Getting ahead of the EV tipping point

Proactive EV management strategies for an efficient and flexible grid

October 2024

Executive summary

AES Indiana, serving more than 500,000 customers in Indianapolis, partnered with Camus to identify the optimal period for investing in electric vehicle (EV) visibility and coordination. This study determined that an inflection or tipping point for AES Indiana occurs when 5% of customers on average have installed residential EV chargers. At this point, which AES Indiana expects to reach in early 2029, the benefits of EV visibility and managed charging exceed the costs. By proactively preparing through actions such as deploying managed charging technologies, establishing customer programs, and engaging regulators, AES Indiana can capture $7.3 million in net present savings from 2025 to 2035 and unlock $75 million per year in capital flexibility.

Key findings

5% EV adoption activates benefits

The tipping point for AES Indiana arrives when 5% of customers on average install residential EV chargers. Even at this relatively low system-wide adoption level, a subset of neighborhoods see much higher EV adoption, with 1 in 5 neighborhoods exceeding 10% adoption. Managing EV charging generates significant grid benefits for these locations, primarily through deferring grid upgrades.

Data-driven planning drives deferrals

With real-time EV visibility and data-driven distribution planning, AES Indiana can defer 87% of expected feeder upgrades for an average of 5.8 years and 66% of service transformer upgrades for 8.4 years. This deferral creates flexibility for reinvestment in grid-wide reliability and affordability measures.

Managed charging outperforms TOU rates

In our analysis, time-of-use (TOU) rates, while helpful in reducing system-wide peaks, inadvertently create new peaks on local equipment, especially later in the analysis period with higher levels of EV adoption. These new peaks drive increased capital expenditures compared to no EV management. In contrast, grid-optimized managed charging reduces capital expenditures during the study period, deferring 30% of feeder upgrades for an average of 4.3 years and 24% of service transformer upgrades for an average of 9.1 years.

Deferrals deliver capital flexibility

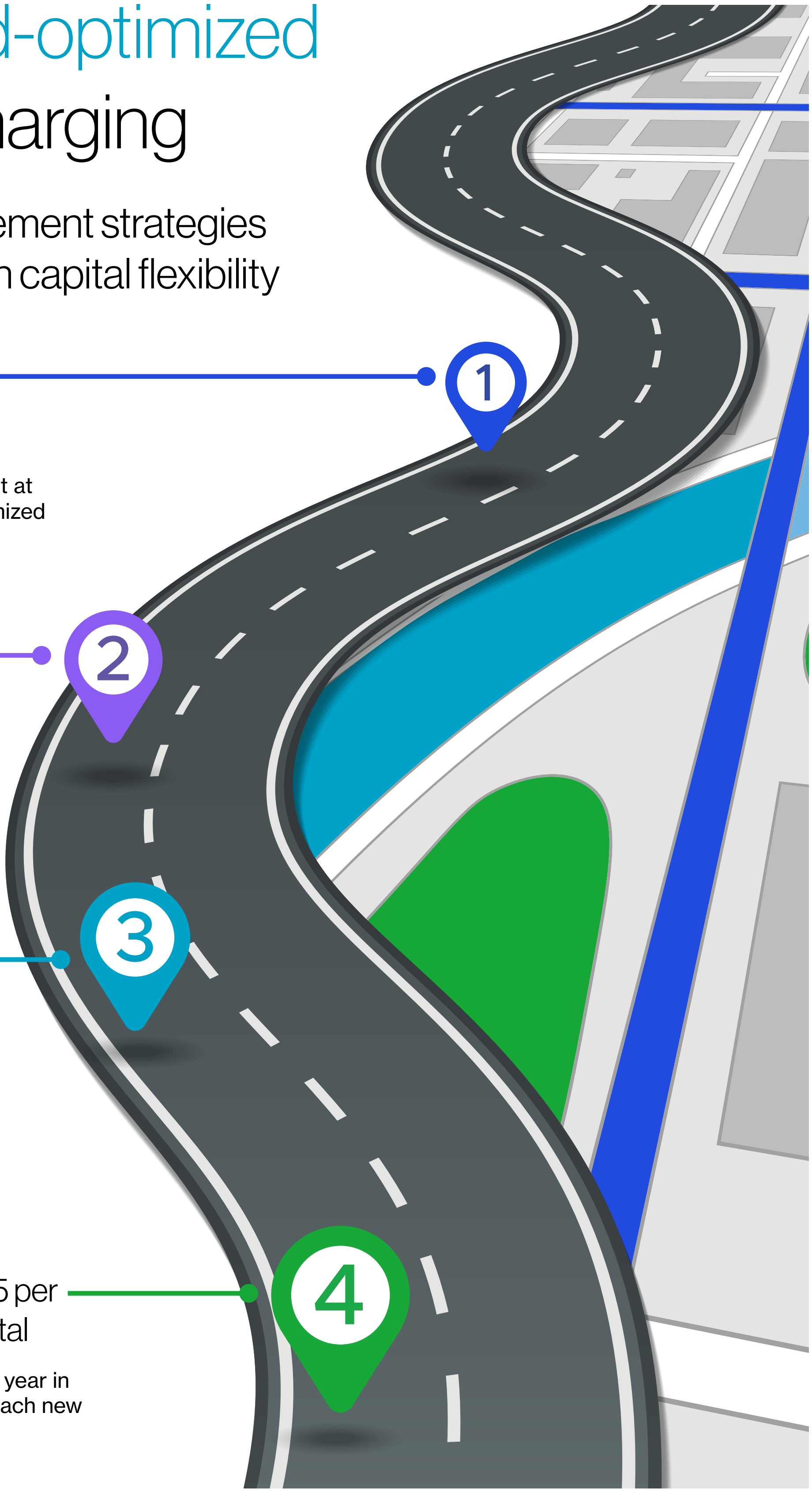
Based on our analysis, the deferral of equipment upgrades would unlock $75 million per year in capital flexibility, equivalent to $1,275 annually for each new EV adopted by an AES Indiana residential customer. This would allow AES Indiana to reinvest in any needed, broader grid improvements, enhancing overall reliability and reducing costs for all customers.

Conclusion

Investing in EV visibility and managed charging programs will allow AES Indiana to minimize upgrade costs and unlock capital flexibility for the benefit of all customers. We believe the approach demonstrated by AES Indiana and Camus provides a valuable framework for utilities to optimize investments, reduce costs, and accelerate the integration of electric vehicles.

The value of grid-optimized managed EV charging

Proactive home EV management strategies unlock $75 million per year in capital flexibility



Our EV tipping point occurs at 5% system-wide adoption

This residential adoption level – which is lower than many utilities expect – represents the point at which investments in EV visibility and grid-optimized managed charging provide annual benefits that surpass annual costs.

1 in 5 neighborhoods see 10%+ EV adoption by 2029

Why does this tipping point occur at low adoption rates? A subset of neighborhoods see much higher EV adoption, with 1 in 5 neighborhoods exceeding 10% residential EV adoption.

EV visibility + grid-optimized charging can defer 85% of utility upgrades for 8.5 Years

Investing in the ability to monitor and actively manage home EV charging in coordination with drivers enables AES to avoid overloading equipment, lengthening the usable life of existing infrastructure.

These deferrals would unlock $1,275 per year for each new EV in flexible capital

Upgrade deferrals would unlock $75 million per year in capital flexibility, equivalent to $1,275/year for each new EV adopted by a residential customer.

