Unlocking the Value of Flexible DERs

The Benefits of Optimizing EV Charging for Systemwide and Distribution Grid-Edge Constraints

Prepared for Rhythmos.io

Energy+Environmental Economics

Energy and Environmental Economics (E3) is an analytically driven consulting firm focused on the transition to clean energy resources with offices in San Francisco, Boston, New York, Calgary, and Denver. Founded in 1989, E3 delivers analysis that is widely utilized by governments, utilities, regulators, and developers across North America. E3 completes roughly 350 projects per year, all exclusively related to the clean energy transition, across our three practice areas: Climate Pathways and Electrification, Integrated System Planning, and Asset Valuation, Transmission, and Markets. The diversity of our clients – in their questions, perspectives, and concerns – has provided us with the breadth of experience needed to understand all facets of the energy industry. We have leveraged this experience and garnered a reputation for rigorous, unbiased technical analysis and strong, actionable strategic advice.

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Acronym Definitions

Acronym	Definition
ACC	Avoided Cost Calculator
DER	Distributed Energy Resource
EV	Electric Vehicle
SCE	Southern California Edison
TOU	Time-of-Use
TRC	Total Resource Cost
VMT	Vehicle Miles Traveled

Executive Summary

Distributed Energy Resources (DERs) are rapidly transforming how electricity customers interact with the electric grid and their energy providers. DERs like rooftop solar and batteries allow customers to generate and store energy for their own use or export, while other DERs, including smart thermostats and electric vehicles (EVs), let customers or utilities control the timing and magnitude of energy use, or load. DERs offer opportunities to advance decarbonization goals and have the potential to provide valuable grid services, but they also present a challenge to grid operations if utilities are not prepared for their integration.

Historically, utility valuation of and interaction with DERs has focused on their impact on the electric system as a whole. However, planning for DERs may in fact be most difficult at the distribution grid edge, where electric utilities will be challenged to predict and quickly recognize where DERs come online and upgrade their equipment to accommodate them. Enabling utilities to evaluate the impact of DERs at the system level and at the distribution grid edge will bring greater potential for avoiding costs and providing benefits. This paper highlights ways in which new management techniques of load-increasing DERs, specifically of EVs, can reduce utility costs both for the broader electrical grid and in targeted, high priority locations. Such management will facilitate a smoother integration of low-carbon technologies and help utilities to maintain both the reliability and affordability of their systems.

EVs are an especially rapidly growing segment of DERs which increase overall electricity demand and will present a significant need for localized distribution upgrades. With 3.5 million light-duty EVs on U.S. roads at the end of 2023[1], electric utilities are already beginning to recognize the challenge of serving new loads from EV charging. As EV adoption accelerates, capacity constraints on distribution infrastructure will become acute, risking infrastructure reliability and requiring costly distribution infrastructure upgrades that a 2021 study estimates could range from $7 billion to $47 billion by 2035 in the U.S. under a high electrification scenario.[2]

To understand the potential cost impacts to utilities and the opportunities for savings, we evaluate the costs of EV adoption under three EV charging behaviors or strategies—unmanaged charging, passive managed charging, and optimized charging. To provide a range of impacts, we examine both the systemwide costs and potential benefits of managing EV load in Southern California Edison's (SCE) service territory as well as the localized distribution impacts of EVs in a confidential Southeast municipal utility territory. In a case study, we assess the results of applying Rhythmos.io's Cadency EdgeAI℠ platform to optimize EV charging around minimizing transformer overloads and avoiding local distribution upgrades on the Southeastern utility's system.

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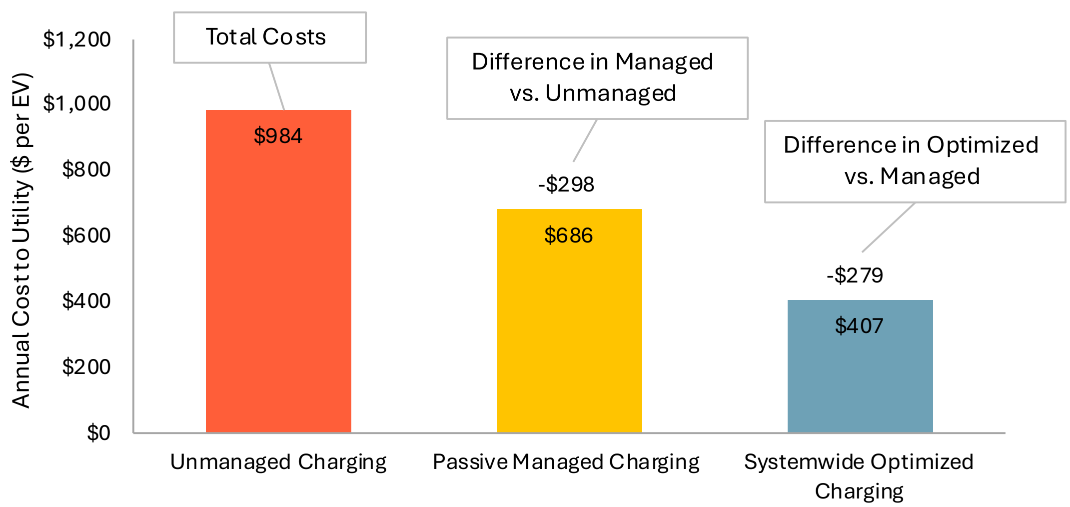
[1] U.S. Department of Energy (U.S. DOE) Alternative Fuels Data Center (2023). https://afdc.energy.gov/vehicle-registration.

[2] Energy & Environmental Economics, GridLab, Goldman School of Public Policy (2021). Distribution Grid Cost Impacts Driven by Transportation Electrification. https://www.ethree.com/wp-content/uploads/2021/06/GridLab_2035-Transportation-Dist-Cost.pdf.

We use California's Avoided Cost Calculator to estimate the total system costs to SCE of charging EVs under each charging scenario. By comparing these costs, we are able to determine the potential benefits of each form of charge management. We find that passive managed charging reduces utility costs by approximately 30% compared to unmanaged charging, while optimizing charging around systemwide costs can reduce those costs by a further 30% of the total, creating up to 60% in savings compared to an unmanaged charging scenario. Results of this analysis are summarized in Figure 1. While recognizing that perfect insight into real-time system avoided costs does not currently exist, these results provide a reasonable estimate of the high-end potential value of different charging strategies at the systemwide level.

Figure 1. EV Charging Management Strategy Impacts on SCE's Costs



To understand the localized value of charging strategies, which cannot be captured with a purely systemwide view, we partnered with Rhythmos.io to analyze the impact of EV charging on an individual distribution transformer for a municipal utility in the Southeastern U.S. For this case study, we considered historical loads on the transformer and how the transformer would be impacted by the addition of two new EVs with unmanaged charging, passively managed charging, and Rhythmos.io's grid-edge optimized charging, which optimizes for the transformer's specific conditions. We examined how managing or optimizing charging can avoid expenses to the utility for upgrading the given transformer.

For this comparison, we first apply an overload threshold approach, which considers whether additional EV load under each charging scenario will trigger a transformer overload, and what the benefit of avoiding or deferring such an overload would be. With this approach, we find that passively managed charging would have no effect under the given conditions, but that an optimized charging strategy would avoid $1,188 in upgrade costs for a 25kVa single-phase transformer, equivalent to $107 in savings for each year that the upgrade could be delayed (Table 1).

