways, which utilities, software providers, and other stakeholders can use to inform their managed charging program design.[6]

Normal attack paths typically include gathering information, enumerating resources, and identifying potential weaknesses. To interact with and eventually compromise a system, an attacker will seek information about technologies used within it or the people that worked to develop it. Traditionally, this type of information might be obtained by directly interacting with the SCM company participants' websites, devices, or people. Attackers also may use a less direct approach. By searching employee social media profiles and public GitHub repositories, an attacker can piece together information about the skills and programming languages that were used to build the SCM system or even pull pieces of company source code. Additionally, an attacker may leverage information disclosure notices to gain a better understanding of the system. Assumptions about skills and programming languages used to build the SCM system can be validated by publicly available job listings at the company. Taking steps to harden the entire system at all levels will improve its security posture and pose a more difficult challenge to potential attackers. In order to protect their own SCM system, companies can evaluate their cybersecurity posture regularly, identify vulnerabilities, and remediate them.

Pilot Launch

EVs are essential for comprehensive decarbonization strategies, contributing significantly to the reduction of greenhouse gas emissions and local air pollutants. Integrating EV charging infrastructure with building efficiency, electrification solutions, and on-site renewable energy generation and storage at the grid edge enhances equity, affordability, and resilience in the transition to a 100% clean electricity system.[7] The electric grid was originally designed to accommodate steady, predictable energy demand from homes, businesses, and commercial locations. Unlike traditional household appliances, EV chargers can switch on instantly and draw as much power as multiple homes combined. As EV adoption grows, it is imperative to rethink grid design to accommodate these dynamic, high-powered loads in a way that maintains reliability and efficiency. While the evolution of grid design is key, so is managed charging. If charging remains unmanaged, adding EVs could strain the grid, ultimately increasing customer rates. Smart charging programs not only reduce the cost of integrating EVs into the system but also leverage the inherent flexibility of EVs to optimize grid operations—turning what could be a liability into an asset.

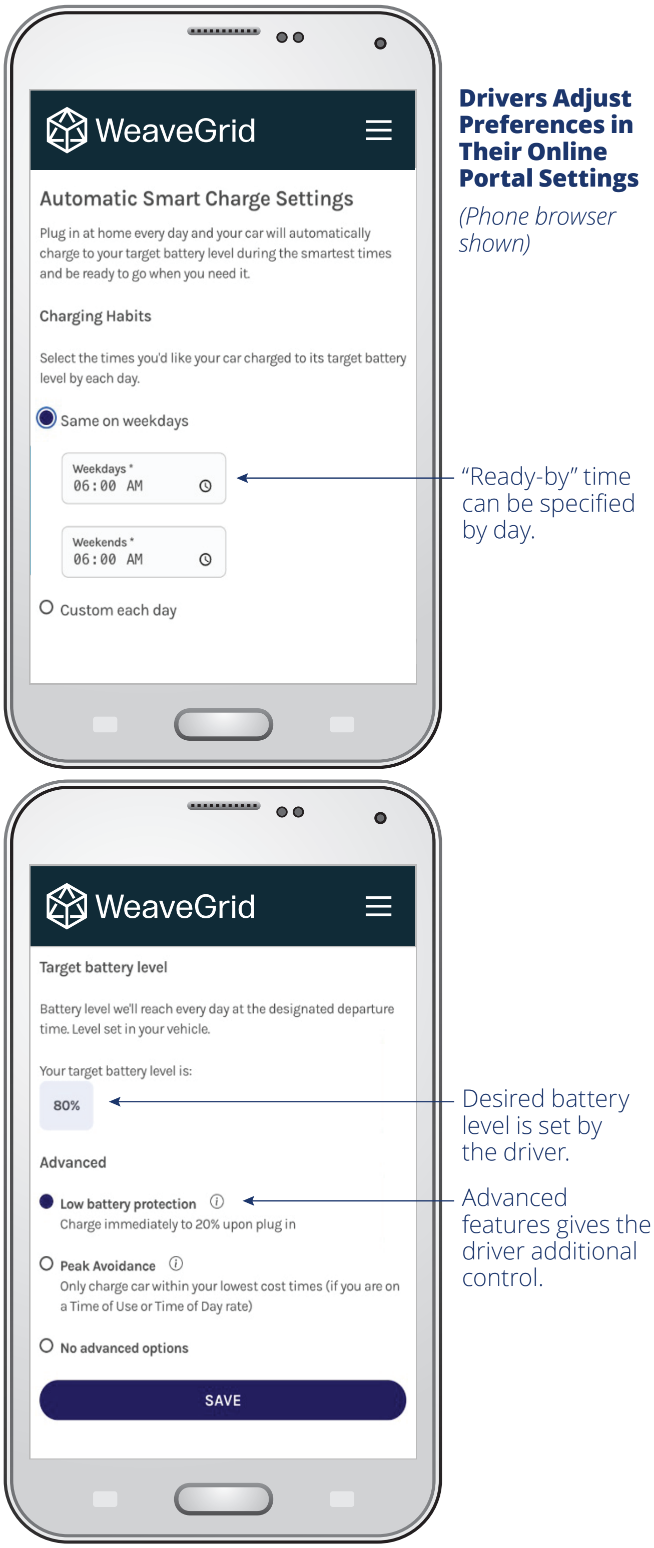
Residential Managed Charging

Exelon launched the SCM pilot in Q1 of 2023 and collaborated with WeaveGrid to implement advanced load-balancing algorithms that created charging schedules tailored to both driver preferences and grid needs.

6 Smart Electric Power Alliance (August 2023) Exelon's Managed Charging Program: Phase 1 Review.

7 U.S. Department of Energy (April 2024) A National Blueprint for Decarbonizing the Buildings Sector.

Figure 7. WeaveGrid User Interface



Source: WeaveGrid (2024). Recreated by SEPA.

Customers opted in to accept SCM controls for automated charging, but they could always override the WeaveGrid-optimized charge schedule if their driving needs changed. As shown in Figure 7, participating customers set their preferred ready-by time and target state of charge to inform charging windows. This enabled WeaveGrid's software to automatically create personalized home charging schedules that ensured a participating customer's vehicle was ready when the driver wanted it.

Drivers always had the ability to 'charge now,' effectively opting out of managed charging schedules provided through SCM. This was important because EVs are not just distributed energy resources (DERs); they are purchased for mobility and need to be treated accordingly. With SCM, EV charging was optimized every time a vehicle was plugged in, but the back-end complexity was hidden from the pilot participant, enabling smart charge management and simplifying customer engagement.

Eligible customers could participate in SCM without needing a separate meter measuring vehicle electricity use, thanks to vehicle-embedded telematics technology—saving them thousands of dollars per avoided meter. This technology also allowed customers to use Level 1 or non-networked Level 2 chargers, removing the cost barrier associated with traditionally more expensive networked Level 2 chargers in utility-managed charging programs. Direct vehicle telematics integration ensured reliable, secure, high-fidelity data transfer between vehicles and the WeaveGrid platform that managed when and how they charged.

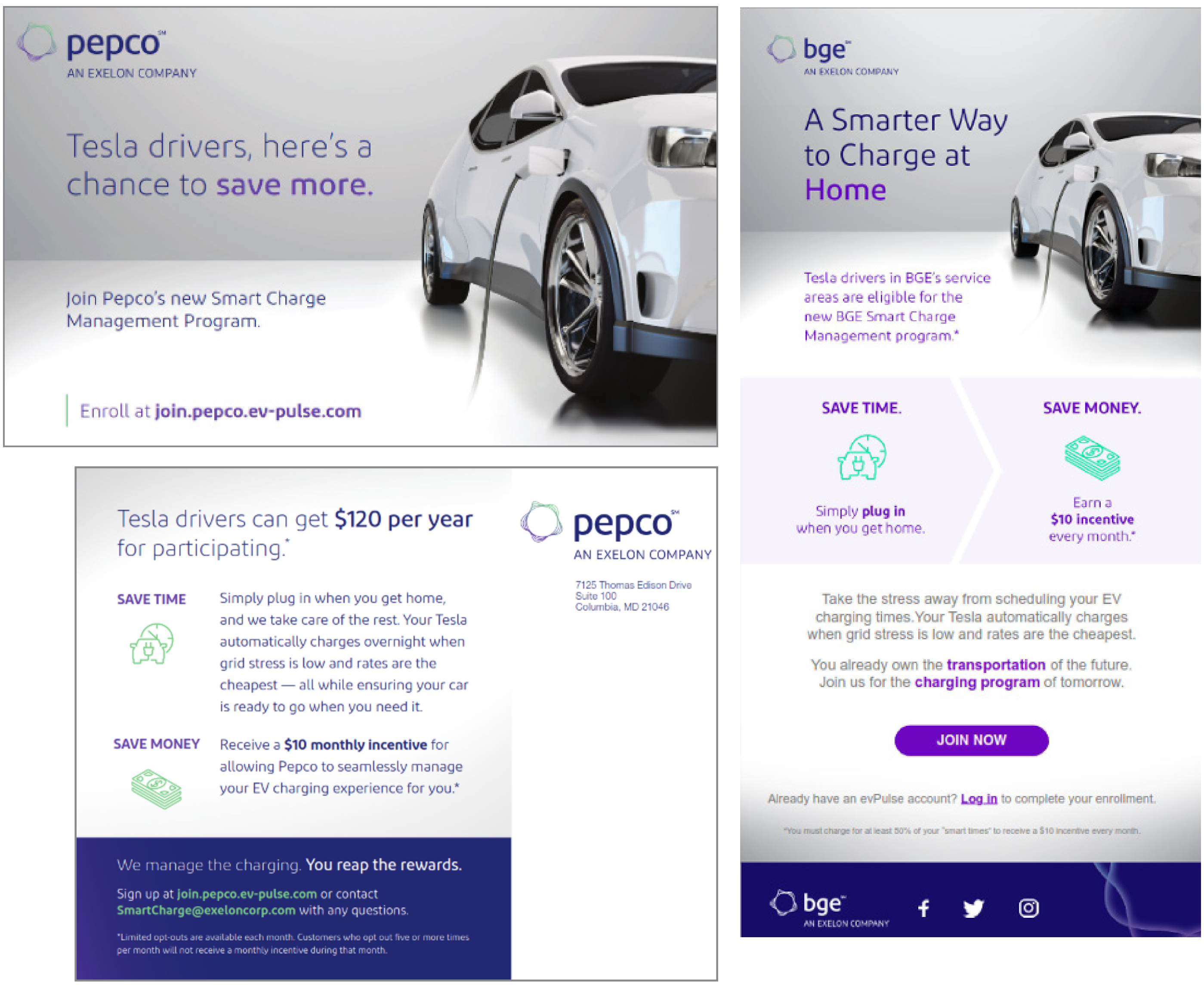
Single-family homeowners were the primary focus of the SCM pilot due to their direct charger access and straightforward characteristics for pilot participation. Furthermore, at the time of the pilot launch, only Tesla vehicles had the necessary telematics capabilities. While Exelon received inquiries from non-Tesla EV owners interested in participating, it highlighted broader demand for managed charging offerings. Given recent advancements in managed charging technology across vehicle and charger manufacturers, the SCM pilot plans to expand to more qualified vehicles in 2025.

Exelon provided a $10 monthly incentive to enrolled customers who charged during smart times at least 50% of the time. Customers could have multiple EVs participating, but there was only one incentive per utility customer account. Each customer could choose the "charge now" option up to four times per month and still receive the monthly credit.

Marketing

Early on in the SCM project, WeaveGrid used its EV Detection machine learning model to analyze one year of AMI data for residential single-family customers in Exelon territories. WeaveGrid identified 10k households across BGE, Pepco, and DPL territories in Maryland as likely or possibly having an EV that uses Level 2 charging. Exelon utilized this information to update their known list of EV drivers within these service territories. With this additional EV detection information, Exelon sent recruitment emails to known EV drivers within their service territories in December 2022 ahead of the managed charging pilot launch in Q1 2023. The marketing focused heavily on the monetary value of the pilot and the fact that customers could earn $120 annually. It also highlighted the "set it and forget" nature of the pilot, which took the charging burden off of customers. Through this recruitment strategy, Exelon was able to quickly enroll over 1,000 customers, exceeding their goal for pilot launch. In addition, Exelon also experimented with digital marketing campaigns in mid-2023, utilizing search engine marketing and targeted social media ads. These paid tactics proved effective, but more expensive than sending emails.

Figure 8. Advertisements from WeaveGrid for BGE and Pepco on Mobile and Web



Source: WeaveGrid (2024).

Demonstration of Utility Smart Charge Management for Multiple Benefit Streams

Exelon chose to halt marketing efforts due to limited incentive budgets, even reallocating leftover funding from other aspects of the DOE grant to support additional incentives given the overwhelming demand for residential SCM. Despite budget constraints, SCM became one of the largest active managed charging pilots in the country.

As shown in Figure 9, by the time enrollment closed in June 2024, over 4.5k EVs were enrolled. This interest highlighted the program's effective design, the eagerness of customers to engage with advanced active managed charging pilots like SCM, and its potential to scale as a mass market program.

Enrollment Process

WeaveGrid's online platform ensured a streamlined sign-up process that was easy for customers. Without the need for a separate app, a seamless customer journey was created whereby participants could go through the sign-up process in a mobile-responsive web-based application. Interested customers provided basic information about themselves and their electric vehicle, then connected their vehicle to the WeaveGrid platform to enable program participation.

Based on the survey completed in August 2024, the desire to save money was the number one driver behind SCM enrollment. Specifically, 51% (PHI)[8] to 65% (BGE) of respondents identified lowest cost periods for charging as a key motivator to enroll and 61% (BGE) to 65% (PHI) said the $10 monthly bill credit was a motivator. Only 25% (BGE) to 45% (PHI) of respondents said 'environmental benefits' was a motivator, but 36% (PHI) to 40% (BGE) shared that 'charging during optimal times for the grid' was a motivator.

Although only 4% (PHI) to 9% (BGE) of survey respondents said 'allowing PHI/BGE to manage my home charging' was a motivator for enrollment, customers appear to appreciate the managed charging experience. Additional feedback is highlighted in Figure 10.

SCM satisfaction scores from September 2023 for BGE revealed that customers ranked the SCM pilot 4.2 out of 5 stars, compared to 3.8 stars for BGE's EV Time of Use (TOU) Rate program. Customers enrolled in both programs, which offers the greatest potential bill savings, reported the highest satisfaction rate with 4.6 stars.

Pilot Successes

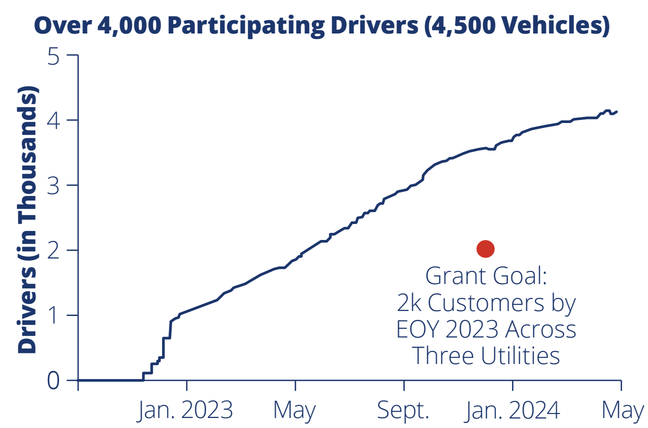
The SCM pilot demonstrated notable success through its innovative approach to residential active managed charging, enhancing the user experience for EV drivers and advancing the integration of novel data for grid optimization. Exelon observed high participation and retention rates among SCM enrollees, highlighting strong customer engagement and sustained program success.

