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A framework to measure the technical, economic, and rate impacts of distributed solar, electric vehicles, and storage

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Abstract

This study explores the joint impacts across the power system of distributed energy resources (DER) that could be deployed in utility distribution systems through an analysis of generation, transmission, and distribution expansion and costs driven by DER adoption. We identify six adoption scenarios that combine deployment levels of rooftop solar photovoltaic modules (PV), electric vehicle charging (EV), and battery storage in residential and commercial customers connected to representative feeders in Indiana by 2025 and 2040. Indiana is a good proxy for many U.S. states with low current DER adoption but potentially high future growth. The economic value of DER is assessed by developing capacity expansion and power flow analysis of the generation and distribution segments, respectively, under future hourly demand assumptions based on each adoption scenarios. Results for the distribution system power flow simulations show that voltage violations are relatively rare. Voltage violations can be mitigated at a very low cost using a combination of smart inverters in future rooftop PV systems and voltage adjustments in the feeder heads. Line loading issues are minimal, with only 0.2% of simulation hours showing loading levels above 100% of capacity. Generation capacity impacts are driven by unmanaged EV charging and could be mitigated with charging management. We estimate that the incremental rate impact from power system investment and operation of increased DER adoption in Indiana will be between -1.6% to +2% in 2025 and +0.2% to +15% in 2040 relative to the base case.

Keywords: distributed energy resources; power system; cost benefit analysis; rooftop solar

List of abbreviations

ANSI	American National Standards Institute
BPS	Bulk Power System
CCCT	Combined Cycle Combustion Turbine
DER	Distributed Energy Resources
DG	Distributed Generation
DR	Demand Response
EE	Energy Efficiency
EV	Electric Vehicle
IOU	Investor Owned Utility
IRP	Integrated Resource Planning
LMP	Locational Marginal Prices
LTC	Load Tap Changer
O&M	Operations and Maintenance
PCA	Principal Component Analysis
PV	Solar photovoltaic
SCCT	Simple Cycle Combustion Turbine
T&D	Transmission and Distribution

1. Introduction

There are several types of emerging technologies that are being deployed or could be deployed in the distribution system and behind the meter. Technologies can produce electricity (e.g. solar photovoltaic (PV) panels, natural gas micro-turbines), store electricity (e.g. batteries, flywheels), consume electricity in novel ways (e.g. electric vehicles) and improve electricity management and consumption (e.g. smart thermostats, super-efficient appliances). These technologies are grouped and identified throughout this document as Distributed Energy Resources (DER). DER hold the promise to add value to the power system, but their decentralized deployment and operation will technically and economically impact different segments in the power system [1]. The motivation for this paper is to understand the impacts that DER adoption and operation will have across a regional power system. This paper answers the question: what are the technical and economic impacts of DER adoption in distribution, transmission, and generation? The paper answers the question by developing a framework to create DER adoption and operation scenarios whose output can be integrated into existing distribution and bulk power system (BPS) techno-economic simulation and optimization tools.

Over the last decade, customer-owned DER uptake has increased across the U.S. This increase has been driven by policies, prices, consumer attitudes, and attractive financing options for customers. Research oriented to understand the impacts of DER penetration has focused on U.S. states with higher adoption levels such as Hawaii, Massachusetts, or California. This paper uses the state of Indiana as a case study to produce results that would apply more generally to the vast majority of U.S. states that have yet to experience an increase of DER uptake. Based on the information shared by the five Indiana investor owned utilities (IOUs) that contributed to this study, only 0.14% of residential customers and 4.7% of commercial customers own a PV system, and almost no customers in Indiana own a storage system. Integrated resource plans (IRP) filed by Indiana IOUs shows an increased focus on customer-owned PV and EV adoption, but no analysis of DER battery storage (see Table A.1 in Supplementary Information(SI)). It follows that states like Indiana have significant room to expand DER adoption and would benefit from a planning framework and research findings that would help understand the impacts of these expansions. This work was developed at the request of the Indiana Utility Regulatory Commission, which explains the applied approach of integrating existing models to make this framework easier to understand and adopt by utilities, system planners, and other stakeholders.

This paper makes several novel contributions. First, it develops and applies a framework to assess impacts of DER adoption across the distribution, transmission, and generation systems. There are very few attempts to develop impacts of DER across all segments of the system, but they usually employ complex models that require substantial simplification of the grid, especially the distribution system. The proposed approach produces a coordinated sequence of simulations that produce technical and cost estimates for DER impacts using industry-standard models. Second, the paper produces empirically-derived adoption scenarios and allocates DER to customers based on income and consumption levels for realistic spatial distribution. The six scenarios developed are generalizable to any jurisdiction that wants to understand the interdependency of solar PV, electric vehicle, and energy storage adoption based on adoption and operational patterns. Third, it develops a rigorous technical impact analysis in distribution and generation using power flow and capacity expansion tools, then estimates cost impacts, and finally translates these outcomes into rate impacts. There are no known papers that have addressed these three impact components in the same framework. The relevance of the joint analysis is two-fold. On one hand, it suggests that certain segments of the power system – distribution, transmission, and generation – can be benefited or unaffected by DER operation, while others can be substantially affected in the same scenario. An individual segment analysis is unable to capture this dependencies. On the other hand, it shows how technical and economic impacts are ultimately reflected in rates, whose levels depend on the balance of retail sales, peak demand, capital investments, and operational costs. A non-integrated analysis may find cost reductions that may, under certain circumstances, still lead to increases in rates. Finally, the paper develops a rigorous statistical method to cluster actual distribution feeders to produce a representative topology of feeders focused on capacity expansion analysis. Distribution systems are complex, but relatively homogenous within service territories, and hence it is possible to represent the aggregate impacts of millions of distribution system customers with a reduced number of representative circuits. While work on this space exists (e.g. [2–4]), this is the first application of representative feeders in a whole-systems analysis.

In the rest of the report, section 2 summarizes applicable literature, highlighting how this paper builds from and expands existing work. Section 3 details the methodology developed to represent the distribution system, develop scenarios, assess technical impacts, and estimate cost and rate impacts. Section 4 explains the approach to create DER adoption and operation scenarios for this application.. Section 5 presents the technical impact results and section 6 presents the economic and rate impacts, both separately for each segment of the power system. Section 7 concludes with result and innovation highlights. All monetary values in this report are expressed in real 2017 dollars unless otherwise indicated.

2. Literature review

Several fields of study contribute to the growing body of literature examining the implications of increasing DER penetration in power systems. These studies explore current and future DER adoption trajectories and assess the impact across a number of dimensions, including the distribution system, bulk power system, distribution planning processes, ratepayer and societal costs and benefits, and utility business models. Table 1 organizes the scope and dimensions of analysis that characterize the work to understand DER impacts in the power system. In terms of the power system structure, the literature generally focuses on either the distribution or the transmission-generation (i.e. the BPS) segments, with much limited work on all three jointly given computational challenges. In terms of dimension of analysis, work can be categorized as focused on technical or physical results, economic results, and in fewer cases rate impacts. As shown in Table 1, each one of these combinations can include several papers. Additionally, papers tend to focus on single DER (e.g. solar PV, distributed generation, or EV) but rarely examine several at the same time. An exhaustive analysis of work in all combinations in Table 1 – essentially, on each cell in the matrix – is impractical. The main purpose of Table 1 is to demonstrate that there is little to no work that encompasses all these cells at the same time and for several different DERs. The framework to achieve this analysis in a coordinated, sequential manner utilizing industry-standard tools is the main contribution of this paper. In this review we focus on research on (1) technical and economic impacts of DER on distribution system, (2) technical and economic impacts of DER in the BPS, and (3) joint analysis of distribution and BPS impacts. This selection is justified because research in these topics is used to inform the tools and approaches employed in this paper and to focus on the few whole-system analyses that exist and how the present work differs from them.

Table 1. Scope of literature reviewed

Power system segment	Dimension of analysis: Technical/Physical	Economic (cost and/or benefit)	Rates
Distribution	[5], [6], [7], [8], [9], [10]	[11], [12], [13], [14] (Value of solar)	[17,18]
Transmission and Generation	[19], [20], [21]	[15,16] (BPS)	

A number of studies have modeled high PV penetration on feeders and assessed the technical impacts. A paper found that distributed generation (DG) can have positive impacts (voltage support, deferred capital investments) and negative impacts (protection coordination, voltage regulation, voltage flicker, short circuit levels) [5]. The Pacific Northwestern National Laboratory (PNNL) summarizes the major types of analysis conducted on electric distribution systems along with their applications and relative maturity levels [6]. Special emphasis is placed on distribution system analyses required for increasing levels of DERs. The National Renewable Energy Laboratory (NREL) catalogs distribution-level impacts of high PV penetration, including overload-related, voltage-related, reverse power flow, and system protection impacts [7]. EPRI discusses practical planning limits for adding DG to distribution circuits [8]. The report classifies the limits into four categories: voltage regulation (e.g. voltage rise), rapid voltage change (fluctuations, sudden loss of generation), thermal limits (capacity, losses), and protection limits (overcurrent, islanding) Another paper investigates the impact of different electricity pricing systems and their impact on charging of electric vehicles (EVs) and battery storage [9]. It then compares the impact EVs and storage would have in the different scenarios on the integration of photovoltaic (PV) systems. However, neither of these studies analyze the technical impacts on transmission and generation.

A growing body of literature analyzes the benefits and costs of DER. [11] reviews methods for analyzing the benefits and costs of distributed PV generation to the U.S. electric utility system. Utilities will occasionally commission “value of solar” studies in their service territories to understand the benefits and costs specific to their geographic location, generation portfolio and customer base. RMI reviews sixteen distributed PV benefit/cost studies by utilities, national labs, and other organizations [12]. These studies reflect a significant range of estimated distributed PV value. Some studies examine costs and benefits at a broader level, such as the economic impact of distributed PV in California [13] and, closer to Indiana, the value of DG in Illinois [14]. Elements of these studies inform the DER valuation framework developed in this paper. It is important to note that these studies solely focus on distributed solar, not capturing the interactions with other DER such as the ones analyzed in this paper. In addition, they tend to significantly simplify the simulation of impacts in the distribution system by using historical investment trends, as opposed to the feeder-level analysis proposed in this paper.