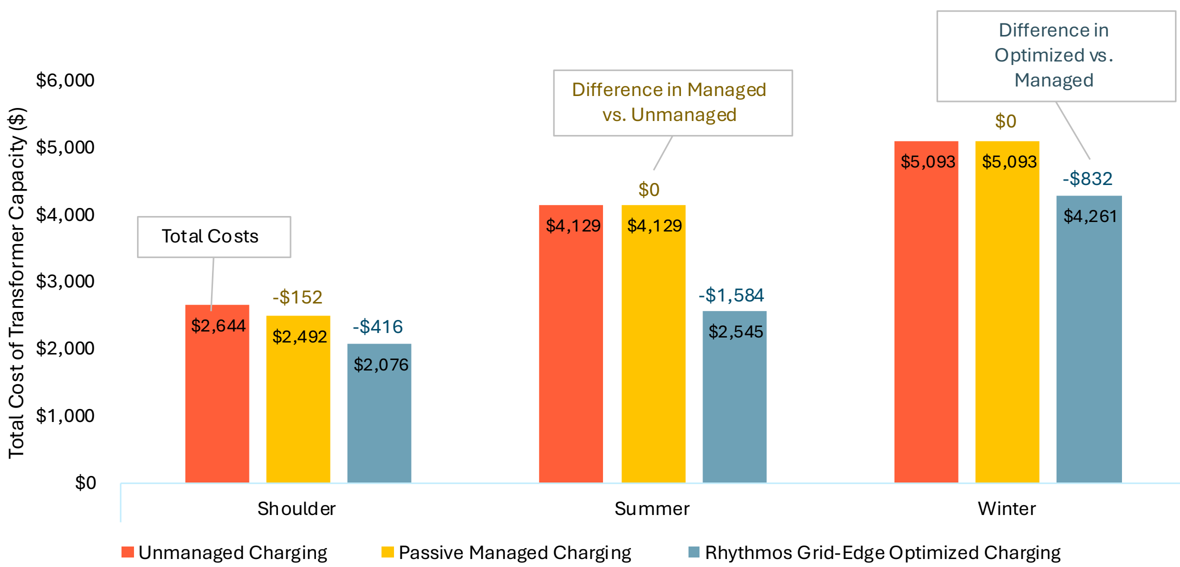
Table 1. Overload Threshold Distribution Transformer Upgrade Costs

Charging Scenario	Total Transformer Upgrade Cost	Benefit Relative to Unmanaged Charging	Annual Deferral Benefit*
Unmanaged	$2,193	$0	$0 / yr
Passive Managed	$2,193	$0	$0 / yr
Optimized	$1,005	$1,188	$107 / yr

**Simple annualization applying a 9.0% Real Economic Carrying Charge*

These results are only applicable for the transformer studied under the specific historical conditions. To estimate the localized distribution benefit as an expected average for similar transformers but under a wider range of existing conditions, we then approach the scenario based on an average $-per-kW cost of transformer upgrades. Here, we see upgrade costs increase as seasonal peak load rises. Figure 2 illustrates how Rhythmos.io's grid-edge optimization strategy results in the lowest transformer capacity costs across all seasons, providing up to $140 in annual savings per transformer based on summer season loads and $75 in annual savings under the winter peak conditions examined when applying a 9% real economic carrying charge.

Figure 2. Total Transformer Capacity Cost by Load Profile



Our study demonstrates the moderate benefits and cost reductions associated with passive managed EV charging and the even greater value that utilities can achieve from various optimized charging strategies. It is also important to note that the systemwide and grid-edge optimization strategies can be applied in tandem to provide even greater cost reductions. While the benefits are not fully incremental, grid-edge optimization strategies can capture the entirety of the localized distribution benefits by optimizing around just a small percentage of hours in locally constrained areas. Systemwide optimization strategies can take over in the remaining hours and lower-value locations to adjust charging based on price signals the utility has available. DER optimization platforms, like Rhythmos.io Cadency EdgeAI℠, enable utilities to better understand when and where new loads and DERs appear as well as the grid-edge conditions on their local system, so that they can optimize against localized distribution constraints with the potential to avoid upgrade costs. As EV adoption continues to grow, managed and optimized charging strategies will provide increasing value to mitigate grid impacts at both a systemwide and distribution level.

Introduction

Distributed Energy Resources (DERs) are small-scale, distribution-connected energy resources that are rapidly transforming how energy is generated and consumed. Rooftop solar, customer-sited storage, electric vehicles (EVs), and demand response are just some of the DERs that customers are adopting. DERs have the potential to provide valuable services to the electric grid and to help meet decarbonization goals, but they also pose challenges to the power grid if there is insufficient preparation for widespread integration.

EVs make up one of the fastest-growing categories of DER adoption. By the end of 2023, there were already 3.5 million light-duty EVs on U.S. roads, and millions more EV sales are expected by 2035.[3] As drivers fuel their cars with electricity instead of gas, they can save money and reduce greenhouse gas emissions, but they also place stress on the electricity grid by adding new load. To accommodate the significant new load growth from EV charging, utilities will need to supply more electricity and address capacity constraints on distribution infrastructure. A 2021 study on the distribution grid cost impacts of transportation electrification finds that under high electrification scenarios distribution costs to accommodate EV load could range from $7 billion to $47 billion in the U.S. by 2035.[4]

Adding to the challenge, utilities frequently are unaware of where and when EVs are coming online and do not always have the staff and equipment available to make immediate upgrades. This means that the difficulty of maintaining reliable services takes on additional dimensions of data, personnel, and supply chain needs on top of the extraordinary cost of infrastructure upgrades. Fortunately, there are avenues to address this challenge which can increase utility visibility into their system while also reducing costs and enabling more sustainable and accelerated EV adoption.

Optimized EV charging leverages data analytics software to shift the schedule of EV charging to times when the electric grid is less constrained. This benefits the grid by reducing load during periods of peak demand or shifting charging to when there is excess energy and capacity available to avoid the need for new generation and system upgrades. At the same time, certain optimization technologies can be used to monitor and to indicate to utilities when equipment is strained or when new EV loads are added, signaling where there may be a need for more careful management of charging or for potential future upgrades. Optimized charging can provide significant cost savings to electric utilities, who may in turn share these savings with EV owners, creating benefits for the utility, electric customers, and EV drivers.

[3] U.S. Department of Energy (U.S. DOE) Alternative Fuels Data Center (2023). https://afdc.energy.gov/vehicle-registration.

[4] Energy & Environmental Economics, GridLab, Goldman School of Public Policy (2021). Distribution Grid Cost Impacts Driven by Transportation Electrification. https://www.ethree.com/wp-content/uploads/2021/06/GridLab_2035-Transportation-Dist-Cost.pdf.

Distributed Energy Resources

DERs encompass a broad set of technologies that interact with the distribution system, including rooftop solar, customer-sited storage, demand response, and electrification technologies, such as EVs. DERs can interact with the grid in three primary ways: 1) reducing load, 2) increasing load, or 3) shifting load. Many DERs interact with the grid in multiple ways—they do not have a singular effect. For example, EV charging increases load overall but can also be controlled to shift load to other hours based on the grid needs. Each interactive effect from DERs offers unique benefits and challenges as DERs are integrated with the grid.

Load Reducing Impacts of DERs

Many DERs are designed to reduce net load on the electricity grid. DERs providing generation, like rooftop solar, can reduce a customer's demand for grid-supplied electricity and also supply excess energy back to the grid. Energy efficiency and demand response programs may utilize DERs and are designed to reduce a customer's overall electricity use, especially during critical periods of high demand. Reduced electricity demand translates to lower costs for energy and the generation capacity needed to supply electricity during those peak periods.

However, these DERs also create integration challenges. DER generation and demand response are often less reliable than utility-scale resources and cannot always be dispatched when needed. These uncertainties reduce DERs' benefits to the system in their ability to provide energy or reduce system load. Further, DERs can require additional distribution infrastructure to enable their interconnection and to accommodate for local operational complexities, increasing system costs.

Load Increasing Impacts of DERs

With the transition toward electrification, including the adoption of EVs and space and water heat pumps, more DERs are increasing system load. These load-increasing DERs are good for the climate as they reduce greenhouse gases and other air pollutants compared to the emissions generated by their fossil-fueled counterparts. However, in regions where DERs are adopted quickly, electric grids must accommodate substantial increases in load on their systems—and quickly. Building out the grid infrastructure to meet this growing load can prove difficult and costly. It can be difficult for grid planners to predict the location, magnitude, and usage patterns of DER adoption, especially since planners often lack visibility into the available capacity—or lack thereof—on the electric distribution system. In some cases, DERs may increase loads when either the local distribution network or the broader electric grid is already experiencing peak demand. Accommodating these DERs requires investments in new infrastructure or generation capacity. At other times, new DER demand may cause shifts in the load shape, creating new peak periods which require utilities to adjust planning and operations.