Throughout the pilot, 92% of the charging load adhered to the targeted and optimized charging schedules. This high compliance rate, despite the inevitable last-minute changes in customers' plans, highlighted the effectiveness of the custom schedules in meeting participants' needs, with few opting to "charge now."

Commercial and Fleet

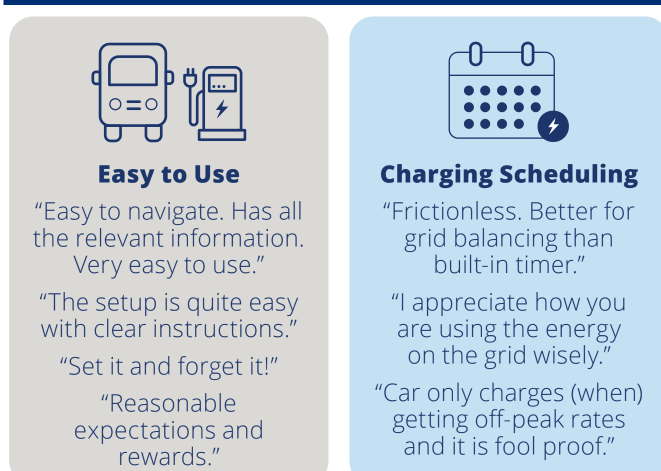
The commercial fleet managed charging pilot was designed to provide load flexibility by optimizing the charging of fleet vehicles. In collaboration with SRS, Exelon developed the pilot to accommodate the unique needs of both small and

Figure 9. Participating Drivers Across All Territories



Source: WeaveGrid (2024). Recreated by SEPA.

Figure 10. Customer Survey Feedback



Source: WeaveGrid (2024). Recreated by SEPA.

8 Pepco Holdings, also known as PHI, is inclusive of both Delmarva Power & Light (DPL) and Potomac Electric Power Company (Pepco) territories.

large commercial fleets. The pilot's primary objective was to install Level 2 charging stations equipped with managed charging functionality at commercial customer sites. These chargers were rigorously tested at Argonne National Laboratory's Smart Energy Plaza to validate their capability to balance fleet operations and Exelon's load-shifting objectives. The chosen hardware was the EvoCharge Level 2 charger, featuring a maximum output capacity of 7.68 kW per unit.

Exelon invited commercial customers to participate, allowing up to ten chargers to be installed at a single site. Incentive structures were designed to encourage participation. Small commercial customers received $25 per month per site for participation. Large commercial customers received $500 per month per site. This incentive equated to approximately 10% of their average monthly energy bill.

Exelon worked closely with customers to gain a detailed understanding of their fleet operations. Key considerations included fleet usage patterns, such as when vehicles were typically out of the depot versus parked and charging. Exelon also reviewed feeder load dynamics, ensuring that customer sites adhered to grid stability requirements.

Using operational data, Exelon developed daily managed charging schedules tailored to customer needs. For example, a business operating Monday through Friday, 8 AM to 5 PM, would typically charge vehicles after hours when fleet vehicles returned to the depot. Exelon and SRS implemented dynamic charging limits to avoid exceeding a specified kilowatt capacity during peak grid hours (5 PM to 9 PM). A customer with ten chargers, each operating at 7.68 kW, could potentially reach a peak load of 76.8 kW. During peak hours, the charging load was capped at 40 kW total. If all chargers were in use, each unit operated at 4 kW, extending the charging time but aligning with grid constraints.

This strategy, when scaled across multiple fleet customers, presented a non-wires alternative to traditional grid upgrades, supporting EV adoption while minimizing infrastructure costs.

Public

Exelon operated a public charging network within its Maryland territory to support EV drivers with convenient on-the-go charging. These charging stations were part of the SRS network and included a mix of Level 2 and Direct Current Fast Chargers (DCFCs). Strategically located at state and local government properties—such as parks, libraries, municipal buildings, and schools—the chargers enhanced accessibility for local communities.

As part of the SCM pilot, Exelon aimed to explore the feasibility of using public chargers as demand response (DR) assets to alleviate grid stress during peak demand periods. In 2023-2024, Exelon and SRS conducted a series of DR events to assess the potential for peak demand reduction through public charging. This initiative marked a significant first for both companies, providing an opportunity to demonstrate DR capabilities in public charging settings.

Each DR event typically lasted two to four hours, during which the kilowatt output of public charging stations was reduced to lower the overall load. To mitigate the impact of slower charging, customer charging rates were proportionally adjusted. For instance:

- **September 8, 2023:** Charger output was reduced by 20%, and charging prices were similarly reduced by 20%.
- **September 10, 2023:** At two specific locations, output was reduced by 35%, with a 20% price reduction.

Customers using the SRS mobile app had the option to override the DR events to access full charging power. However, customers initiating charges via credit card or RFID card could not override and participate for the event's duration if they started charging after the event began. Drivers already charging before the event's start were excluded.

Exelon promoted these DR events through social media and the PlugShare website. However, opportunities for improvement in better informing customers about the override option emerged, as this information was only available via the mobile app. Without onsite promotion or signage at charging stations, many drivers were unaware of the DR event when they initiated a charge.

Data collection and reporting also presented challenges. SRS was unable to provide customized DR event reports, thus Exelon had to manually extract raw charging data from event days and corresponding control events. Such control events occurred one week prior to event days. This manual process added complexity to reporting and analysis.

Exelon initially planned 40 DR events, but experienced six scheduling failures due to issues with SRS's system. Additionally, poor data quality affected another 11 events, leaving 23 successful events for analysis. On average, these events achieved a 54% reduction in peak load compared to control events, with Saturdays showing the greatest impact due to higher charger utilization. Approximately 10% of customers opted to override the events.

Despite the pilot's success in reducing peak demand, it highlighted a potential drawback: over time, reduced charging speeds could decrease customer loyalty and usage of Exelon's charging network.

While the SCM pilot demonstrated the potential for DR through public charging, Exelon decided not to pursue additional DR events at public stations beyond the pilot period. The trade-off between grid relief, with the relatively small scale of available chargers, and customer experience was deemed unsustainable for the long-term success of the public charging network.

Pilot Implementation

To ensure greater reliability at the distribution level, Exelon moved from single-segment optimization to multi-segment managed charging, which enabled WeaveGrid to break up a customer's home charging over multiple, shorter sessions while still providing a full charge by the morning. This allowed WeaveGrid to prioritize charging a vehicle with a lower battery level over fully charging a vehicle that had neared its desired state of charge if they were located on the same distribution asset (e.g., transformer or circuit). With each new program enhancement, Exelon communicated the changes in advance to enrolled customers to ensure they were not surprised or confused by the change in their charging patterns. At the beginning of the demonstration period, customers were engaged and curious but had reservations about the "set it and forget it" model. Over time, as customers became more confident that their vehicles would be fully charged by their indicated departure time, the number of questions decreased significantly, and overall satisfaction remained high.

Active managed charging programs enable dynamic optimization with real-time inputs, including vehicle-to-grid integration, offering a broad spectrum of EV load flexibility with significant potential. Given these evolving capabilities, the Exelon experience demonstrates that pilot design, implementation, and evaluation should follow an iterative approach, prioritizing both customer experience and utility objectives. In order to prioritize customer experience, Exelon allowed customers to opt-out of having the utility manage their charging up to four times a month. Additionally, WeaveGrid's customer online dashboard provided users with enhanced customization options, allowing them to set ready-by times to ensure their vehicle was fully charged according to their specific needs. Exelon found that on average 14% of customers opted out one time per month, 5% of customers twice, 2.5% of customers opted out three times, 1.3% of customers four times, and 2.5% of customers more than four, thus losing their monthly incentive. WeaveGrid sent regular emails to drivers to share insights on their charging and Exelon sent quarterly retention emails to drivers participating in the SCM pilot.

During the pilot, Exelon sent out two surveys to participants, one in 2023 and one 2024. The survey results provided valuable insights into customer preferences and highlighted areas for improvement. Customers appreciated the flexibility, ease of scheduling, and the "plug it and forget it" approach, but there were suggestions for enhancing the program further. Participants expressed interest in increased access to EV TOU rates and greater financial incentives for participation. Specifically, Pepco customers requested on-bill credits, a feature already available in BGE territory, and there was a consensus that increasing the value of participation credits would make the program more attractive to EV drivers. These recommendations offer useful guidance for refining the pilot and boosting overall customer satisfaction as the initiative transitions into a full-scale program.

Of the 332 customers who completed the survey, 149 were in the PHI[9] service territory and 183 were in BGE service territory. Key insights included:

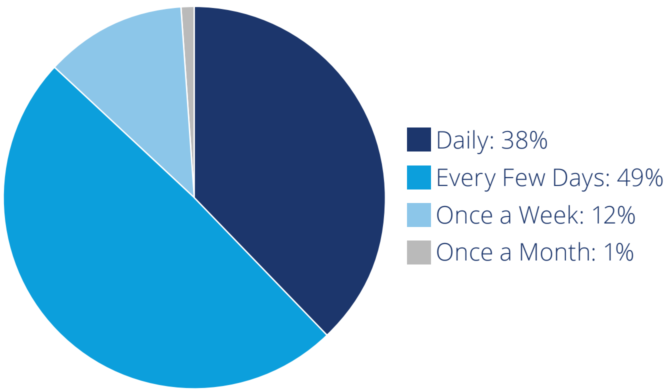
- **Overall participant satisfaction with the utility's management of their home charging was 83% for PHI customers and 80% for BGE customers.** In addition, 90% of PHI participants and 83% of BGE participants said they would likely recommend the program to a friend or neighbor with an EV.
- To be prepared for possible discussions with Maryland stakeholders regarding program design, Exelon sought to survey customers to understand their satisfaction or dissatisfaction with different program levers.
    - 14% of PHI participants and 22% of BGE participants said they would remain in the program even if there were no bill credits.
    - If participants were required to upgrade from an L1 charger to an L2 charger, 44% (PHI) to 45% (BGE) of respondents indicated that they would still remain in the program.

9 Pepco Holdings, also known as PHI, is inclusive of both Delmarva Power & Light (DPL) and Potomac Electric Power Company (Pepco) territories.

The SCM pilot found that accessible and non-technical customer information was key to maintaining participation and facilitating SCM's expansion to a broader audience. The customer experience needs to be straightforward, with minimal effort required from drivers. Most participants valued reliable EV charging and the assurance that their involvement either saved them money or contributed positively to grid stability.

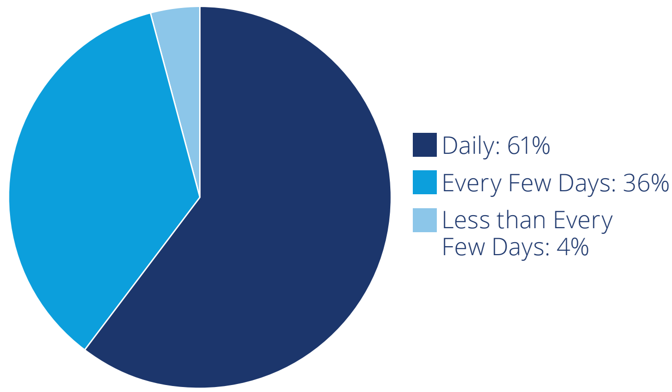
The survey also captured the frequency with which customers charged their vehicle at home. For PHI, 38% of customers were plugging in daily, 49% every few days, 12% once a week, and 1% once a month. For BGE, 61% plugged in daily, 36% charged every few days and 4% charged less frequently than that (see Figure 11 and Figure 12).

Figure 11. Frequency With Which PHI Customers Charged Their Vehicles at Home



Source: WeaveGrid (2024).

Figure 12. Frequency With Which BGE Customers Charged Their Vehicles at Home



Source: WeaveGrid (2024).

Strategies and Impacts

In the second quarter of 2023, Exelon launched SCM to align all charging, regardless of driver rates, with "off-peak" windows similar to those defined in the BGE EV TOU rate. This strategy shifted EV charging from expected high-demand periods to low-demand periods (e.g., shifting afternoon load to off-peak times). However, these peak and off-peak periods were static and did not adjust based on weather, usage patterns, generator outages, or grid congestion.

From June through September 2023, SCM optimized charging to align with driver needs and the lowest cost times based on the PJM[10] day-ahead forecast. The "PJM Integration" was an API-driven integration where WeaveGrid ingested Day-Ahead Hourly locational marginal pricing (LMP) values. The PJM Integration results, for the period spanning June 21 through September 21, 2023, applied to 1,716 vehicles. The PJM price signal reflected the actual price of electricity set a day ahead, for a specific location on the grid, as determined by PJM's day ahead market.

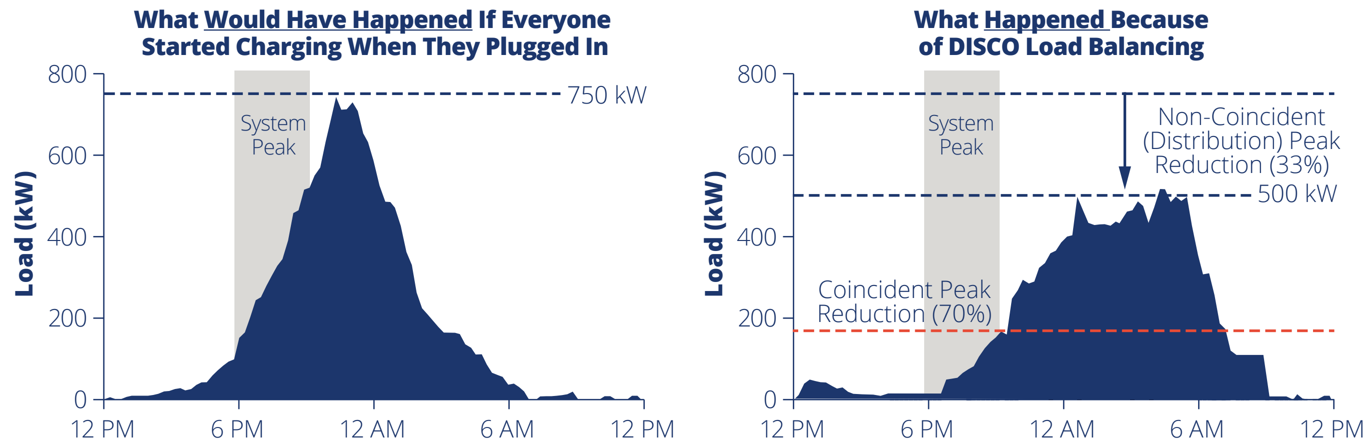
Charging schedules changed significantly in response to dynamic market prices. Consistently aligning EV charging with periods of higher electricity supply and lower demand could minimize utility customer costs over time as the program scales.

As predicted, these first two approaches successfully shifted charging schedules but left value on the table for both the utility and customers. Residential EV charging requires more power than nearly any other type of residential load. These two approaches reduced EV charging's demands on the generation and transmission systems. **However, the simultaneous charging of EVs in a neighborhood stressed the distribution system, which was not reflected in TOU periods or PJM pricing.**

While these initial optimization strategies focused on energy cost reduction, the implementation of WeaveGrid's Distribution Integrated Smart Charging Orchestration (DISCO) technology allowed for a deeper focus on balancing load at the distribution level. In October 2023, the SCM pilot aimed to change the shape of the aggregate EV charging load curve at the distribution level

10 PJM is a Regional Transmission Organization (RTO) and Independent System Operator (ISO) that manages the electric transmission grid and operates a competitive wholesale electricity market across all or parts of 13 states and the District of Columbia.

