21st Century Energy Policy Task Force

Report on the methods, data, and assumptions for the Indiana Utility Regulatory Commission study

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1. Introduction

The Indiana Congress enacted the House Enrolled Act No. 1278 in 2019 to explore the impact that fuel transitions and emerging technologies may have on the state's power system. The Act created the 21st Century Energy Policy Development Task Force (see Indiana Code § 8-1-8.5-3.1 (b)), which is tasked with identifying energy policy recommendations for the House focused on affordability and reliability of future electric utility service. One of the inputs for the Task Force's deliverables is a comprehensive study of the impacts of fuel transitions and emerging technologies across Indiana.

The Indiana Utility Regulatory Commission (IURC) was tasked with producing a comprehensive study of the statewide impacts of fuel transitions and emerging technologies on generation capacity, reliability, resilience, and rates. The IURC divided the study into two components: (1) generation-transmission and (2) distribution. The State Utility Forecasting Group is leading the assessment of impacts on generation capacity, costs, and reliability, while Lawrence Berkeley National Laboratory (LBNL) and Nexant, Inc. ("Nexant") are leading the assessment of impacts on distribution systems.

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 references throughout this document as Distributed Energy Resources (DER). Given the current landscape in Indiana and the focus of the Task Force, this study is limited to the following DER: solar PV, battery storage, electric vehicles, demand response, and energy efficiency. More details about how these technologies are treated in the study are available in the "Scenario" section. Throughout this document, we report the status of data collection, assumptions, and methods of the DER study led by LBNL and Nexant. More specifically, we discuss the following:

- Overview of study methodology
- Relevant literature for this study
- Scenarios
- DER valuation framework
- Reliability assessment framework
- Simulations

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The final section provides an update on the data collection process for each component of the study.

2. Overview of study methodology

The study focuses on producing a quantitative assessment of the value, rates, and reliability/resilience impacts from deployment of DER. To this end, the study is based on the implementation of a number of key steps including:

1. Conducting a literature review to identify the main sources of value (cost and benefits) of DER in distribution, transmission, and generation.
   - Includes literature that identifies reliability impacts of DER in the distribution system and in the bulk-wholesale system.
2. Developing two assessment frameworks to:
   - Monetize the rate/costs impacts of different DER value streams.
   - Quantify the impact of DER on standard distribution system reliability metrics.
3. Developing adoption forecasts for DER using Investor Owned Utility (IOU) data,
   - Includes adoption of solar PV and battery storage, but possibly electric vehicles (EV), demand response (DR), and energy efficiency (EE).
4. Producing scenarios that represent different load and DER adoption forecasts
5. Developing a set of feeders that are representative of Indiana IOU grid architecture
   - Use feeder characterization data provided by the IOUs and apply clustering methods.
6. Running power flow simulations through the representative feeders using forecasted variables for the years 2025 (short-term) and 2040 (long-term) for all scenarios
   - For the long-term scenario, determine necessary upgrades to the distribution system to maintain basic quality of service metrics such as voltage drop, line and transformer loading, as well as line and transformer losses.
   - For both scenarios, determine cost impacts at the wholesale-level and
   - For both scenarios, determine the impact of DER adoption on indices for distribution system reliability

The following sections provide details on the methodology, data, assumptions, and framework for the study components.

3. Relevant literature

Several fields of study contribute to the growing body of literature examining the implications of increasing DER penetration. 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. These subjects are summarized below.

Impacts of DERs on the Distribution System

A number of studies have modeled high PV penetration on feeders and assessed the impacts. Brown and Freeman (2001) found that DG could have positive impacts (voltage support, deferred capital

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investments) and negative impacts (protection coordination, voltage regulation, voltage flicker, short circuit levels). They also developed methods to analyze DG impacts using predictive reliability assessment tools. CIRED (2019) presents a flexible DER modelling framework along with recent developments in DER dynamic modelling. It also reviews DER system impact studies in California. PNNL summarizes the major types of analysis conducted on electric distribution systems along with their applications and relative maturity levels (PNNL, 2017a). Special emphasis is placed on distribution system analyses (DSAs) required for increasing levels of DERs. NREL (Seguin et al., 2016) catalogs distribution-level impacts of high PV penetration, including overload-related, voltage-related, reverse power flow, and system protection impacts. It also provides a model-based study guide for assessing PV impacts and lists techniques for mitigating impacts.