DER Load Shifting and EV Charging

As DER-integration technology advances, there is a growing opportunity to leverage load-shifting capabilities of DERs. DERs like EVs and heat pumps naturally increase total load on the system, but the timing of that load may be flexible and controlled to minimize impacts. Strategies to take advantage of load shifting are similar to and include many traditional demand-response programs where utilities offer incentives to customers to reduce or shift their energy usage away from peak hours. EV charging, for example, can be managed to shift the charging load from the evening when drivers arrive home to the middle of the night when there is expected to be less demand from other end-uses. Utility pricing signals and optimization technology can further enable dynamic load shifting to align customer end-use demand with times when the grid is under less strain, either across the entire system or at a local distribution level.

White Paper Purpose

The goal of this white paper is to assess the costs and benefits of managing DER loads, and specifically to compare the different impacts of unmanaged, passive managed, and actively managed or optimized EV charging strategies. We will demonstrate the value that can be unlocked with EV charging management at a systemwide level to alleviate grid impacts and at a localized distribution level to mitigate costly transformer overloads.

We estimate the benefits to utilities and their ratepayers by analyzing the costs to the electricity grid that can be avoided by shifting EV load with strategies to manage charging. We conduct two assessments: First, we evaluate the *system average* hourly avoided costs from shifting EV load in Southern California Edison's (SCE) service territory to measure the magnitude of systemwide impacts. Second, we assess the *localized distribution* benefit of reducing EV load at the transformer level for a municipal utility in the Southeastern U.S. to demonstrate value that is not captured at a system level but rather at the localized distribution transformer level. In a case study, we evaluate Rhythmos.io's Cadency EdgeAI^{SM} platform's EV charging optimization to minimize transformer overloads and avoid or defer distribution upgrades on the municipal utility's system.

Rhythmos.io

"The Rhythmos.io Cadency EdgeAI^{SM} platform creates transparency for utilities, fleet managers, EV manufacturers, and service providers to uncover and understand the hidden effects of accelerating electrification, especially EV load, on the distribution grid edge at a granular level. Using a multi-disciplinary analytical methodology combining machine learning, power systems engineering, and data analytics, Cadency EdgeAI^{SM} enables distribution system optimized EV charging and other behind-the-meter DER optimization while simultaneously providing critical asset management for utilities and EV fleets."

- *Rhythmos.io value proposition*

Methodology

We analyze the potential systemwide avoided costs from EV charging strategies in SCE's service territory in California and the potential localized distribution avoided costs in a confidential Southeastern municipal utility's territory. We consider three charging strategies—unmanaged, managed, and optimized—that determine which hours an EV will charge. SCE and the municipal utility offer an informative comparison of the potential value EV charging management can provide to the grid due to their geographic and policy differences and because of differences in data availability or a codified structure to quantify the benefits.

EV Charging Strategies

As EV adoption accelerates, the additional load to charge EVs creates stress on grid operations. EV charging strategies can be employed to shift the load to periods of the day that reduce impact to the grid, such as by reducing load during peak periods of demand or by planning charging during high renewable generation hours that would otherwise result in curtailment. We consider three primary EV charging strategies in our assessment and describe Rhythmos.io's optimization platform in the following sections.

Unmanaged Charging

Unmanaged charging describes when an EV begins charging as soon as it is plugged into a charger without considering impacts to the grid or impacts to the customer's electricity bill. At an aggregate level, unmanaged charging can result in large load increases at times with higher energy and generation capacity prices. For example, many EV drivers come home around 5 or 6pm when the sun is going down and solar generation is declining and plug in their EVs to start charging immediately. At the same time, electricity demand is increasing across the grid as residents begin their end-of-day routines—making dinner, turning on home heating or air conditioning, and using other appliances. This creates an imbalance between supply and demand, especially in regions with a reliance on renewables. Unmanaged EV charging is ambivalent to this combination of increasing load and declining renewable generation and the resulting pressure on the electric system.

Passive Managed Charging

Managed charging broadly refers to strategies that incentivize EV charging during hours that are less costly to the grid, such as by avoiding charging during peak demand hours. Managed charging is most frequently achieved through Time-of-Use (TOU) electricity rates, which incentivize drivers to schedule their charging during certain hours of the day by offering lower rates during those hours. This is referred to as passive managed charging because, once the vehicle is plugged in and scheduled to charge, there is no further interaction—the vehicle will simply charge at maximum capacity from whenever its schedule starts until it is full. In addition, TOU rate schedules are often consistent year-round, or with minor variation between seasons or weekdays versus weekends.

These rates are designed to reflect hours when utilities are expecting that on an average systemwide level there will be a lesser impact on the grid.

The extent to which TOU rates actually minimize grid impacts depends on the rate incentive level, how well the TOU hours match real-time conditions, and other factors. Due to the lack of granularity in most TOU rate structures and the fact that they may only be updated annually or on a multi-year basis, these rates may fall out of alignment with system needs. Furthermore, TOU rates have yet to be widely adopted by utilities, leaving significant opportunity to maximize the benefits from passive managed charging.

Optimized Charging

Optimized charging, sometimes also known as active managed charging, refers to more advanced charging strategies that can charge an EV based on specific control signals and minimize grid costs or strain while still meeting the EV driver's needs. Optimized charging relies on specialized data analytics and software to dynamically adjust vehicle charging around real-time or statistically significant historical system conditions. Optimized management can support grid operations by shifting EV load based on a range of factors, such as available generation or transformer loads. EV optimized charging expands on the capabilities of traditional demand response programs by offering these capabilities to new customer segments and providing load shifting benefits in real-time. Optimized EV charging programs may also aggregate EV data and details on system load to provide more certainty and visibility for grid operators.

Optimized charging solutions may also provide utilities with another way to engage their customers under positive circumstances, increasing customer touchpoints where traditionally utilities may only interact with customers when starting or stopping service or if something goes wrong. Utilities can proactively reach out to customers about the opportunity to save money and pursue continual engagement by notifying them of their savings and illustrating their resulting charging patterns through mobile applications or other interfaces. Even better, optimized charging can be designed to require little to no effort or behavioral change from the customer, making it a painless experience from which the customer only sees the benefits.

With optimized EV charging, there are opportunities to benefit from multiple value streams. For instance, EV charging can be optimized for systemwide conditions like energy prices and generation capacity costs, or the availability of renewable energy. Alternatively, electric grid operators may prefer to optimize around localized conditions, like available transformer capacity. The effective capacity available at a transformer is limited by the transformer's power rating and risks premature asset failure due to the unanticipated and recurring added load from EVs. Optimization for local grid conditions, therefore, schedules charging based on these physical constraints instead of generalized price signals. This requires a great deal of precision but can allow utilities to avoid costly upgrades even by shifting load in only a small number of hours and in specific high need locations. Because of this concentrated impact, it may be possible to unlock even further value if optimization strategies for systemwide and localized conditions are combined.

Rhythmos.io Grid-Edge Optimized Charging

Rhythmos.io Cadency EdgeAI℠ is a DER optimization platform that optimizes EV charging against localized, distribution grid-edge conditions at each service transformer. The charging strategy executes at every grid-edge asset where EV charging interfaces with utility infrastructure, without requiring direct utility control of customers' charging and ensuring that vehicles are charged according to the EV driver's preferences. Additionally, Rhythmos.io's platform provides visibility of grid-edge EV charging load on each service transformer, providing grid operators with critical information and a greater degree of certainty to support infrastructure planning.

Utility Service Territories for Benefits Analysis

The selected utility service territories provide a comparison of how avoided costs may be valued by different types of utilities and in different parts of the country.

SCE is an investor-owned utility that serves 15 million people across central and coastal Southern California. Its service area spans more than 180 cities and 15 counties. California has some of the most progressive clean energy goals in the country, requiring SCE to provide 100% carbon-free electricity by 2045. Compared to other states, California has high electricity system costs, operates a large wholesale electricity market, and values the system avoided costs to evaluate the benefits of DERs and utility programs.

Rhythmos.io partnered with a municipal utility to demonstrate the local distribution benefits enabled by optimized charging. The municipal utility provides electricity service to a much smaller territory and customer base of approximately 500,000 customers. The utility is located in the Southeastern U.S., which does not have a regional wholesale electricity market from which to purchase electricity. The municipal utility is representative of electric utilities in the more rural parts of the eastern U.S with lower electricity costs.