Change is sweeping the grid; flexibility is paramount

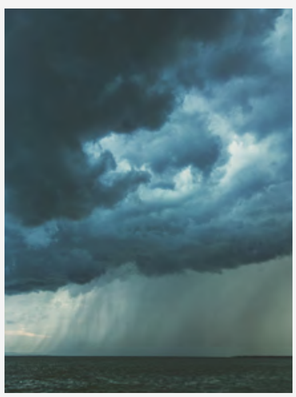
It's no secret that demands on the grid are evolving at a pace not seen in a half century.

From electrification and load growth to aging infrastructure, a rise in extreme weather events, and new regulatory requirements, rapid change is challenging traditional approaches to grid operations and planning.

4 changes impacting the grid

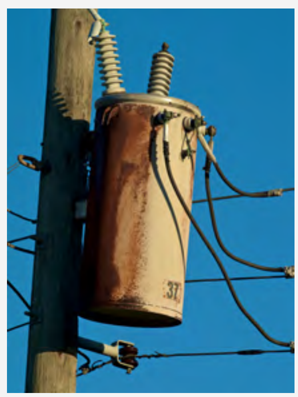
Rising electricity demand

From 2022 to 2024, demand growth projections increased by 1.8x



Increase in extreme weather

In 2023, the U.S. experienced a record 28 billion-dollar climate disasters



Aging utility infrastructure

Most transformers are reaching the end of designed life (40 years)

New regulatory requirements

Regulations like FERC Order 2222 are expanding utility responsibilities

Sources: Grid Strategies, NOAA, NREL, FERC

The cost of traditional grid adaptations is increasing

The traditional method of adapting the grid for change focuses on investing in physical infrastructure, such as procuring more generation and transmission capacity, reconductoring lines, upgrading distribution circuits, and installing larger capacity transformers. However, a continuation of business-as-usual approaches is likely to result in increasing costs.

In California, where EV adoption has moved faster than other states, recent studies[1,2] commissioned by the California Public Utilities Commission (CPUC) estimated the need for $25 billion to $50 billion in traditional distribution grid upgrade investments by 2035 to meet state electrification goals – assuming load management measures are not implemented. This includes a 150% to 300% increase over average feeder upgrades from the beginning of the decade.

In the context of rising costs, flexibility is paramount

With the cost of traditional grid adaptations rising, flexibility is essential. With limited resources, utilities are exploring how to best allocate limited time and money to deliver grid-wide reliability, affordability and sustainability. Identifying ways to increase the utilization of existing grid capacity can unlock valuable capital that can be used to invest sooner in additional customer-serving projects and programs.

Utilities unlock flexibility through DER visibility and coordination

To illustrate how flexibility leads to reduced costs, one can consider a hypothetical utility experiencing EV adoption but lacking the systems to accurately monitor and quantify the resulting grid impacts. Its grid planners assume high levels of charging coincidence[3], allocating requisite budgets to upgrade transformers and reconductor lines. But depending on the existing distribution network capacity, actual EV growth rates, and real-world charging behavior in the utility's service territory, the planned level of investment may be vastly higher than what is actually required.

Equipped with DER visibility and coordination, planners at that same hypothetical utility can more precisely understand local grid capacity and confidently rely on customer programs such as managed EV charging when developing their forecasts and infrastructure investment plans. Such planning insights provide the utility with flexibility to decide how to best invest finite resources to benefit customers, delivering on reliability while maintaining affordability[4].

Engaging EV drivers to unlock flexibility

Engaging EV drivers is an essential component of unlocking EV charging flexibility. Motor, incubated by AES, enables utilities to grow participation in managed charging programs through customer engagement at point-of-sale. Motor partners with auto dealerships in the utility's service territory to reach customers through an EV Concierge service included with their vehicle purchase. This allows Motor to work with new EV drivers to help them set up home charging and sign up for utility EV programs, unlocking flexibility for the distribution system.

1. Kevala study (CPUC)
2. PAO Study (CPUC)
3. Charging "coincidence" refers to the number of EVs that plug in at the same time. The coincidence of these loads occurring at the same time has a significant impact on the infrastructure required to support these new loads
4. To give a recent example of the potential savings, a study by the Regulatory Assistance Project and the International Council on Clean Transportation found that, in Colorado, EV charging flexibility can reduce annual grid infrastructure costs by $100–$300 million by 2035. Link: https://theicct.org/wp-content/uploads/2024/06/RAP-ICCT-farnsworth-enterline-basma-kadoch-unlocking-system-savings-flex-ev-colorado-2024-june.pdf

5 steps to identify an EV tipping point

Knowing when to invest is challenging; tipping points are the solution

While the potential value of DER visibility and coordination is easy to understand, identifying exactly when benefits outweigh costs is more complicated. As a result, utilities may wait to invest in these capabilities until it's abundantly clear that doing so will provide net benefits for customers. However, waiting has consequences. In a marathon, if a runner waits until she is thirsty to drink, she is already dehydrated. She needs to plan ahead and make proactive choices to avoid problems before they arise. For utilities, it is similarly important to have a plan that doesn't rely on cues from obvious problems to begin developing strategies to deliver optimal outcomes. Utilities need tools they can use today to determine the best time to proactively invest – not too early and not too late.

AES, a global power company, and Camus, a grid visibility and orchestration software provider, joined forces to identify the moment, or "tipping point", at which the annualized benefits of investing in DER visibility and coordination clearly outweigh the costs. The remainder of this paper describes a set of methods for and findings from identifying a residential EV tipping point for AES' Indiana utility.

How we identified an EV tipping point

The objective of our analysis was to identify the point of residential EV adoption in the service territory of AES Indiana–a distribution utility that serves more than 500,000 customers in the Indianapolis area–at which investing in EV visibility and management provides more benefits than their costs.[5]

These benefits include economic improvements like better utilized grid infrastructure and efficient operations as well as qualitative outcomes such as increased customer satisfaction. By waiting beyond the tipping point, utilities not only miss out on these benefits but also risk a series of shocks to the system as DER behaviors, such as coincident EV charging, result in new system peaks and stress to existing infrastructure.

Additionally, given lead times on establishing customer programs, new rate approvals, and securing equipment for new capital projects, in many cases these tipping points require utility action much earlier than expected.

Our approach to identifying an EV tipping point contained five key steps

1 Where

Identify EV locations and establish the system loading baselines using AMI and GIS data

2 When

Model future EV adoption across multiple scenarios

3 How

Establish EV charging coincidence assumptions

4 What

Assess the network impacts of business-as-usual and modeled interventions

5 Why

Quantify direct benefits and costs, including all hardware and software investments

5. A recent paper by the U.S. Department of Energy describes a three-stage framework outlining how grid capabilities need to evolve with growing DER penetration. The framework laid out in the paper is valuable, yet it acknowledges that the tipping points between the stages are rough estimates. A generalized analysis does not capture the individual nature of each utility's distribution system and customer base, making it less actionable and the tipping points not as easily discernible.

Step 1: Identify EV locations and establish the system loading baselines

To determine the EV-related tipping point for AES Indiana's distribution system, we first needed to understand the baseline for the system. This required establishing the current load on system components (e.g., feeders, distribution transformers) and identifying EV locations across the network.