Several studies have addressed the impacts of DER on the BPS. The Electric Reliability Council of Texas (ERCOT) identified areas of concern related to reliability impacts of DER to the BPS: increased error in load forecasting, less accurate inputs to Independent System Operator (ISO) functions, and uncoordinated system restoration after a load shed event [19]. The North American Electric Reliability Corporation (NERC) examined the potential reliability risks and mitigation approaches for increased levels of DER on the BPS. The objective was to help regulators, policy makers, and other stakeholders better understand the differences between DER and conventional generation with regards to the effect on the BPS [20]. NERC also created a DER Task Force which developed DER modeling recommendations for BPS planning studies [21]. There are techno-economic analyses investigating the impact of DERs on transmission costs and investments using an approach to optimize the location of DERs to minimize costs [15,16]. While these techno-economic studies are useful, they do not reflect the impacts of unmanaged DER location that characterize existing distribution systems.

Whole system studies have been framed in different ways. A strand of literature concerns with integrating energy and electricity delivery systems. For example, heat and electricity systems were analyzed for the U.K. [22] and Germany [23], including generic national optimization frameworks [24]. A few studies have investigated the impacts of DER on the distribution and bulk power system in an integrated or combined analysis. One study utilized synthetic distribution grid models combined with a transmission grid model to represent the German transmission grid to generate an integrated model of the distribution and bulk power system [25]. Another study did create an integrated model to analyze reactive power management in an approach considering the transmission and distribution level. This was also based on the German transmission grid and combined with generic distribution grid models [26]. The present paper, however, focuses on a sequential analysis of all electricity system segments: distribution, transmission, and generation. In this space, papers have developed whole-system modeling efforts to jointly optimize investment in generation, transmission and distribution. For example, the techno-economic effect of bulk and distributed energy storage on the power system of Great Britain were analyzed [27]. Another example discussed investment decisions in DER vs distribution system expansion in the context of electricity access [28] and for a mature U.S. vertically integrated utility [1]. A recently developed model was built with enhanced capacity to handle vast amounts of data to simulate distributed and BPS resources [29]. These integrated models generally simplify distribution system simulation and use synthetic distribution system models for their analysis rather than real world feeder models, which ignore the unique configurations of some real world feeders. These large integrated models are useful for coordinated planning, but this only applies to certain vertically integrated utilities. In contrast to a single integrated model, this paper suggest methods to produce and interpret results of system-specific models – BPS and distribution – to assess the impacts of DER across the whole system, regardless of their economic organization [30].

3. Methodology

Figure 1 describes the structure of this study in terms of four key processes. First, the distribution system is characterized by identifying representative feeders and creating scaling factors for each.

Second, DER adoption and operation scenarios are developed for each customer on each representative feeder. Their net load is scaled and aggregated to the state level for the transmission-generation analysis. Third, a techno-economic capacity expansion and dispatch analysis is developed for the distribution system and the BPS using the industry-standard Cymdist and Aurora models, respectively [31]. This analysis is based on the two previous steps: representative feeders and customer net load for distribution system power flow and transmission-level demand for generation-transmission expansion and dispatch. Finally, retail sales, peak demand, and cost impacts are integrated into a ratemaking model to assess rate impacts.

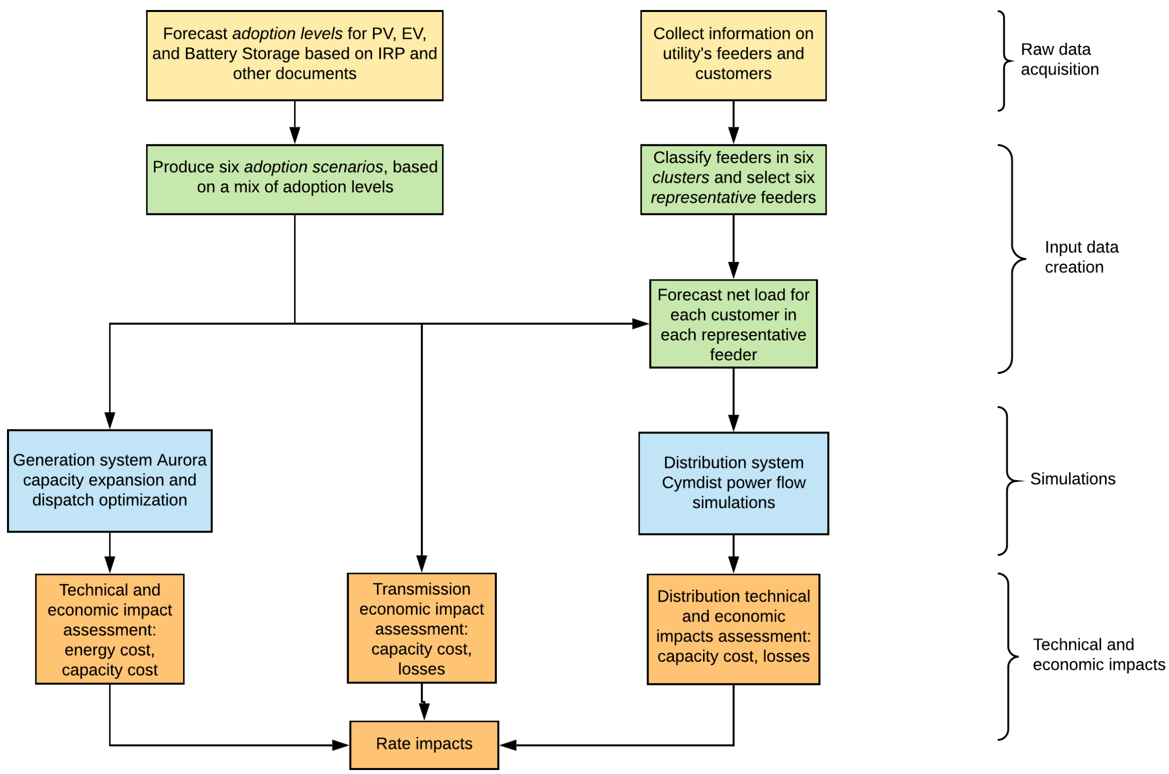

Fig. 1. Process and stages included in the methodology

DER can impose technical costs to the distribution system due to their impact on voltage levels and line loading, among other impacts. DER can also benefit the distribution system by reducing line and transformer losses and by deferring capacity investments. Due to the integrated nature of power systems, DER costs and benefits can also accrue in the transmission and generation levels. We call these economic outcomes of DER integration “value streams”. DER have a wide array of value streams [32–34], but this study focuses on a subset of possible value components including energy cost, losses, and capital deferment (capacity value). Due to technical and resource limitations, a number of additional value streams identified in the literature were not considered. These include DER impacts on ancillary services, fuel price hedging, and wholesale price reduction. Ancillary services such as frequency regulation can be a relevant value stream for battery storage [35]. However, there is no simplified method to determine the potential contribution of DER to this value stream that could be applied within our framework.

3.1 Representative feeders

In contrast to most integrative studies of DER impacts, we sought to rigorously capture the impact of DER on distribution system through power flow simulations. The sheer number of feeders in Indiana require a sampling approach to identify representative feeders that can be used for simulation and result extrapolation. This study employs clustering techniques, especially the method developed by [2], to produce a set of six representative feeders for the five IOUs in the state of Indiana. The number of representative feeders balances breadth with the ability to accommodate the number of power flow simulations necessary given the number of customer loads, time horizons, and DER adoption scenarios. On average, each feeder is simulated approximately 570 times.

The method to identify representative feeders involves four steps: (1) identify available feeder metrics for clustering, (2) transform the data using Principal Component Analysis (PCA) and identify outliers, (3) determine the optimal number of clusters, and (4) select representative feeders for each cluster. After feeders are selected, DER adoption and synthetic hourly operation are simulated for each customer on each feeder. A detailed explanation of the feeder sampling, clustering, and selection process, and input data creation for power flow runs is available in section C in the SI. Since the feeder clustering process is considered part of the method – rather than a result of this study – a description and key statistical variables for the final representative feeders with are shown in Table 2.

Table 2. Six representative clusters and a sample set of parameter statistics

Cluster	General description of feeders in cluster	Average customer number	Average total length (miles)	Average CAIDI (min)	Share of installed capacity (residential)	Share of installed capacity (commercial)	Share of installed capacity (industrial)	Share of circuit length that is underground
1	Short and high commercial, about 1/3 underground	445	9.5	145.1	25%	58%	6%	30%
2	Short, urban residential	567	11.5	142.4	77%	17%	2%	19%
3	Suburban mostly overhead, residential, relatively dense	1,472	21.7	135.4	70%	21%	7%	20%
4	Very long residential mostly rural	1,133	59.3	148.5	78%	15%	3%	19%
5	Suburban underground residential relatively dense	1,535	26.2	121.4	77%	17%	5%	67%
6	Short, heavy industrial, substantial underground	463	10.0	120.8	15%	31%	51%	39%

3.2 Energy costs

Operation of DER changes the shape and level of the net demand that is supplied by the BPS. The change in shape can produce costs or benefits depending on how the BPS dispatch curve changes and whether more flexible resources for ramping are needed (e.g. to address the "duck curve" phenomenon) that would incur additional fuel charges.

Change in levels can also be bidirectional: net demand can decrease with high levels of PV generation, often resulting in savings from less energy produced at the utility-scale. However, BPS energy consumption can also increase with EV charging. The timing of these changes, captured by the shape component, impacts resource adequacy requirement at the BPS-level. However, these capacity requirements are captured through a different value stream described later.

Changes in energy consumption and their monetization will employ the Aurora capacity expansion and production cost model. The process to employ Aurora for this purpose follows these steps:

1. Produce hourly net demand differentials between the base case scenario and each one of the five adoption scenarios presented in Section 4.
2. Add the scenario net demand differentials to the base case to produce five net demand sets that are consistent with their assumptions, but at the same time reflect the adoption levels determined in this study's scenarios.
3. Interpolate the years between 2025 and 2040 to provide the data needed for the capacity expansion model.
4. Input these assumptions in the model and run it for each hour of the year.
5. Calculate the dispatch costs (fuel and non-fuel variable costs, ramping costs, and spinning and non-spinning reserves costs) for each hour, and produce annual totals.
6. Compare state-wide present value of dispatch costs for each adoption scenario against the base case.