Evaluating benefits for SCE and the Southeastern municipal utility provides a distinct comparison for the value that DERs can provide in jurisdictions across the U.S. By looking at systemwide avoided costs in SCE territory, we can understand the potential for high-cost savings for some of the largest utilities in densely populated regions, whereas by analyzing the localized distribution avoided costs in the municipal utility's territory, we can demonstrate how utilities with less formalized valuation mechanisms can still recognize clear benefits to their systems from DERs. Understanding the systemwide or localized value of DERs can help utilities prepare for DER integration and evaluate programs and technologies that may mitigate their cost impacts.

Evaluation of DER Value using Avoided Costs in SCE's Service Territory

When assessing the benefits of utility programs or DERs to the electric grid and society, utilities and public entities often rely on a set of metrics known as avoided costs. Avoided costs refer to the incremental costs incurred by the utility to supply additional load and which may be avoided in part or in full if that load is shifted, reduced, or met by some other source. In codified avoided cost calculations, such as California's Avoided Cost Calculator (ACC), avoided costs estimate the time-specific marginal costs of providing electricity service at a system-level, and consider multiple cost components.[5] Table 2 defines some of the major avoided cost components that are considered in this paper. Avoided costs can be calculated for all electricity systems, though the magnitude and timing are specific to each system and different avoided cost components may be more or less relevant to different DERs or programs.

Table 2. Major Electricity Avoided Cost Components

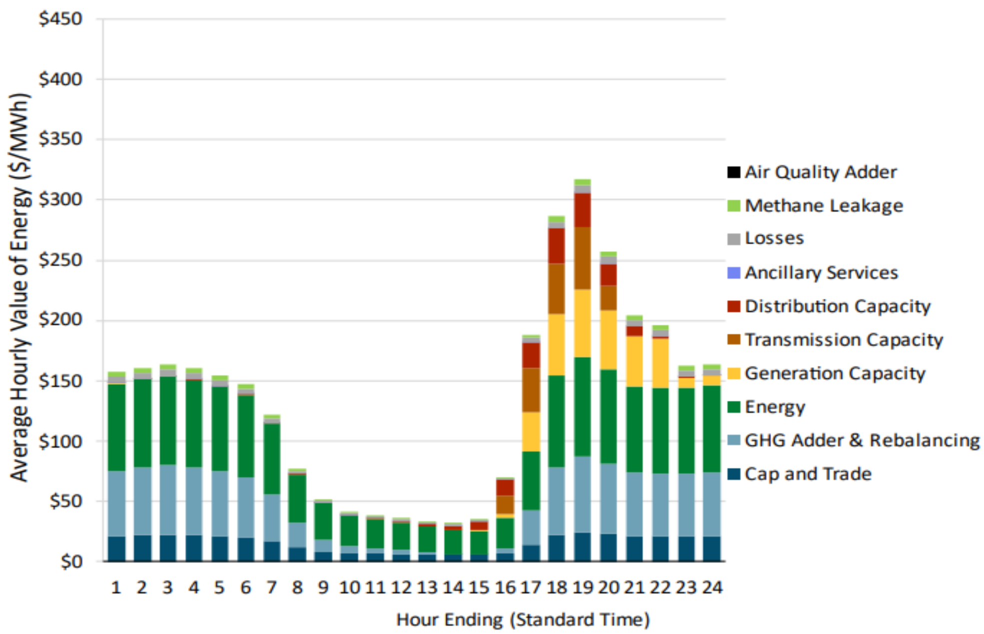
Avoided Cost Component	Definition
Energy	The avoided cost of purchasing an additional megawatt hour of energy and ancillary services to meet system load.
GHG	The avoided incremental cost to supply-side resources needed to reduce emissions by one metric ton. GHG costs are costs to society but can also be accrued directly to utilities and ratepayers via cap and trade or carbon penalties.
Generation Capacity	The avoided cost of procuring one additional megawatt of generation capacity to meet a grid's reliability requirements.
Transmission Capacity	The avoided cost of investments to upgrade transmission capacity resulting from changes to system peak loads.
Distribution Capacity	The avoided cost of investments to upgrade distribution capacity resulting from changes to distribution-level peak loads.
Transmission & Distribution Losses	The difference between the electricity generated and the electricity eventually distributed to consumers.

In our first assessment to evaluate the benefits of EV charging strategies in SCE's territory, we rely on the 2024 update to the California Avoided Cost Calculator. The ACC calculates hourly, $/kWh system-level costs of providing electric service to customers in each climate zone for California's largest utilities. This tool is used by California utilities and agencies for evaluating energy efficiency programs and DERs. As such, it provides an extremely useful and relevant framework for estimating the total system costs of EV charging and determining the avoided cost or benefits of both passive managed and optimized charging strategies. For this analysis, we use the ACC results for SCE Climate Zone 10, with a 2024 start year and 20-year levelization period. We include the total levelized value from all components tied to the Total Resource Cost (TRC) test, which includes additional

[5] California Public Utilities Commission and Energy and Environmental Economics. (2024). California Avoided Cost Calculator Documentation, https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/demand-side-management/acc-models-latest-version/updated-2024-acc-documentation-v1b.pdf

avoided costs beyond those described in Table 2.[6] These hourly $/kWh values depicted in Figure 3 also provide a price signal basis to inform the optimized charging strategy and subsequent load profile.

Figure 3. 2024 California Avoided Cost Calculator - Average Hourly Values



Load Profiles in SCE's Territory

To calculate total system costs for each charging scenario, the ACC outputs are multiplied by the hourly load profile of the given charging scenario. This study follows simple heuristics to generate load profiles for the unmanaged and passive managed charging scenarios. In the unmanaged scenario, a driver is presumed to be able to charge their EV overnight at their home between the hours of 6pm and 7am and will start charging as soon as that window begins until the EV is fully charged. Driving and charging parameters for a light duty EV in California are used to determine the average time to full charge and are displayed in Table 3.

[6] The California Avoided Cost Calculator also includes avoided cost streams for California's Cap and Trade program, ancillary services, transmission and distribution system losses, methane leakage, and air quality.

Table 3. SCE Vehicle and Charging Assumptions

Assumption	Value	Units	Notes
Annual Vehicle Miles Traveled (VMT)	9670	*mi*	*NHTS 2017 California VMT*[7]
Battery Efficiency	0.35	*kWh/mi*	*Mid-range LDV assumption*
Charging Losses	10%	*%*	*Mid-range loss assumption*
Average Daily Charge	*10.30*	*kWh*	*VMT / 365 days * Battery Efficiency / (1 - Losses)*
Charger Capacity	7.7	*kW*	*L2 home charger*

For the passive managed charging scenario, the same base parameters apply, except that we model the driver charging according to the schedule of SCE's current managed charging program with TOU rates. Under SCE's TOU-D-Prime rates, EVs can charge at lower prices during off-peak hours beginning at 9pm, and lasting until 4pm, year-round for all days of the week. The winter months have an additional super off-peak period from 8am-4pm with a slightly lower rate, though for this analysis the EV was assumed not to be at home to charge during those hours. As a result, the passive managed charging pattern was consistent throughout the year, with charging starting at 9pm with the lower off-peak rates and continuing until the vehicle is fully charged.

Finally, the optimized charging strategy modeled for SCE optimizes for the system average hourly avoided costs and assumes perfect insight into those costs within a single overnight charging period. Like the unmanaged or passive managed scenarios, the vehicle's charging need is set by its state of charge when the driver arrives home at 6pm. Next, the model checks whether the vehicle is home and available to charge for each of the following 24 hours. The hours when the vehicle is available to charge are ranked from lowest to highest according to their avoided cost signal, and the vehicle is set to charge at the maximum charger capacity during those lowest cost hours. Given that the vehicle needs to charge for one full and one partial hour, the full hour of charging is modeled to occur in the lowest cost hour and the partial hour of charging occurs during the second-lowest cost hour.

After generating load profiles for each scenario, these profiles are multiplied by the hourly avoided costs for SCE to calculate a systemwide cost associated with each charging strategy. The unmanaged scenario provides a baseline against which to compare the benefits, or costs avoided, from pursuing passive managed or optimized charging.