To accomplish this, the AES-Camus team compiled GIS, AMI, and interconnection datasets for the entire AES Indiana service territory and integrated them into the Camus composite data model. The datasets enabled Camus to map AMI data to precise grid locations served by specific transformers and upline feeders. Because AES Indiana has limited direct visibility into the specific location of EV chargers on their system, Camus utilized the 15-minute AMI data along with an EV detection algorithm to identify load patterns indicative of EV charging. This generated ~4,600 detected EVs–along with associated detected charging sessions–at sites across AES Indiana.

This baselining effort leveraged the existing investments that AES Indiana had made in AMI and GIS, allowing Camus to stand up the composite grid model, establish loading across the network, and begin identifying EV charging sessions in eight weeks.

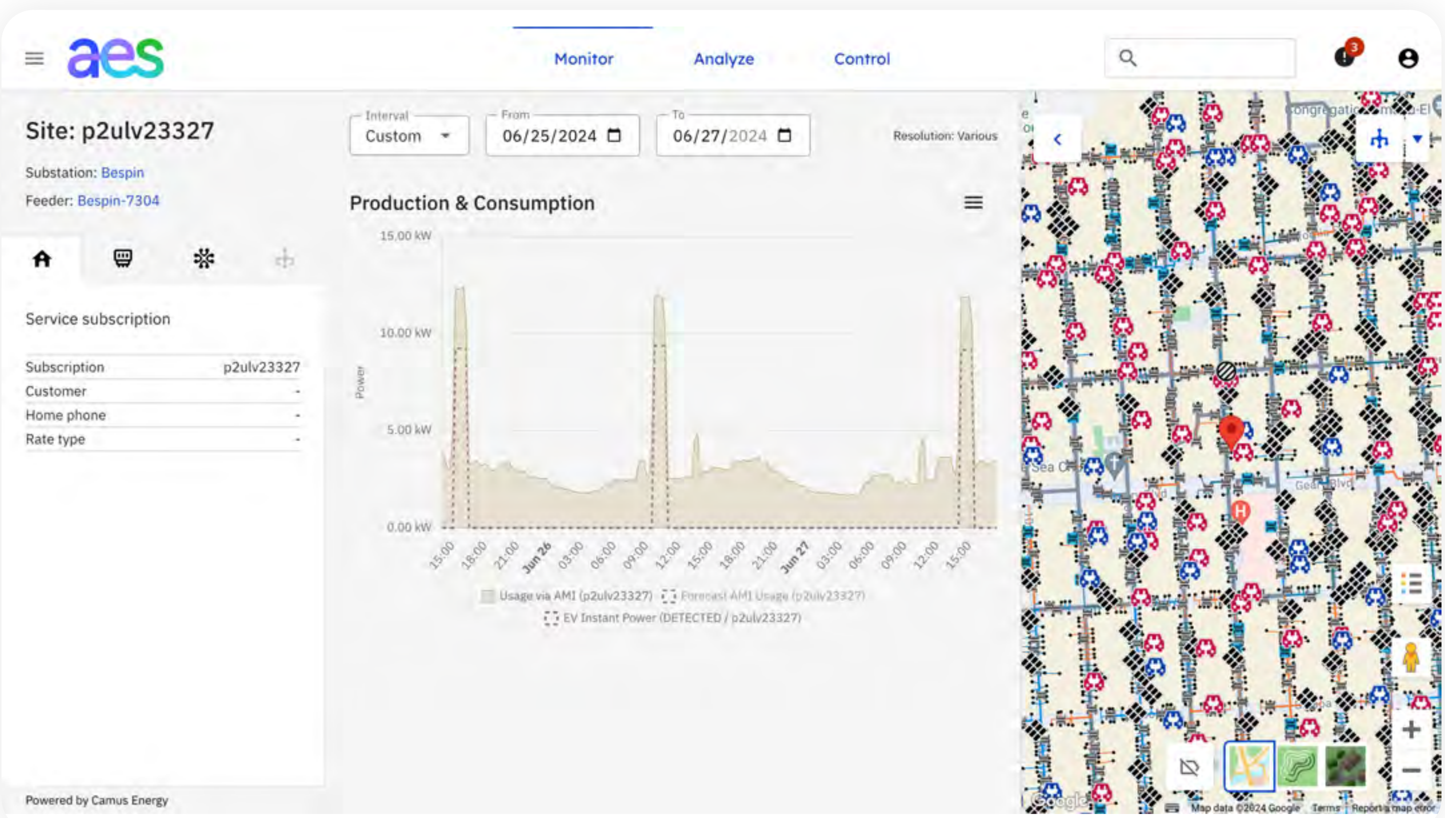


Figure 3. Screen capture of the view into a single site with a detected EV in the Camus platform. GIS data is combined with AMI and DER data to enable data exploration, time-series data aggregation (leveraging connectivity in the data model), and DER orchestration that respects grid constraints.

Step 2: Model future EV adoption

Using data from the National Renewable Energy Laboratory's (NREL) Demand-Side Grid (dsgrid) TEMPO Light-Duty Vehicle Charging Profiles[6], Camus projected a 2025-2035 EV adoption trajectory for each feeder. While the same adoption rate was applied across all feeders (consistent with the NREL dataset), the initial number of EVs for each feeder was based on the number of identified EVs from Step 1 above. This resulted in certain feeders reaching higher numbers of EVs earlier than others that started out with low adoption.

Camus used the conservative reference case data, which is based on the U.S Energy Information Administration's Annual Energy Outlook[7]. This aligns closely with the low-to-medium growth rates from the AES Indiana 2022 Integrated Resource Plan.[8]

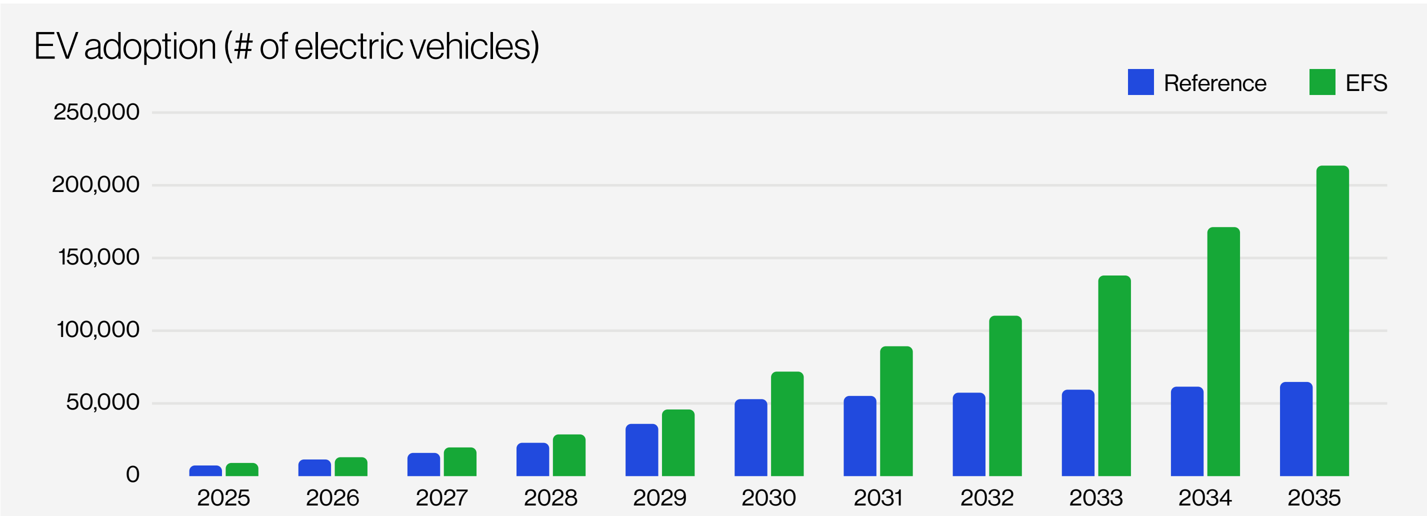


Fig 4. Residential EV adoption for AES Indiana service territory by case. Reference (blue) refers to the Energy Information Administration's Annual Energy Outlook. EFS (green) refers to NREL's Electrification Futures Study.