3.3 Losses

Transmission and distribution losses may be reduced or increased due to the presence of DER. Distribution losses can go in either direction depending on their capacity relative to the hosting capacity and their location within the feeder. Traditionally, distribution feeders follow a "conic" construction method, with higher gauge wire close to the head and lower gauge wire close to the ends. Then, higher power flow levels close to the end of the feeder have a disproportionate impact on losses compared to the same flow levels close to the feeder head. Transmission losses would generally decrease due to reduced loading in the lines. For the purposes of this study, we do not assume that DER deployment results in power flowing back into the transmission system with a corresponding increase in losses.

Distribution line losses for the primary voltage system will be assessed directly from the Cymdist modeling results for each representative feeder. We will prepare and run a specific set of simulations for energy losses using 24 hours on a typical day per season (fall, winter, spring, and summer). The days are selected as the median load day on each season. The objective of this approach is to capture typical losses levels that are representative of the adoption scenario, rather than losses at maximum/minimum load conditions. Feeder-level energy losses levels for each scenario will be compared against the base case. Losses differences can then be monetized using either retail rate or an average wholesale purchase price.

Transmission losses cannot be directly calculated because there is no explicit modeling of the transmission system available. We will estimate transmission losses changes based on the difference between aggregate net demand in the base case scenario and the adoption scenarios. For example, if energy consumption is 10% higher in one adoption scenario compared to base case, then we will assume that transmission system losses will be 10% higher as well. While imperfect, this will allow to monetize transmission losses changes into rates.

3.4 Capital deferment (capacity value)

DER operation can defer or increase future investments in generation, transmission, and distribution. As with losses reductions, DER may produce capital deferments in generation and transmission. However, DER deployment can require flow capacity and safety upgrades in the distribution system and can trigger the need for flexible resources at the generation and transmission level to meet additional ramping requirements.

Generation

Capacity value of DER for the generation system can be directly calculated using the results from the Aurora capacity expansion model. Typically, most studies estimate the capacity credit of the different DER technologies, accounting for T&D losses (i.e. referring the capacity credit to the transmission network). However, since the Aurora model is able to simulate capacity expansion for different net demand scenarios, we can directly compare the adoption scenarios against the Base scenario to determine the difference in resource type, capacity mix, and cost.

We estimate potential reductions in planning reserve margin that come from peak demand reductions as part of the generation capacity value. We will implement a simple method that values the changes to the reserve margin based on the reserve requirement output from the Aurora model.

Transmission

Transmission expansion costs are complex to estimate because of the bulky nature of transmission investments and the spatial distribution of transmission system lines and substations. The NREL study proposes three methods to assess capital deferments in transmission systems. Two of these methods require explicit modeling of the transmission network, which is out of the scope of the Comprehensive Study. The third method proposes obtaining transmission locational marginal prices (LMP) and determining the marginal contribution of DER to reduce those LMP. This reduction serves as a proxy for transmission capacity values. However, this method assumes that DER penetration levels do not substantially change the underlying LMP data used for the estimates. This assumption can produce large distortions when applied on analysis performed over long time frames such as this study's.

We developed a simplified method that involves linearizing transmission expansion by estimating a cost of transmission per peak MW transported. These costs are estimated using the rate base information separated by functional category.

Distribution

The methods to assess impacts of DER on distribution system vary significantly in complexity and outcomes. Given that this is a focus of the study, we implement a more sophisticated method based on power flow simulation of actual primary voltage feeder and load data as indicated earlier in this Section. This method has three parts. First, we run power flow simulations for each representative feeder for several combinations of adoption scenarios, hours of the year, and horizon (2025 and 2040). Second, we analyze the technical outcome of each power flow simulation by tracking voltage levels per node, line losses, and line loading. These three parameters are drivers of the feeder upgrades. Finally, we scale feeder upgrades for each cluster to the whole cluster level, and then estimate state-wide DER distribution system integration costs and benefits.

Simulations are performed on the Cymdist power engineering software from CYME/Eaton. Cymdist has a Python API that is used to automate simulations[1]. All active and reactive loads from each Cymdist feeder model are overwritten by reading a csv file with pre-determined hourly values based on the Cymdist input data explained in section C.3 in the SI. The automated framework allows executing thousands of simulations within a short period of time.

We assume that feeders will be upgraded, if needed, to maintain voltage drop, line and transformer loading and losses, within prescribed and accepted levels. In some cases, the DER scenarios may be such that they will prevent an upgrade that would otherwise be required in the base case, accruing savings to the system. This means that we will estimate upgrades required for the base case and determine a total cost for a representative feeder. We then compare these reference costs against the costs to maintain the representative feeders for other adoption scenarios. The cost differential is the DER integration value, which could be positive (a cost) or negative (a savings).

There are no trustworthy automatic upgrade algorithms for distribution systems that can be applied to our setting [36]. Given the volume of simulations performed (close to 1800 individual power flows), we select certain scenarios, years, and hours of the year to manually inspect each representative feeder and decide to implement the following strategies to correct technical issues with feeders:

- Repowering conductors (line loading and losses)
- Add a new voltage regulator or modify the setting of an existing voltage regulator (voltage regulation)
- Modify a substation's tap changers (voltage regulation)
- Adopt and calibrate smart inverters for DER PV (voltage regulation)

Finally, distribution-level capital investments or deferments will be monetized based on current infrastructure costs that were provided by the three Indiana utilities whose feeders were used as the basis of this analysis (see section B in SI).

3.5 Rate impacts

The methods developed in subsections 3.2, 3.3 and 3.4 produce cost estimates for energy, losses, and capacity in generation, transmission, and distribution systems due to DER adoption. We calculate aggregate energy consumption by utility and year and pass this information along with the DER value changes to the ratemaking model. As stated in [37], "the [ratemaking] models determine annual revenue requirements based on each utility's costs associated with existing and future capital investments, operational expenses, debt, and taxes. Those costs are then allocated to the customer sectors and rates are determined using the annual energy forecasts." This is the same ratemaking

[1] The Cymdist power flow simulations were performed using models and Functional Mockup Units developed during the DOE-funded project "CyDER: A Cyber Physical Co-Simulation Platform for Distributed Energy Resources in Smart Grids", which delivered a co-simulation platform based on the Functional Mockup Interface standard.

model employed by the Indiana Utility Regulatory Commission (IURC) in their proceedings.

4. Scenarios

This study produces six scenarios based on different levels of DER and EV adoption. The scenarios were developed to explore how the distribution system would perform under different DER adoption and demand levels. DER and demand are characterized across three dimensions: PV adoption, battery storage, and system demand. Each dimension has one of three adoption levels: business as usual (BAU), high, and very high. The scenarios cover two horizons: a short-term horizon (2025) and a long-term horizon (2040). See Table 3 for the quantitative details of the adoption levels in 2040.

Table 3. Quantitative scenario adoption levels in 2040

Adoption Level	PV	Storage	Electric Vehicles	System Demand
BAU	Established from base case forecast from utility IRPs.	Established from base case forecast from utility IRPs.	Established from base case forecast from utility IRPs.	Established from base case forecast from utility IRPs.
High	15% of customers by 2040 (Based on scenario from IPL IRP)	1% of customers by 2040	23% of vehicle stock by 2040 (Based on scenario from MISO Study)	Base Demand + EV addition
Very High	25% of customers by 2040 (Extrapolation of High Scenario)	5% of customers by 2040	68% of vehicle stock by 2040 (Based on scenario from MISO Study)	Base Demand + EV addition

The purpose of these scenarios is to represent a set of possible futures to explore the behavior of the power system under different circumstances. This type of scenario exploration can help to identify situations in which the system may perform poorly and thus inform decision-makers. Given the applied nature of this work, scenario development follows a more intuitive approach that balances political sensitivity, technical feasibility, and data-driven quantitative approaches. The scenarios are policy-agnostic in that there is no assumption whether the DER adoption or system demand levels are attained through a particular policy mechanism.

The PV and storage dimensions for each scenario reflect the adoption of behind-the-meter DER by customers—and not utility-scale solar or storage. PV systems would thus be customer-installed rooftop PV for residential and commercial customers. Battery storage systems are less common than PV in each scenario and are assumed to be installed at the same site as PV. The batteries were sized to reflect the capacity of a system on the customer side of the meter and did not include any utility-scale batteries. The levels of system demand are driven by the adoption of electric vehicles. While a number of factors could arise to impact system demand, EVs are the most likely option for large-scale changes and provide a means to simplify scenario development. Table 4 shows the six scenarios:

Table 4. DER adoption scenarios

Scenario name	Description
Base	Represents the base case scenario. Each scenario dimension (PV, battery storage, and system demand) are taken from the base case scenarios of the utility IRPs. Note the distinction between "Base" to refer to this scenario and business-as-usual (BAU) to refer to the specific DER projection level as in BAU, high, and very high (see Table 2.2).
High electrification	Represents a scenario where system demand increases beyond base case projections, but DER adoption does not. This allows the analysis to explore the behavior of the distribution system in the case of high EV adoption—but with a configuration that reflects BAU levels of DER penetration.
High PV	Tests the scenario where PV adoption increases beyond BAU projections, but without large-scale additional system demand and without a large increase in battery storage adoption. Battery storage can mitigate some of the integration challenges for the utility of high rooftop PV penetration and this scenario tests the ability of the grid to handle more PV without the customer-side storage.
High PV and battery storage	Examines a scenario where a high level of rooftop PV penetration is coupled with a relatively high penetration of battery storage systems. The scenario assumes some breakthrough in battery technology, financing, and/or policy that would boost adoption, as current levels are close to zero. Even at a 'high' level, only 1 percent of customers adopt batteries. In this scenario, all battery storage systems are co-located with rooftop PV—though many rooftop PV systems are installed without batteries due to high PV penetration.
Battery storage arbitrage	Reflects a scenario where a storage breakthrough occurs, achieving a 'high,' 1 percent penetration level, with BAU levels of rooftop PV adoption. This scenario allows exploration of the impact of higher-than-expected battery storage adoption, while holding other factors at the baseline level.
Boundary case	Extrapolates adoption of rooftop PV, battery storage, and EVs to 'very high' penetration trajectory levels. The purpose of this scenario is to act as a boundary case and test the behavior of the distribution system with stressors that are beyond even the 'high' project levels. The 'very high' adoption levels are not present in any other scenarios.