It is important to note that in a real-world scenario, perfect insight into electricity system costs is not available. However, within the timeframe of a 24-hour forward-looking period, a forecast of certain cost components such as relative energy prices and renewable generation constraints may be fairly reliable. Similarly, the simple heuristics for charging availability, need, and responsiveness to price signals will not fully reflect actual, dynamic driver needs and behaviors. This analysis is therefore

[7] Federal Highway Administration. (2017). National Household Travel Survey, Average Annual Vehicle Miles Per Vehicle: Household State: California. https://nhts.ornl.gov/

expected to indicate a reasonable estimate of the high-end potential value of different charging strategies centered on systemwide avoided costs.

Evaluation of Localized Distribution Benefits in a Municipal Utility

To support a broad application across programs or an entire customer base, codified avoided cost structures tend to focus on an average value across the relevant geography or utility network. This is useful for our systemwide optimization analysis because we can determine the general expected values described. However, avoided costs can also be measured on a more location-specific basis. While terminology in this space can be fluid, these localized avoided costs are sometimes referred to as benefits available at the 'grid edge'.[8] The grid edge describes the point where electric customers and customer-owned DERs interface with the utility's distribution grid. Just one step beyond the customer-utility distribution interface is the utility distribution infrastructure, including distribution substations, feeders, and the individual transformers whose capacity needs may be dictated by just a handful of customers. Within this paper, we refer to the avoided costs or benefits that can be found at this level as localized distribution benefits.

Distribution capacity avoided costs are already a component of some codified avoided cost structures, but they are typically averaged at a system level along with the other components under a given structure. This means that it is not always possible to know if DERs connecting at a specific location are actually providing those particular benefits—whether their value may be lesser or greater than what the systemwide estimates indicate. In this study, E3 and Rhythmos.io have partnered to examine a specific use case, relying on transformer-specific utility data from a municipal utility in the Southeastern U.S. and Rhythmos.io's utility grid-edge analytics platform to simulate the expected impact of adding EVs to a transformer under different charging management scenarios.

The municipal utility in whose territory the case study is sited does not have a codified structure for the full range of avoided costs for valuing DERs. Therefore, while charging management may provide additional benefits in terms of avoided energy, generation, or transmission capacity costs, Rhythmos.io's grid-edge optimization strategy and this analysis focus solely on the local transformer and how optimizing EV charging may avoid expenses to the utility for upgrading a given transformer. Where the systemwide optimization modeled for California can present an especially high-value case for charging management, the case study with Rhythmos.io illustrates how even with relatively limited data and a focus on only the grid edge, optimizing EV charging can still provide worthwhile benefits.

[8] US Department of Energy. (2023). Communications with the Grid Edge [White paper]. https://www.energy.gov/sites/default/files/2023-07/Communications%20with%20the%20Grid%20Edge%20-%20Unlocking%20Options%20for%20Power%20System%20Coordination%20and%20Reliability_0.pdf

Transformer-Specific Cost Determination

When assessing benefits based on the impact on local distribution equipment, a value must be assigned to the cost of upgrading affected equipment to accommodate increasing loads. Estimates for hardware upgrade costs for a single-phase transformer were provided by the municipal utility and are listed in Table 4.

Table 4. Transformer Hardware Upgrade Cost Estimates

Transformer Size	Upgrade Cost
15 kVA to 25 kVA	$1,005
25 kVA to 37 kVA	$1,188

Overload Threshold Distribution Cost Evaluation

Because localized distribution benefits are realized on a case-by-case basis, these costs can be applied in a binary manner: that is either load growth on a given transformer will require an upgrade and incur the full upgrade cost because the transformer overload threshold has been exceeded, or the transformer will not require an upgrade and incur no cost for that specific upgrade. This approach relies on the total upgrade costs, an assumption for the effective capacity threshold of each transformer type (i.e., the amount of load it can be expected to bear at a given time), and the peak or maximum load on the transformer under each charging scenario. This is a stark but realistic assessment of how costs might actually be realized by a distribution system operator.

For this approach, the effective capacity threshold is estimated using a power factor of 0.95, an allowable overload of 200%, and a target capacity utilization of 100%. This means that the effective kW output of the transformer will be 95% of its kVA load and that it is expected to bear up to 200% of its rated capacity for at least a short period without experiencing an overload and requiring an upgrade. These values are multiplied by the transformer rating, either a 15 kVA or 25 kVA rating. This calculation is shown in Table 5. If the addition of EV load under a given charging scenario would cause it to exceed the effective capacity under one or both listed transformer ratings, then the charging scenario is assumed to incur the costs associated with one or both subsequent upgrades.

Table 5. Transformer Effective Capacity

Transformer Rating (a)	Power Factor (b)	Allowable Overload (c)	Target Utilization (d)	Effective Capacity (a * b * c * d)
15 kVA	0.95	200%	100%	28.5 kW
25 kVA	0.95	200%	100%	47.5 kW

Per-Unit Distribution Cost Evaluation

As an alternative to the overload threshold approach, the estimated distribution benefit may be generalized by calculating the upgrade cost per unit of effective transformer capacity. The upgrade unit cost is multiplied by the peak load under each charging scenario to determine the unit-based expected distribution cost under that scenario. This allows for a slightly more nuanced estimate of the value of different charging strategies, though it is still specific to the load patterns and modeled charging impacts on the studied transformer.

Based on discussions with Rhythmos.io and expected utilization targets for the utility, we again assume a 0.95 power factor but set allowable overloads of 125% in the summer and 150% during the rest of the year to reflect more conservative distribution planning targets and thermal overload conditions by season. We also assume a target utilization of 75% to allow for some headroom that would typically be incorporated in distribution planning. The goal of these adjusted assumptions is to better align this generalized value with the methodology applied to the systemwide distribution capacity cost calculations of a codified avoided cost structure.

The initial upgrade costs are then divided by this effective capacity value to achieve a distribution capacity per-kW cost. These values vary slightly with the level of transformer upgrade required but vary more significantly between seasons. These costs are displayed in Table 6.

Table 6. Upgrade Unit Costs

Season	Transformer Size	Upgrade Cost	Upgrade Capacity	Effective Capacity Change	Upgrade Unit Cost
Summer	15 kVA to 25 kVA	$1,005	10	*8.9*	*$113 / kW*
	25 kVA to 37 kVA	$1,188	12	*10.7*	*$111 / kW*
Winter	15 kVA to 25 kVA	$1,005	10	*10.7*	*$94 / kW*
	25 kVA to 37 kVA	$1,188	12	*12.8*	*$93 / kW*
Shoulder	15 kVA to 25 kVA	$1,005	10	*10.7*	*$94 / kW*
	25 kVA to 37 kVA	$1,188	12	*12.8*	*$93 / kW*

Load Profiles for the Municipal Utility Transformer

Given the narrower focus of the localized distribution benefit analysis, load profiles for the utility are developed with a greater focus on the peak impacts for the transformer than on changes in load for every hour of the year. Similar to the SCE example, the unmanaged and passive managed charging profiles are developed using simple heuristics on when an EV may be available to charge and with the assumption that passive managed charging favors charging during off-peak hours if possible. For this analysis, Rhythmos.io generated and provided these profiles for a week each in August 2023, October 2023, and January 2024[9] to represent the peak load weeks in summer (August) and winter (January) as well as a typical shoulder-season week (October). Driving and charging assumptions from Rhythmos.io are listed in Table 7.

[9] In January 2024, the utility service territory experienced a blizzard and extremely cold temperatures that are not typical weather conditions for January.

Table 7. Charging Assumptions

Load Assumptions	Value	Unit
EV Charger Capacity	9.6	*kW*
EV Charge Requirement (including losses)	38.4	*kWh*
EVs under Transformer	2	*#*

Contrasting with the SCE evaluation, these loads are layered on top of historical load data from a residential transformer in the municipal utility's territory to illustrate the impact if two EVs are adopted by drivers serviced by the same given transformer. The optimized load profiles in this case study are also provided by Rhythmos.io using their proprietary software and modeled around the historical load and equipment conditions on that transformer. Rather than reacting to systemwide price or avoided cost signals, the Rhythmos.io-optimized charging profiles are responsive to localized impacts on transformers and other upstream grid assets. The effect of this optimization generally flattens the EV load on the transformer, reducing the peak and risk of overload. The peak loads under each charging scenario are ultimately compared against the transformer overload thresholds and are also multiplied by the unit costs of the per-unit alternative approach to determine the total costs and relative avoided costs from each charging strategy.

