Emerging distribution planning analyses

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GE Energy Consulting

Distribution Systems and Planning Training for Midwest Public Utility Commissions, Jan. 16-17, 2018
Outline

► Introduction
► Multiple scenario forecasts
► Hosting capacity
► Locational net benefits analysis
► Key questions to ask
Introduction
Autonomous DER deployment with little information/guidance

► Customer decides what kind of DER to install, how big, where, and how to operate it
  • Utilities must manage integration of the DER
  • Location may be unfavorable leading to expensive interconnection and no one is happy
► If the next DER requires upgrade/mitigation, that next customer is responsible, even though it might enable many more customers to install DERs
► Utility compensates customer (e.g., net metering, fixed tariff)
  • Compensation may not reflect actual net value that DER brings
Consequences of passive planning

- 6 GW of uncontrolled distributed PV (DPV), resulting in negative prices, overgeneration events, difficulty in forecasting load (California)
- Uncontrolled DPV that increases curtailment of wind plants (Maui)
- Projects in difficult locations that require challenging mitigation (National Grid)
- Inability to recover cost of service from DPV customers (multiple utilities)
- Unhappy customers who want to install DER but whose feeder can’t accommodate additional DER (Hawaii)

Photos by NREL, 7400 and 14697
Smart, proactive planning

Give customers information about where the grid needs help. Incentivize them.

- Hosting capacity shows how much more DER can be managed on a given feeder easily, or where interconnection costs will be low/high
- Locational net benefits analysis helps determine the specific benefits of specific services at a specific location to guide developers
- Proactive upgrades of circuits that are likely to see DER growth
- Defer traditional infrastructure investments through non-wires alternatives that provide specific services at specific locations
- Help prioritize solicitations
- Inform rates and tariffs
- Leverage third-party capital investments
Distribution Resources Plans (DRPs)

► California’s 3 investor-owned utilities (IOUs) submitted DRPs to CPUC July 2015
http://www.cpuc.ca.gov/General.aspx?id=5071

http://jointutilitiesofny.org/

DRP Objectives

- Modernize distribution system to accommodate expected DER growth through two-way power flow
- Enable customer choice of new electric DER technologies and services
- Identify and develop opportunities for DERs to realize grid benefits

Identify Optimal Locations for deployment of DERs

PG&E, DRP Webinar, 2015
Multiple Scenario Forecasts
Types of Scenarios

► Business-as-usual (eg, California’s Trajectory case)
► High penetrations of DERs
► Costs decrease for certain DERs
► Policy-driven
► Carbon/sustainability
► High community choice aggregation scenario

What are the main drivers in your region?
Making load forecasts more granular in time and space

► State level: California
  □ Annual peak load forecast
  □ Annual energy
  □ By climate zone

► Utility system level: Southern California Edison (SCE)
  □ Annual hourly load forecast by customer class, accounting for DERs

► Utility distribution level: SCE
  □ Annual peak hour by substation (subtransmission and below) with limited accounting for DERs at present
  □ Goal: Annual hourly load forecast by feeder, accounting for all DERs
Example of Load Forecasting with DER

Con Edison, *Distributed System Implementation Plan, June 30, 2016*
Various models need to be run to determine each component.
### Where does the data come from?

<table>
<thead>
<tr>
<th></th>
<th>SCE</th>
<th>PG&amp;E</th>
<th>SDG&amp;E</th>
</tr>
</thead>
<tbody>
<tr>
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<td>(IEPR) Mid Case</td>
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<td><strong>Energy Efficiency</strong></td>
<td>IEPR – Low Mid AAEE and EE Potential &amp; Goals Study</td>
<td>IEPR – Low Mid AAEE</td>
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<td><strong>Load modifying Demand Response (DR)</strong></td>
<td>DR Load Impact Report</td>
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<td><strong>Electric Vehicles</strong></td>
<td>SCE Latest Forecast</td>
<td>IEPR Mid Case</td>
<td>SDG&amp;E Latest Forecast</td>
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<tr>
<td><strong>Storage (BTM)</strong></td>
<td>SCE Contracted Procurement</td>
<td>PG&amp;E Contracted Procurement + Interconnection Queue</td>
<td>AB2514 Targets</td>
</tr>
</tbody>
</table>
Scenario Summary for PG&E

PG&E Peak Impact Forecast Scenarios (2015-2025)

Trajectory
High Growth
Very High Growth

Hansell, Navigant Consulting, 2015
Load profiles/shapes are important

► Traditional generation offered fixed capability at all times
  • Resource adequacy could be determined by peak

► However, DERs may offer variable output
  • Resource adequacy needs to be based on hourly profile for peak day

► “Peak” is moving because of a changing grid
  • As we move to time-varying rates, as solar penetrations increase, as EVs proliferate, it becomes harder to predict when peak will be

► System peak is different from circuit peak

W. Henson, ISONE, 2016
Distributed Generation (DG)

► How much, where, when?
► How much does it contribute to peak demand?
► How much does it reduce energy demand?
► How is it operated?