Fig. 2 depicts the expected Indiana DER installed capacity for each scenario in 2040 (2025 is available in Fig. A.1 in the SI). These charts present nameplate installed capacity of each DER rather than coincident peak capacity. Residential and commercial PV adoption are relatively low in the Base and High Electrification scenarios, but up to 2 GW are deployed in the High PV scenarios. Battery storage adoption is relatively small across scenarios, ranging from 1 MW in the base scenario to almost 1 GW in the Boundary scenario. EV capacity is broken out by the type of charger used for the vehicle. Type 1 EV charges use less load at any given time, but take longer to charge, while Type 2 EVs charge quickly and use more load during a given hour. As a result, Type 1 EV makes up 21% of EV customers but only 11% of EV capacity. EV penetration ranges from 1.7 GW of charging capacity by 2040 in the Base scenario to over 12 GW of charging capacity in the Boundary scenario. The Boundary scenario then acts as a stress-test case to analyze the behavior of the distribution system with adoption levels beyond the most optimistic existing adoption scenarios. It is important to highlight that EV charging may occur at different times of day while PV injections across the Indiana territory will be highly correlated. This means that the coincident hourly impact of PV may be higher than that of EV, even in scenarios where the latter has larger installed capacity.

These adoption patterns translate to varying net consumption outcomes at the state-wide level (see Figs. A.2 and A.3 in SI). By 2040, there are comparatively larger changes in annual consumption, with overall consumption levels increasing or decreasing depending on the scenario. The high electrification and boundary scenarios have relatively high levels of EV adoption and annual consumption for residential customers increase by 8% and 21%, respectively, compared to the base case. The scenarios with BAU EV adoption and high PV adoption show a 10% decrease in residential annual consumption and an 8% decrease in commercial annual consumption compared to the base case. The annual consumption for industrial customers does not vary by scenario because they are not considered DER adopters in this study. Industrial customers, however, make up a large portion of Indiana's overall consumption, accounting for 46% of total annual consumption in 2025 and 45% of total annual consumption in 2040.

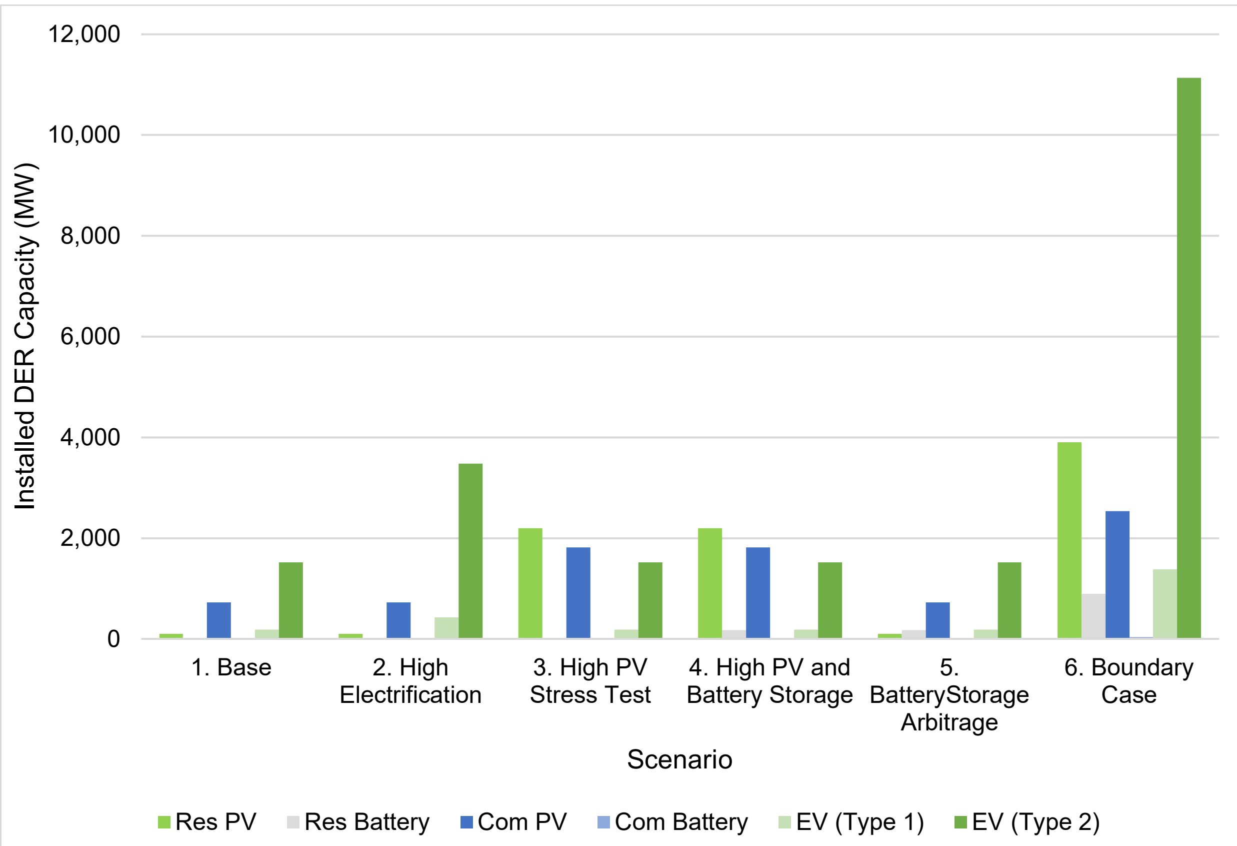

Fig. 2. 2040 Indiana installed DER/EV capacity by scenario

Impacts during specific hours of the day exist even though on an annual basis net demand may not change substantially as a result of additional DERs. Solar PV and EV charging, for example, offset each other on an annual basis, but solar production and EV charging generally happen at different times during the day. Therefore, there are potentially large changes on an hourly level on each scenario. One of these changes is a shift in the hours that have the highest load concentration on peak days. Fig. 3

illustrates the timing of state-level aggregate peak day usage for each scenario. The plot shows the average hourly loads over the top ten peak load days in 2040 for each scenario. We can compare scenarios by displaying the percentage of usage in each hour (the area under each curve adds up to 100%). Peak days occur during summer months in all scenarios, but the peak hour changes depending on which DER is dominant. For scenarios with high levels of solar penetration, the peak hour tends to occur later in the evening, between 6-7 pm (hour 19 on the plot). For the Base, High Electrification, and High Storage scenarios the peak occurs earlier in the day, between 3-4 pm (hour 16 on the plot). The Boundary scenario, with large PV and solar penetration, shows a high concentration of load in the evening hours, with load from 6-9 pm, accounting for more than 30% of the daily load on peak days.

In addition to changes in peak load concentration, the magnitude of the annual peak as compared to the Base Case also changes. The High Electrification and Boundary scenarios have relatively high levels of EV adoption and peak demand increases by 17% and 83%, respectively. The scenarios with BAU EV adoption and high PV adoption show a 6% decrease in peak demand.

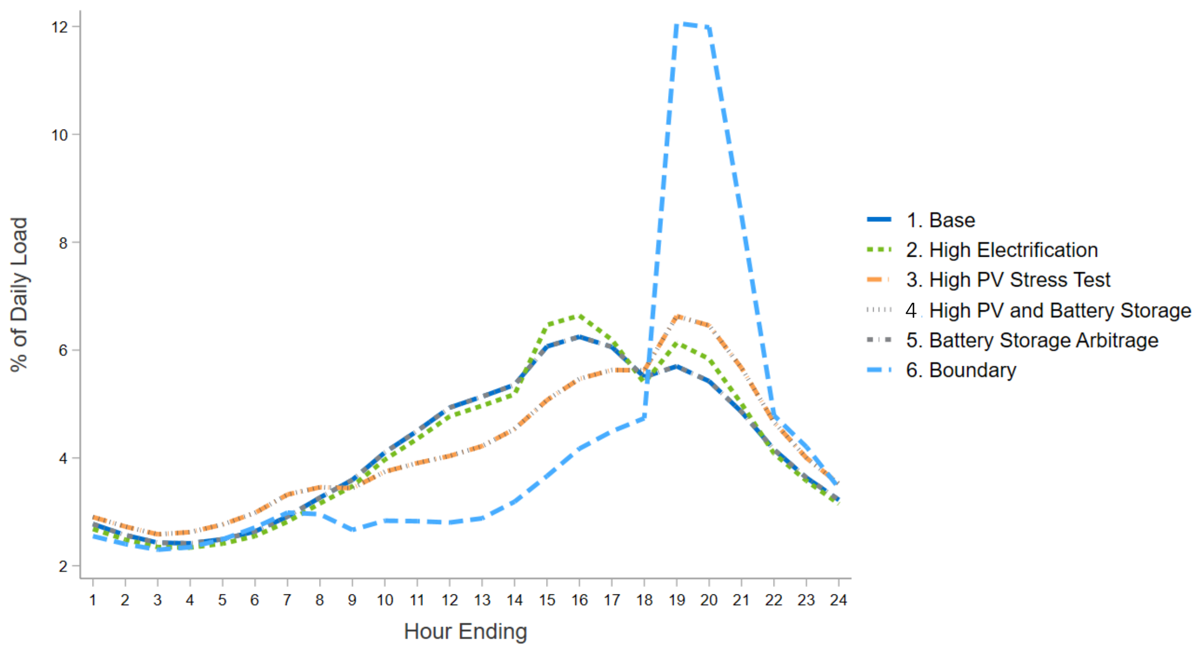

Fig. 3. Peak day load concentration by scenario

Finally, demand response (DR) and energy efficiency (EE) availability across scenarios was based on IRP forecasts provided by the IOUs. Unlike the other DERs, customer participation in EE and DR programs are largely driven by utility efforts. Therefore, EE and DR adoption were not varied in the above scenarios. For both 2025 and 2040, Indiana is expected to have a total DR capacity of almost 750 MW and total annual EE savings of almost 1,900 GWh.

5. Technical impact of DER on the distribution and generation systems

This section reports the technical impact analysis for the distribution and generation systems.

5.1 Distribution system technical impacts

This section reports the Cymdist power flow results on the distribution system for the three key output variables: voltage regulation, line loading, and line losses. Simulations are executed on each of the six representative primary voltage feeders, and characterized by (1) the year of analysis (2025 or 2040), which drives load growth and adoption levels; (2) six adoption scenarios, which establish different combinations for adoption levels of distributed PV, storage, and electric vehicles; and (3) twenty-four hours (a full day) on the minimum and maximum load days, for a total of 48 hours per feeder-scenario-year-cluster combination. These variables result in 576 power flow simulations per representative feeder, for a total of 3,456 simulations.

