Sequential Integrated Analysis of Distributed Energy Resources in Distribution and Bulk Power Systems

Juan Pablo “JP” Carvallo
Electricity Markets and Policy Department – Lawrence Berkeley National Laboratory

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Agenda

- Sequential Integrative Modeling (SIM)
- Indiana case study: introduction
- Model input components
- Distribution system technical results
- Generation-transmission technical results
- Cost results and rate impacts
<table>
<thead>
<tr>
<th>Modeling for planning</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Bulk Power System Planning</strong></td>
<td><strong>Distribution Planning</strong></td>
</tr>
<tr>
<td>• Decisions: investment in supply side technologies and transmission lines/substations</td>
<td>• Decisions: grid investments to maintain distribution reliability</td>
</tr>
<tr>
<td>• Models: capacity expansion models (e.g., Aurora); production cost (dispatch) models used for verification</td>
<td>• Models: power flow models (e.g., CYME) to identify technical issues; then manual upgrades, with non-wires alternatives used by some utilities</td>
</tr>
</tbody>
</table>
What is sequential integrative modeling (SIM)?

► Regulators and system planners want to understand the impacts of DERs across domains in the power system: distribution and bulk power system (BPS—generation+transmission)

► DER impact assessments are usually constrained to one domain (distribution or BPS) based on analyses developed in planning processes—distribution planning, integrated resource planning (IRP), cost-benefit analysis

► Joint simulation of distribution system and BPS is possible, but can be challenging:
  ■ Requires substantial computational capacity
  ■ Makes potentially unrealistic assumptions about investment coordination across power system domains
  ■ Uses nascent tools, not industry-standard

► SIM is a method to simulate the impacts of DER across the whole electric value chain employing industry standard tools
SIM framework overview

- DER adoption and operational profile scenarios
- Native load forecast
- Distribution system characterization
- Power flow simulations and manual upgrades
- Capacity expansion and production cost modeling
- BPS characterization
- Technical and economic impacts
- Rate impacts
SIM case study: state of Indiana
Indiana implementation

Forecast adoption levels for PV, EV, and Battery Storage based on IRP and other documents

Produce six adoption scenarios, based on a mix of adoption levels

Collect information on utility's feeders and customers

Classify feeders in six clusters and select six representative feeders

Forecast net load for each customer in each representative feeder

Generation system Plexos and Aurora simulations

Transmission economic impact assessment

Technical and economic impact assessment

Rate impacts

Distribution system Cymdist power flow simulations

Technical and economic impacts assessment

SAIDI and SAIFI impacts

Distribution system reliability analysis of DER adoption levels

Simulations

Input data creation

Raw data acquisition

Technical and economic impacts
Indiana implementation

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Transmission economic impact assessment

Technical and economic impact assessment

Rate impacts

Distribution system Cymdist power flow simulations

Technical and economic impact assessment

SAIDI and SAIFI impacts

Distribution system reliability analysis of DER adoption levels

Raw data acquisition

Input data creation

Simulations

Technical and economic impacts
DER adoption levels

- Business as usual (BAU) adoption levels based on Indiana IRPs are very modest.
- High and Very High levels for various types of DERs based on the following:
  - EV: MISO EV adoption scenarios
  - PV: IP&L (now AES Indiana) IRP
  - Storage: Estimated at 1% and 5% of customers
DER adoption scenarios for 2025 and 2040

<table>
<thead>
<tr>
<th>Scenario</th>
<th>PV</th>
<th>Storage</th>
<th>EV</th>
</tr>
</thead>
<tbody>
<tr>
<td>1: Base</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2: High Electrification</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>3: High PV Stress Test</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>4: High PV and Battery Storage</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>5: Battery Storage Arbitrage</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>6: Boundary Case</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
Distribution system characterization: Representative feeders

► Objective: determine a minimum number of representative feeders that can be used for power flow simulations and represent large portions of the existing customer base

► Approach:
  ■ Collect data to characterize feeders (e.g., overhead and underground circuit length, number of customers by segment, SAIDI/SAIFI, peak demand, etc.)
  ■ Process data to produce a set of feeders with a balance of valid fields and utilities represented
  ■ Use statistical methods to process the data and cluster feeders
  ■ Run sensitivities on clusters
  ■ Determine final clusters and qualitatively characterize them
## Distribution system characterization: Clusters – Feeder selection