Source: PG&E, DRP, 2015
### Example: Constructing a Demand Forecast

#### 2016 - Electric System Peak Demand Forecast (in Megawatts)

<table>
<thead>
<tr>
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<tr>
<td>Updated System Forecast</td>
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<td><strong>13,781</strong></td>
<td><strong>13,942</strong></td>
<td><strong>14,048</strong></td>
<td><strong>14,124</strong></td>
<td><strong>14,164</strong></td>
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<td>MW Growth:</td>
<td>181</td>
<td>161</td>
<td>106</td>
<td>76</td>
<td>40</td>
<td></td>
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<tr>
<td>% Growth:</td>
<td>1.30%</td>
<td>1.20%</td>
<td>0.80%</td>
<td>0.50%</td>
<td>0.30%</td>
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<td><strong>Additional MW Growth</strong></td>
<td></td>
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<td>Electric Vehicles (EVs)</td>
<td>1</td>
<td>5</td>
<td>6</td>
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<td>Steam A/C Conversion</td>
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<td>22</td>
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<td><strong>Load Modifiers</strong></td>
<td></td>
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<td>Photovoltaics/Solar (PVs)</td>
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<td>-40</td>
<td>-51</td>
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<td><strong>Coincident DSM</strong></td>
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<td>NYSERDA EE</td>
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<td>-8</td>
<td>-7</td>
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<td>NYPA</td>
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<td>-5</td>
<td>-5</td>
<td>-1</td>
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<td>BQDM</td>
<td>-6</td>
<td>-24</td>
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<td>13^{27}</td>
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<td>DMP</td>
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<td>-68</td>
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<td>Demand Response</td>
<td>-32</td>
<td>-9</td>
<td>-8</td>
<td>-3</td>
<td>-3</td>
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<td>Total Incremental DSM:</td>
<td>-109</td>
<td>-126</td>
<td>-46</td>
<td>-24</td>
<td>-36</td>
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<td>Rolling Incremental DSM:</td>
<td>-109</td>
<td>-235</td>
<td>-281</td>
<td>-305</td>
<td>-341</td>
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<tr>
<td>System Forecast less DSM, less DG, PVs and Batteries + EVs + Steam A/C</td>
<td><strong>13,652</strong></td>
<td><strong>13,653</strong></td>
<td><strong>13,677</strong></td>
<td><strong>13,724</strong></td>
<td><strong>13,729</strong></td>
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<td>MW Growth:</td>
<td>52</td>
<td>1</td>
<td>24</td>
<td>47</td>
<td>5</td>
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<td>Rounded System Forecast less DSM, less DR and PVs + EVs + Steam A/C</td>
<td><strong>13,650</strong></td>
<td><strong>13,655</strong></td>
<td><strong>13,675</strong></td>
<td><strong>13,725</strong></td>
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<td>MW Growth (Rounded):</td>
<td>50</td>
<td>5</td>
<td>20</td>
<td>50</td>
<td>5</td>
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<tr>
<td>% Growth:</td>
<td>0.37%</td>
<td>0.04%</td>
<td>0.15%</td>
<td>0.37%</td>
<td>0.04%</td>
<td></td>
</tr>
</tbody>
</table>

Con Edison, *Distributed System Implementation Plan*, June 30, 2016
**SCE Territory Amounts of Potential DER Deployment by 2025**