Figure 13. BGE Feeder-Lever Group Results



Note: The graph shows the peak reduced from 750 kW to 500 kW through Load Balancing. Similar results are observed on other days and with various group sizes. This analysis was completed 10/12/2023 and shows a feeder group with 880 vehicles assigned. However, large group sizes like this group generally demonstrate more consistent and substantial load balancing results.

Source: WeaveGrid (2024). Recreated by SEPA.

by leveraging DISCO. Charging load was balanced within groups of customers to reduce non-coincident peaks. The number of vehicles in each group aligned with the average number of connections to a feeder, circuit, or transformer. In this phase, nearly 3,000 vehicles across 19 groups were aligned with various distribution assets (e.g., feeders and transformers), using managed charging to flatten the EV charging load curve. When a participating EV was plugged in, its charging schedule was informed by the schedules of other group members who had plugged in previously.

Figure 13 shows results from an analysis conducted in October 2023. In this example, a BGE feeder-level group with 880 vehicles demonstrated a peak of only 500 kW; if all these customers had started charging as soon as they plugged in, the peak would have reached 750 kW. With DISCO load balancing, approximately 250 kW of non-coincident peak reduction was achieved.

Similar results were demonstrated across group types and sizes. The findings support Exelon's efforts to anticipate future infrastructure needs and defer distribution-level investments. Load balancing results like these reduce distribution infrastructure wear and tear in the long term. Charging load management is positioned to become an increasingly vital tool as EV adoption grows.

Adjustments

A key lesson learned during the implementation of the SCM pilot was the need to clearly communicate with drivers when significant shifts in charging schedules were anticipated. For example, when SCM transitioned from PJM-focused optimization to load balancing, many charging schedules shifted to later in the evening than customers had previously experienced, leading to confusion among participants. This experience underscored the importance of providing clear and proactive communication before, during, and after major program changes. To address this challenge, Exelon and WeaveGrid collaborated to refine customer messaging, ensuring that program requirements and pilot details were transparent. Exelon implemented a strategy of sending quarterly retention emails to all pilot participants, offering insights, participation tips, and updates on any modifications to their charging schedules. This revised communication approach reinforced the goals and benefits of participation, thereby enhancing customer engagement and satisfaction.

Additionally, Exelon's approach to incentives evolved throughout the SCM pilot. Ongoing incentives were identified as essential to sustaining program engagement. Customer participation in load management programs, including SCM, was primarily driven by the prospect of bill savings and other financial incentives. To maintain customer participation while enhancing the cost-effectiveness of the SCM pilot, Exelon proposed a revised incentive structure in a recent regulatory filing. BGE's incentive changes are set to be implemented when the full-scale program launches in April 2025 and PHI's changes will go into effect in late 2025.

Initially, SCM pilot participants received $10 a month as an incentive regardless of whether they used a Level 1 (L1) or Level 2 (L2) charger. While L2 chargers perform faster than L1 chargers and provide increased load flexibility, they exert greater strain on the electric grid. Pilot data indicated that SCM participants using L1 chargers required charging 56% of the time they were plugged in, compared to 17% for those using L2 chargers. Those using L1 chargers were less flexible in their charging needs compared to L2 chargers and imposed significantly higher demands than other household loads. Recognizing these differences, Exelon revised the incentive structure in a Maryland Public Service Commission filing. Under the updated design, participants with L2 chargers will continue to receive $10 per month, whereas those using L1 chargers now receive $5 per month. This adjustment preserves access for L1 charger users while improving overall cost efficiency in the program's next iteration.

The SCM pilot successfully provided customers with a valuable experience while generating distribution system benefits. Customer satisfaction, engagement, and interest remained high, with the majority of enrollments occurring organically. The pilot demonstrated the capability to shift EV load with sufficient flexibility to accommodate various operating parameters.

Pilot Redesign: A Case Study of BGE and Sunrun's V2H Demonstration

On March 6, 2024, the Maryland Public Service Commission approved BGE to conduct a Vehicle-to-Home (V2H) demonstration for up to 10 customers. BGE and Sunrun partnered to assess the capabilities of the Ford F-150 Lightning in terms of its vehicle-to-home (V2H) functionality and in June 2024, launched the nation's first V2H demonstration using customer-owned F-150 Lightnings to reduce grid demand. To qualify, participants had to be BGE electricity customers who owned an F-150 Lightning, had installed the Sunrun Home Integration System, and did not use a net meter. The demonstration ran from June 1 to September 30, during BGE's summer peak. Participants were incentivized to discharge power from their F-150 Lightning during weekday event windows from 5-9 PM. Instead of drawing from the grid, BGE measured the average kilowatts (kW) each participant used from their vehicle and provided incentives based on their monthly kW demand. Participants earned $800 per kilowatt for the full summer or $200 per kilowatt per month, paid via a Visa gift card at the end of the program.

The overarching objective of this demonstration was to lay the foundation for a market-oriented, open-access program that encourages EV owners equipped with bidirectional EV chargers to actively engage and deliver vehicle-to-everything (V2X) energy services to the utility distribution grid in a least-cost manner. BGE and Sunrun aimed to gather insights pertaining to customer education, recruitment processes, enrollment procedures, system dispatch management, and performance evaluation in support of this larger objective.

This initiative made BGE the first U.S. utility to successfully test V2H capabilities in a customer-facing pilot. The project gained significant media attention, with over 150 news articles and clips featuring BGE and Sunrun. Additionally, the demonstration provided valuable insights into customer engagement, particularly how often participants were home and plugged in during summer weekdays.

Ford developed a custom rate schedule aligned with the 5-9 PM event window and deployed it via a firmware update, integrating Ford Intelligent Power software. Three eligible customers enrolled in the pilot. Customer #1, the Enthusiastic Early Adopter, successfully discharged their truck beginning on June 21. The remaining two customers, Customer #2, one of the Occasional Participants, began discharging on July 22, after a one-month delay caused by firmware update issues between the truck and the charging station. Customer #2 experienced Wi-Fi connectivity issues with their F-150 Lightning due to the distance between the router and the vehicle. Since Wi-Fi connectivity was required to download the firmware,

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Sunrun worked with the customer to connect the F-150 Lightning to a mobile hotspot. Customer #3, the other Occasional Participant, frequently traveled during the summer, making them unresponsive to Sunrun's attempts to update the firmware, as the vehicle was often not at home. BGE and Sunrun observed varying levels of engagement from the enrolled participants when updating their Home Integration System to the latest firmware required for vehicle discharge scheduling.

Customer #1, the Enthusiastic Early Adopter, was the most engaged participant and discharged nearly every event day. This customer had a higher-than-average demand on the grid due to the home's large square footage, two air-conditioning units, and a second EV. As a result, they earned a total incentive of $1,695 during the demonstration period. As a retired former tech employee, Customer #1 was highly engaged in the demonstration, eagerly providing insights on the hardware and software and consistently submitting feedback, including app screenshots, thus playing an active role in testing and refining the system.

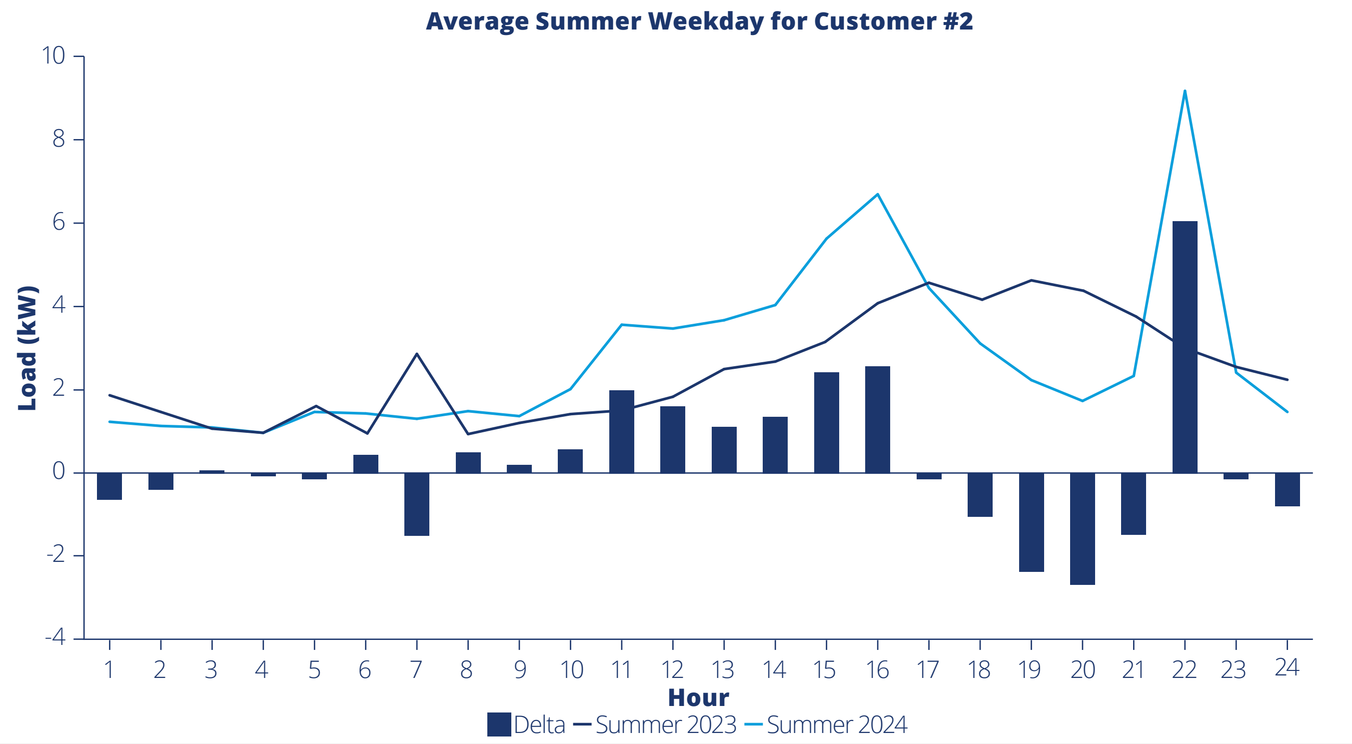
In contrast, Customers #2 and #3, the Occasional Participants, engaged willingly but had less availability and interest in maximizing plug-in frequency to earn rewards. Their participation was influenced by personal schedules and accessibility. Customer #2 and Customer #3 plugged in less frequently and had smaller total household demand, earning total incentives of $324.29 and $322.19, respectively.

Vehicle usage patterns also played a role in participation. For example, Customer #1, the Enthusiastic Early Adopter, primarily used their F-150 Lightning for occasional towing rather than daily commuting, allowing the truck to remain parked and available for nearly all event days. Customer #1 participated in 88% of the event days, while the Occasional Participants plugged in for less than half of the event days. Customers #2 and #3 engaged in 46% and 41% of the event days, respectively.

BGE evaluated the reduction in household demand during event windows by comparing customer meter data from the summer of 2023 to the summer of 2024. Figure 14 depicts Customer #2's demand during event windows.

This customer saw a significant reduction in energy usage from hours 17-21 (5-9 PM) as a result of discharging their vehicle during the event window rather than relying on energy from the grid to power their home. This shows that the V2H concept can be effective in reducing peak load.

Figure 14. Customer Meter Data for Summer 2023 vs. Summer 2024



Source: Baltimore Gas and Electric (2024).

Testing Verification and Scenario Modeling

Argonne National Laboratory (ANL) was tasked with evaluating two of BGE's and Pepco's[11] vendor platforms, WeaveGrid and Shell Recharge Solutions (formerly known as "Greenlots"), at the Smart Energy Plaza (SEP) through a series of functional tests in a controlled environment. The two vendor platforms shared a common goal of charge scheduling and optimization through curtailment, however they leveraged distinct approaches. WeaveGrid used a telematics-based approach while SRS used a networked-based approach.

Vendor Platform Testing

For the first vendor platform tested by ANL, the SCM pilot WeaveGrid communicated directly with the EV telematics, utilizing the vehicle's onboard system to gather real-time information, including battery status and charging behavior. By analyzing this data, WeaveGrid's system generated an optimized schedule for each vehicle charging at home. These active managed charging schedules aligned charging with the grid's operational needs and the user's preferences, such as desired state of charge and desired readiness time, which were communicated through WeaveGrid's online driver portal.

The WeaveGrid telematics-based approach was tested using ANL's AC Level 2 charging equipment to emulate typical at-home charging. Four managed charging approaches were tested and validated to function as intended: (1) static time of use (TOU), (2) demand response (DR), (3) TOU and DR together, and (4) a Dynamic Price Signal (DPS). Overall, the WeaveGrid platform effectively managed the optimization of charging sessions with all four approaches and was capable of performing cost optimization to find the cheapest window of time based on users' input while remaining responsive with strong LTE/Wi-Fi connection. In addition, the system ensured a smooth customer experience via the application interface, communicating information and allowing hands-on prioritization of the desired end state of charge over charge optimization. Telematics-based managed charging approach by WeaveGrid could be improved, particularly in addressing vehicle connectivity issues that may lead to message packet loss and prevent charge sessions from resuming after curtailment.

The second vendor-platform tested by ANL, Shell Recharge Solutions (SRS), focused on controlling charging through the charging station rather than the vehicle. By monitoring and managing the load on chargers across multiple locations, the system optimized charging schedules for both vehicles and stations. This network-based approach enabled centralized control over charging times and power levels, helping to balance the grid load and efficiently use resources. The SRS platform was tested using three EVs and four DCFCs at ANL's Smart Energy Plaza (SEP). Multiple demand response (DR) variations were tested, including scheduled curtailment, emergency curtailment, multi-stack DR events (multiple DR events in succession), multiple charge events within a single DR event, and opt-in/opt-out capabilities. The platform showed strong performance in several areas, including reliable performance of scheduled and emergency curtailments, minimal communication packet loss through OpenADR or OCPP, and flexible curtailment options (kW or %). Multi-stack DR events were tested and validated to function properly, the mobile app provided useful information and multiple payment options, and the opt-in/opt-out features worked smoothly across various scenarios. However, improvements are recommended to ensure the "cancel curtailment" functionality works as intended, adjust the "percentage offset" to reflect real-time max power data, and improve EVSE firmware validation. Compatibility issues between ANL's AC Level 2 charger, a DC fast charger, and SRS' platform led to test failures or delays, emphasizing the need for more thorough firmware testing.

Both approaches demonstrated distinct advantages and limitations during testing. The telematics-based approach by WeaveGrid enabled a more **tailored charging strategy, aligning with each vehicle's specific needs and usage patterns**. However, its effectiveness depended on the accuracy of vehicle telematics data and the strength of network connections.

11 For the vendor-platform testing and scenario modeling, ANL solely analyzed BGE and Pepco territories.

In contrast, **the network-based approach by SRS provided a broader perspective on the charging ecosystem, facilitating strategic resource management across multiple vehicles and charging stations**. However, the lack of individual vehicle data limited its ability to optimize charging for specific user needs. At the time of testing, each platform had trade-offs. Teslas offered the most robust API for charge scheduling and optimization, while broader participation in active managed charging required direct integration with automaker software—a process that takes time. As the industry progresses, bridging these approaches with deeper integrations and broader participation from automakers will be key to optimizing managed charging for both efficiency and user-specific requirements.

Some improvements in future vendor software testing efforts could be lowering the sampling rate for detecting pre-charge drive sessions and utilizing real-time power instead of historical charge power for managed charging time estimations.