Step 3: Select EV charging coincidence assumptions

EV charging coincidence is a crucially important assumption when evaluating the impacts of residential EV charging on distribution grid upgrades. When chargers activate at the same time, they cause sizable increases to total electricity demand, exacerbating existing peaks or creating new ones. The level of coincidence is a major driver for the number of upgrades needed to reliably service EV charging demand.

> AES Indiana and Camus used coincidence assumptions based on standard utility planning practices and existing, real-world charging patterns observed in the AES Indiana AMI data.

Standard Charging Coincidence: 70% for service transformers, 40% for feeders

A theoretical "worst case" for distribution planners would be that every residential EV charges at full power during the peak demand periods, adding massive EV demand on top of baseline electricity usage. However, AES Indiana planners indicated that assuming 100% coincidence would be too conservative and therefore too costly. In the absence of data on actual EV charging behavior, the planners' standard assumption for service transformers would be that 70% of home EV chargers may be charging at maximum power at the same time. At the feeder level, increased heterogeneity allows distribution planners to assume 40% coincident charging.

Behavior-Informed Charging Coincidence: 40% for service transformers, 20% for feeders

Based on discussions with AES Indiana planners, we included a "behavior-informed" assumption for service transformers that assumes a maximum of 40% of EVs charge at the same time. At the feeder level, this is reduced to 20%. These assumptions are based on a mix of standard practices (e.g. the 70% and 40% assumptions above) and real-world charging behavior (~5% coincidence during the study period). Importantly, AES Indiana distribution planners articulated that planning for lower coincidence is only feasible where backstops, such as grid-optimized managed charging or automated switching, are available to mitigate negative impacts during infrequent periods of elevated coincidence.

7. https://downloads.regulations.gov/EPA-HQ-OAR-2017-0357-0060/attachment_45.pdf
8. Additional results for the middle growth scenario of the TEMPO data set (aligned with NREL's Electrification Futures Study assumptions) are included in the Appendix

Step 4: Assess the grid impacts of business-as-usual and the deferral opportunities from modeled interventions

The next step was to determine load profiles for the baseline case of business-as-usual grid infrastructure investments. Camus calculated 15-minutely load profiles for each feeder and a representative sample of service transformers[9] across each year in the 2025-2035 analysis period and for each future EV adoption scenario. Two types of EV load profiles were generated:

Observed behavior profiles: These load profiles were generated by building up charging sessions for each EV on the feeder/transformer. The charging sessions were created by sampling into probability distributions on session start time, session duration, sessions per month, and session power level. The distributions and their parameters were established by fitting the data from tens of thousands of sessions extracted from AMI data for detected EVs.

Planning scenario profiles (standard and behavior-informed coincidence assumptions): These load profiles reflect a specified percentage of EVs charging at the same time for planning purposes. The percentage varies during the course of a day using session start time distributions to reflect TOU and non-TOU rates, but in all cases the average percentage matches the 20%, 40% or 70% coincidence figures.

The observed profiles were used as benchmarks to understand historical EV charging coincidence and impacts on upline equipment. The planning scenario profiles meanwhile were used to reflect "business-as-usual" assumptions -- with no intervention. In addition to business-as-usual assumptions, we modeled the impacts of two interventions – TOU rates and grid-optimized managed EV charging[10].

For each intervention, Camus repeated the process of calculating 15-minute load profiles for each feeder and the sample of service transformers. With those load profiles in hand, Camus quantified the peak load reductions relative to the business-as-usual case. TOU load reductions stemmed from shifting session start times to off-peak hours. Managed charging load reductions stemmed from curtailing charging for enrolled participants for up to 20 hours per year with a subset of participants opting out of each event.

Finally, Camus identified grid upgrade deferral opportunities. These were the cases in which the reduced peak loads resulting from interventions were below upgrade thresholds for a given year.

Time of Use (TOU) rates

TOU rates are a common tool for shifting EV charging out of system peak periods without requiring direct control or signaling from the distribution utility. This analysis used charging session data from AES Indiana customers on the EVX rates to characterize the TOU rate impact on charging behavior (the EVX rate incentivizes customers to reduce usage between the hours of 2-7pm in the summer and 8am-8pm in the winter through lower rates in off-peak periods).

Grid-optimized managed EV charging

Grid-optimized managed EV charging uses EV charge scheduling and communication capabilities to delay charging or reduce the power draw from charging during periods of local and/or system peak electricity demand. Importantly, "grid-optimized" refers specifically to the ability to keep an EV charger's contribution within upline equipment's capacity constraints, such as the thermal limits of a service transformer. This differs from many common managed charging approaches focused solely on system peak management.

Compared to TOU rates, grid-optimized managed charging provides more flexible control over load shapes, because the instructions to the charger can be modified based on forecasted and/or real-time needs.

9. We analyzed 671 transformers from three feeders that were at the 25th, 50th, and 75th percentiles for EV adoption. This sample size provides 99% confidence that true values are within +/- 5% of calculated.

10. Interventions not evaluated in this analysis include real-time pricing, home-level firm capacity limits (e.g. utility-managed smart panels), and local distribution flexibility markets. These interventions are much less common across U.S. utilities today, but could be interesting interventions to model in future analyses.

Step 5: Quantify benefits and costs

Next a utility cost test was used to model benefits and costs on an ongoing basis over 10 years.

Direct benefits

The test included two direct benefits:

- → System-level peak demand savings for both generation and transmission
- → Distribution savings based on the time-value-of-money benefits from deferral of feeder and transformer upgrades

Additional information on our utility cost test assumptions are available in the Appendix.

Indirect benefit: capital flexibility

Capital flexibility refers to the amount of investment that can be reallocated to other projects when an expected upgrade is avoided or deferred. We quantified annual capital flexibility by calculating deferral values based on the cost of a relevant equipment upgrade and the quantity of deferrals in a given year. Investments in other projects enabled by capital flexibility can unlock significant reliability, safety, and affordability benefits. In addition, deferring capital projects can lead to a reduction in operations and maintenance costs, including truck rolls and overtime pay for emergency upgrades. For the current analysis, we did not attempt to quantify those additional benefits and therefore did not include any value from capital flexibility or O&M benefits in the utility cost test.

Direct costs

To complete the utility cost test, we modeled ongoing direct costs over 10 years, including:

- → One-time, start-up costs and annual, recurring program costs for the EV managed charging programs
- → Rebates for participants: robust initial rebate on the purchase of a level II EV charger and recurring participation incentives
- → Software costs for supporting grid-optimized charge management, including a Grid DERMS / Orchestration Platform

The program costs and rebates were based on current or previously deployed AES Indiana programs, while the grid-optimized managed charging costs are inclusive of the full annualized cost of Camus' orchestration platform. Importantly, this includes a very conservative assumption that the full cost of the orchestration platform is associated only with the benefits modeled in this analysis. This ignores other quantitative and qualitative benefits of grid-wide visibility, forecasting, and DER orchestration.