EPRI (2015) provides an overview of the hosting capacity method, which was developed to determine the ability of feeders to accommodate PV. The impact of PV penetration on distribution performance and the amount of PV (and other DER) a feeder can accommodate depend on a number of factors, including the characteristics of both the feeder and the DER, the location of the DER on the feeder, the feeder operating criteria, and the control mechanisms. EPRI (2010) discusses practical planning limits for adding DG to distribution circuits. 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). The study used a set of IEEE test feeders to investigate the limits of each category. Over ten years ago, the IEEE developed this set of test feeders for researchers to use when modeling the distribution system (Schneider et al., 2009, 2008, 2018). Schneider et al. (2018) provides an overview of the existing distribution feeder models and clarifies the specific analytic challenges that they were originally designed to examine. The set of feeders reflect the diversity in design and have been used for a wide range of research (Cale et al., 2014).

Bulk Power System

Several studies have addressed the impacts of DER on the bulk power system (BPS). ERCOT identified areas of concern related to reliability impacts of DER to the BPS: increased error in load forecasting, less accurate inputs to ISO functions, and uncoordinated system restoration after a load shed event (ERCOT, 2017). 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 (NERC, 2017). NERC also created a DER Task Force which developed DER modeling recommendations for BPS planning studies (NATF, 2018).

Value of DER

A growing body of literature analyzes the benefits and costs of DER. NREL (2014) reviews methods for analyzing the benefits and costs of distributed PV generation to the U.S. electric utility system. This NREL review is one of the main sources for the DER valuation framework used in this study. 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 (2013) reviews sixteen distributed PV (DPV) benefit/cost studies by utilities, national labs, and other organizations. Completed between 2005 and 2013, these studies reflect a significant range of

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estimated DPV value. Some studies examine costs and benefits at a broader level. Cohen et al. (2015) estimated the economic impact of DPV in California, and, closer to Indiana, PNNL (Orrell et al., 2018) estimated the value of DG in Illinois.

Utility of the Future

Some states have conducted "Utility of the Future" studies. These studies generally examine the role and business model of today's utilities and explore ways they could change in the face of an evolving business environment measured by customer expectations, DER adoption, and technological advances. In the Midwest, several states have conducted such studies: Ohio, Michigan, Illinois, and Kentucky. Ohio's PowerForward Roadmap examined potential future regulatory paradigms, distribution grid architecture, and grid modernization (Ohio PUC, 2018). Michigan's study specifically focused on the near-term challenge of ensuring an adequate electricity supply (Public Sector Consultants, 2014). Illinois' NextGrid study assessed options for further grid modernization and candidate updates of state regulatory policies (NextGrid Illinois, 2018). Kentucky developed a Smart Grid Roadmap in 2012, where it examined the modernization of the electric power grid (KSGRI, 2012).

DER Forecasting and Planning Integration

A critical input to the body of work on DER impacts is the adoption forecast for DERs. The methods for developing these forecasts can be divided into two categories: (1) top-down and (2) bottom-up (NREL, 2019). Top-down methods tend to be simpler and require less data and computing power. They include time series models, econometric models, and Bass diffusion models. Time series models are the most straightforward to implement, as they take historical data and extrapolate to future outcomes. Econometric models use statistical methods to explain historical observations by finding relationships between penetration levels and other variables. Researchers can then use these relationships to predict future adoption levels. Bass diffusion models represent adoption patterns of new products or technologies and are the most frequent top-down model used (NREL, 2019). Bottom-up methods require more data and are more methodologically sophisticated, as they evaluate DER adoption based on characteristics of individual customers. For example, agent based models simulate the actions of individuals to model the impacts to the larger system. These types of models allow for more complex decision-making processes and can simulate a more heterogeneous customer base (Mills, 2018).

A number of researchers have examined how to incorporate DERs into the distribution planning process. For example, LBNL conducted a comparative analysis and evaluation of roughly 30 recent planning studies, identifying innovative practices, lessons learned, and state-of-the-art tools (Mills et al., 2016). PNNL describes activities in states that have adopted some advanced elements of integrated distribution system planning and analysis and also covers a broader array of state approaches (PNNL, 2017b).