5.1.1 Voltage regulation

Results for voltage regulation are reported in Fig.4 (next page). In this figure, the column panel reports the six adoption scenarios while the row panel depict the six representative feeders identified by their cluster CL1 to CL6. The charts show the statistical distribution of voltage in p.u. (per unit or the fraction of nominal voltage) for each simulated node-hour[2], where the red shade represents 2025 and the blue shade 2040. The vertical lines represent the two ANSI voltage violation criteria: orange for the optimal range and red for the acceptable range. The y-axis is normalized to the highest value for each cluster to compare statistical distributions across scenarios for a given cluster, rather than across clusters.

At first glance, voltage violations are rare and minimal. About 0.5% of the node-hours simulated are under the 0.975 p.u. lower voltage range for the optimal scenario and 0.3% node-hours are above the 1.05 p.u. upper range. Only 0.04% of the node-hours are under the 0.95 p.u. lower acceptable range, and none are above the 1.058 upper acceptable range. The absolute minimum and maximum voltages are reasonably close to the ANSI limits for all of the node-hours simulated (Table 5). High voltage violations are very small, exceeding the optimal range by 0.009 p.u. in the worst case. Low voltage violations are also very limited, with a worst case excursion 0.053 p.u. below the optimal limit. Low load day simulation hours fall almost entirely within optimal and acceptable ranges; the majority of the voltage violations occur during high load days.

Table 5. Ranges in voltage regulation for low and high load day simulated hours, by year

		Voltage Levels (p.u.)				
Year	Type of Load Day	Minimum	25th Percentile	Median	75th Percentile	Maximum
2025	High	0.957	1.009	1.02	1.033	1.054
2025	Low	0.988	1.016	1.025	1.038	1.046
2040	High	0.908	1.008	1.019	1.031	1.058
2040	Low	0.945	1.016	1.026	1.038	1.057

[2] A node-hour is a unique observation for a node on one of the 48 simulated hours. We treat node-hours as a single variable to be able to show results for the same node across different hours in the same chart, and avoid one additional dimension in the visualization.

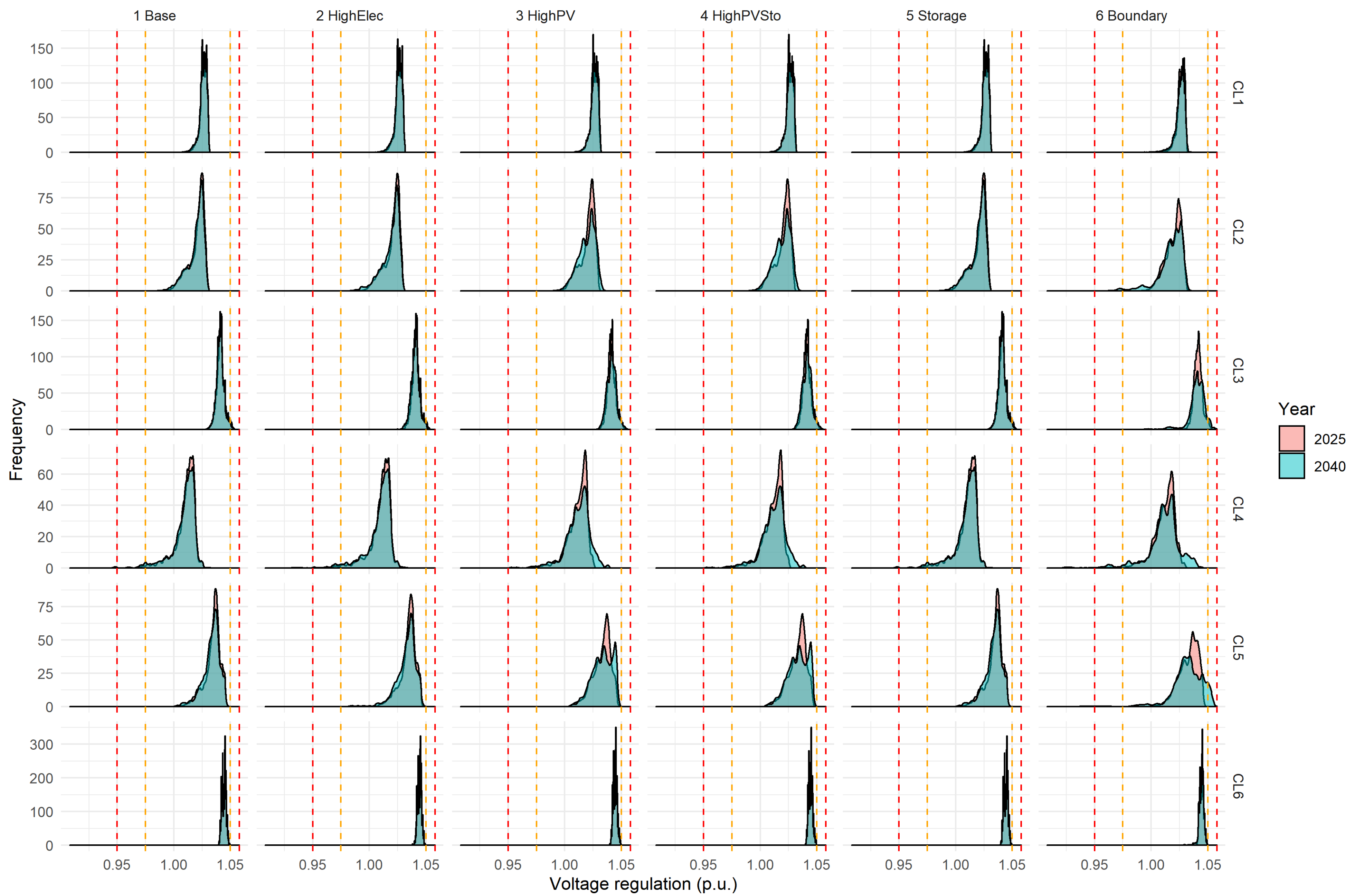

Fig. 4. Distribution of voltage regulation by node-hour

However, it is important to study power systems in the extreme, because critical issues can be lost in a simple analysis of averages. We find optimal range voltage violations in at least one feeder node on 159 of the 3,456 simulated hours and acceptable range violations in 17 simulated hours (see Table 6 for optimal range violations). Representative feeders in clusters 1, 5, and 6 exhibit voltage violations, but only in the Boundary scenario. Cluster 2 feeder has two to three simulation hours with violations in the Base, High PV, High PV and Storage, and Storage scenarios; and five hours in the Boundary and High Electrification scenarios. Feeders for clusters 3 and 4 – among the longest in the sample – have the highest number of hours of voltage violations. In cluster 3, almost 20% of the simulated hours in the Boundary Case show voltage issues.

Table 6. Number of simulation hours with ANSI optimal range voltage violations by cluster and scenario for 2025 and 2040

	Scenario					
Cluster	**Base**	**High Electrification**	**High PV**	**High PV and Battery Storage**	**Storage**	**Boundary Case**
CL1	0	0	0	0	0	9
CL2	3	5	2	2	3	5
CL3	9	8	11	11	9	19
CL4	11	11	6	6	11	9
CL5	0	0	0	0	0	8
CL6	0	0	0	0	0	1

This overview of voltage violation results suggests that some representative feeders are much more impacted by DER adoption than others and that the impact produces both low and high voltage issues. A detailed cluster by cluster analysis is included in section D in SI.

5.1.2 Line loading

Cymdist calculates the percent loading of each line segment for each simulated hour, based on the line segments' capacity and power flow solution for a specific hour. Results for line loadings are reported in Fig. 5. In general, lines loading issues are non-existent in the short-term (2025) and minimal in the long-term (2040). Loading issues in 2040 arise in the Boundary scenario for clusters 3, 4, and 5 and in the High Electrification scenario for cluster 4.

Only eight simulation hours out of 3,456 simulated hours have overloaded line segments. In these eight hours, between 0.4% and 8% of line segments are overloaded, depending on the cluster (see Table 7). Line overloading takes place in very specific times of day, coinciding with peak residential demand (2-3 pm) or with DER PV production decline coupled with EV charging (6-7 pm). Overloading is also incremental, which means that mitigating the overload for the worst case scenario in each cluster (6 pm at each cluster) will also mitigate issues for the other simulated hours in the same cluster.