Putting it all together

After executing on the methodology outlined above, we assessed the impacts on both the system level and the distribution system assets and calculated the costs and benefits associated with each of the included scenarios (including time-of-use and managed charging interventions, both EV charging coincidence levels, and conservative versus aggressive EV adoption rates).

We present the results of this analysis–including the identification of the tipping point for AES Indiana–in the following section.

Results: A tipping occurs at 5% system-wide EV adoption

Investing in EV visibility and grid-informed managed charging in 2025 generates optimal outcomes: $7.3 million in net present savings and $75 million per year in capital flexibility

We found that AES Indiana's tipping point occurs at 5% system-wide EV adoption for residential customers. This adoption level–which is lower than many utilities expect–represents the point at which investments in grid-optimized managed charging and EV visibility provide annual benefits that surpass annual costs.

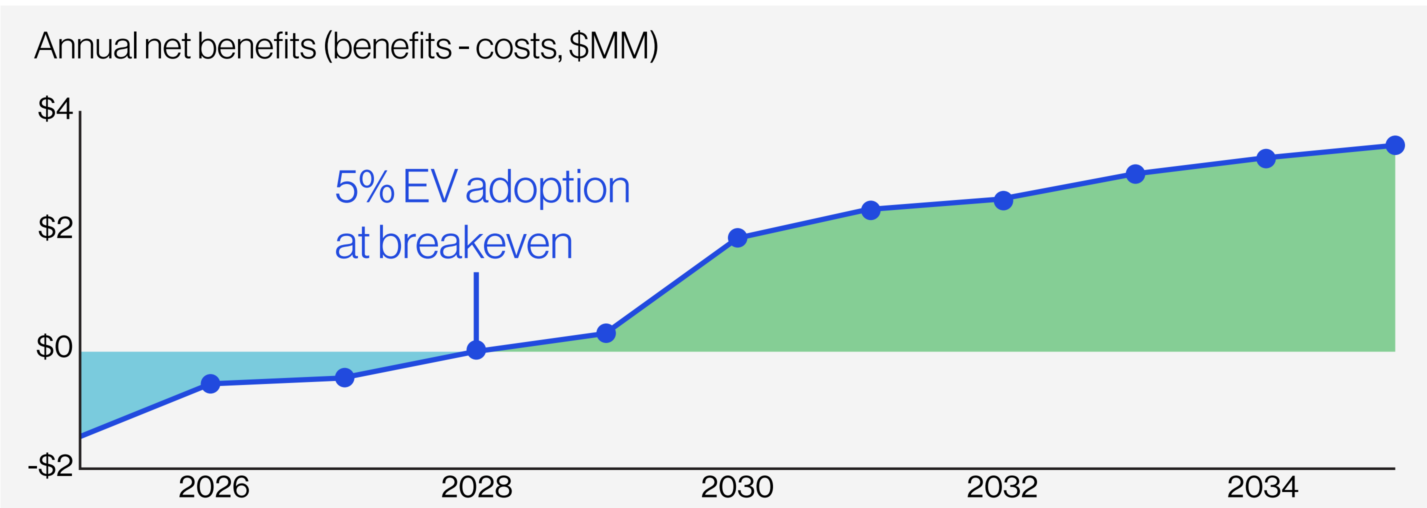


Fig 5. Area chart of annual net benefits from optimal strategy; the point where benefits from EV visibility and managed charging exceed costs occurs in early 2029, at which point the system-wide EV adoption is 5%

Why does this tipping point occur at low adoption rates? This adoption rate equates to a higher penetration of EV loading on a subset of feeders and transformers – with nearly 1 in 5 feeders seeing more than double the system wide adoption of 5% (see Figure 6). The coincident charging sessions for these feeders and transformers drive the initial set of deferrable equipment upgrades, which in turn provide 70% of the benefits in the tipping point year. As EV adoption continues to increase after this tipping point, additional feeder upgrades are able to be deferred as more feeders see higher percentages of EV adoption.

We found that AES Indiana can best reduce costs and increase investment flexibility by proactively preparing for the tipping point. The optimal outcome comes from investing in EV visibility and grid-optimized managed charging starting in 2025 – with EV programs scaled and active by the time the tipping point is reached in the early 2029. Doing so drives 1) $7.3 million in net present benefits and 2) an increase of $75 million in annual capital flexibility – or $1,275 per year for each new EV in the service territory.

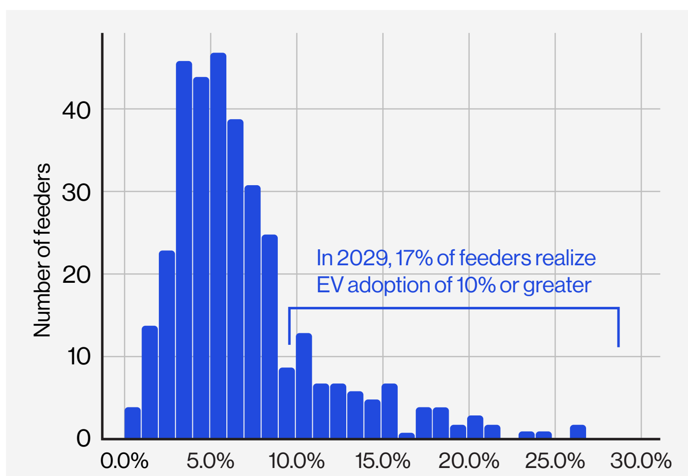


Fig 6. Histogram of EV adoption (as a percentage of meters on a given feeder) for the 2029 tipping point year.

Beneficial actions enabled by visibility and coordination

The analysis revealed that AES Indiana can take 4 actions to unlock benefits that greatly exceed the costs of deploying hardware and software systems as EV adoption approaches 5% penetration:

Pursue both system-wide peak management and local distribution capacity management through integrated distribution planning – increasing total benefits by 3.8x versus system peak management alone

Deploy EV visibility solutions to enable AES Indiana distribution planners to refine and reduce their charging coincidence assumptions to 20% (feeders) and 40% (transformers). This will defer upgrades on 87% of eligible feeders and 66% of eligible service transformers for ~7.4 years.

Transition from time-of-use rates to grid-optimized managed charging programs, enabling further deferral of 30% of equipment upgrades and extending deferral duration by an average of 4.3 years relative to standard coincidence assumptions

Use the $75 million in annual capital flexibility unlocked through upgrade deferrals, or $1,275 per new EV, to invest in enhancing grid-wide reliability and affordability

Beneficial Action 1: Pursue both system-wide peak management and local distribution capacity management through integrated distribution planning – increasing total benefits by 3.8x versus peak management alone

At AES Indiana, like many utilities, the responsibility for procuring sufficient generation capacity – such as the solar, wind, and natural gas plants that generate electricity – is held by the resource planning team, while the responsibility for planning infrastructure investments that ensure sufficient transmission and distribution capacity is held by the distribution system planning team.