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4. Scenarios

The study will include six separate scenarios based on different levels of DER adoption as well as the overall system demand. The levels of DER adoption will fall into the following three categories:

1. Business as Usual	2. High	3. Extrapolated

Table 1 summarizes the six scenarios, a brief description of each scenario, and the proposed DER adoption category for each scenario. The scenarios cover two horizons: (1) a short-term horizon (2025) and (2) a long-term horizon (2040).

Table 1 Summary of scenarios

Scenario	Description	PV	Storage	System Demand
1: Business as Usual (BAU)	Base case			
2: High Electrification	BAU DER, high demand			
3: High PV Stress Test	High PV penetration <u>without</u> storage breakthrough			
4: High PV and Battery Storage	High PV penetration <u>with</u> storage breakthrough			
5: Battery Storage Arbitrage	Storage breakthrough with BAU PV			
6: Boundary Case (Distribution system stress test)	Very High PV, storage, electrified demand			

Table 2 reports preliminary definitions for the BAU, High, and Extrapolated categories for each resource. In discussions with the IURC, two additional sensitivity scenarios that may be included if data and resources are available:

1. Utility-owned DER
    - Several utilities in the U.S. are considering owning DER as an alternative to distribution infrastructure investments.

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- Utility-owned DER would be located and operated following different criteria than customer owned DER. Hence, a sensitivity would be needed over customer-owned DER investment and operation profile.

2. Location of DER

- The physical impact of DER in the distribution system depends on its location within the network. This study will develop a simple methodology to allocate DER within a feeder based on customer segment and installed capacity.
- If revised customer-level data became available, the study team may consider implementing an alternate allocation method to test the impacts of alternative locations.

Table 2 Preliminary quantitative scenario criteria

PV	Storage	Electric Vehicles (EVs)	System Demand
To be established from base case forecast from utility IRPs.	To be established from base case forecast from utility IRPs.	To be established from base case forecast from utility IRPs.	To be established from base case forecast from utility IRPs.
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
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

5. DER valuation framework

DER have a wide array of value streams (EPRI, 2014; Frick et al., 2018; Shenot et al., 2019). This study focuses on a subset of all possible value components including:

- Energy cost
- Losses
- Capital integration investments or deferments (capacity value)

Due to technical and resource limitations, a number of addition value streams 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 (Nassuato et al., 2016). However, we are still determining if there is a simplified method to determine the potential contribution of DER to this value stream.

The framework to track these value components is largely based on an NREL study titled "Methods for Analyzing the Benefits and Costs of Distributed Photovoltaic Generation to the U.S. Electric Utility System" (NREL, 2014). This study is focused on DER PV, but its methodology can be applied to other types of DER. The DER valuation framework components and measurement methodology specific to our study are described below.

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Energy

Operation of DER changes the shape and level of the net demand curve that is supplied by the bulk-power system. The change in shape can produce costs or benefits depending on how the BPS dispatch curve changes and whether ramping is needed (e.g. to address the "duck curve" phenomenon). The contraction (change in levels due to reduced net load) often results in savings from less energy produced at the utility-scale. We will measure these changes by comparing the different net demand scenarios in Aurora/Plexos and determining the cost reductions (or increase in dispatch) due to higher DER penetration.

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. 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. Below, we discuss how distribution and transmission losses will be addressed in this study:

1. Distribution losses
    - Assessment of distribution losses will be produced with power flow simulation of selected feeders, using Cymdist.
    - Simulations will be run for a sample of representative hours and scaled to determine changes in loss levels at different penetrations.
2. Transmission losses
    - Transmission loss reduction may be estimated heuristically based on the hourly reduction for representative day/season coming from the net load.
    - However, since transmission expansion is not part of the IURC study, we may not evaluate this specific type of loss.

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. Below, we discuss how capital deferment will be addressed in this study:

1. Generation
        - We will first determine the capacity credit of the different DER technologies, accounting for T&D losses (i.e. referring the capacity credit to the transmission network). This capacity credit may have been already calculated by IOUs in their IRPs. If so, we will use these estimates. If not, a suitable method will be developed that estimate changes in the Effective Load Carrying Capacity (ELCC)
    - Next, we will estimate potential reductions in planning reserve margin that come from peak demand reductions. We will implement a simple method that increases the capacity credit by an amount proportional to the reserve margin.