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

► Translate state-wide penetration scenarios to feeder-level customer adoption:
  ■ Develop scaling factors from feeder-level to cluster-level
  ■ Develop an adoption logic for each connected customer

► Hourly production
  ■ PV systems from NREL’s PVWatts for several Indiana locations; use average since clusters are not necessarily geographically split
  ■ EV charging assumed “charge as available,” mostly after work
  ■ Storage operation designed to maximize netting of PV production, subject to a minimum charge of 25%
• Assumed size for DER systems by customer segment

<table>
<thead>
<tr>
<th>DER System</th>
<th>Residential</th>
<th>Commercial</th>
<th>Industrial</th>
</tr>
</thead>
<tbody>
<tr>
<td>Rooftop PV</td>
<td>• 8 kW</td>
<td>• 16 kW</td>
<td>N/A</td>
</tr>
<tr>
<td>Battery storage</td>
<td>• 7 kW max discharge capacity</td>
<td>• 14 kW max discharge capacity</td>
<td>N/A</td>
</tr>
<tr>
<td></td>
<td>• 12 kWh storage capacity</td>
<td>• 0.1% of annual kWh consumption of storage</td>
<td></td>
</tr>
<tr>
<td></td>
<td>• 90% roundtrip efficiency</td>
<td>capacity</td>
<td></td>
</tr>
<tr>
<td></td>
<td>• 25% maximum discharge level</td>
<td>• 90% roundtrip efficiency</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>• 25% maximum discharge level</td>
<td></td>
</tr>
<tr>
<td>Electric vehicle charging</td>
<td>• T1 charger: 1.75 kW peak capacity</td>
<td>N/A</td>
<td>N/A</td>
</tr>
<tr>
<td></td>
<td>• T2 charger: 5.25 kW peak capacity</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
Power flow simulation

- Use API-enabled CYMDIST platform, which allows users to “batch” run simulations

- Simulate maximum and minimum load days, for each cluster/scenario/year combination
  - About 3,500 power flows simulated
Method – Distribution cost impacts

► Use power flow simulations to track three metrics:
  ■ Voltage issues
  ■ Line loading issues
  ■ Line losses

► Strategies to mitigate voltage and loading impact:
  ■ Volt/Var control in PV smart inverters (automatic)
  ■ Line reconductoring (manual)
  ■ Install tap changers in feeder heads (manual)
  ■ Install voltage regulators (manual)
Results – Voltage Violations
Results – Line losses changes relative to Base

► In High Electricity scenario, increase in losses tied to EV charging especially in long, sparse feeders
► In High PV scenario, substantial loss reduction during PV production hours
► In Boundary scenario, losses dominated by uncontrolled EV charging
Results – Cost impacts

► Voltage regulation
  ■ Smart inverters (assumed installed by default)
  ■ ~$10M annual cost to equip substations with load tap changers

► Line loading
  ■ ~$12.5M and $70M annual cost
    for High Electricity and Boundary scenarios

► Line losses
  ■ Between -$2M to $12M annual cost in energy losses
  ■ Negative range comes from reduction in losses due to lower current flows driven by PV operation

<table>
<thead>
<tr>
<th>Cluster</th>
<th>Underground Cable Length (feet)</th>
<th>Overhead Line Length (feet)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Copper</td>
<td>Aluminum</td>
</tr>
<tr>
<td>3</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>4</td>
<td>57</td>
<td>0</td>
</tr>
<tr>
<td>5</td>
<td>172</td>
<td>0</td>
</tr>
</tbody>
</table>
Generation and transmission assessment
Method – Generation and transmission impacts

► Employ Aurora capacity expansion model and Plexos production cost model. Analysis developed by Purdue University’s State Utility Forecasting Group (SUFG)
  ■ Models produce capital and operational cost estimates for scenarios

► Input data
  ■ Scale the hourly customer-level net demand profile to the cluster-level, and then to the state-wide level
  ■ Express the hourly net-demand as a % variation of the Base scenario to minimize distortions with the data that SUFG uses to calibrate their models
  ■ Apply the % hourly variation over the SUFG baseline scenario, verify that baseline scenarios are compatible