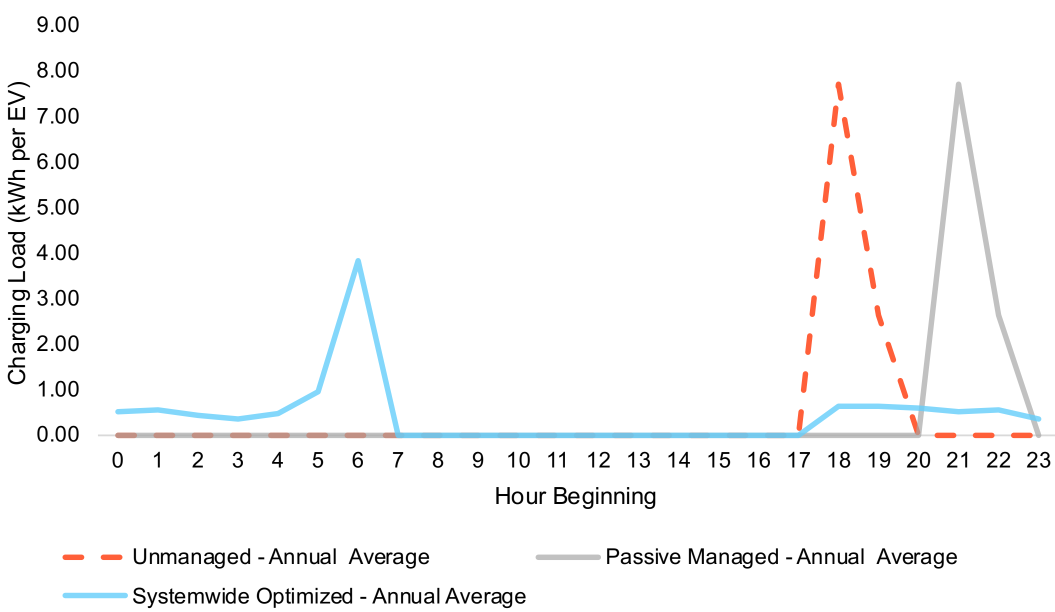
Results

Total Value Proposition from Avoided Cost Streams in SCE

As EV adoption grows, utilities will experience increases in load and some level of impact on the electric grid regardless of a driver's charging behavior. However, strategies for managing EV charging can mitigate these impacts and resulting costs for the utility.

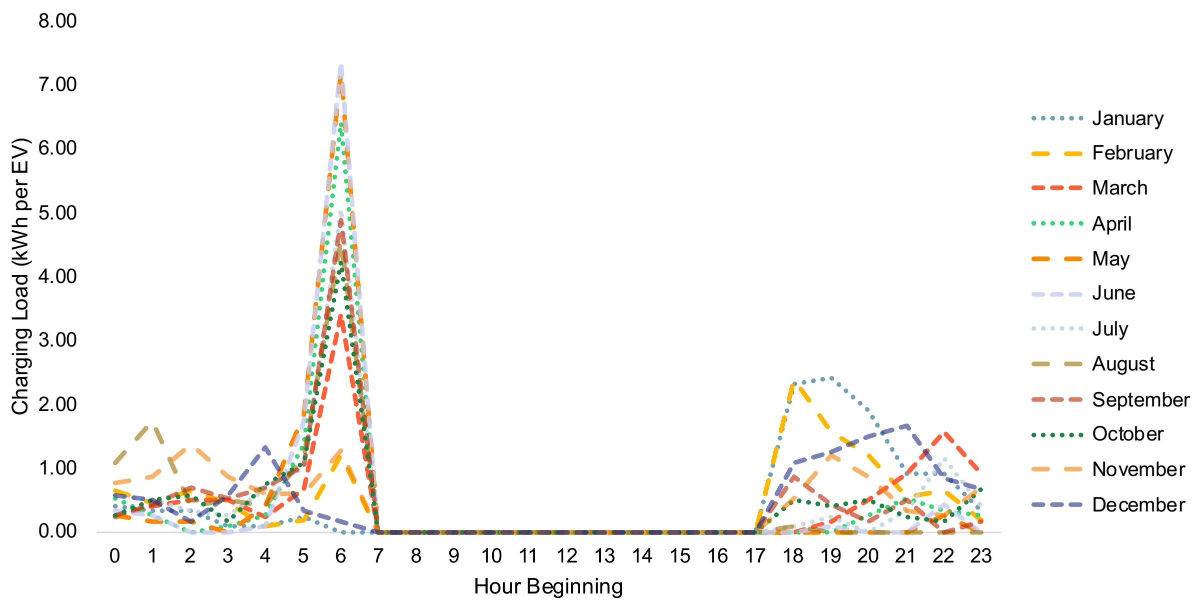
Under the unmanaged and passive managed charging scenarios laid out for SCE, the load from EV charging is consistently concentrated in the same hours of the day throughout the year. Because drivers are charging as soon as they are able or as soon as the off-peak TOU rate begins, and because SCE's current TOU schedules are similar throughout the year, the expectation is that many EV drivers will be charging at the same time on any given day of the year. In contrast, optimizing charging around hourly avoided costs directs EV owners to charge in many different hours throughout different days and months. Figure 4 displays the resulting annual average hourly load for each charging strategy, while Figure 5 illustrates just how variable the optimized charging behavior is across different months of the year.

Figure 4. SCE Average Hourly Load by Charging Strategy



Note that loads are averaged by hour of day across the year—this will not necessarily reflect the behavior of any EV on a single given day.

Figure 5. SCE Systemwide Optimized Average Hourly Charging by Month

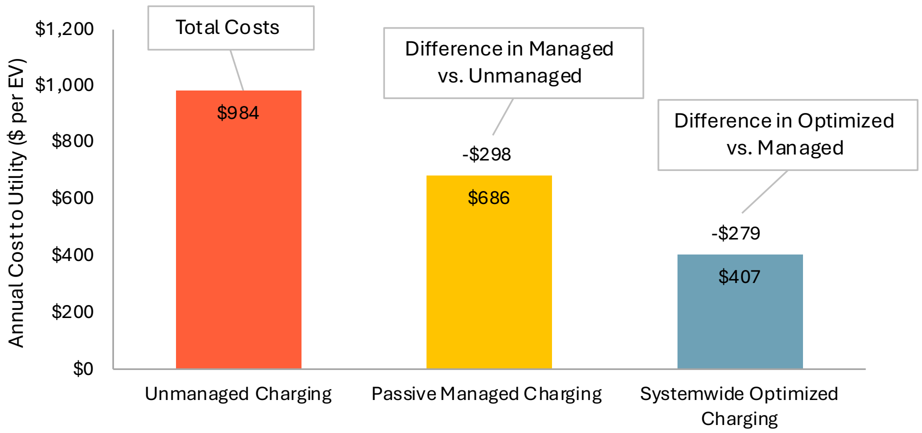


Note that loads are averaged by hour of day across the month—this will not necessarily reflect the behavior of any EV on a single given day.

While the *total* EV load in a given 24-hour period is the same between all three scenarios, the contrast between the selected timing of charging indicates that unmanaged and passive managed charging are rarely taking place during the lowest cost hours to the grid. This hints at a great deal of potential value to be had from optimizing charging.

Figure 6 shows the results of this dynamic when we combine the load profiles with the system avoided costs for all hours of the year. In an unmanaged charging scenario, adding one EV's worth of charging load results in $984 incremental annual costs to the utility. Passive managed charging under SCE's existing TOU rates can help with this, shifting charging to hours when there is less concentrated demand from other sources and thus reducing energy and capacity costs. As a result, the passive managed charging scenario decreases incremental system costs from EVs by about 30%, or $298 per EV. Optimizing EV charging to be scheduled during hours with the lowest systemwide costs reduces those costs by a further $279. This provides a cumulative savings of almost 60% of grid costs for charging or $600 per EV per year compared to unmanaged charging. Put another way, by optimizing charging, 2.5x as much EV adoption could be enabled without incurring incremental costs for the grid.