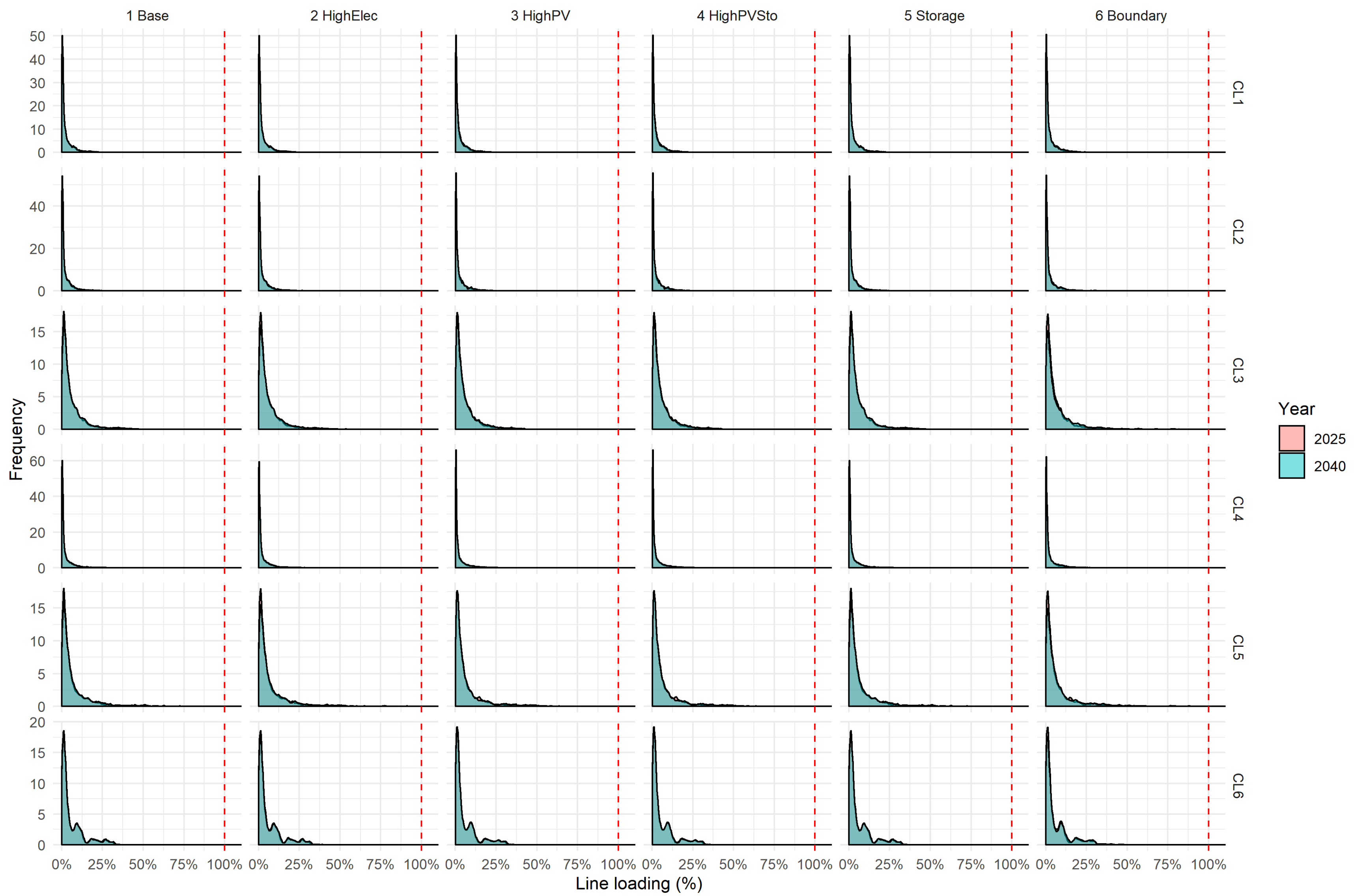

Fig. 5. Distribution of line loading by node-hour

Table 7. Simulation hours with overloading issues

Scenario	Cluster	Hour of Day	Number of Overloaded Segments	Number of Total Segments	Share of Overloaded Segments (% total)
Boundary	CL3	6 pm	31	592	5.2%
Boundary	CL3	7 pm	28	592	4.7%
Boundary	CL4	6 pm	15	1,621	0.9%
Boundary	CL4	7 pm	12	1,621	0.7%
High Electrification	CL4	2 pm	10	1,621	0.6%
High Electrification	CL4	3 pm	10	1,621	0.6%
Boundary	CL5	6 pm	43	535	8.0%
Boundary	CL5	7 pm	42	535	7.9%

Adoption of distributed PV has a beneficial effect in line loading. In the scenarios with higher PV adoption (High PV and High PV with Storage) the worst case line loading is typically 10%-15% less than the High Electrification scenario (with high EV adoption) and 5% less than the BAU scenario (with very little PV adoption). In contrast, it is likely that electric vehicle charging is leading to overloading issues across clusters because the timing of some of the overloading issues coincide with residential type I charging operations.

In summary, these results suggest that the existing capacity of line segments in representative feeders would be enough to accommodate the DER deployed under even the most stringent adoption scenario. Required re-conductoring expenditures should be relatively small considering the DER adoption levels. These costs are discussed in Section 6. Note that this analysis does not cover distribution transformer loading or secondary network loading. It is possible that these two components do not have the flexibility that the primary distribution system has and would therefore accrue additional DER integration costs.

It is important to highlight limitations of the loading analysis performed in this study. Annual energy consumption by customer was allocated using aggregate load profiles for the three customer types provided by some IOUs due to the lack of actual hourly load shapes or peak power consumption for each customer. The simulation results show that even in the Base case some line segments experience very high loading, while the average line segment loadings are around 5 percent for most clusters and scenarios. These high line loadings may have originated in the method of load allocation, which does not reflect actual customer peak loads. On one hand, the method employed may result in a higher peak load for customers with a relatively flat load demand. On the other hand, the method may produce lower peak load (and lower line loading) for customers with a volatile load profile.

5.1.3 Line energy losses

Unlike voltage violations and overloading issues, line energy losses do not translate to power quality issues for customers. However, utilities monitor line losses to maintain a level that is cost-effective for the utility as well as their customers. This means that there is no set standard or benchmark for assessing an acceptable limit for line losses as this cost-effectiveness test will vary across utilities and over time. Consequently, we focus on measuring change in losses between the Base scenario and the other scenarios as a measure of the differential impact of DER adoption.

Feeder losses for the highest hour of the year may be several times higher than average losses calculated using annual aggregates, but it is the latter that informs the overall economic impact of increases or reductions in energy losses. For this reason, we develop a special set of simulations depicting typical conditions in four seasons of the year that are more conducive to aggregate estimates. We select one day per season to capture seasonal patterns in demand and solar PV production. We report hourly losses to show the variation of losses throughout the day and how they correlate with specific DER usage patterns.

Feeder losses for 2025 and 2040 are reported in Fig. A.4 and Fig. A.5 in the SI, respectively. We report the average percentage change in feeder losses for three selected adoption scenarios: High Electrification, High PV, and Boundary relative to the Base case. We use these three scenarios because results for the High PV and Storage and Storage scenarios are almost identical to the results for the other scenarios and the Base case, respectively.

Results show that line losses follow the new patterns of net demand that arise with PV and EV adoption. Losses are higher than the Base case during the times of day when EV is charging (High Electrification scenario, between 2 pm and 7 pm). Losses are lower than the Base case in the scenarios with higher PV penetration and during the hours of PV production between 10 am and 4 pm. The Boundary scenario in years 2025 and 2040 shows the highest variation in losses compared to the Base case, because it includes very high PV and EV adoption levels. Losses can be 10 to 13 times higher than the Base case during peak demand hours with substantial amounts of residential EV charging.

We estimate annual average losses by calculating the average for each cluster and scenario across all simulated hours for all seasons (see Table A.2 in SI). Average results show moderate increases or decreases in losses across clusters and scenarios for 2025, following the hourly patterns. For 2040, all clusters have higher losses than the base case in the High Electrification scenario, and all clusters have lower losses in the High PV scenario. In the Boundary scenario, losses increase across clusters due to the dominance of EV charging load over PV production.

We extrapolate feeder-level results in Table A.2 for all IOU service territories by applying the same scaling factors described in section C.3 (SI) and by multiplying the average hourly losses by 8,760 to extend these estimates to a whole year (Table 8). These results will then be used in the following section to provide a first-order estimate of the economic impacts.

Table 8. Aggregate change in losses relative to base case for all IOUs (MWh)

	Annual Change in Losses Relative to Base (MWh)					
	High Electrification		**High PV**		**Boundary**	
Cluster	**2025**	**2040**	**2025**	**2040**	**2025**	**2040**
CL1	41	709	-656	-1,264	-710	10,348
CL2	306	4,478	-1,817	-3,837	-1,651	28,556
CL3	276	10,289	-2,606	-8,310	-2,861	88,606
CL4	2,005	19,655	-8,739	-13,278	-856	40,458

CL5	985	14,640	-8,310	-17,794	-6,669	39,308
CL6	0	55	-267	-401	-392	129

5.2 Generation technical impacts

Hourly net demand for each scenario scaled at the state-level was produced as an input to the capacity expansion and production cost modules of Aurora. Aurora produces optimal capacity expansion decisions, which are tested on an hourly basis employing the production cost module. The resulting electricity prices are input on a demand forecasting model that considers price elasticity, and the resulting demand is input back into Aurora. This modeling system is solved iteratively until equilibrium is reached. The simulation then reflects the incremental generation investment needs and annual costs to meet those demand levels for years 2025 and 2037[3]. Details of the modeling approach and assumptions can be found in [37].

Table 9 reports resulting differences in capacity additions under each scenario over the long-term. Natural gas simple-cycle combustion turbines (SCCT) are deployed in larger amounts in scenarios with higher penetration of electric vehicles, and lower amounts in scenarios with higher PV penetration. The Boundary scenario—dominated by EV adoption—requires more than three times the incremental capacity of SCCTs compared to the Base case despite having only 50% higher peak demand. In contrast, capacity additions of natural gas combined-cycle combustion turbines (CCCT) remain relatively constant across scenarios. The significant adoption of SCCT in the Boundary scenario reflects the flexibility and resource adequacy demands that large swaths of coincident EV charging may impose on the power system.

Table 9. Utility-scale resource mix by scenario in year 2037

	Incremental Installed Capacity (MW)			
Scenario	**Natural Gas: Simple Cycle Combustion Turbine**	**Natural Gas: Combined Cycle Combustion Turbine**	**Wind**	**Solar**
Base	4,971	6,034	5,696	579
High Electrification	6,214	5,748	7,000	1,278
High PV	3,879	6,330	2,385	414
High PV and Storage	3,960	6,338	2,384	316
Storage	4,987	6,010	5,766	579
Boundary	16,959	7,360	4,030	55

Wind and solar adoption is substantially higher in the High Electrification scenario compared to any other scenario. This is may be due to coincidence between solar and wind production and EV charging patterns. Higher DER PV adoption in scenarios 3 and 4 correlates with lower wind and solar adoption than the Base case. This is explained by DER PV reducing the capacity value of solar PV given the high

[3] This is the latest year available in the Aurora modeling implementation available to us, hence it is being used as equivalent to 2040 for our purposes.

production correlation of both resources.

6. Economic impacts of DER across the power system

The costs and benefits of DER are determined separately for the three major components of the power system: (1) generation, (2) transmission, and (3) distribution. Generation cost impacts come directly from the Aurora capacity expansion results. Transmission cost impacts are estimated based on peak demand increase. Distribution cost impacts are based on the results described in the previous section.

6.1 Distribution

There are three cost components tracked for the integration of DER into the distribution system: (1) voltage regulation, (2) line loading, and (3) line energy losses.

6.1.1 Voltage regulation

Results discussed earlier show that voltage issues are a relatively minor issue across scenarios and that, in some cases, they are driven by the high voltage set point at the substation load tap changer. In this study, we assume that smart inverters are a standard feature in PV systems deployed within every scenario presented. Accordingly, we find that voltage issues for all scenarios can be mitigated by a combination of load tap changer (LTC) adjustments and smart inverter use with PV systems. Consequently, simulations using a combination of volt-var control at PV systems and adjustment of substation LTC result in no voltage issues in the short and long term. This approach and result is consistent with similar studies on management of voltage issues due to rooftop solar adoption (see e.g. [38]).