EV Charging Impact Scenario Modeling

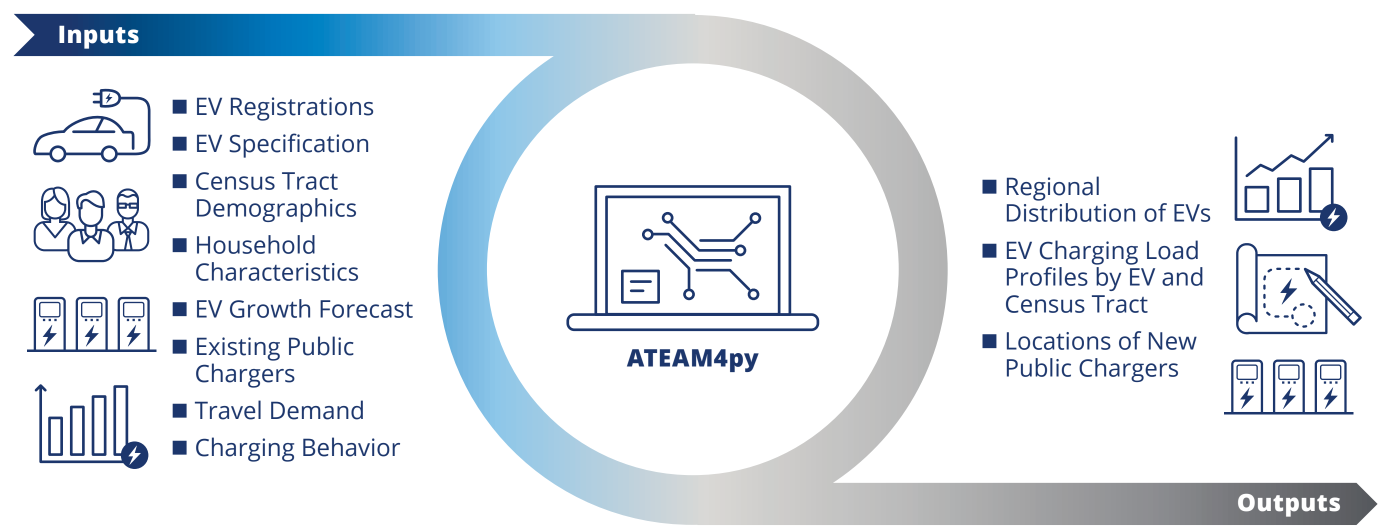
Simulating charging impacts provide utilities with critical insights into where grid investments may be needed to support transportation electrification and mitigate potential system overloading from EV charging.

ANL and Exelon co-developed the Agent-based Transportation Energy Analysis Model (ATEAM) to simulate the evolution of future EV charging demand and the need for charging infrastructure at the local level. This tool aligns charging infrastructure deployment planning with EV adoption trends, enabling strategic and efficient development. ATEAM models a region's daily and annual EV charging load—including home and public charging—while projecting future public charging infrastructure locations by census tract.

As shown in Figure 15, ATEAM integrates baseline data as inputs, including, but not limited to, existing vehicle registrations and charging infrastructure, household characteristics, future EV growth forecast, regional travel demand, and typical charging behavior. The outputs of ATEAM simulations include the forecasted regional distribution of EVs, suggested locations for charging infrastructure deployment, and the resulting daily charging load profiles. For this analysis, ANL modeled the representative EVs' daily home charging load profiles under unmanaged and utility-managed charging scenarios for BGE's and Pepco's service territories. For this study, the definition of EVs only included battery electric vehicles, not plug-in hybrid electric vehicles.

WeaveGrid provided ANL with weekly charging reports containing charging session data from the EV drivers who were enrolled in the SCM pilot. Between April 2023 and October 2024, the data included 1,203,912 charging session records from 4,661 EV drivers. BGE, Pepco, and WeaveGrid developed and implemented several SCM strategies, including TOU-based SCM, PJM pricing-based SCM, and load balancing SCM. These strategies are further

Figure 15. Inputs and Outputs of ATEAM



Source: Argonne National Laboratory (2025). Recreated by SEPA.

defined under the Pilot Implementation section of this report. ANL's analysis focused on TOU-based SCM and load balancing SCM.

The TOU-based SCM strategy aimed to reduce charging demand during the TOU on-peak window (5 PM to 9 PM). During this time, charging was paused and automatically resumed after 9 PM.

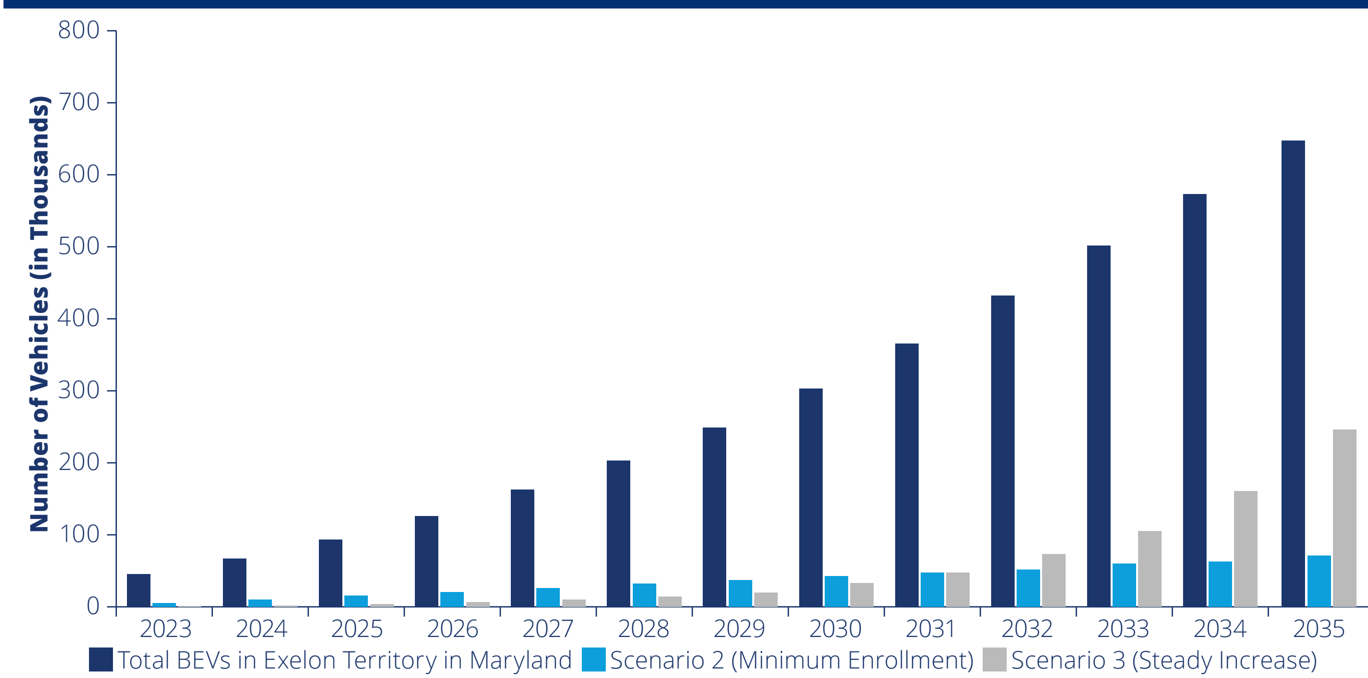
The load balancing strategy grouped consumers by grid asset connection (e.g., feeder, transformer, substation, etc.) to smooth the charging load. This approach staggered charging sessions to prevent overloads, ramping up the load gradually from early evening to overnight. When high charging demand was detected, the strategy paused some charging sessions and shifted them to periods of lower anticipated demand, all while ensuring the customer met their desired state of charge by their scheduled departure time.

ANL analyzed the WeaveGrid charging reports to assess the impact of the two SCM strategies, TOU-based SCM and load balancing, on EV charging load profiles. Based on these insights, ANL developed scenarios to project EV charging loads under varying customer enrollment rates for each SCM strategy in future years.

ANL examined three potential SCM enrollment scenarios for both BGE and Pepco's service territories: Scenario 1: No Enrollment (unmanaged charging), Scenario 2: Minimum Enrollment (11% by 2035), and Scenario 3: Steady Growth (a linear increase in enrollment from 2% to 8% between 2023 and 2029, followed by exponential growth reaching 38% by 2035). Scenario 4: Very High Enrollment (50% enrollment from 2023-2035). While ANL did model the Very High Enrollment scenario, we do not present detailed results for it, as it is not considered a realistic scenario; it was included primarily to help capture system trends as enrollment scales from low to high levels. The results from modeling each enrollment scenario helped BGE and Pepco understand the value of SCM as more vehicles participated over time and provided BGE and Pepco with a realistic view of what the deferred distribution infrastructure costs could be under different enrollment levels. Figure 16 shows the yearly increase in EVs and customer enrollment assumptions for different scenarios in Exelon's territory.

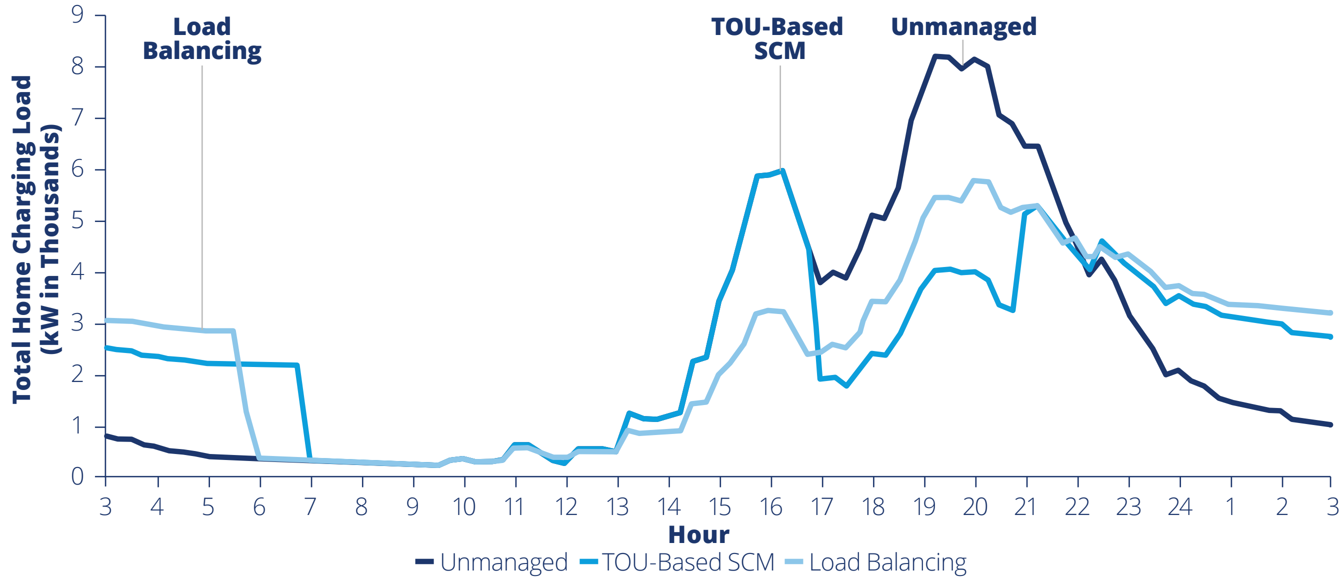
The ATEAM model generated home charging load profiles for unmanaged and managed scenarios—TOU-based SCM and load balancing—from 2023 to 2035 across feeders under three customer enrollment scenarios. Figure 17 represents the aggregated EV charging load across multiple charging profiles on the feeder, excluding all other residential loads; it does not reflect an actual home load profile or a full feeder load profile. In this feeder, the unmanaged scenario saw peak home charging demand around 7 PM, while the load balancing scenario successfully reduced the peak. On average, load balancing

Figure 16. Number of EVs and SCM Enrolled Customers in Exelon Service Territory for Different Enrollment Scenarios



Source: SEPA and Argonne National Laboratory (2025).

Figure 17. Aggregated EV Charging Load Across Multiple Charging Profiles on the Feeder, Excluding All Other Residential Loads



Source: Argonne National Laboratory (2025). Recreated by SEPA.

achieved greater peak load reduction across all feeders compared to TOU-based SCM.

The model had two primary limitations that could be addressed in future research. First, ATEAM's results were based on a typical travel day without accounting for variations in travel behavior across different days of the week or seasons. Second, the travel survey data underpinning the study were collected from a limited sample of households on a single day,[12] requiring the extrapolation of historical patterns to a broader population. This approach may not have fully captured the diversity and complexity of future travel behaviors.

Feeder Selection and Grid Impact Assessment

The grid impact assessment began with 19 representative feeders—ten from BGE and nine from Pepco. This covered different feeder types, load types, EV penetration levels, and other characteristics. ANL converted the utility-provided feeder models from CYME to OpenDSS, conducted detailed scenario-based analysis, and estimated upgrade costs for various strategies.

The results were then scaled to the entire distribution network to demonstrate the benefits of SCM. BGE and Pepco each initially provided ten representative feeders, chosen to reflect the diverse characteristics of their service territories. The selection considered factors such as rural, urban, and suburban settings, variations in residential, commercial, and industrial electric loads, population density, and the availability of controllable devices.

As part of the simulation testing methodology for the overall distribution network, BGE's and Pepco's feeder systems were assessed across various voltage levels. BGE operated 1,320 feeders, distributed across 4.4 kV, 13.2 kV, and 13.8 kV, while Pepco had 772 feeders at 12.47 kV, 13.2 kV, and 13.8 kV.

In the TOU strategy, charging was scheduled to avoid the 5-9 PM period. In the load balancing strategy, charging was scheduled to minimize peak charging loads, regardless of time of day. These strategies were inputs for estimating EV charging demand at the feeder level. BGE and Pepco selected three representative days to capture the summer peak, winter peak, and average load conditions. A detailed assessment was performed for each feeder, SCM strategy, and enrollment level, focusing on transformer and line overloading, as well as voltage profiles within the service territory from 2022 to 2035.

Based on observed operational violations for each feeder and study year, a targeted system upgrade plan was developed to address feeder constraints and accommodate increasing EV loads, estimating the minimum required

12 Chicago Metropolitan Agency for Planning (2019). A Pre-Pandemic Snapshot of Travel in Northeastern Illinois.

costs for distribution system enhancements. Insights from the analysis of these representative feeders were generalized using regression and scaling, offering a broader perspective across BGE's and Pepco's entire service territories. This approach highlights the potential for smart charging strategies to optimize grid performance, reduce infrastructure strain, and defer distribution system upgrade costs directly associated with EV load growth. As an example, a description of the BGE feeders are shown in Table 2.