► Transmission impact very simplified, based on increase in peak demand and average cost of transmission buildout per MW
Results – Generation mix

- Energy levels in Boundary scenario balance PV and EV adoption; low capacity impact
- Distributed solar crowds out utility-scale solar
- Note: Model does not assess utility-scale storage
Results - Generation costs

- Savings largely driven by demand reduction

- Boundary scenario has low energy impact, but very high capacity impact; model deploys natural gas peaker plants
Results – Aggregate cost impacts

- Non-boundary scenarios have cost savings in generation driven by PV adoption

- Boundary scenario has high cost impacts in generation and transmission, mostly from unmanaged EV charging

- Very low distribution cost impacts
# Results – All-in average rate impacts

<table>
<thead>
<tr>
<th>Scenario</th>
<th>2025 Rate Change Relative to Base</th>
<th>2040 Rate Change Relative to Base</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Residential</td>
<td>Commercial</td>
</tr>
<tr>
<td>High Electrification</td>
<td>0.25¢</td>
<td>0.24¢</td>
</tr>
<tr>
<td>High PV</td>
<td>-0.06¢</td>
<td>-0.10¢</td>
</tr>
<tr>
<td>High PV and Storage</td>
<td>-0.06¢</td>
<td>-0.10¢</td>
</tr>
<tr>
<td>Storage</td>
<td>0.00¢</td>
<td>0.00¢</td>
</tr>
<tr>
<td>Boundary</td>
<td>0.52¢</td>
<td>0.47¢</td>
</tr>
</tbody>
</table>
Summary of SIM for Indiana

► Expected DER penetration levels in Indiana will have minor technical and economic impacts on the distribution system.

► Most impacts of DER penetration are on generation and transmission costs, especially capacity to meet demand from unmanaged EV charging.

► Rate impacts continue to be positive, mostly due to assumptions about future utility “fixed costs” and rate increases needed to pay for them as retail sales decline due to DERs.

► Feeder clustering represents vast portions of the distribution system with a few representative feeders, allowing for detailed simulations.

► This framework could serve as a blueprint for joint distribution-BPS planning studies in other states.
Summary of framework

► The SIM framework develops integrated analyses of DER impacts on distribution, transmission, and generation domains of the power system and at the technical, economic (cost), and rate levels.

► The SIM approach addresses computational and regulatory challenges by:
  ■ Developing detailed adoption and operational profiles for DERs
  ■ Characterizing the distribution system through representative feeders that enable rigorous modeling of distribution system impacts across vast territories with reasonable fidelity
  ■ Applying a standard method for assigning DERs to customers and customers to feeders, and scaling feeders to the state level or other aggregations, which allows modeling and analysis in the absence of detailed customer data

► The framework can produce feeder-level and statewide estimates for DER-avoided or driven costs across all three domains of the power system.
Questions states can ask

► How consistent are assumptions for native load and DER adoption and operation between: (1) distribution planning studies and (2) bulk power system studies?

► How is DER adoption modeled in distribution planning processes?
   ■ What assumptions are made about drivers of adoption in terms of costs, incentives, and behavior?
   ■ Where applicable, how do these assumptions map to bulk power system assumptions for similar technologies such as solar PV and storage?

► How is DER operation modeled in distribution planning processes?
   ■ What drives different operational patterns for each type of DER?
   ■ How diverse are the operational patterns?
   ■ How are these patterns reflected at the bulk power system level?

► How would a whole-system planning analysis — including upstream benefits of DER — result in different non-wires alternative decisions for utilities compared to localized benefit-cost analyses, (assuming consistent assumptions)?

► Has the utility conducted analysis to identify feeders representative of the distribution system? How diverse are feeders on the utility's distribution system? For example, how many long rural feeders compared to shorter, urban, mostly underground feeders are there?
Resources for more information


► Indiana’s 21st Century Energy Policy Task Force, for which the Indiana SIM was developed: https://www.in.gov/iurc/research-policy-and-planning-division/hea-1278-energy-study/

► SIM-LA100: The LA 100 project developed by LADWP and the City of Los Angeles with support from NREL is another SIM example: https://maps.nrel.gov/la100/report
Contact