Figure 6. EV Charging Management Strategy Impacts on SCE's Costs



Localized Distribution Value from Avoided Transformer Overload

Zooming in from the systemwide view of avoided costs, Rhythmos.io's optimized management of EV charging and other DER loads have the potential to demonstrate value at a local level by coordinating with other connected loads and dynamically optimizing EV and other DER loads against statistically significant, historically available capacity for localized distribution infrastructure and equipment. The case study leveraging Rhythmos.io Cadency EdgeAI℠ illustrates this in the Southeastern municipal utility's service territory, demonstrating how equipment and load data can provide insight into a grid-edge capacity constraint to yield localized distribution value as explicitly as systemwide pricing might.

Figure 7 displays the resulting total load profiles from adding unmanaged, passive managed, and optimized charging from two EVs to existing shoulder-season load on a given transformer within the utility. It is evident from focusing on the peaks in each day that EVs with unmanaged charging would put the greatest strain on the transformer, followed by the passive managed charging, though for this example transformer this is not enough additional load to result in an overload.

Figure 7. October Transformer Load Profile

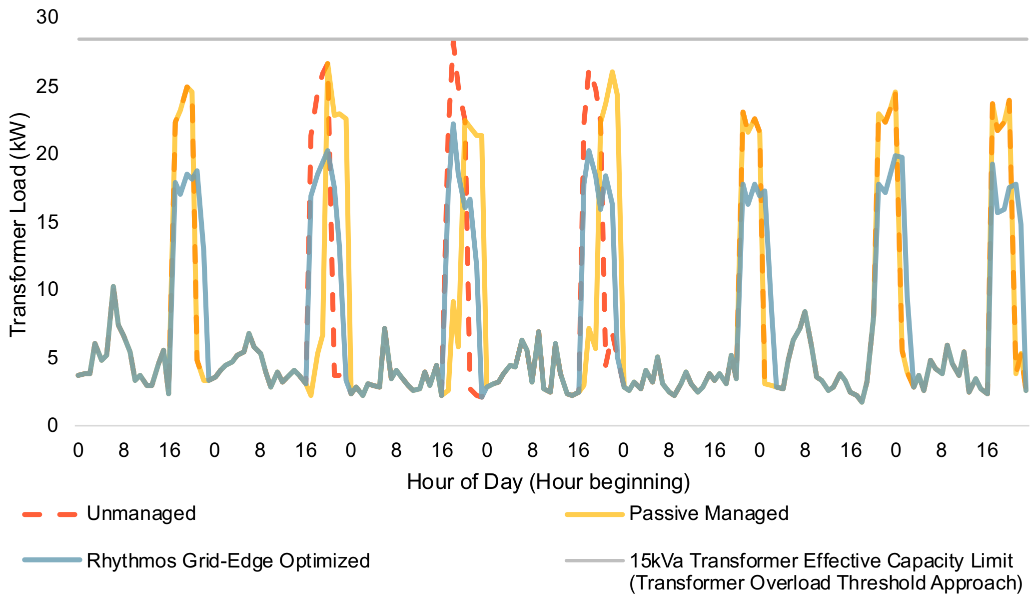
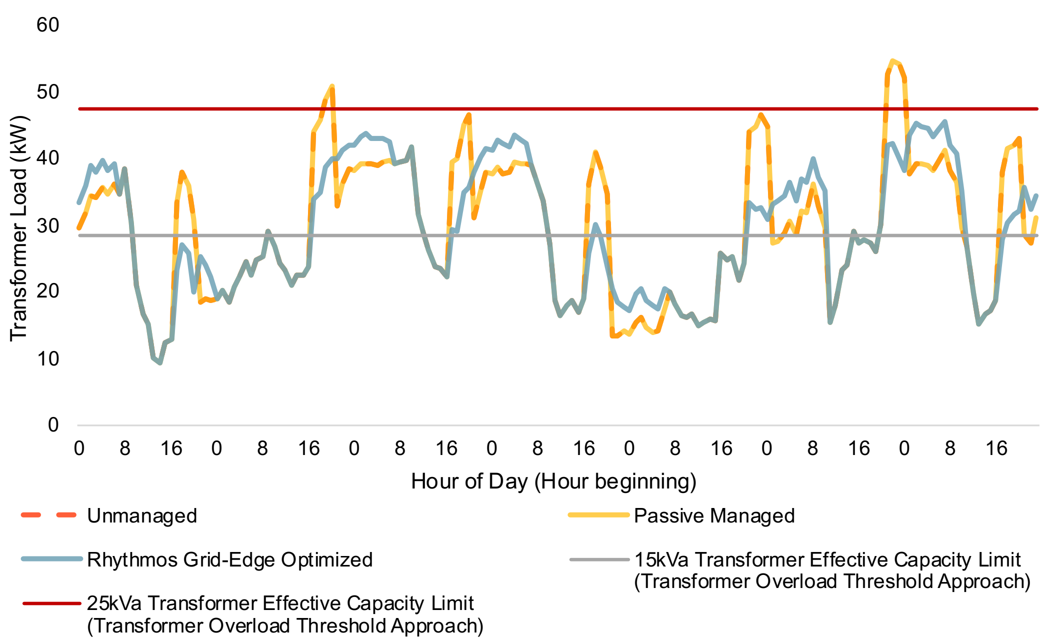


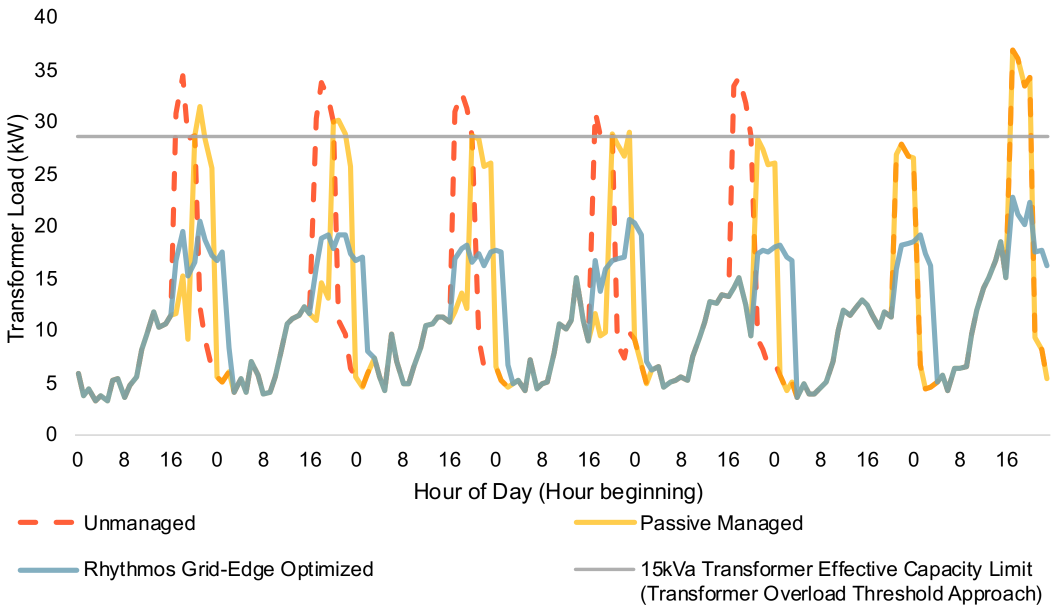
Figure 8 shows a more nuanced picture, in which both unmanaged and passive managed charging have identical impacts on transformer load, because drivers are expected to charge during the utility's winter off-peak periods even without conscious behavior change. However, the winter season's load increases drastically in all three charging scenarios, such that at least one transformer upgrade will be needed in every case and an additional upgrade from the 25 kVA nameplate transformer to an ever larger sized 37 kVA nameplate transformer is required under the unmanaged and passive managed charging strategies.

Figure 8. January Transformer Load Profile



Finally, the transformer load profiles generated for August in Figure 9 highlight the greatest differential between unmanaged or passive managed and grid-edge optimized scenarios. If limited to this single month's patterns, both unmanaged and passive managed charging strategies would require an upgrade to a 25kVA-rated transformer, while by optimizing charging the utility would be able to avoid an upgrade to a 15kVA-rated transformer.