<table>
<thead>
<tr>
<th>Growth Type</th>
<th>Scenario 1</th>
<th>Scenario 2</th>
<th>Scenario 3</th>
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</thead>
<tbody>
<tr>
<td>Base Load</td>
<td>27,019 MW</td>
<td>27,019 MW</td>
<td>27,019 MW</td>
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<tr>
<td>Solar PV (nameplate AC)</td>
<td>1,636 MW</td>
<td>1,905 MW</td>
<td>4,770 MW</td>
</tr>
<tr>
<td>AAEE (annual)</td>
<td>10,536 GWh</td>
<td>17,031 GWh</td>
<td>17,243 GWh</td>
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<tr>
<td>Demand Response</td>
<td>1,265 MW</td>
<td>2,087 MW</td>
<td>2,981 MW</td>
</tr>
<tr>
<td>CHP (annual)</td>
<td>6,350 GWh</td>
<td>8,576 GWh</td>
<td>13,612 GWh</td>
</tr>
<tr>
<td>EV (annual)</td>
<td>2,422 GWh</td>
<td>3,395 GWh</td>
<td>3,395 GWh</td>
</tr>
<tr>
<td>Storage (D&amp;C)</td>
<td>270 MW</td>
<td>270 MW</td>
<td>637 MW</td>
</tr>
<tr>
<td>Storage (T)</td>
<td>310 MW</td>
<td>310 MW</td>
<td>731 MW</td>
</tr>
</tbody>
</table>

Southern California Edison, Distribution Resource Plan, 2015

Growth rate declines from 1.4% to 0.2 – 1.0%
Allocate DERs to feeders

► **Ignore limitations of existing distribution grid**

► Identify likely adopters:
  • Who is likely to have interest in different DERs?
  • Who is likely to have economic potential to install different DERs?

► What are some of the drivers?
  • **Potential savings**
  • Clustering effect
  • Early adopter effect
  • Green customers
  • Self-sufficiency
  • Income levels

► What data can help?
  • Existing installations
  • Interconnection queue
  • Customer surveys/studies

Frank Goodman, SDG&E, UVIG Spring Workshop, 2016
Very High Growth DER Scenario - SCE
Integration Capacity Analysis/Hosting Capacity
Hosting Capacity

- Amount of DER that can be accommodated without adversely **impacting** power reliability or quality under **current** configurations, without requiring mitigation or infrastructure **upgrades**

\[
\frac{\text{max } P_{\text{DER}}}{\text{max } P_{\text{LOAD}}} = 0.6 \text{ MW} \quad 15 \%
\]

0.6 – 1.5 MW
Who’s doing it?

▶ California
▶ New York
▶ Minnesota
▶ Hawaii
▶ Pepco Holdings Inc.
▶ Unitil

ConEd, DSIP, 2016
Why?

- Inform developers where DER can interconnect without system upgrades
- Streamline and potentially automate the interconnection process
- Inform distribution planning, such as where to proactively upgrade the grid to accommodate autonomous DER growth

PG&E, DRP Webinar, 2015
Typical DER Interconnection Process

Application

Process Redefinition in CA, CO, HI, MA, MD, MN, NY, WI, and OH

Initial Review

Fail

Pass

FastTrack and/or Supplement

Fail

Pass

Interconnect Study

Pass

Application Approved
California DER Interconnection Process

“15% rule”
Allows aggregate DER penetration below 15% of peak load
California DER Interconnection Process

Application

Initial Review

Fail

Pass

FastTrack and/or Supplement

Interconnect Study

Fail

Pass

Application Approved

False positives and negatives
What level of Granularity is needed?

Power System Criteria for Hosting Capacity

Integration of Hosting Capacity Analysis into Distribution Planning Tools, EPRI, Palo Alto, CA: 2015. 3002005793
Examine power system limits at each relevant point in the system

Flexible Layered Framework

Each criteria limit is calculated for each layer independently and the most limiting values establish the integration capacity limit. 

- SQL Server calculates final results for the whole dataset across selected DER types
- Utilizing SQL scripting enables collaboration with Integral Analytics to more easily incorporate methodology into commercial software