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- The final step involves monetizing the capacity credit employing one of two options depending on whether the SUFG study includes optimal capacity expansion modeling. If the SUFG study includes optimal capacity expansion modeling, then the capital costs for generation, ramping, and planning reserve margins will be implicit in the optimal mix. However, if the SUFG study does not include optimal capacity expansion modeling, then we will use a simplified approach based on a capacity market price data equivalent that can be obtained from MISO, PJM, or other publically available sources.

2. Transmission
   - The NREL study proposes three methods to assess capital deferments in transmission systems. Two of these methods are quite complicated and require explicit modeling of the transmission network, which we will not be able to perform given resource/time constraints. A more simplified method involves obtaining transmission locational marginal prices (LMP) and determining the marginal contribution of DER to reduce those LMPs. This reduction serves as a proxy for transmission capacity values. It should be noted that this method assumes that DER penetration levels do not substantially change the underlying LMP data used for the estimates. If this assumption is violated, then the method can produce biased results. For this reason, we will check if MISO has performed and is willing to share power flow analyses with high DER penetration levels.
3. 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 feeder and load data (see more details in the "Simulations" section of this document). We assume that feeders will be upgraded, if needed, to maintain voltage drop, line and transformer loading and losses, within prescribed and accepted levels. The method used to upgrade the feeders is still under development. Distribution-level capital investments or deferments will be monetized based on current infrastructure costs that may be provided by the Indiana utilities.

As indicated, this study monetizes the impacts of DER for the different value streams outlined above. The study tracks the impacts of DER on three widely accepted reliability performance indices for distribution system reliability: (1) System Average Interruption Duration Index (SAIDI); (2) System Average Interruption Frequency Index (SAIFI); and (3) Customer Average Interruption Duration Index (CAIDI). We discuss the reliability impact framework in the following section.

6. DER reliability impact assessment framework

The study will use a database of past power interruptions to examine the potential for DERs to mitigate future interruptions to customers. Potential DER impacts on traditional reliability indicators are collected through a literature review (see a preliminary overview on Table 3). The quantification of the positive and negative effects of DER on reliability will be based on the types and frequency of interruptions in Indiana distribution systems. The characterization of interruptions is based on a five-year history of outage data and reliability indices provided by the utilities. The study will consider monetizing the changes in SAIDI, SAIFI, and CAIDI using LBNL's ICE calculator to assign value to the lost load.

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Table 3 DER reliability assessment framework overview

DER	Reliability Metric	DER Effects
Solar PV	SAIFI	• **Reduce demand during times of higher interruption probability** • **Reduce "overload" outages – use historical outage data.**
	SAIDI (UTILITY PERSPECTIVE)	• **Fewer outages because of reduced likelihood of "overload" outages** • **Reduce "overload" outages – use historical outage data. SAIDI impacts depend on relative duration of "overload" outages compared to other types.**
	SAIDI (CUSTOMER PERSPECTIVE)	• **None**
Battery Storage	SAIFI	• **Reduce demand during times of higher interruption probability** • **Reduce "overload" outages – use historical outage data.**
	SAIDI (UTILITY PERSPECTIVE)	• **Fewer outages because of reduced likelihood of "overload" outages** • **Reduce "overload" outages – use historical outage data. SAIDI impacts depend on relative duration of "overload" outages compared to other types.**
	SAIDI (CUSTOMER PERSPECTIVE)	• **Duration reduction based on battery charge/discharge profiles to be developed for modeling 8760 load profiles. Assumes battery storage system used for backup.**
DR	SAIFI	• **Reduce demand during times of higher interruption probability** • **Reduce "overload" outages – use historical outage data.**
	SAIDI (UTILITY PERSPECTIVE)	• **Fewer outages because of reduced likelihood of "overload" outages** • **Reduce "overload" outages – use historical outage data. SAIDI impacts depend on relative duration of "overload" outages compared to other types.**
	SAIDI (CUSTOMER PERSPECTIVE)	• **None**
EE	SAIFI	• **Reduce demand during times of higher interruption probability** • **Reduce "overload" outages – use historical outage data.**
	SAIDI (UTILITY PERSPECTIVE)	• **Fewer outages because of reduced likelihood of "overload" outages** • **Reduce "overload" outages – use historical outage data. SAIDI impacts depend on relative duration of "overload" outages compared to other types.**
	SAIDI (CUSTOMER PERSPECTIVE)	• **Potential change in duration of backup potential when combined with batteries**

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7. Feeder selection and simulations

Simulations of distribution systems through optimal power flow methods are computationally intensive and time consuming due to the breadth and complexities of these systems. Given these restrictions, this study considers a statistical analysis of Indiana IOU feeders to determine a set of representative feeders that will be simulated. Hypothetical feeders will be developed in order to be representative for each utility, and then an additional process will produce a set of statewide representative feeders. Results will then be scaled back to the utility- and state-level based on the sampling criteria.