Figure 9. August Transformer Load Profile



If applying costs on an overload threshold basis for the studied transformer, the winter peaks would dictate an upgrade is needed because the transformer must maintain operability during hours of the year with the greatest level of strain. The resulting costs for each scenario are laid out in Table 8, with the results showing that passive managed charging provides effectively no benefit to this transformer under the modeled circumstances because a transformer upgrade is triggered to the 25 kVA level, while optimized charging allows for a savings of $1,188 because it avoids the secondary transformer upgrade to a 25kVA capacity rating. Even if optimization is only able to delay, rather than fully avoid the need for a transformer upgrade, it would still be able to provide a deferral value of $107 per year.

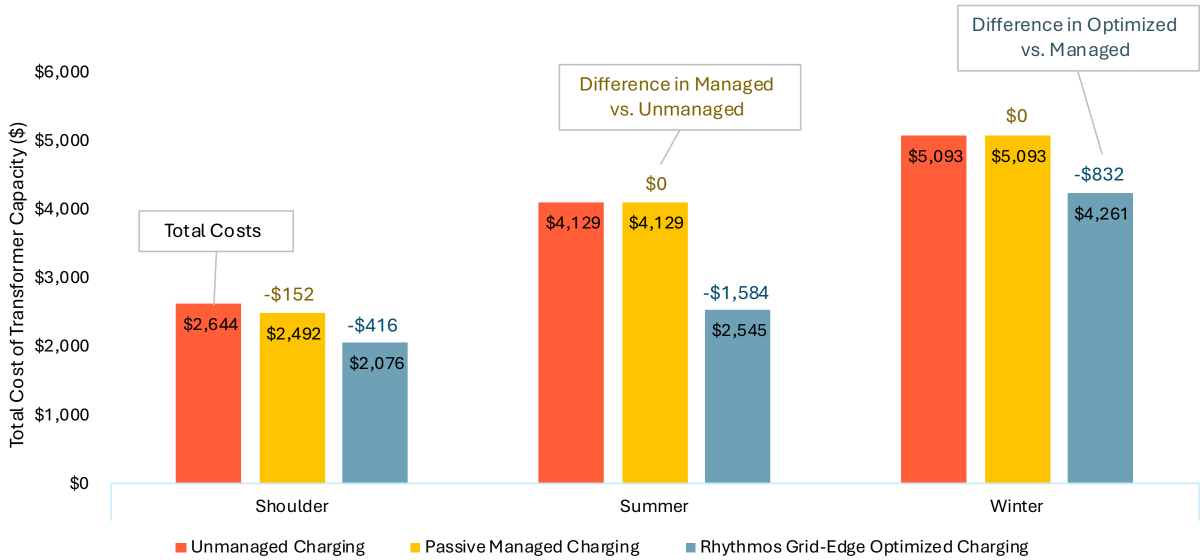
Table 8. Overload Threshold Transformer Upgrade Costs

Charging Scenario	Total Transformer Upgrade Cost	Benefit Relative to Unmanaged Charging	Annual Deferral Benefit*
Unmanaged	$2,193	$0	$0 / yr
Passive Managed	$2,193	$0	$0 / yr
Optimized	$1,005	$1,188	$107 / yr

**Simple annualization applying a 9.0% Real Economic Carrying Charge*

Figure 10 provides an alternative perspective, indicating localized distribution value based on per-unit costs of transformer capacity.

Figure 10. Total Transformer Capacity Cost by Load Profile



Here, we see a graduated increase in costs as seasonal peak load rises, with optimized charging consistently showing the lowest costs and passive managed charging providing some benefit in the shoulder season relative to an unmanaged charging scenario. In the shoulder season, the upgrade costs are less than $3,000 under all charging scenarios. Passive managed charging avoids $152 in upgrades and optimized charging avoids an additional $416, providing $568 in savings compared to a passive managed charging scenario. The upgrade costs increase to over $4,000 for unmanaged and passive managed charging scenarios in the summer while optimized charging saves $1,584 comparatively. The upgrade costs to meet additional EV load during the winter are highest, requiring over $5,000 in upgrade costs in unmanaged and passive managed charging scenarios. The optimized charging strategy saves $832 in the representative winter month. Whereas the cost differences in the overload threshold scenario were specific to the transformer under the assumed conditions, the differences in cost under the per-unit approach can be interpreted as an expected average for other transformers with perhaps similar new EV load but some variability in available headroom.

Though the case study results are specific to the selected transformer and are not applicable to a subset of other transformers even on the utility's system, this reflects the extremely localized nature of distribution capacity benefits. Systemwide cost models, like the California ACC, informed by distribution cost of service studies provide a useful way to estimate average distribution value, even by hour of the year, but for any given transformer the actual value may be higher, lower, or non-existent. Strategies of passive management or optimizing for systemwide cost signals may therefore miss opportunities to reduce localized costs or even exacerbate conditions that would cause distribution overloads. By selectively applying grid-edge optimization strategies, such as those offered by Rhythmos.io, utilities can seek out and capture benefits at the local distribution level, where such strategies will provide the highest value.

As EV adoption grows, the value of optimized charging will increase since the electric grid and more individual transformers will experience capacity constraints. There will be additional opportunities to defer or avoid investments, saving utilities and ratepayers money. Utilities may be able to capture additional value by combining optimization strategies to consider systemwide conditions during most hours and focusing on targeted, localized distribution opportunities during peak hours. Only a small percentage of hours each year will experience distribution capacity constraints that risk equipment failure. Focusing on the localized distribution conditions during those hours can achieve the benefits of avoiding upgrades, while optimizing for systemwide avoided costs during the rest of the year can provide additional benefits. A dual approach that optimizes systemwide conditions year-round while targeting localized distribution during peak hours can maximize cost savings and improve grid resilience.

Conclusions

As EV adoption accelerates, accommodating the increased load results in costs for the electric grid. Shifting EV charging load via passive managed or optimized charging strategies can help mitigate those costs and provide savings to utilities and their customers. We evaluated the benefits of shifting EV load across contrasting geographies and under two different optimization and valuation approaches.

In California, which has a codified Avoided Cost Calculator to draw upon to value DERs, we compare unmanaged charging with a passive managed charging strategy based on SCE's EV TOU rate, as well as a systemwide optimized charging strategy which takes advantage of each hour's avoided costs to capture a wide range of system benefits. This approach presents a high-end estimate of the average value that could be provided within a wide region. For the Southeastern municipal utility, we again model unmanaged and TOU passive managed charging but determine an optimized charging strategy and value associated with each approach based on solely the impacts to distribution grid equipment. This latter approach relies on both historical utility system data and the Rhythmos.io Cadency EdgeAI℠ optimization platform to develop a case study for an individual transformer.

In the SCE example, passive managed charging is estimated to provide nearly $300 in annual utility savings compared to unmanaged charging for a single EV. Optimizing charging around all available avoided cost streams provides a further $250 in annual savings. Systemwide optimized charging thereby reduces the system costs due to EV adoption by approximately 60% compared to unmanaged charging. This offers a path to mitigate impacts on customer rates and, at the same time, to facilitate accelerated adoption of EVs and to support climate policy goals.

The case study applying Rhythmos.io Cadency EdgeAI℠ to an individual municipal utility transformer provides a highly-specific example of another form of optimization—one based around grid-edge distribution equipment and loading conditions. While this strategy may not be necessary in every location, the benefits can equate to thousands of dollars in each location where it does make a difference. This strategy may also be more easily adopted by utilities where clear or reliable price forecasts are not available, or simply when localized costs are expected to exceed the system average. It may also be possible to combine optimization strategies such that each one will determine EV charging hours whenever it can provide greater value to maximize benefits throughout the year.

Our results demonstrate the benefits of managing charging to reduce costs that will result from increasing EV loads. Optimization platforms, like Rhythmos.io Cadency EdgeAI℠, present an opportunity for utilities to maximize savings based on the utility's own data and understanding of its system operations. As EV adoption continues to grow, passive managed and optimized charging strategies will provide increasing value to mitigate grid impacts.