This is a subtle but important distinction. The resource planners focus on how DER flexibility can reduce electricity demand during system-wide peaks – thereby lowering the quantity of required generation capacity. This is the traditional role of demand response programs. The distribution system planners, meanwhile, focus on local network capacity management – and have historically viewed residential DERs as too small and diffuse to impact their approaches.

We found that capturing both peak management and distribution network management benefits of EV flexibility is essential to achieving a robust return on EV-related investments. With just peak management alone, the net present costs of EV programs at AES Indiana ($9.6 million) over the study period are 50% higher than the net present benefits ($6.4 million).

Managing charging in ways that reduce peaks and defer feeder and service transformer upgrades, however, increased net present benefits by 3.8x to $24.7 million and shifted EV programs from net negative to net positive.

To pursue both system peak management and distribution network management benefits, AES Indiana can support the adoption of integrated distribution system planning practices – enabling the resource and distribution planners to work together to maximize benefits from DERs.

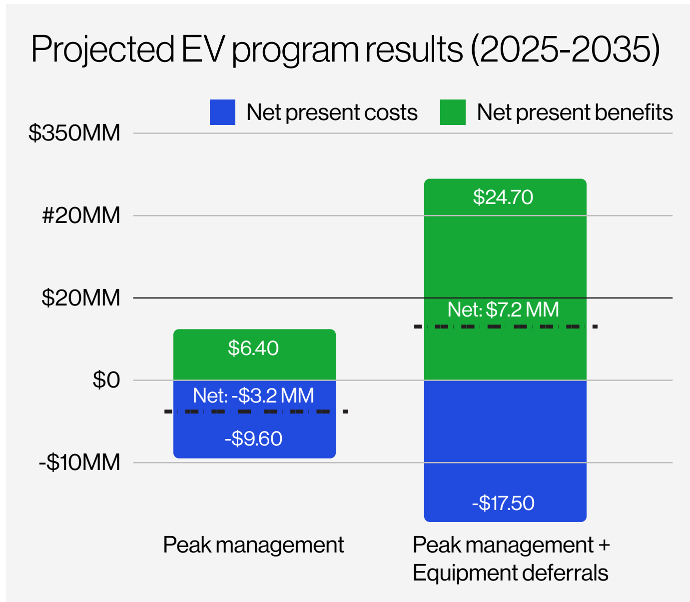


Fig 7. Projected EV program results

EV Program Results	Peak Management	Peak Management + Equipment Deferrals
Net Present Benefits	$6.4M	$24.7M
Net Present Costs	$9.6M	$17.5M
Utility Cost Test (UCT) (Net Benefits / Net Costs)	0.67	1.42

Table 1. Projected EV program results with peak management versus peak management and equipment deferrals

12. As described in Beneficial Action #2, time of use rates have a negative impact on deferral benefits (decreasing the utility cost test score); the results in this table are for managed charging programs

13. https://www.energy.gov/oe/integrated-distribution-system-planning

Beneficial Action 2: Deploy EV visibility solutions to enable AES Indiana distribution planners to refine and reduce their charging coincidence assumptions to 20% (for feeders) and 40% (for transformers). This will defer upgrades on 87% of eligible feeders and 66% of eligible service transformers for ~7.4 years.

As discussed in Step 3 of our methodology, EV charging coincidence is a crucially important assumption when evaluating the impacts of residential EV charging on distribution grid upgrades. In the business-as-usual case with a 40% coincidence assumption for feeders and a 70% coincidence assumption for service transformers[14], AES Indiana would need to upgrade approximately 46 feeders and 7,370 service transformers between 2025 and 2030. These represent 11% and 9% of currently installed feeders and service transformers, respectively.

By reducing the charging coincidence assumptions, AES Indiana can defer 40 feeders (87% of expected upgrades) for an average of 5.8 years and 4,872 service transformers (66% of expected upgrades) for an average of 8.4 years (see Table 2).

	Feeders	Service transformers
Equipment Count	~400	~83,000
Expected Upgrades (Standard Coincidence Assumptions: 40%, 70%)	46 (11% of total)	7,370 (9% of total)
Upgrade Deferrals (Shift to Behavior-Informed Coincidence Assumptions: 20%, 40%)	40 (87% of expected)	4,872 (66% of expected)
Average Deferral Duration	5.8 years	8.4 years

Table 2. Expected upgrades and deferrals for feeders and service transformers across coincidence assumptions

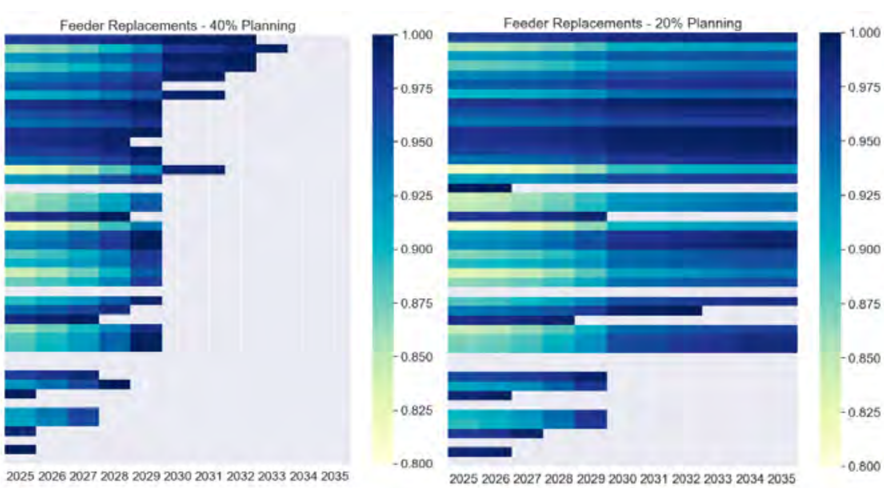


Fig 8. Duration until feeder upgrades are required over the 10 year analysis period for the two different coincidence scenarios modeled. Longer bars equate to a longer period before an upgrade. Feeder capacity is shown in the color scale (a value >1.0 triggers the feeder upgrade).

The figure to the left illustrates the impacts of shifting the feeder coincidence assumption from 40% to 20%. The chart on the left shows the number of years until each feeder is replaced with a 40% assumption. When a horizontal bar ends, that feeder is replaced. This includes all 46 feeders upgraded in the business-as-usual scenario. On the right, the same information for the 46 feeders is shown, but with a 20% charging coincidence assumption. By comparing the charts, it's clear that the 20% coincidence assumption results in longer periods of time before feeders must be replaced.

14. The lower coincidence assumption for feeders (relative to transformers) is based on the fact that as you move higher up in the distribution system, load diversity increases. There are more meters/EVs/etc. and there is a greater chance that they do not all turn on at the same time.

How can AES Indiana confidently adopt lower coincident charging assumptions?

AES Indiana distribution planners articulated that planning for lower charging coincidences is only feasible where backstops are available to avoid negative impacts during infrequent periods of elevated coincidence.

Distribution planners need to know that operators have the right tools to ensure loads do not exceed distribution network capacity if EV chargers begin charging at full power at the same time. While infrequent, events like winter storms or even a big summer holiday can cause charging coincidence to spike temporarily.

By deploying operational solutions to avoid equipment overloading during times of elevated charging coincidence, AES Indiana can unlock significant benefits. The two solutions on which this analysis focuses are 1) EV visibility and 2) grid-optimized managed charging. While the latter is well defined in Step 4 of our methodology, EV visibility refers to the ability to monitor EV charging behavior and analyze impacts on upline equipment.