The no-cost result for voltage regulation is based on the assumption that LTC is available and adjusted in the IOU-operated electricity substations across Indiana. Unfortunately, we do not have information confirming the reasonableness of this assumptions. For this reason, we include a cost to retrofit half of the existing substations with LTC—assuming the remainder already have LTC installed.

Researchers report that it costs $310,000 per substation to implement LTC based on a Northeastern U.S. utility [38]. We adjust this cost down by 25% to $232,500 based on information from two Indiana utilities. We estimate there are ~1,000 substations serving distribution customers across the Indiana territory. It will cost ~$235 million, or an annual equivalent of $20 million, to retrofit all of these substations. In the end, we assume that half of the substations need the LTC retrofit resulting in an annual cost of ~$10 million.

6.1.2 Line loading

Line loading was addressed by manually replacing conductors in underground and overhead line segments as needed. We re-ran simulations for the affected cluster-scenario combinations to verify that the re-conductoring effectively solved line overloading. Tables A.5 to A.7 (SI) include the segment-by-segment details for this re-conductoring process. The lengths of upgraded circuits are reported in Table 10.

Table 10. Length of re-conductored segments by material and cluster

	Underground Cable Length (feet)		Overhead Line Length (feet)	
Cluster	Copper	Aluminum	Copper	Aluminum
3	0	0	0	3,634
4	57	0	2,386	0
5	172	0	0	6,461

We monetize re-conductoring using costs per foot of conductor as reported in two sources. First, two of the three IOUs with representative feeders reported costs of $95/ft and $80/ft for overhead and underground line re-conductoring, respectively. The overhead costs include replacing supporting structures to bear additional conductor weight. Second, an NREL cost study reported low, medium, and high costs of $130/ft, $173/ft, and $258/ft, respectively.

We use the preceding cost information to estimate costs based on four re-conductoring "steps" that depend on the ampacity difference between the original and replaced conductor. Each step reflects a 15% increase in conductor ampacity. We assume that the lower cost applies to the first step, and the highest cost to the fourth step. Underground cables are upgraded in a single step, so we use the $80/ft reported by the utility. Finally, we use a 50% cost adder for copper conductors assuming that all costs are for aluminum conductors. Feeder level results are escalated to the aggregate IOU level using the scaling factors described earlier in this manuscript (Table 11).

Table 11. Feeder-level and aggregate costs for line loading by scenario and cluster

	Feeder Costs (million $2017)		Aggregate Costs for All IOUs (million $2017)	
Cluster	High Electrification	Boundary	High Electrification	Boundary
3		$0.396		$297.0
4	$0.271	$0.412	$147.4	$223.8
5		$0.973		$306.5

Re-conductoring was only required for clusters 3, 4 and 5 and for the High Electrification and the Boundary scenarios. We estimate about $150 million in upgrade costs for feeders in cluster 4 in the High Electrification scenario, and roughly $820 million in investments for the Boundary scenario. These investment values correspond to approximate annualized costs of $12.5 million for the High Electrification scenario and $70 million for the Boundary scenario.

It is important to acknowledge that this linear segment-by-segment upgrade method is just one of the ways in which utilities address real line loading issues in their systems. Our assessment uses individual segment upgrades, usually called an "incremental line upgrade", largely due to data availability and resource constraints. Another example of an incremental upgrade not employed in this study is adding phases to a single-phase circuit to increase its capacity. Furthermore, in some situations, poles will need to be replaced along supporting structures and conductors in a "major line upgrade". In some cases these methods will be insufficient and utilities may be required to build additional feeder sections and reconfigure feeders to offload affected circuits. Regulators, utilities, and/or other stakeholders should consider sponsoring a more detailed line-loading study under different DER adoption pathways.

6.1.3 Energy losses

Distribution system energy losses is energy that a utility procured, but could not deliver to end-use customers. Estimating the cost of these losses entails using an average wholesale market delivery cost to value the energy losses first reported in Table 8. We use the generation and transmission costs—reported in dollars per MWh— from the generation production cost model to monetize energy losses under each scenario relative to the base case (see Table 12). The cost of energy-related losses in the High PV and High PV and Storage scenarios are identical and there is no difference between the Base case and Storage scenario.

Table 12. Changes in the cost of energy losses relative to the base case

	2025		2040	
Scenario	Wholesale Electricity Cost Assumption (¢/kWh)	Cost of Energy Losses (million $2017)	Wholesale Electricity Cost Assumption (¢/kWh)	Cost of Energy Losses (million $2017)
High Electrification	4.23¢	$0.15	5.40¢	$2.69
High PV	4.05¢	-$0.91	5.21¢	-$2.34
High PV and Storage	4.05¢	-$0.91	5.21¢	-$2.34
Storage	4.16¢	$0	5.32¢	$0
Boundary	4.31¢	-$0.57	6.05¢	$12.55

By 2025, the economic impact of energy losses under increased DER adoption in energy losses is modest, ranging from an additional cost of $150,000/year in the High Electrification scenario to savings of almost $1 million per year in the two High PV scenarios. The economic impact becomes more over the long-term. The High PV scenarios save over $2 million in distribution-related energy losses compared to the Base case, while the Boundary scenario has an additional $12.5 million in energy loss-related costs compared to the Base case.

6.2 Transmission

Transmission expansion is not modeled directly in the comprehensive study. We estimate the impact of DER on transmission costs by calculating an incremental transmission expansion cost per MW transmitted during peak hours in 2025 and 2037 and multiplying this value by the peak demand in each adoption scenario.

We estimated the incremental transmission expansion costs by comparing the revenue requirements for the reference scenario in the ratemaking model both with and without incremental transmission expenditures. These expenditures include the return on investment and depreciation of all future capital expenditures, but not from the current rate base, and future transmission system O&M costs. These costs were translated to a dollar per peak MW basis for the revenue requirements in 2025 and 2037 for the reference scenario. This process produces an incremental transmission cost of $55,821 per peak MW in 2025 and $68,896 per peak MW in 2037 that are reasonable approximations for expansion costs in the transmission system.

We apply these values to the statewide peak demand by scenario to estimate transmission costs and calculate the difference from the Base case (see Table 13 for cents per kWh costs and Table A.4 in SI for total costs). DER impact is relatively modest in all but the Boundary scenario, with savings of 3 cents per MWh in the High PV and High PV and Storage scenarios in 2025 to an increase of 57 cents per MWh in the High Electrification scenario in 2037. These figures translate to differences in the -0.3% to 4.7% range.

Table 13. Changes to incremental transmission costs relative to the base case

	Cost Change with Respect to Base Case (¢/kWh)		Annual Cost Change with Respect to Base Case (million $)	
	2025	**2037**	**2025**	**2037**
High Electrification	0.01¢	0.06¢	$15.8	$91.3
High PV	0.00¢	0.01¢	-$32.4	-$71.9
High PV and Storage	0.00¢	0.01¢	-$32.4	-$70.6
Storage	0.00¢	0.00¢	$0	$0.01
Boundary	0.07¢	0.64¢	$27.5	$734

The Boundary scenario has the highest cost difference for both planning horizons. Transmission costs are almost 7% higher in 2025 and up to 53% higher in 2037. This is explained due to the peak demand levels of this scenario, which at 31.8 GW in 2037 are roughly 50% higher than the 21.1 GW in the Base scenario.

6.3 Generation

We report four components of generation costs produced by the simulations: (1) annualized capital costs, (2) fixed costs, (3) fuel costs, and (4) non-fuel variable costs (usually O&M).

In the short-term, all scenarios, including the Boundary case, exhibit similar costs relative to the Base case (Fig. 6). However, over the long-term, the cost differences associated with increased adoption levels become more evident. Scenarios with relatively higher adoption of PV (High PV and High PV and Storage) have 8% lower costs relative to the Base case, largely driven by reduced capital and fixed costs. Costs are roughly 3% higher relative to the Base case in the High Electrification scenario, likely driven by EV charging taking place in the middle of the day. This is supported by the much higher adoption of utility-scale solar PV—whose production peaks midday—in this scenario compared to any other scenario (e.g. twice as much as the Base case).

The Battery Storage scenario is basically identical to the Base case. This is, in part, due to the relatively small levels of adoption of DER storage. However, it also suggests that when customers manage their DER storage without following wholesale market signals, their decisions do not necessarily benefit the system through lower peak demand needs. Finally, the Boundary scenario has ~12% higher costs than the Base case, driven by the strong demand growth of EV charging. It is important to note that the Boundary scenario is serving a 50% higher peak demand than the Base case.

These results suggest that DER adoption, especially PV, could create significant costs savings in both energy and capacity for the Indiana power system. The High PV scenario has 3% higher fuel costs, but 30% lower annual capacity costs compared to the Base case by 2040. In contrast, the higher demand levels of EV charging in the High Electrification scenario result in ~17% additional capital costs relative to the Base case.