Table 2. Characteristics of BGE Feeders

Feeder	Region			Load Type			Population Density	
	Rural	Suburban	Urban	Residential	Commercial	Mixed	Heavily Populated	Sparse
1	■			■			■	
2		■		■			■	
3	■			■				■
4		■		■			■	
5		■		■			■	
6		■				■	■	
7		■			■			■
8		■				■		■
9			■		■			■
10			■			■	■	

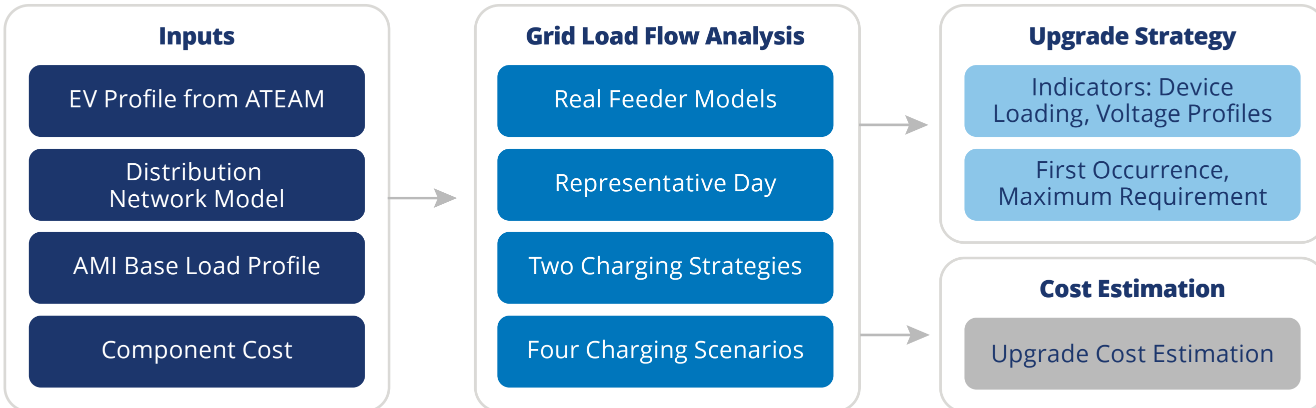
Source: Argonne National Laboratory (2025). Recreated by SEPA.

The inputs for the feeder level smart charging analysis include distribution network configuration, non-EV load profiles, EV profiles, cost of each component, and the energy price at the energy market and utility levels. The feeder configurations were obtained through feeder format conversion, followed by developing an OpenDSS model for each feeder, validated against power flow results provided by BGE and Pepco. ANL utilized Advanced Metering Infrastructure (AMI) data for different load types—residential, commercial, and industrial—for both BGE and Pepco feeders.

This data was used to distribute the projected cumulative base load from the 2022 PJM Load Forecast Report[13] across 24-time steps per day for each node in the distribution network. The EV charging load profile, mapped to the feeder node level, was derived from ATEAM simulations. The methodology adopted for the work is depicted in Figure 18. A Python-based environment was developed to execute the load flow analysis in OpenDSS using the compiled profiles, feeder model, and EV profiles throughout the study period. For each study year, the load flow analysis identified overloaded transformers and lines and voltage issues such as under-or over-voltage at specific nodes. A one-time upgrade strategy was implemented, where overloaded components are upgraded as they reach capacity limits, ensuring sufficient capacity to accommodate the maximum projected load through 2035.

13 PJM Interconnection (January 2022). PJM Load Forecast Report.

Figure 18. Methodology for Grid Impact Assessment



Source: Argonne National Laboratory (2025). Recreated by SEPA.

Cost Analysis

Furthermore, ANL conducted a cost analysis to assess the financial implications of infrastructure upgrades. ANL incorporated generalized distribution system upgrade costs from the National Renewable Energy Laboratory's (NREL) cost database. This comprehensive approach provides a detailed investment assessment and underscores the value of smart charging strategies in managing demand efficiently while deferring upgrade costs.

ANL observed a clear reduction in peak load and a decrease in upgrade costs from both smart charging strategies (TOU and load balancing), varying by enrollment scenarios. The load balancing strategy outperformed TOU for most of the representative feeders. However, feeders exhibited varied characteristics, resulting in differences in potential reliability standards (e.g., ANSI C84.1 for voltage limit, IEEE C57.91 for transformer loading) violations and corresponding upgrade strategies.

The analysis evaluated the impact of EV adoption on each representative distribution feeder by examining the number of overloaded transformers and lines, transformer upgrade capacity, and the associated costs of upgrading transformers and lines. A distribution asset was considered overloaded if the power flowing through it exceeded 100% of its nominal rating.

Note: *The estimated deferred upgrade cost for the entire distribution system can be found in the **Modeling Results** section.*

The Modeling Process

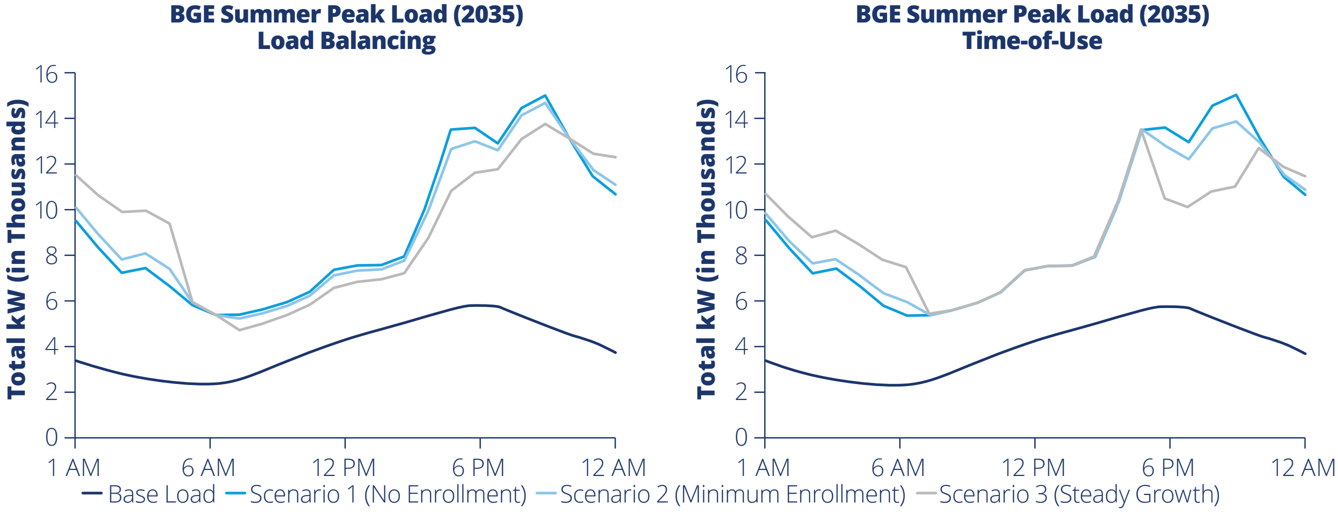
ANL selected three representative dates to evaluate the impact of EV charging on the distribution system: a hot July day, a winter holiday, and a typical day. These dates were chosen to capture seasonal variations in load, particularly the peak EV demand during holiday periods.

The analysis for each day revealed that the summer peak had the highest demand on the Maryland electric grid, leading to the most potential reliability standard violations and presenting the most critical scenario to address. As a result, ANL designed the upgrade strategy based on summer loading conditions, ensuring it would also be sufficient for the other two seasons.

Feeder Level Load Profiles

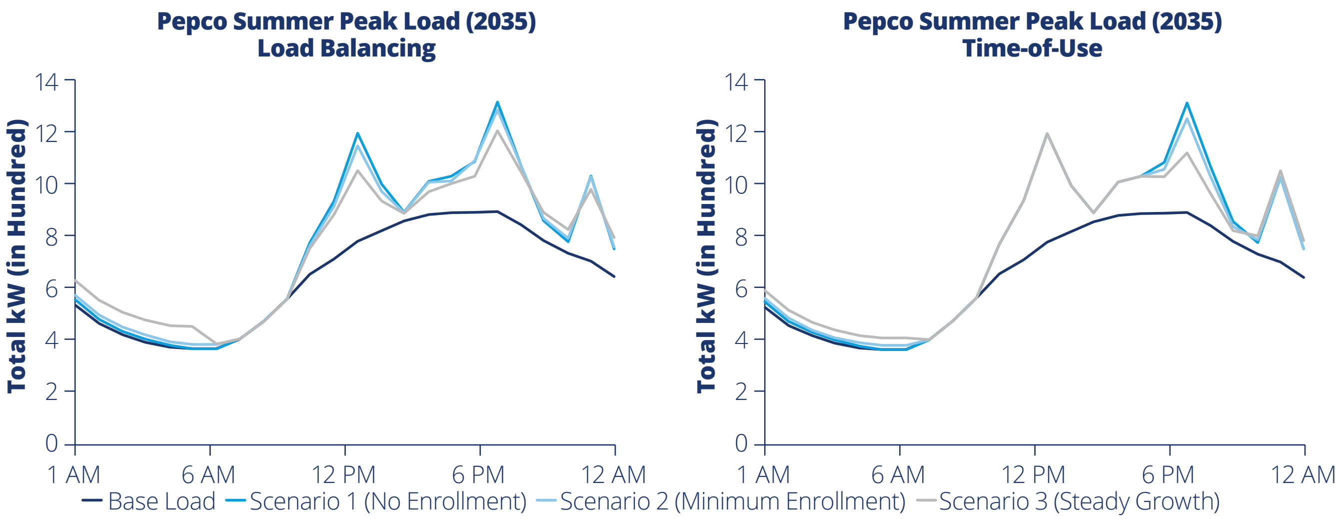
Figure 19 and Figure 20 represent the total load variation for one representative feeder from BGE and Pepco's system under the three SCM enrollment scenarios using both the load balancing and TOU-based smart charging strategies. **Both the TOU and load balancing smart charging strategies reduce the peak load in all scenarios.** TOU shifted the peak EV charging load to off-peak hours (9 PM), but the load balancing approach flattened the load during the period. The data also showed that the TOU scenario may create a secondary peak at the start of the off-peak time. In such cases, **additional enrollment reduces the load between 5-9 PM but does not decrease peak load outside of this period and can create a higher secondary peak at the start of the off-peak period.**

Figure 19. Load Variation of a Representative Feeder from BGE with Smart Charging Strategies (Load Balancing and Time-of-Use)



Source: Argonne National Laboratory (2025). Recreated by SEPA.

Figure 20. Load Variation of a Representative Feeder from Pepco with Smart Charging Strategies (Load Balancing and Time-of-Use)



Source: Argonne National Laboratory (2025). Recreated by SEPA.

In contrast, load balancing reduces the load more smoothly and uniformly, without creating a noticeable secondary peak.

Scenario Descriptions:

- **Scenario 1:** No Enrollment (unmanaged charging)
- **Scenario 2:** Minimum Enrollment (11% by 2035)
- **Scenario 3:** Steady Growth (a linear increase from 2% to 8% between 2023 and 2029, followed by exponential growth reaching 38% by 2035)

Feeder Upgrade Analysis

Implementing smart charging strategies, in general, shifted EV loads to off-peak periods, redistributing the total load across different times to prevent the overlap of peak base load and peak EV load. Additional peak reduction could have been achieved if the load balancing modeling strategy had been designed to specifically avoid the 5-9 PM on-peak period. However, this consideration was not incorporated at the time of pilot deployment, as real-world charging data revealing this insight only became available after the strategy was implemented.

Both charging strategies demonstrated superior performance in Scenario 3: Steady Growth, which featured the highest base load and EV adoption rate. The analysis of load balancing and TOU-based strategies on representative feeders reveals notable variations in peak load and transformer upgrade requirements for BGE and Pepco across different scenarios.

For BGE, the average peak total load was highest in Scenario 1 at 14.38 MW, followed by 13.94 MW in Scenario 2, and 13.25 MW in Scenario 3. Similarly, for Pepco, Scenario 1 recorded the highest peak load at 8.3 MW, while Scenario 2 reached 7.96 MW, and Scenario 3 peaked at 7 MW.

In terms of transformer upgrade capacity requirements, BGE required 11.43 MVA in Scenario 1, decreasing to 11.01 MVA in Scenario 2 and further to 9.9 MVA in Scenario 3. For Pepco, the transformer upgrade demand was 7.4 MVA in Scenario 1, reducing to 6.6 MVA in Scenario 2 and 5.4 MVA in Scenario 3.

This indicates that the smart charging strategies effectively managed the increased charging demand with minimal adverse effects on distribution system assets and power quality.

In addition to device overloading, undervoltage was observed on the low-voltage side of the transformer for certain feeders. Addressing the overloading issues by upgrading transformers effectively resolves the under-voltage issues for most of the feeders simultaneously. For the remaining feeders, additional capacitor banks were added to maintain voltages within ±5% of the rating.

Overall, the impact of smart charging strategies varied across feeders, with most experiencing noticeable benefits. However, two of the ten representative feeders showed no difference in performance regardless of the smart charging strategy tested. For these two feeders, no significant shift in load was observed when employing the load balancing and TOU smart charging strategies. In these cases, the peak load hour for TOU fell outside the designated TOU period, while the managed EV load under load remained too small to produce a meaningful reduction. **These findings highlight the importance of feeder-specific characteristics in determining the effectiveness of smart charging strategies.**

The modeling of Pepco feeders revealed that transformer overloading would occur, but no line overloading would result. Both charging strategies demonstrated superior performance in Scenario 3: Steady Growth. Despite the increase in charging demand and base load, none of the representative feeders experienced under- or over-voltage issues. Since the Pepco feeders had more available capacity to accommodate load growth than those on BGE feeders, the number and the capacity of overloaded transformers were also lower compared to BGE.

Modeling Results

The simulation assessing the impact of EV adoption on the distribution grid indicated that the existing infrastructure would need upgrades to accommodate the additional load from EV charging.

- In Scenario 2: Minimum Enrollment, the TOU strategy was the most effective, showing deferred infrastructure costs of $139M for BGE and $13M for Pepco by 2035. In comparison, the load balancing strategy resulted in savings of $80M for BGE and $8M for Pepco.
- In Scenario 3: Steady Growth, the load balancing strategy outperformed the TOU strategy, with deferred infrastructure costs of $186M for BGE and $29M for Pepco by 2035. The TOU strategy, however, still provided significant savings, amounting to $159M for BGE and $30M for Pepco by 2035.

At lower EV penetration and participation levels, TOU rates are more effective. However, as enrollment increases, the overall benefits of load balancing surpass those of TOU. Therefore, focus should be placed on increasing participation to at least a minimal threshold where the advantages of load balancing outweigh those of TOU.

Smart charging strategies based on load balancing and TOU effectively shift charging loads to off-peak periods, reducing the burden on the existing grid infrastructure. **When it comes to reducing or deferring infrastructure investment, the load balancing-based charging strategy proved more effective than the TOU-based strategy for both the BGE and Pepco feeders at higher levels of enrollment.**

Transformer Overloading

The impact analysis revealed that transformers were the most affected component and the most critical distribution system asset requiring upgrades. ANL's research indicated the cumulative trend of overloaded transformers across BGE and Pepco's systems. illustrated in Appendix E, Figures 30-33, rising **EV loads led to increased transformer overloads, particularly in urban and suburban areas.** Scenario 3: Steady Growth, which utilized smart charging with the maximum enrollment rate, resulted in the fewest overloaded transformers, demonstrating the effectiveness of SCM in handling high EV penetration.

A steady increase in the number of overloaded transformers was observed from 2022 to 2035 in both cases. **However, as enrollment in smart charging programs increased, the number of overloaded transformers decreased.** In the load balancing case, the final number of overloaded transformers was notably lower in Scenario 3: Steady Growth compared to Scenario 1: No Enrollment. **Small-sized single-phase transformers were found to experience the majority of overloading conditions**, making them a high priority for upgrades and the primary focus of upgrade efforts. In terms of distribution lines, most had sufficient capacity to accommodate the integration of EVs, with only a few laterals showing relatively smaller current-carrying capacities, which led to minor overloading. Some feeders experienced undervoltage alongside overloading; however, upgrading the transformers resolved most of these undervoltage issues. **Only a few feeders required additional capacitor banks to fully address the voltage problems.** These findings underscore the importance of implementing smart charging strategies, particularly for urban and suburban feeders where demand is highest.

Utility Market Analysis Results: Value Streams from Utility-Managed Smart Charging to the EV Owner

Both the load balancing and TOU smart charging strategies enhance the operational performance of distribution feeders. Higher SCM enrollment levels lead to further performance improvements and delay the need for distribution power system upgrades. As more customers participate, the required upgrade costs can be deferred to a later date, extending the lifespan of the network.