These capabilities are key to enabling effective integrated distribution system planning workflows and laying the data foundation for grid-optimized managed charging.

While not explored directly in this analysis, another operational solution leveraged by AES Indiana planners is automated switching. Automated switching refers to the ability to use observed data from distribution grid sensors to automatically configure switches open or closed, intentionally altering the flow of power across utility equipment. This solution is typically most relevant for urban feeders and highly localized coincidence events.

For this analysis, we assume investments in EV visibility enable the following capabilities:

- Monitor near real-time and historical EV charging at every meter
- Forecast day-ahead, non-EV loads for every meter
- Aggregate EV charging and meter data to upline transformers, feeders, and substations
- Estimate day-ahead available capacity for EV charging at every upline transformer, feeder, and substation

15. For example, overloading of a substation transformer from a heavily-loaded downline feeder could be mitigated by switching a portion of that feeder's loads to another connected substation.

Beneficial Action 3: Transition from time-of-use rates to grid-optimized managed charging programs, enabling further deferral of 30% of equipment upgrades and extending deferral duration by an average of 4.3 years relative to standard coincidence assumptions

Utilities and regulators around the world are examining the relative efficacy of time of use rates versus active managed charging programs. In this analysis, we examined both interventions, leveraging real-world charging data to inform our time of use modeling. We found that:

1. TOU rates were much less effective than grid-optimized managed charging in deferring upgrades. In fact, they caused projected upgrade costs to surpass traditional infrastructure investments by creating new peaks for downline equipment, especially in later years with greater EV adoption.
2. Compared to the business-as-usual base case, grid-optimized managed EV charging delivers significant reductions in the number of projected feeder upgrades throughout the 10-year horizon.

Time-of-use rates can cause earlier equipment upgrades

In numerous programs and studies, time-of-use rates have proven effective at reducing total system demand during high-cost, peak periods. We found this to be true for AES Indiana's existing time-of-use customers.

However, the shifting of heterogeneous loads to an off-peak period can cause demand spikes at the start of that period. Such spikes occur in the EV load profiles of customers on AES Indiana's TOU rate.

As residential EV loads become the leading contributor to local peaks for residential feeders, the effect of TOU rates can be to inadvertently create a new local peak for the feeder at the start of the shoulder and/or off-peak periods (see Figure 9).

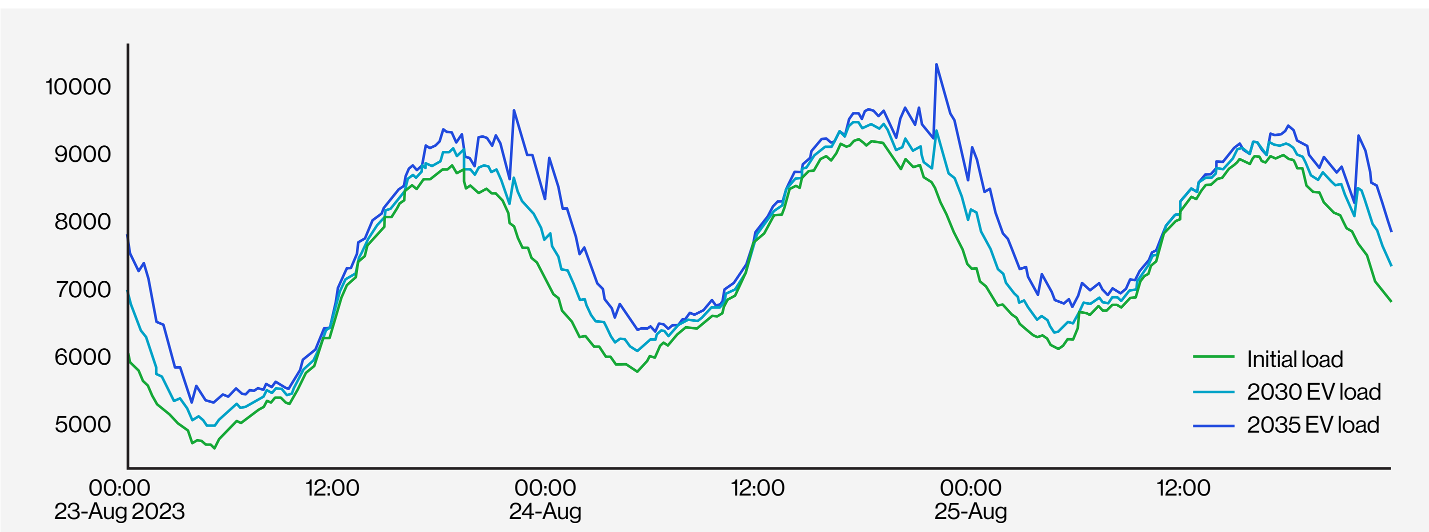


Fig 9. This chart shows how TOU rates push EV charging load on an AES Indiana feeder to later into the evening by 2030 and create a significant new peak by 2035. The green line is the initial pre-TOU loading, while the blue and aqua lines each represent future loading with EVs on TOU rates.

As a result, TOU rates accelerate the time to upgrade for feeders by an average of 5.1 years, leading to 2.2x as many feeder upgrades over the 10-year analysis period. Similarly, TOU rates accelerate the time to upgrade for service transformers by an average of 6.2 years, leading to 1.5x as many upgrades during the analysis period.

14. The lower coincidence assumption for feeders (relative to transformers) is based on the fact that as you move higher up in the distribution system, load diversity increases. There are more meters/EVs/etc. and there is a greater chance that they do not all turn on at the same time.

Grid-optimized managed charging more effectively defers upgrades

Unlike TOU rates, as residential EV loads become the leading contributor to local peaks for residential feeders, grid-optimized managed charging is able to adjust charging schedules to avoid creating new peaks. As a result, grid-optimized managed charging is effective at delaying feeder upgrades across all modeled planning assumptions.

Compared to TOU rates, grid-optimized managed charging delivers better performance in deferring equipment upgrades during the 10-year horizon. With behavior-informed charging coincidence assumptions (20% for feeders, 40% for transformers), grid-optimized managed charging further defers 30% of expected feeder upgrades for an average of 4.3 years and 24% of expected service transformer upgrades for an average of 9.1 years.

Impacts from Interventions (Assumes 40% Charging Coincidence for Transformers, 20% Charging Coincidence for Feeders)	Feeders		Service Transformers	
	Net Deferrals	Duration	Net Deferrals	Duration
Time of Use Rates	-23 (50% of expected)	-5.1 years	-1,624 (22% of expected)	-6.2 years
Grid-Optimized Managed Charging	+14 (30% of expected)	4.3 years	+1,750 (24% of expected)	9.1 years

Table 3. Effectiveness of interventions in deferring upgrades relative to the base case

Compared to TOU rates, grid-optimized managed charging provides significantly longer deferral periods, driving increased capital flexibility and savings for AES customers.