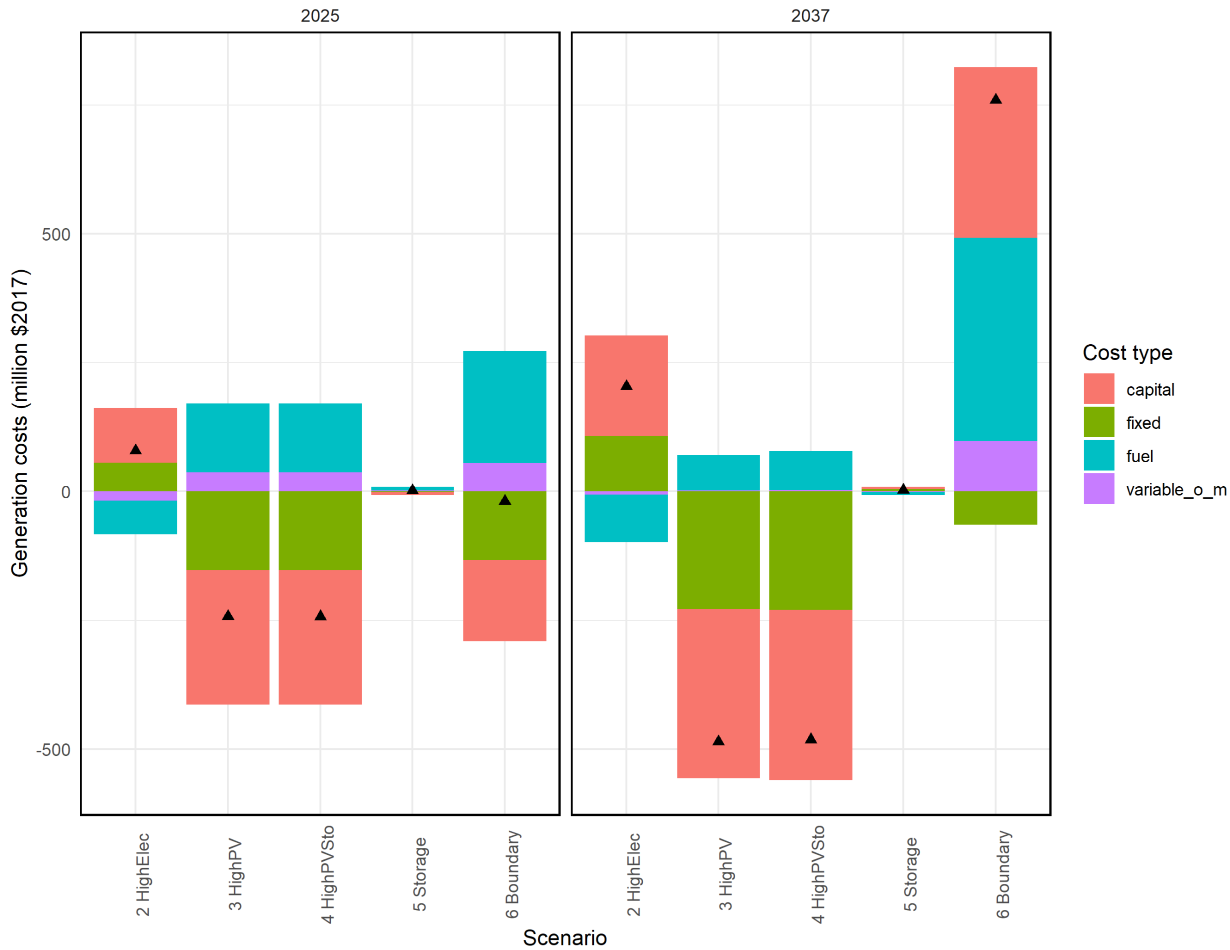

Fig. 6. Generation costs by type (bars) and net outcome (point) relative to the Base case

6.4 Economic and rate impacts of DER adoption

Table 14 shows the incremental combined economic impact of increased DER adoption relative to the Base case in cents per kWh (see Table A.3 in SI for absolute cost impacts). Costs are reported by scenario and for the three segments of the power system: generation, transmission, and distribution.

Table 14. Overall incremental economic impact of DER adoption by scenario and power system segment relative to the base case (2017 cents/kWh)

	2025 Annual Cost Change Relative to Base				2040 Annual Cost Change Relative to Base			
Scenario	Gen.	Trans.	Dist.	Total	Gen.	Trans.	Dist.	Total
High Electrification	0.11¢	0.02¢	0.01¢	0.14¢	0.25¢	0.11¢	0.03¢	0.39¢
High PV	-0.34¢	-0.04¢	0.01¢	-0.37¢	-0.64¢	-0.09¢	0.01¢	-0.72¢
High PV and Storage	-0.34¢	-0.04¢	0.01¢	-0.37¢	-0.63¢	-0.09¢	0.01¢	-0.72¢
Storage	0.00¢	0.00¢	0.01¢	0.02¢	0.00¢	0.00¢	0.01¢	0.02¢
Boundary	-0.03¢	0.04¢	0.01¢	0.03¢	0.96¢	0.93¢	0.12¢	2.01¢

There are relatively modest economic impacts of DER adoption for all scenarios in the short term. Over the long term, impacts range from 0.7 ¢/kWh in savings for the High PV scenarios to 2 ¢/kWh in additional costs for the Boundary scenario, all relative to the Base case. The largest cost impacts are observed in the generation sector, with nearly 90% of the cost savings occurring in this segment for the High PV scenarios. Distribution-related cost impacts from DER adoption are generally the smallest among the power system segments studied, ranging 1% to 10% of the overall cost change under any given scenario.

Rate impacts of these incremental costs are reported in Table 15. This assessment employs the ratemaking model using the existing rate base and the incremental cost changes reported in Table A.3 in SI. The ratemaking model takes into consideration DER-driven investments reported in this study and non DER-driven investments that are part of utilities' investment plans, in addition to increase or reduction in retail sales and peak demand depending on the scenario. Details of the ratemaking model can be found in [37,39].

Table 15. Impact of DER adoption on electricity rates by scenario and customer type (2017 cents/kWh)

	2025 Rate Change Relative to Base				2040 Rate Change Relative to Base			
Scenario	**Residential**	**Commercial**	**Industrial**	**Average**	**Residential**	**Commercial**	**Industrial**	**Average**
High Electrification	0.25¢	0.24¢	0.19¢	0.22¢	-0.03¢	0.05¢	0.14¢	0.06¢
High PV	-0.06¢	-0.10¢	-0.19¢	-0.13¢	1.01¢	0.73¢	0.23¢	0.59¢
High PV and Storage	-0.06¢	-0.10¢	-0.19¢	-0.13¢	1.00¢	0.71¢	0.22¢	0.58¢
Storage	0.00¢	0.00¢	0.00¢	0.00¢	0.05¢	0.05¢	0.01¢	0.03¢
Boundary	0.52¢	0.47¢	0.18¢	0.35¢	1.88¢	1.96¢	1.46¢	1.70¢

In contrast to the incremental costs reported earlier, average all-in rates increase for all scenarios in the long term. In the High PV scenarios this is due to the reduction in sales that needs to be compensated with higher rates for utilities to recover their fixed costs. In the other scenarios this is compounded with the need for incremental generation and transmission infrastructure to meet increased peak demand. Overall, the average changes in rates are relatively modest in the non-Boundary scenarios. Rates are expected to decrease in the short-term in the High PV scenarios (~-1.6%) and to increase in the High Electrification and Boundary scenarios (~2%). In the long-term, rates increase between 0.2% to 2.5% in non-Boundary scenarios and 14.5% in the Boundary scenario due to very high unmanaged EV load. This result suggests distributional issues of EV owners potentially imposing rate increases on non-EV owners.

7. Conclusion

This study explores the joint impacts across the power system of DER technologies. We identify six adoption scenarios that combine deployment levels of rooftop solar (PV), electric vehicle charging (EV), and battery storage in residential and commercial customers connected to representative feeders in Indiana by 2025 and 2040. Indiana is a good proxy for many U.S. states with low current DER adoption but potentially high future growth.

This paper uses

Methodologically, this is the first paper that develops and applies a sequential integrative framework that rigorously identify technical, cost, and rate impacts across all segments in the power system. The sequential approach operates in two stages. First, it simulates DER impacts in the distribution system using a clustering technique to identify six representative feeders. Second, it suggests an approach to scale and aggregate resulting net demand to produce the inputs for a transmission-generation analysis. Each stage includes estimation of technical and cost impacts using industry-standard power flow and capacity expansion tools. Finally, the technical and economic impacts of all three segments – distribution, transmission, and generation – are input into a rate making model that jointly processes the changes in retail energy sales and demand with the changes in investment and operational costs across segments.

The scenario-based sequential methodology proposed in this paper integrates methods from several strands of literature that have individually analyzed DER impacts on different segments of the power system. The method proposed is particularly well suited for utilities, system planners, regulators, and other stakeholders that require a blueprint to conduct state- and national-level analyzes of the penetration of DER and its impacts on ratepayers. The method develops simple but insightful scenarios for DER adoption and operation that are easily reconstructed with own data and that represent a wide range of future performance possibilities for these technologies. The data and tools required to implement the method proposed in this paper are readily available to the stakeholders mentioned before, maximizing its applicability.

This paper develops an application of the method based on data provided by the five IOUs operating in the State of Indiana. These results show the applicability of the method and exemplify its implementation. In addition, they suggest interest system-wide impacts of DER and their interactions that would apply to most U.S. states and other regions in the world. We find that primary voltage distribution systems are well situated to absorb moderate to large DER load and production. Optimal range voltage violations appear in at least one feeder node on 159 of the 3,456 simulated hours and acceptable range violations in 17 simulated hours. Most voltage violations occur in the longest feeder (e.g. clusters 3 and 4) and seem to be driven primarily by DER solar and EV operation. Line loading is the most common technical impact on distribution systems: between 1% and 8% of circuit segments are overloaded across cluster feeders 3, 4 and 5, especially in the “stress test” or Boundary scenario. Distribution system impacts could be mitigated with a mix of volt-var regulation from smart inverters, reconductoring, and load tap changer implementation and control in substations. It is estimated that the economic impact of these mitigation strategies in the primary voltage system by year 2040 would be between 0.01¢/kWh and 0.03¢/kWh in the five standard scenarios, and 0.12¢/kWh for the Boundary scenario. However, the secondary voltage system – transformers and circuits – may require more complex circuit segmentation and expensive reconductoring on underground circuits that are not captured in this study. This is a further area of research.

Out of the three power system components, generation is the most impacted due to needed peak demand capacity that stem from generally tighter planning margins compared to distribution and transmission. Unmanaged EV charging drive gas combustion turbine adoption for peak demand, at a rate of roughly 1 MW of gas turbine capacity per MW of EV demand. Higher DER PV adoption displaces utility-scale wind and solar PV capacity by 20%-50% and 30%-90% respectively, compared to the BAU scenario. Higher peak capacity could be mitigated through imports for utilities that are members of RTO/ISO, which would in turn strain the transmission system. These result demonstrate the relevance of integrative results that identify the components of the power system that are more impacted. They also show the substantial impacts of DER adoption in the BPS and suggest that managed EV charging should be prioritized. An analysis that includes regional modeling and managed EV charging was outside the scope of this work but it is a worthwhile research avenue.

Plausible scenarios for EV, PV, and battery storage adoption by residential and commercial customers in Indiana suggest that PV and battery storage will have low to moderate impact. EV adoption will likely be the DER that will produce the highest technical and economic impacts, especially with unmanaged charging or in the absence of time-sensitive rates. Results show modest long-term increase in rates up to 2.5% in non-Boundary scenarios, but up to 14% increase in the Boundary scenario due to EV impacts in the BPS. DER PV could reduce rates in the short-term, but reduced retail sales lead to higher rates in the long-term. Regulators will need to assess whether to react to the distributional consequences of all-in rates increasing for non-EV owners.

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