Juan Pablo “JP” Carvallo
jpcarvallo@lbl.gov
Feeder clustering – Pre-processing

- Pre-processing: Principal Component Analysis (PCA).
  - PCA is a method designed to extract and display the systematic variation in a data set (Broderick and Williams, 2013)
  - “PCA provides a roadmap for how to reduce a complex data set to a lower dimension to reveal the sometimes hidden, simplified structure that often underlie it.” (Shlens, 2005)
- Outlier detection using Mahalanobis distance
Feeder clustering - Results

► Partitioning Around Medoids (PAM) algorithm used to group feeders and create clusters.
► Used in similar work by Cale et. al (2014)
## Selected feeder parameters for clustering

<table>
<thead>
<tr>
<th>Parameter name</th>
<th>Description</th>
<th>Count</th>
<th>Mean</th>
<th>Standard deviation</th>
</tr>
</thead>
<tbody>
<tr>
<td>poles</td>
<td>Number of poles</td>
<td>2,252</td>
<td>549</td>
<td>474</td>
</tr>
<tr>
<td>len_oh</td>
<td>Total overhead circuit length (miles)</td>
<td>2,252</td>
<td>13</td>
<td>14</td>
</tr>
<tr>
<td>len_ug</td>
<td>Total underground circuit length (miles)</td>
<td>2,252</td>
<td>6</td>
<td>8</td>
</tr>
<tr>
<td>agg_tr_cap</td>
<td>Aggregate MV/LV transformer capacity (MVA)</td>
<td>2,252</td>
<td>13,485</td>
<td>8,385</td>
</tr>
<tr>
<td>sh_cap_res</td>
<td>Share of connected capacity, residential customers</td>
<td>2,252</td>
<td>57%</td>
<td>30%</td>
</tr>
<tr>
<td>sh_cap_com</td>
<td>Share of connected capacity, commercial customers</td>
<td>2,252</td>
<td>29%</td>
<td>23%</td>
</tr>
<tr>
<td>sh_cap_ind</td>
<td>Share of connected capacity, industrial customers</td>
<td>2,252</td>
<td>9%</td>
<td>17%</td>
</tr>
<tr>
<td>sh_cap_other</td>
<td>Share of connected capacity, other customers</td>
<td>2,252</td>
<td>5%</td>
<td>10%</td>
</tr>
<tr>
<td>avg_caidi</td>
<td>Average feeder CAIDI (2014-2018)</td>
<td>2,252</td>
<td>137</td>
<td>55</td>
</tr>
<tr>
<td>num_cust_tot</td>
<td>Total number of customers in feeder</td>
<td>2,252</td>
<td>902</td>
<td>659</td>
</tr>
<tr>
<td>tot_len</td>
<td>Total feeder circuit length (Derived)</td>
<td>2,252</td>
<td>19</td>
<td>17</td>
</tr>
<tr>
<td>sh_len_und</td>
<td>Share of underground length from total length (Derived)</td>
<td>2,252</td>
<td>32%</td>
<td>26%</td>
</tr>
</tbody>
</table>
## Annual energy consumption thresholds for DER adoption