Feeder Upgrade Cost Comparison

Results from ANL revealed a clear trend: implementing smart charging strategies, both TOU and load balancing, deferred costs, particularly in Scenario 3: Steady Growth.

Scenario Descriptions:

- **Scenario 1:** No Enrollment (unmanaged charging)
- **Scenario 2:** Minimum Enrollment (11% by 2035)
- **Scenario 3:** Steady Growth (a linear increase from 2% to 8% between 2023 and 2029, followed by exponential growth reaching 38% by 2035)
- **Scenario 4:** Very High Enrollment (50% enrollment from 2023 onward)

  Note: *Scenario 4 is included to illustrate directional trends associated with scaling enrollment from low to high levels. However, detailed results are not presented in other sections of the analysis, as the assumption of 50% enrollment across all years is not considered a realistic or supportable forecast scenario.*

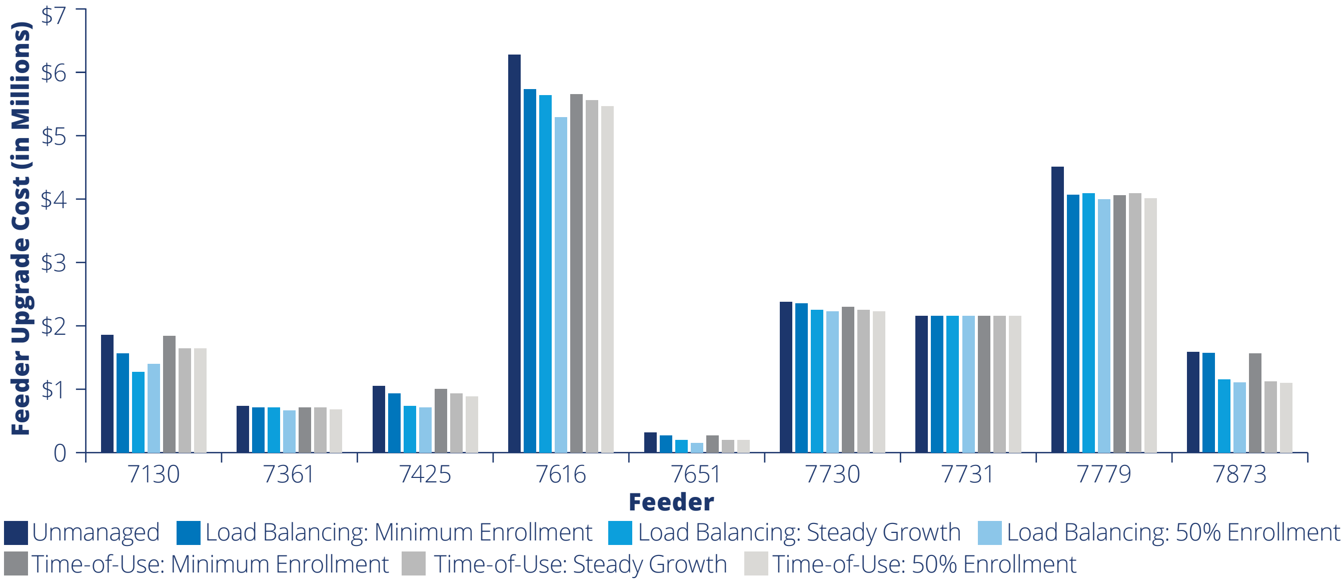
Figure 21 and Figure 22 compare feeder upgrades for the load balancing strategy versus the unmanaged scenario for BGE and Pepco respectively. All feeders showed some level of upgrade cost deferral with load balancing.

Figure 23 and Figure 24 compare BGE and Pepco feeder upgrade costs for the load balancing strategy versus the time-of-use (TOU) approach. While most feeders had similar upgrade costs under both strategies, several feeders experienced an additional cost reduction of 10% to 20% with load balancing.

For both BGE and Pepco, **Scenario 3: Steady Growth, TOU and load balancing both demonstrated the favorable performance over unmanaged charging**, resulting in the lower net present value across various feeder upgrades. Additionally, the load balancing (LB) strategy proved to be more cost-effective than the Time-of-Use (TOU) strategy for the higher enrollment scenarios.

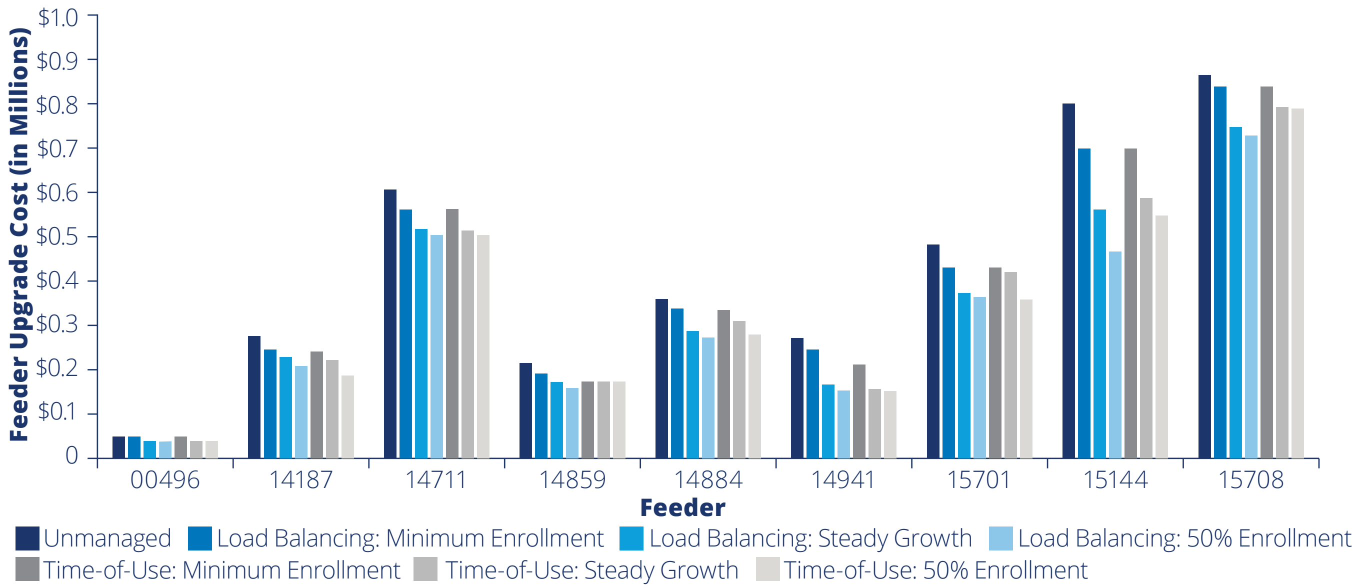
ANL concluded that over the study period, the net present value of savings for load balancing across both utilities was $215M under Scenario 3: Steady Growth. Dividing by the cumulative enrollment for both utilities results in savings of **$297 per vehicle per year.** It is important to note that these savings are only at the feeder and secondary transformer level. Managed charging creates additional benefits, including generation capacity, transmission capacity, generation energy, carbon reduction and other distribution-system benefits that were not analyzed as

Figure 21. Feeder Upgrade Costs for BGE



Source: Argonne National Laboratory (2025). Recreated by SEPA.

Figure 22. Feeder Upgrade Costs for Pepco

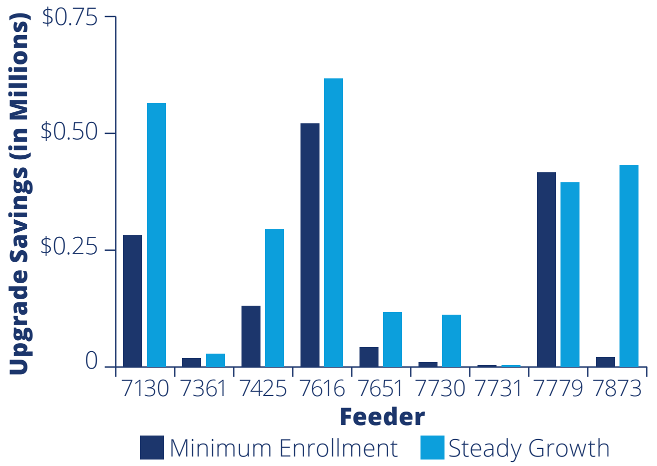


Source: Argonne National Laboratory (2025). Recreated by SEPA.

part of the ANL scope of work. These benefits would be in addition to the $297 in benefits per vehicle per year that ANL found. As the all-in cost of running a load balancing managed charging program, including incentives, should be comfortably below $300 per vehicle per year, the ANL study is evidence that managed charging will be cost-effective and can put downward pressure on rates.

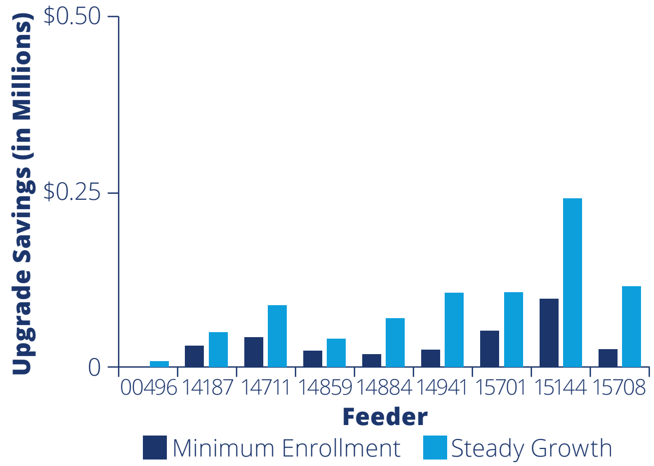
The analysis demonstrated that smart charging strategies are advantageous for utilities with different load conditions, effectively lowering upgrade costs in both high- and moderate-load environments. For Pepco, the smart charging and load balancing strategies facilitated efficient EV integration within a less heavily loaded network.

Figure 23. Difference Between Upgrade Costs for the Load Balancing Scenario Compared to the Unmanaged Scenario for BGE



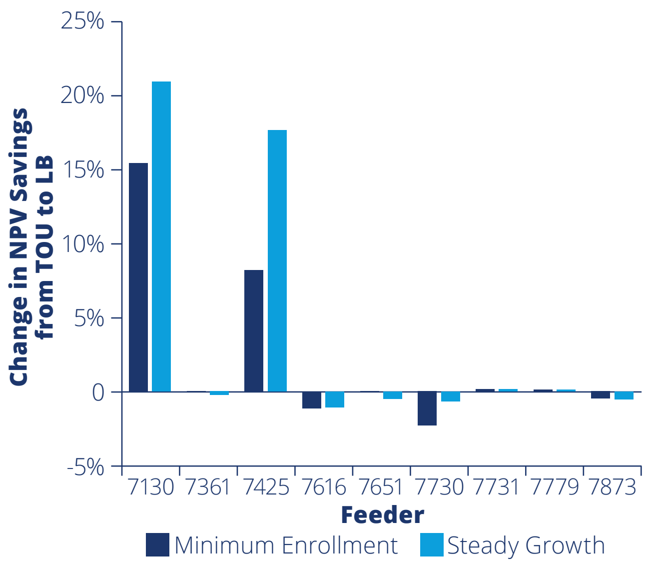
Source: Argonne National Laboratory (2025). Recreated by SEPA.

Figure 24. Difference Between Upgrade Costs for the Load Balancing Scenario Compared to the Unmanaged Scenario for Pepco



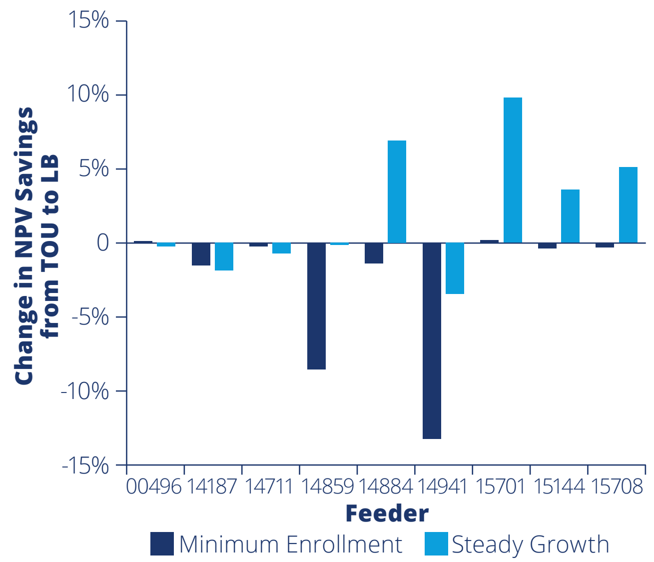
Source: Argonne National Laboratory (2025). Recreated by SEPA.

Figure 25. Comparison of BGE Feeder Upgrade Costs for Load Balancing vs. Time-of-Use (TOU) Approach



Source: Argonne National Laboratory (2025). Recreated by SEPA.

Figure 26. Comparison of Pepco Feeder Upgrade Costs for Load Balancing vs. Time-of-Use (TOU) Approach



Source: Argonne National Laboratory (2025). Recreated by SEPA.

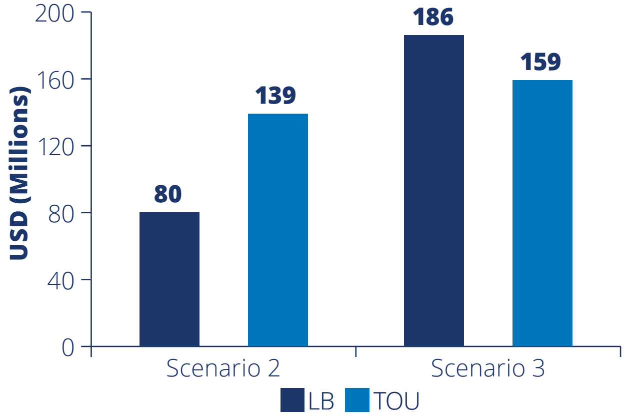
This suggests that smart charging is both scalable and beneficial across a range of utility infrastructures. **Smart charging strategies can reduce infrastructure upgrade costs and support EV integration, making them a scalable and effective solution for utilities with varying load conditions.**

Figures 27 and Figure 28 illustrate the comparison of upgrade cost reductions for Scenario 2: Minimum Enrollment and Scenario 3: Steady Growth compared to Scenario 1: No Enrollment for BGE and Pepco.

For BGE, in Scenario 2: Minimum Enrollment, the load balancing strategy resulted in a cost difference of $80M, while the TOU strategy achieved a significantly higher reduction of $139M. In Scenario 3: Steady Growth, load balancing delivered the greatest deferral of distribution system upgrade costs at $186M, surpassing TOU's $159M.

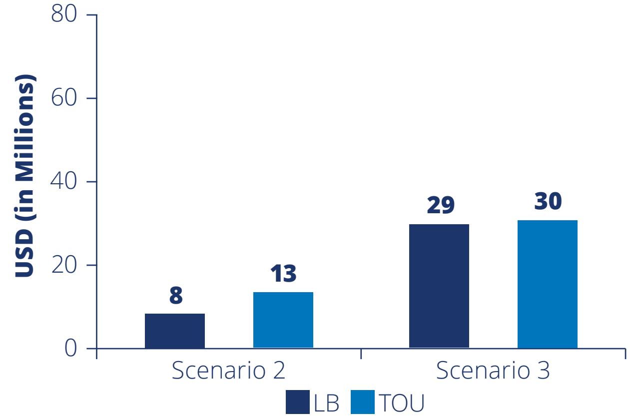
For Pepco, Scenario 2: Minimum Enrollment saw cost differences of $8M with load balancing and $13M with TOU. In Scenario 3: Steady Growth, both strategies delivered higher reductions, with load balancing reducing costs by

Figure 27. Comparison of Upgrade Cost Deferrals for BGE Feeders



Source: Argonne National Laboratory (2025). Recreated by SEPA.