The main steps in the feeder selection process are detailed as follows:

1. Request from the IOUs information that characterizes their feeders. This data request includes overhead and underground circuit length, aggregate transformer capacity, number of customers by segment, share of energy sales by segment, share of installed capacity by segment, and feeder header peak demand for 2018. This basic information is supplemented with reliability indices information by feeder obtained from the utilities.
2. Data provided by the utilities is cleaned to remove feeders with very short lengths or very few customers, which may represent short segments to supply specific commercial or industrial operations.
3. Calculate a few derivative metrics such as customers per unit length (a proxy for density)
4. Use a mixed heuristic and hierarchical clustering methodology to produce between 5-7 feeder clusters at the IOU- and state-level. This method will be based on previous work for representative feeder clustering (e.g. Broderick and Williams, 2013; Cale et al., 2014; Schneider et al., 2008).
5. Determine a methodology to scale up the results from the representative feeders to the respective IOU- and state-level.

Simulation will be conducted using Cymdist, a power flow software that is an industry standard for electric utility distribution operation and planning. Four out of the five Indiana IOUs employ this software in their technical operation analysis. This study leverages this software to simulate their selected feeder models directly. The simulation process is detailed as follows:

1. Acquire Cymdist feeder models for the four utilities that employ this software.
2. Performa a basic verification of feeder topology and quality of the information.
3. Determine what information is available for load nodes in the model. This information will be used to assign proper consumption and DER profiles to each load node for simulation purposes.
4. Develop typical 8,760-hour one-year vectors for native load, PV production, battery storage charge and discharge, electric vehicle charging, demand response, and energy efficiency.
5. For selected feeders, develop 8,760-hour one-year vectors for each load node by aggregating as net load the vectors from step #3 for each load node. Scale the 8,760 net load vectors to the utility level and use this information as input to the generation segment analysis.
6. Select specific hours of the year (usually high demand or low demand hours, or potentially high and low net-demand hours) and run power flow simulations for each feeder-period-scenario combination.

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7. For the 2040 simulations, develop basic upgrades to feeders whose voltage drop, line/transformer loading, and line/transformer losses are not within an acceptable range or standard.
8. Monetize these upgrades for each scenario to quantify cost impacts.

8. Summary of data collection progress

Table 4 summarizes the progress for the data collection identified in the previous sections. Non-disclosure agreements (NDA) were drafted, discussed, and fully executed between LBNL-Nexant and each one of the five Indiana IOUs. Following the execution of the NDA, a data request was submitted to the IOUs, which was fulfilled in December 2019. Subsequently, a thorough review of the data was performed for each utility and a set of comments and further requests was submitted to each of them. The final responses and clarifications are being processed, and should be finalized before the end of January 2020.

Table 4 Status of data collection

Task number	Task name	Comments
1	Literature review	Key papers identified and used to inform different tasks in the study; summaries and outcomes are being developed.
2	DER value framework	Framework under development, need to finalize quantitative assumptions, define how/whether to assess transmission impacts, and coordinate details with SUFG. Review of current and forecast DER data submission.
3	DER reliability framework	Framework under development, need to finalize quantitative benchmarks and run a preliminary test. Review of five-year outage data submission.
4	Scenarios and forecasting	Developed basic scenario structure and framework, approved by the IURC. Finalizing quantitative implementation of the scenarios. DER adoption and native load forecasts are being produced based on data submission
5.1	Feeder selection	Preliminary analysis of data submitted by the IOUs, still pending full submission for one of them. Testing different hierarchical clustering algorithms and optimal cluster numbers. Comparing feeder characterization data against Cymdist model data, both part of the data submission.
5.2	Simulation	Preliminary verification of feeder models from the four IOUs with Cymdist models is performed. Developing 8,760-hour vectors for 2025 and 2040 for native load and DER based on #4.

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