Interventions modeled

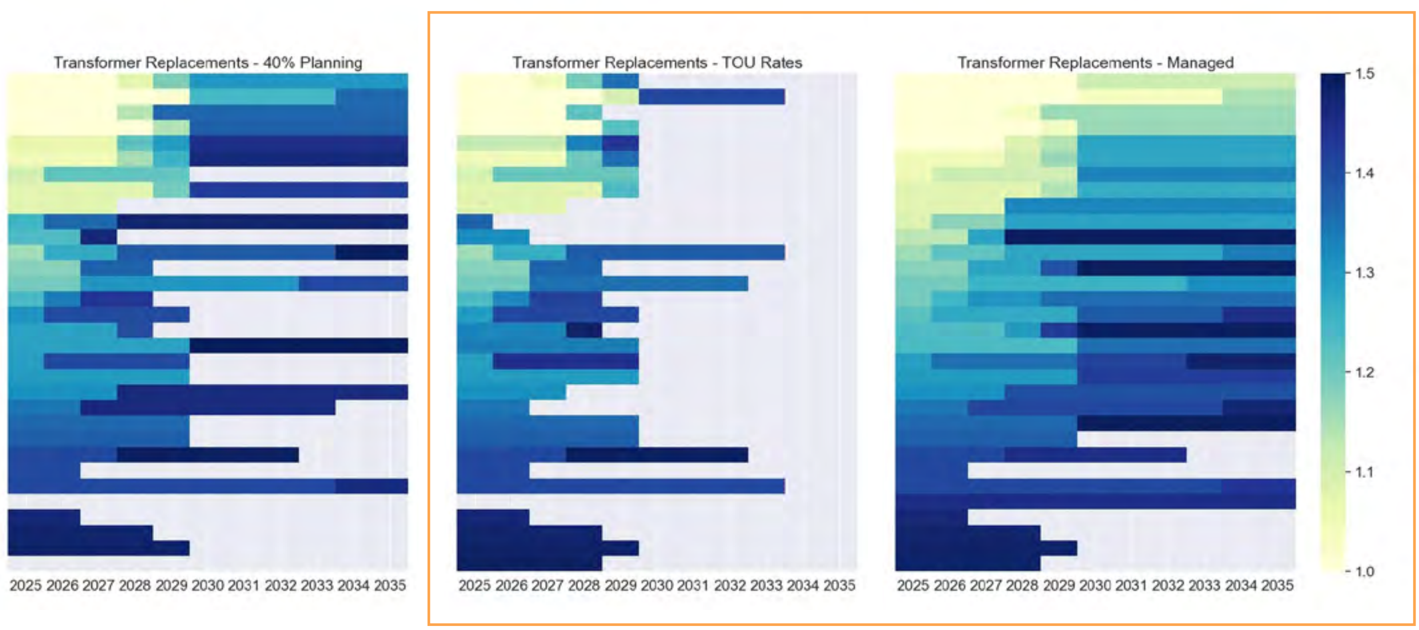


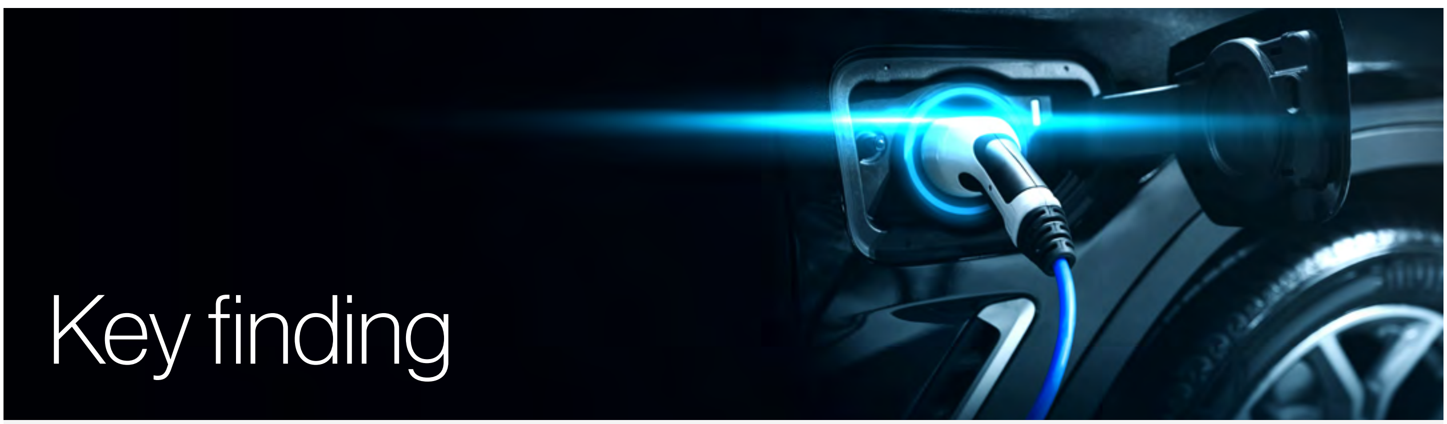
Fig 10. Duration until feeder upgrades are required over the 10 year analysis period for the two different coincidence scenarios modeled. Longer bars equate to a longer period before an upgrade. Feeder capacity is shown in the color scale (a value >1.0 triggers the feeder upgrade).

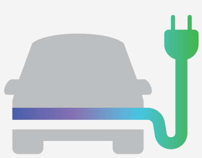
Beneficial Action 4: Use the $75 million in annual capital flexibility unlocked through upgrade deferrals, or $1,275 per new EV, to invest in enhancing grid-wide reliability and affordability

By adopting behavior-informed charging coincidence assumptions and optimizing EV charging to remain within available distribution network capacity, AES Indiana can defer 43 feeders for an average of 6.8 years and 5,872 service transformers for an average of 9.7 years. That sums up to delay ~$112 million in upfront capital expenditures for an average of 8.5 years, providing nearly $1 billion in cumulative capital flexibility versus the business-as-usual scenario.

> This equates to $75 million per year in capital flexibility or ~$1,275 per year for each of the ~59,000 new EVs added to AES Indiana's service territory between 2025 and 2035.

AES Indiana could instead use this money to invest in grid-wide reliability and affordability efforts, turning capital that would have been used to benefit a small number of customers into investments that bring benefits to all.





EV visibility and grid-optimized charging unlocks $1,275/year in capital flexibility for each new EV adopted.

Fig 11. Summary figures from our analysis estimating the amount of capital flexibility unlocked through investments in EV visibility and grid-optimized EV managed charging.

Recommendations for utilities and regulators

Through this analysis, AES Indiana discovered that EV adoption rates do not need to be large to cause material impacts on the distribution grid. For utilities grappling with numerous competing priorities, choosing the right actions today to prepare for an uncertain pace of EV adoption is a difficult challenge.

Our hope is that by sharing these findings, we can provide a framework for how other utilities can analyze the impacts of residential EVs on their distribution systems and determine when and how to invest in EV visibility and coordination. We believe our bottom-up methodology is effective and repeatable for utilities across the country – as the required data and technology is readily available.

By taking these actions, we believe utilities can best prepare for EV-related grid impacts at a pace that delivers maximum value to their communities. We welcome engagement on these findings and hope our experience can benefit others.

For utilities and regulators looking for a short list of priority actions to take today, we share three main recommendations:

1. Invest in EV visibility to avoid leaving value on the table or unintentionally building more grid infrastructure than necessary.

2. Deploy operational tools to manage periods of high EV charging coincidence through coordination. One approach might be to start with demand response and then implement managed charging, creating a clear roadmap to fully scaled, grid-optimized managed charging by the time the EV tipping point occurs.

3. Free up capital flexibility through equipment deferrals to enable more strategic investments that address increasing demands on the power system