Figure 28. Comparison of Upgrade Cost Deferrals for Pepco Feeders



Source: Argonne National Laboratory (2025). Recreated by SEPA.

$29M and TOU slightly outperforming load balancing with a $30M deferral by 2035.

Overall, BGE demonstrated a greater potential for deferral system upgrade costs than Pepco, though Pepco showed similar results for both strategies. The findings indicate that in Scenario 2: Minimum Enrollment, the TOU strategy generally outperforms load balancing in reducing upgrade costs, while in Scenario 3: Steady Growth, load balancing performed better for BGE.

These results provide compelling evidence for the SCM pilot's long-term value to the distribution system. **While TOU pricing offers significant cost deferrals by 2035, the data reveals a critical insight: load balancing, which inherently avoids on-peak periods, has the potential to achieve even greater savings than TOU alone. This is especially evident in Scenario 3: Steady Growth for BGE, where load balancing surpasses TOU in upgrade cost reductions by a substantial margin.**

By demonstrating how customer enrollment in managed charging can defer costly distribution infrastructure upgrades to later years, with greater savings as enrollment scales, this analysis makes a powerful case for continued investment in managed charging programs. In addition, the estimated benefits may be conservative due to inflation in distribution costs outpacing the assumed 3% rate by ANL. For example, the cost of a 150 kVA transformer has increased at a rate of 4.96% in recent years[14]. The inflationary effect of recently imposed tariffs, especially on steel, may further increase distribution costs. These insights highlight the critical role that managed charging plays in optimizing system performance and delivering long-term cost deferral for both utilities and customers. Ultimately, the findings underscore the importance of leveraging smarter load management strategies beyond TOU pricing to both minimize the costs that EVs may impose on the grid and maximize the benefits that they can bring to the grid.

Conclusion

As EV adoption accelerates, utilities should prioritize managed charging as a standard practice for the power grid stability. Programs must be tailored to customer needs, with early stakeholder engagement and seamless integration of software and hardware. The SCM pilot highlighted the critical role of iterative design and customer experience in developing effective managed charging programs. Findings suggest that utilities can leverage time-of-use and load-balancing strategies to optimize grid performance, defer—but not eliminate—future distribution system upgrades, and extend equipment lifespan.

14 Argonne National Laboratory's research relied on a 2019 Distribution System Upgrade Unit Cost Database where the source for a 150 kVA transformer was listed as $39,200 and cited a PG&E Unit Cost Guide. A 2025 version of the same guide showed the unit cost had risen to $52,413—a 4.96% annual increase.

While managed charging can delay infrastructure investments, these upgrades will eventually be necessary. The objective is to extend asset life and spread costs gradually, reducing the financial burden on customers. To address this increasing demand and delay necessary upgrades, active managed charging strategies—such as load balancing and time-of-use pricing—are essential. While both strategies are effective, load balancing has a slight edge by dynamically spreading demand across various times, minimizing overloads and reducing the need for costly upgrades. This makes it a more efficient solution for managing peak demand. Prioritizing smart charging, especially load balancing, allows existing infrastructure to support high EV adoption rates efficiently and sustainably.

Looking ahead, BGE leveraged insights from the SCM pilot to develop a full-scale program, achieving a cost-effectiveness score exceeding 1.5 and demonstrating net benefits for ratepayers. The Maryland Public Service Commission order stated that *"extending and expanding BGE's SCM program is in the public interest because of the pressing need to expand EV charging with the least impact on the distribution grid."* The Maryland Public Service Commission approved BGE's expansion of the SCM pilot, positioning the program for broader implementation and reducing the cost of EV integration into the electric grid. BGE's full-scale program launches in April 2025. By 2027, BGE aims to enroll 30,000 devices in the SCM Program. The success of the SCM pilot in Maryland serves as a national model, providing insights for similar programs in other jurisdictions. It establishes a foundation for managing and optimizing EV charging programs, offering a framework that can be adapted for more complex implementations in the future. As EV adoption accelerates across the nation, managed charging programs like the SCM pilot will play a pivotal role in optimizing grid integration and ensuring sustainable, equitable access to clean transportation.

Opportunities for Further Research

Several opportunities for further research could help refine the design and implementation of managed charging programs nationwide. Future studies might explore:

- **Distribution Upgrade Cost Deferral:** Analyzing the cost deferral potential of charging optimization strategies that account for underlying non-EV baseload and aim to minimize peak load on a given asset. Understanding these impacts could help utilities defer or reduce costly distribution upgrades.
- **Incentive Structures for Participation:** Experimenting with incentive models to identify the minimum incentive value required to maximize enrollment and participation. Insights from this research would enable utilities to scale managed charging programs effectively while balancing participation targets and program costs.
- **Expanding EV Load Studies:** Including plug-in hybrid electric vehicles (PHEVs), fleet vehicles, and public charging in future EV load analyses to assess their collective impact on the grid. Understanding these dynamics could inform managed charging strategies that mitigate grid strain across all charging scenarios.
- **Comprehensive Baseload Analysis:** Shifting from a narrow focus on EV load impacts to a broader examination of total baseload compared to EV load. Accounting for all sources of electricity demand could lead to more effective managed charging strategies that integrate with renewable energy generation.
- **Quantifying Grid Benefits:** Defining the average value a managed charging participant provides to the grid. Establishing this metric could help utilities and policymakers assess the financial and operational benefits of managed charging at scale.
- **Platform Performance Testing:** Investigating the platform's functionality under various conditions to improve reliability and applicability across different use cases. Potential areas of exploration include:
  - Testing with different vehicle makes and models
  - Evaluating performance in multi-vehicle households
  - Assessing reliability in areas with poor cellular connectivity
  - Charging to different end states of charge (SOC) beyond 80%
  - Adjusting EV charge rates to determine optimal configurations
  - Conducting further negative Dynamic Price Signal (DPS) testing

Appendix A. Research-Based Recommendations for Program Design

In the early stages of this project, SEPA conducted desk research and interviewed utilities to gather managed charging program design data and recommendations. The information below summarizes the research and recommendations SEPA collected regarding program objectives, charging behavior, incentive design, program size, customer segment approaches, and regulatory considerations. It also outlines how Exelon applied these recommendations to their own managed charging program design. Other utilities who are seeking to build their own managed charging program can use this information to get started.

Program Objectives

Clearly defined program objectives serve as a north star for program design, implementation, and improvement, which is why it is important to identify them early on in the process. Program objectives outline which program elements to test, overall goals at the electric grid, utility, and customer levels, and how success will be measured.[15]

Program managers of the Exelon SCM program identified the following program objectives:

- Identify managed charging techniques that can be shared industry-wide (residential, commercial, public charging);
- Understand and reduce grid impacts of EV charging on the utility's distribution and transmission systems;
- Lessen customers' capital investment required to manage EV charging demand as EV ownership grows; and
- Identify potential cybersecurity risks and vulnerabilities of EVSEs and vehicle telematics software.

Charging Behavior

Baseline current charging behavior data, both at the feeder level and across a utility's service territory, is crucial to developing an effective managed charging program. EV drivers generally plug in their vehicles every few days to charge. The timing of these charging sessions varies; not all drivers plug in during peak periods.[16] By comparing current load profiles with desired grid conditions, a program manager can identify when and where load reductions need to occur and calculate a specific, quantifiable goal for the managed charging program. Next, the utility can choose a method to achieve that goal, whether through passive managed charging or active managed charging.

Then, the utility will identify which customer behaviors will meet the program goals and customer needs. Perhaps desired customer behavior entails charging during a general off-peak window or simply enrolling and giving the program permission to continuously control charging according to live grid conditions. Regardless, a properly designed managed charging program will not impact the driver's ability to use their car when they please.[17]

15 Smart Electric Power Alliance (October 2021). Managed Charging Incentive Design: A Guide to Utility Program Development.

16 Smart Electric Power Alliance (September 2024). The State of Managed Charging in 2024.

17 Smart Electric Power Alliance (October 2021). Managed Charging Incentive Design: A Guide to Utility Program Development.

Incentive Design

Oftentimes, utilities use incentives to draw customers to their managed charging program. The four types of incentives that programs most frequently offer include:

- Time-of-Use (TOU);
- EVSE Rebate;
- Enrollment; and
- Participation.

TOU incentives are the most common incentive across utilities due to their simplicity. Utility proposals to implement TOU incentives are palatable to regulators because they are non-invasive to customers and do not require utility control over charging. Additionally, they are easy to integrate into existing billing systems, making them an attractive and safe choice. One drawback of TOU incentives, however, is that they do not eliminate grid stress. They incentivize charging behavior that can create a secondary peak around midnight.[18]

Utilities provide customers with EVSE rebates for networked smart chargers in exchange for access to charging data and capabilities. This incentive type is less popular than TOU rates but is still leveraged by 64% of active managed charging programs. The median EVSE rebate is $600 for single-family homes, $4,000 for multi-unit dwellings, $4,000 per port at workplaces, and $4,900 per port at public charging sites. As the program size grows, issuing EVSE rebates becomes increasingly cost-prohibitive relative to the value of charging data and control. Instead, utilities might consider other methods for collecting data and controlling charging and focus primarily on marketing and customer education, as over-subsidization of EVSE may not be necessary to achieve desired program outcomes.[19]

Enrollment incentives draw customers to sign up for the managed charging program. About 32% of active managed charging programs offer an enrollment incentive, with values ranging from $25 to $450, with a median value of $125. It is implied that, in exchange for this one-time incentive, enrolled customers will participate in the managed charging program, whether that entails adhering to a charging schedule or relinquishing complete control of charging.

Utilities offer participation incentives in exchange for customers' continued cooperation with the program. Depending on the method of charge management, participation incentives may be issued following the customer's participation in an individual demand response event or issued monthly or annually in exchange for participating in multiple demand response events or cooperating with continuous curtailment. About 40% of active managed charging programs offer a monthly or annual incentive; this structure enables more proactive grid management through continuous managed charging and gives utility program managers the flexibility to increase or decrease the number of demand response events according to expected or actual grid conditions. Monthly or annual incentive structures typically allow customers to opt-out of participation a set number of times to increase flexibility. Research shows that utilities have been able to reach their enrollment goals using various combinations of incentive structures and values.[20]

Program Size & Customer Segment Approaches

Ideally, the targeted size of the program should be driven by projected grid needs—though this is not common. Typically, the approved budget or the number of customers willing to participate determines the program's size. There are several methods that utilities and their partners use to identify prospective program participants of various customer classes. In targeting residential customers, utilities use self-registration forms on their websites and review lists of customers that have previously participated in their other programs. Additionally, utilities partner with third parties to gather EV owner information within their service territories, and sometimes use a statistical technique called propensity modeling to predict the likelihood of EV ownership based on known customer characteristics.[21] WeaveGrid uses a proprietary machine learning algorithm to analyze AMI data from utility meters and determine which households are likely to have EVs. All of these approaches are effective ways to identify potential managed charging program participants and target marketing efforts.

18 Smart Electric Power Alliance (September 2024). The State of Managed Charging in 2024.

19 Smart Electric Power Alliance (October 2021). Managed Charging Incentive Design: A Guide to Utility Program Development.

20 Smart Electric Power Alliance (September 2024). The State of Managed Charging in 2024.

21 Smart Electric Power Alliance (October 2021). Managed Charging Incentive Design: A Guide to Utility Program Development.

Demonstration of Utility Smart Charge Management for Multiple Benefit Streams

When building a managed charging program that will operate at multi-unit dwellings (MUDs), workplaces, or public charging stations, utilities can leverage their account managers in identifying potential participants. These account managers can initiate conversations with their major customers, including local governments, schools, hotels, commercial businesses, and industrial businesses. Additionally, utilities can reach the property managers of sites of interest by connecting with multi-family property owner groups, real estate trade groups, and commercial real estate agents.[22]

Regulatory Considerations

Before implementing a new managed charging program, most utilities will need the approval of a public service commission, board of directors, city council, or other oversight body. Utilities can shape the managed charging program according to their regulators' preferences, which could be identified by examining the characteristics of similar customer programs that were approved versus those that were rejected. Providing information that demonstrates the long-term value of the program will give the regulators the context they need to approve the utility's request.[23]

These recommendations serve as an aggregation of best practices based on the real-world experience and data from utilities that have conducted their own managed charging pilots and programs. Other utilities that are seeking to design their managed charging programs may benefit from following these recommendations, though there is no one-size-fits-all solution for this type of program. In addition to these recommendations, program design should be informed based on a utility's unique customer base, applicable regulatory guidance, and preferred managed charging technologies and approaches.

22 Smart Electric Power Alliance (October 2021). [Managed Charging Incentive Design: A Guide to Utility Program Development.]

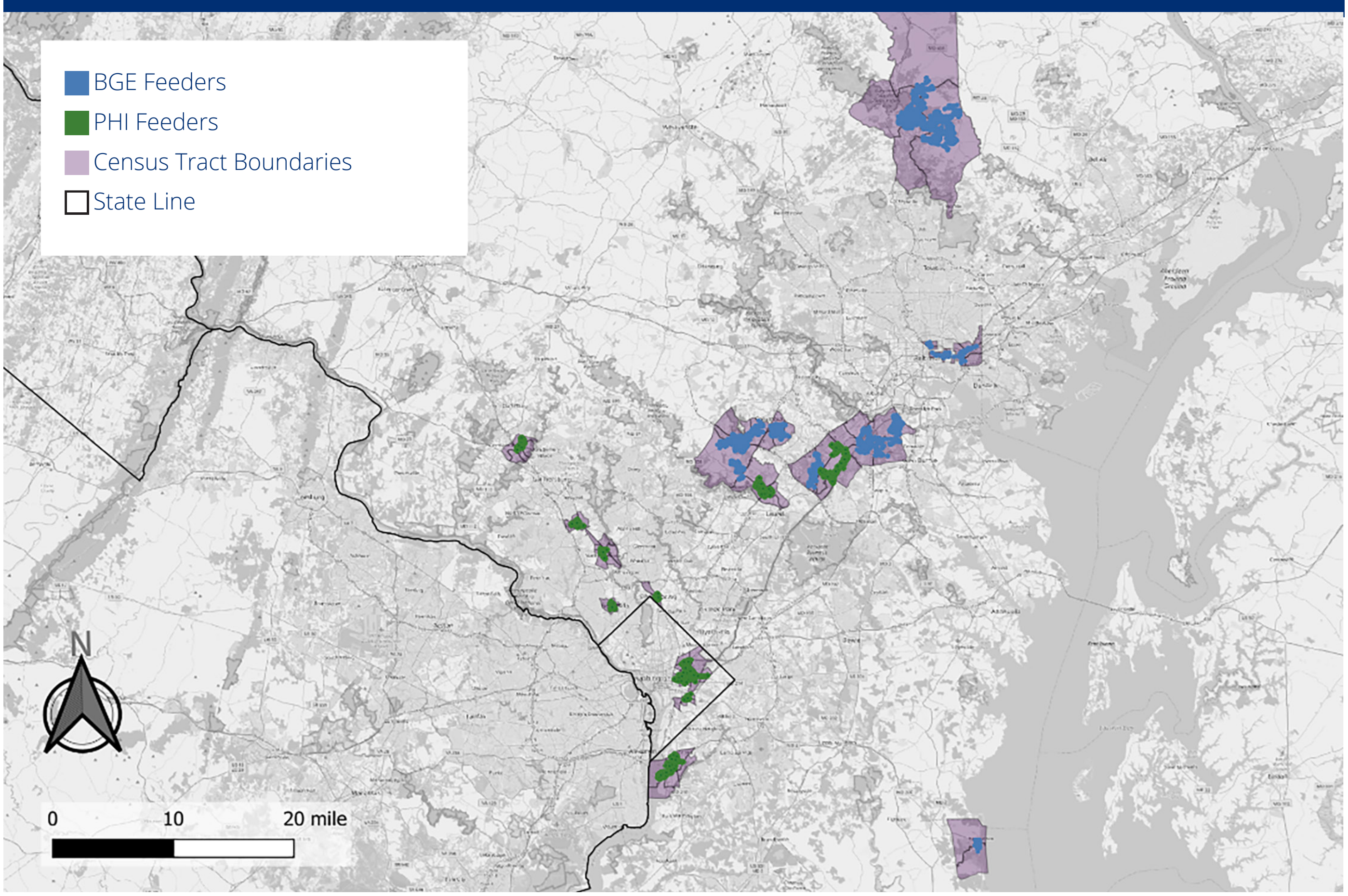
23 Ibid.