<table>
<thead>
<tr>
<th>DER</th>
<th>Adoption level</th>
<th>Residential 2025 threshold level (kWh)</th>
<th>Residential 2040 threshold level (kWh)</th>
<th>Commercial 2025 threshold level (kWh)</th>
<th>Commercial 2040 threshold level (kWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>PV</td>
<td>Base</td>
<td>50,000</td>
<td>41,000</td>
<td>75,000</td>
<td>34,000</td>
</tr>
<tr>
<td>PV</td>
<td>High</td>
<td>24,500</td>
<td>18,500</td>
<td>32,000</td>
<td>7,600</td>
</tr>
<tr>
<td>PV</td>
<td>Very High</td>
<td>21,000</td>
<td>14,250</td>
<td>18,000</td>
<td>3,000</td>
</tr>
<tr>
<td>EV-T1</td>
<td>Base</td>
<td>44,000</td>
<td>24,500</td>
<td>N/A</td>
<td>N/A</td>
</tr>
<tr>
<td>EV-T1</td>
<td>High</td>
<td>36,000</td>
<td>18,500</td>
<td>N/A</td>
<td>N/A</td>
</tr>
<tr>
<td>EV-T1</td>
<td>Very High</td>
<td>27,000</td>
<td>11,000</td>
<td>N/A</td>
<td>N/A</td>
</tr>
<tr>
<td>EV-T2</td>
<td>Base</td>
<td>34,500</td>
<td>18,100</td>
<td>N/A</td>
<td>N/A</td>
</tr>
<tr>
<td>EV-T2</td>
<td>High</td>
<td>28,200</td>
<td>12,800</td>
<td>N/A</td>
<td>N/A</td>
</tr>
<tr>
<td>EV-T2</td>
<td>Very High</td>
<td>19,350</td>
<td>4,700</td>
<td>N/A</td>
<td>N/A</td>
</tr>
<tr>
<td>Storage</td>
<td>Base</td>
<td>N/A</td>
<td>140,000</td>
<td>N/A</td>
<td>N/A</td>
</tr>
<tr>
<td>Storage</td>
<td>High</td>
<td>46,500</td>
<td>37,000</td>
<td>700,000</td>
<td>600,000</td>
</tr>
<tr>
<td>Storage</td>
<td>Very High</td>
<td>32,000</td>
<td>24,500</td>
<td>400,000</td>
<td>220,000</td>
</tr>
</tbody>
</table>
Method – Reliability impacts

► Reanalysis of historical outage data based on storage adoption levels, consumption levels, outage onset hour, and storage operational mode

► Output: reliability impacts from a customer’s perspective

► Assumes:
  ■ Only storage has a meaningful impact on reliability levels
  ■ No changes in consumption patterns during an outage (no conservation)
  ■ Base scenario electrification (very few EV)
  ■ A PV system for every storage system
Method - Reliability Data Processing

► Five years of outage data + circuit characteristics from each utility
  ■ Each row is an outage
  ■ Each outage has a circuit or feeder, cause, number of customers affected, duration, etc.

► Cleaned data
  ■ Uniformity: outage types, included/excluded outages, time frame (2014-2018)
  ■ Removed outliers, momentary outages (<5 min.), major event days (MEDs)
Outage Characteristics - Statewide

- More customer-outages occur mid-day than at other hours
- Outage duration has a long tail to the right

[Graph showing customer outages by onset hour and outage duration distribution]
Customer Minutes Interrupted by Outage Type
Results Setup

► 3 levels of storage adoption corresponding to the levels in the scenarios
  ■ Baseline/BAU: 0.01% overall
    • Scenarios 1, 2, 3
  ■ High: 1% overall
    • Scenarios 4, 5
  ■ Very High: 5% overall
    • Scenario 6

► Assumed battery capacity of:
  ■ 12 kWh for residential
  ■ 20 kWh for commercial
Available Storage Varies by Operating Mode

- Modes of operation:
  - Full: Battery only for outages – does not discharge otherwise
  - Half: Same as “Full” but with half of the capacity
  - Peak Times: Battery charges during off-peak times and discharges to offset on-peak
  - PV: Battery charges from PV system – net of on-site usage
  - Islanding: Similar to PV mode, but allows PV to continue operating during an outage
Results - Impact of Batteries to Customer-Perceived Outage Metrics

- Cluster 4 has higher SAIFI, SAIDI, CAIDI, while Clusters 5 and 6 are generally lower
- SAIDI and SAIFI improve most for Clusters 4 and 5, driven by residential adoption assumptions
  - No substantial changes to CAIDI
Reductions in Customer-Perceived SAIDI (and SAIFI) by Scenario and Battery Mode

► SAIDI and SAIFI reductions show similar magnitude for different modes of operation:

- A mode of operation that offsets peak usage will have similar impact on system-wide outage metrics as full battery
- Half-capacity batteries (6/10 kWh for Res/Com) mitigate outages almost as effectively as full capacity batteries
Outage Impacts for Battery Owners

- 80-90% reduction in outage frequency and total outage time
  - Consistent across clusters
- Average duration increases, likely because shorter outages were mitigated
  - Highest increases in Clusters 3 and 6
Results - Resilience

► Use a simplified metric of outages lasting more than 24 hours
► Widespread battery adoption for all res/com customers still leaves about 60% of long-term outages unmitigated
► Again, this assumes no conservation or DR strategies
Resilience impact of Very High level of battery storage adoption