Appendix B. Challenges In the Simulation Process: Geospatial Incongruence of Utility and Demographic Data

The EV charging load from ATEAM simulation is generated at the census tract level, while the assets for a given feeder may span across multiple census tracts, and each census tract can have several feeders passing through it. This created a complex mapping challenge. First, the geographical coordinates of the assets needed to be converted from their original coordinate system to a common reference system, which allowed ANL to map the asset locations to the irregular polygon defined by census tract boundaries. Once the mapping was completed, ANL obtained a linkage between the distribution system assets and the corresponding census tracts.

The second challenge involved reconciling EV charging data at the census tract level with loading data at the individual buses within the distribution feeder. The analysis assumed that future EV loading would closely correlate with current loading patterns. For instance, a census tract with 500 houses would be more likely to have higher EV adoption and, consequently, a higher EV load than a tract with only 50 houses. Therefore, a weighted approach that used existing loading conditions to allocate EV load from the census tract level to specific points within the distribution feeder was used.

Figure 29. Geographic Location of Representative BGE and Pepco Feeders



Source: Excelon (2025).

Appendix C. Modeling Methodology for Grid Impact Assessment

To estimate the total upgrade cost for the entire network based on selected representative feeders, ANL conducted a network clustering analysis for both BGE and Pepco feeders (1,100 feeders for BGE and 700 for Pepco) to select additional representative feeders beyond the originally chosen 10 from each utility. In this approach, feeders were grouped into clusters based on their similarity. Feeders within each cluster shared similar characteristics and upgrade results, while differences in violations and upgrade needs existed across clusters. Therefore, representative feeders were selected from each cluster to represent the whole group. The analysis was performed on the selected feeders and then applied to all feeders within the same cluster. ANL employed the k-means methodology to group feeders based on several key features, including:

- Peak base load of the feeder
- Peak EV load
- Total transformer capacity
- Type of feeder (residential, industrial, commercial)
- Peak load of each type
- Count and total kVA of each phase type of transformer
- Feeder length

ANL identified five clusters for each utility. To represent each cluster, ANL selected 10 additional representative feeders. Using the results from these feeders, ANL developed a linear regression model to capture the relationship between feeder characteristics and upgrade costs. This model was then applied to estimate the upgrade cost for each feeder within the same cluster. By aggregating these estimates, ANL approximated the total upgrade cost for each cluster, ultimately providing an estimate for the entire distribution system.

This methodology significantly improved accuracy and reliability compared to traditional approaches, which often relied on synthetic feeder models and overlooked actual power flow within feeders. By incorporating real-world data and accounting for feeder-specific characteristics, this approach provided a more precise and realistic estimate of upgrade costs.

Appendix D. Feeder Upgrade Cost Comparison

The following approach was used to estimate total upgrade costs for BGE and Pepco feeders. The method for selecting these representative feeders is outlined in IV. Testing Methodology. Ten representative feeders were selected from each cluster for both utilities. Regression analysis was performed based on the results from these feeders to generalize the economic impact across the entire cluster.

For BGE, feeders were grouped into five clusters based on load type and EV adoption levels:

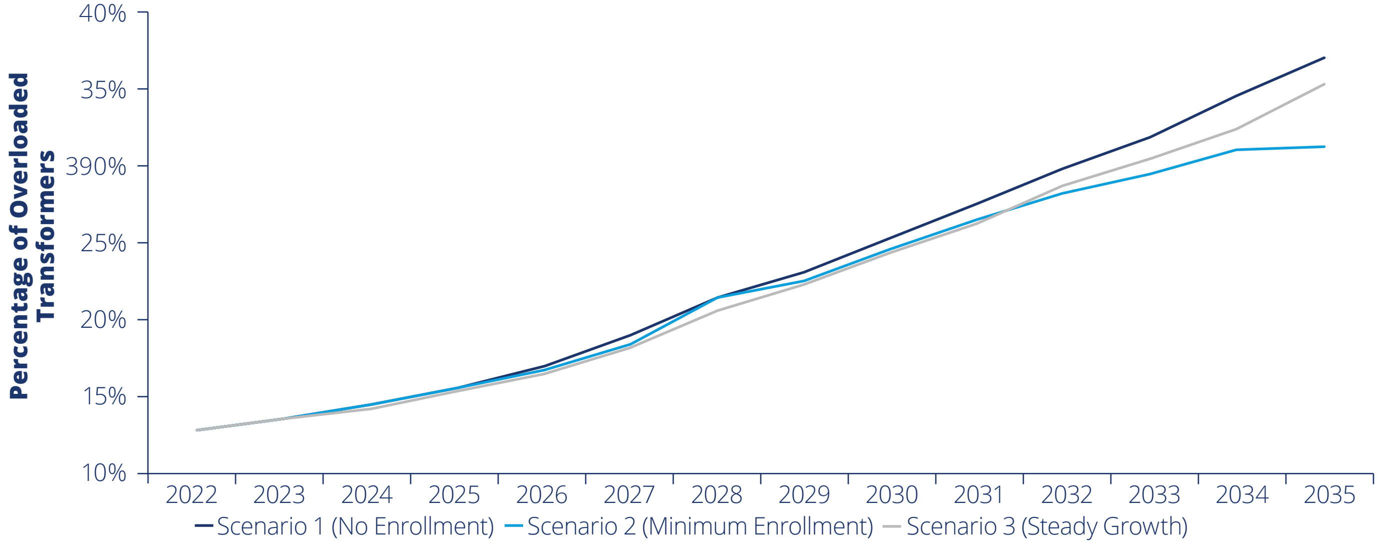
1. A balanced mix of residential and commercial loads with moderate EV adoption (301 feeders).
2. Industrial feeders with low EV adoption (248 feeders).
3. A mix of residential, commercial, and mixed-use loads with high EV adoption (230 feeders).
4. Residential and commercial feeders with very high EV adoption (519 feeders).
5. Moderate base and EV loads, balanced between commercial and mixed-use (194 feeders).

For Pepco, the clustering approach was similar:

1. A balanced mix of residential and commercial loads with moderate EV adoption (66 feeders).
2. Industrial feeders with low EV adoption (139 feeders).
3. A mix of residential, commercial, and mixed-use loads with high EV adoption (130 feeders).
4. Residential and commercial feeders with very high EV adoption (141 feeders).
5. Moderate base and EV loads, balanced between commercial and mixed-use (105 feeders).

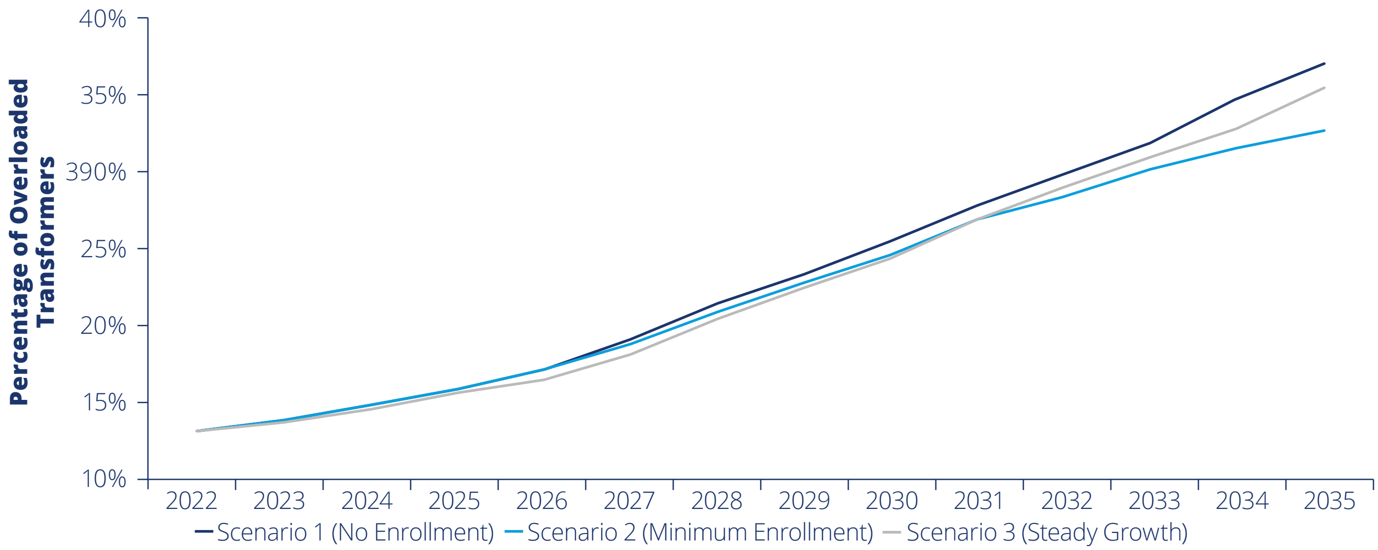
Appendix E. Modeling Results

Figure 30. Summary of Overloaded Transformers for the Study Period by Scenario for BGE (Load Balancing)



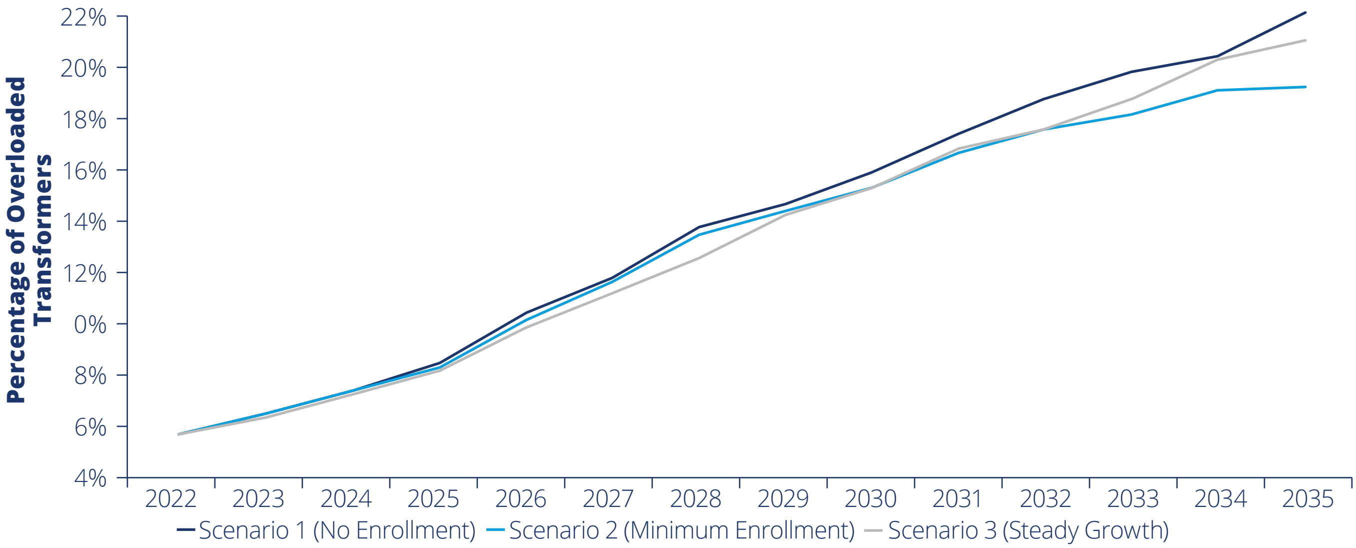
Source: Argonne National Laboratory (2025). Recreated by SEPA.

Figure 31. Summary of Overloaded Transformers for the Study Period by Scenario for BGE (Time-of-Use)



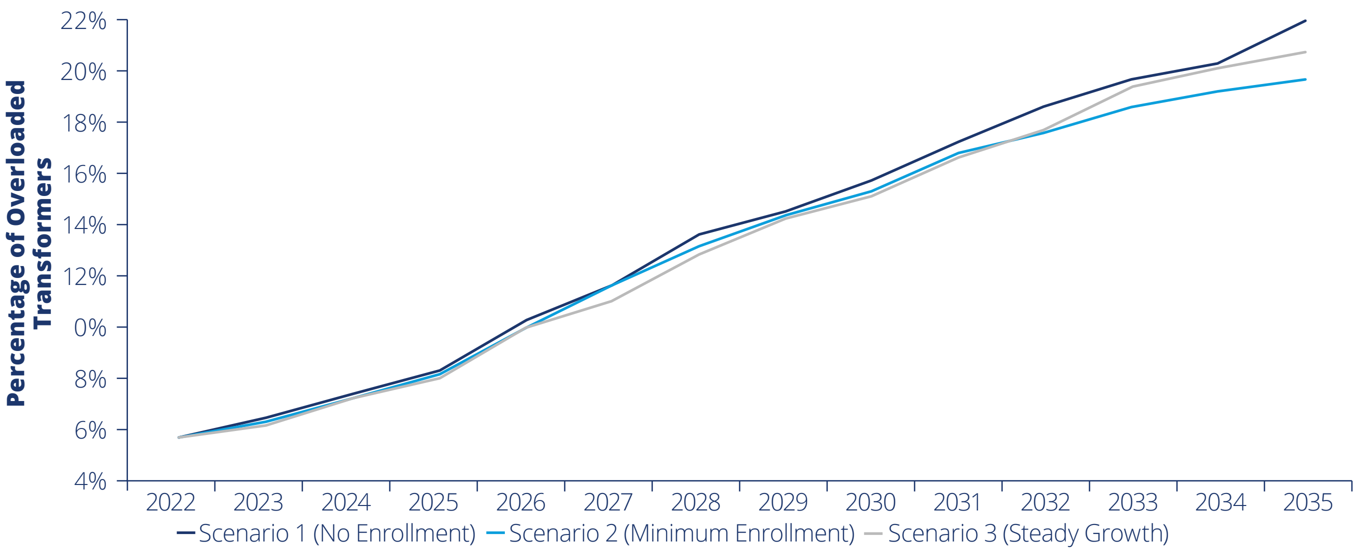
Source: Argonne National Laboratory (2025). Recreated by SEPA.

Figure 32. Summary of Overloaded Transformers for the Study Period by Scenario for Pepco (Load Balancing)



Source: Argonne National Laboratory (2025). Recreated by SEPA.

Figure 33. Summary of Overloaded Transformers for the Study Period by Scenario for Pepco (Time-of-Use)



Source: Argonne National Laboratory (2025). Recreated by SEPA.

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