PG&E Distribution Resources Plan, 2015
## Typical DER Impacts Threshold Levels

<table>
<thead>
<tr>
<th>Category</th>
<th>Criteria</th>
<th>Basis</th>
<th>Flag</th>
</tr>
</thead>
<tbody>
<tr>
<td>Voltage</td>
<td>Overvoltage</td>
<td>Feeder voltage</td>
<td>$\geq 1.05$ Vpu</td>
</tr>
<tr>
<td></td>
<td>Voltage Deviation</td>
<td>Deviation in voltage from no PV to full PV</td>
<td>$\geq 3%$ at primary</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>$\geq 5%$ at secondary</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>$\geq \frac{1}{2}$ band at regulators</td>
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<tr>
<td></td>
<td>Unbalance</td>
<td>Phase voltage deviation from average</td>
<td>$\geq 3%$</td>
</tr>
<tr>
<td>Loading</td>
<td>Thermal</td>
<td>Element loading</td>
<td>$\geq 100%$ normal rating</td>
</tr>
<tr>
<td>Protection</td>
<td>Total Fault Contribution</td>
<td>Total fault current contribution at each sectionalizing device</td>
<td>$\geq 10%$ increase</td>
</tr>
<tr>
<td></td>
<td>Forward Flow Fault Contribution</td>
<td>Forward flow fault current contribution at each sectionalizing device</td>
<td>$\geq 10%$ increase</td>
</tr>
<tr>
<td></td>
<td>Sympathetic Breaker Tripping</td>
<td>Breaker zero sequence current due to an upstream fault</td>
<td>$\geq 150\text{A}$</td>
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<tr>
<td></td>
<td>Breaker Reduction of Reach</td>
<td>Deviation in breaker fault current for feeder faults</td>
<td>$\geq 10%$ decrease</td>
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<tr>
<td></td>
<td>Breaker/Fuse Coordination</td>
<td>Fault current increase at fuse relative to breaker current increase</td>
<td>$\geq 100\text{A}$ increase</td>
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<td></td>
<td>Anti-Islanding</td>
<td>PV beyond each sectionalizing device</td>
<td>$\geq 50%$ minimum load</td>
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<tr>
<td>Power Quality</td>
<td>Individual Harmonics</td>
<td>Harmonic magnitude</td>
<td>$\geq 3%$</td>
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<td></td>
<td>THDv</td>
<td>Total harmonic voltage distortion</td>
<td>$\geq 5%$</td>
</tr>
<tr>
<td>Control</td>
<td>Regulator</td>
<td>Increased duty</td>
<td>$&gt; \text{basecase}+1$</td>
</tr>
<tr>
<td></td>
<td>Capacitor</td>
<td>Increased duty</td>
<td>$&gt; \text{basecase}+1$</td>
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## Typical Steady-State Voltage Threshold Levels

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<tbody>
<tr>
<td>Voltage</td>
<td>Overvoltage</td>
<td>Feeder voltage</td>
<td>( \geq 1.05 \text{ Vpu} )</td>
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<tr>
<td></td>
<td>Voltage Deviation</td>
<td>Deviation in voltage from no PV to full PV</td>
<td>( \geq 3% \text{ at primary} )</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>( \geq 5% \text{ at secondary} )</td>
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<tr>
<td></td>
<td></td>
<td></td>
<td>( \geq \frac{1}{2} \text{ band at regulators} )</td>
</tr>
<tr>
<td></td>
<td>Unbalance</td>
<td>Phase voltage deviation from average</td>
<td>( \geq 3% )</td>
</tr>
<tr>
<td></td>
<td>Thermal</td>
<td>Element loading</td>
<td>( \geq 100% \text{ normal rating} )</td>
</tr>
<tr>
<td>Loading</td>
<td>Total Fault Contribution</td>
<td>Total fault current contribution at each sectionalizing device</td>
<td>( \geq 10% \text{ increase} )</td>
</tr>
<tr>
<td></td>
<td>Forward Flow Fault Contribution</td>
<td>Forward flow fault current contribution at each sectionalizing device</td>
<td>( \geq 10% \text{ increase} )</td>
</tr>
<tr>
<td></td>
<td>Sympathetic Breaker Tripping</td>
<td>Breaker fault current due to an adjacent breaker</td>
<td>( \geq 150\text{A} )</td>
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<tr>
<td></td>
<td>Unbalance</td>
<td>Phase voltage deviation from average</td>
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<td>Element loading</td>
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<td>Anti-Islanding</td>
<td>( \geq 100% \text{ minimum load} )</td>
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<td>THDv Total harmonic voltage distortion</td>
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<tr>
<td></td>
<td>Control</td>
<td>Regulator Increased duty</td>
<td>( &gt; \text{ basecase+1} )</td>
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<tr>
<td></td>
<td></td>
<td>Capacitor Increased duty</td>
<td>( &gt; \text{ basecase+1} )</td>
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### ANSI C.84 limits

<table>
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<th>Nominal Voltage (V)</th>
<th>Service Voltage (V)</th>
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<tbody>
<tr>
<td></td>
<td>Min</td>
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<tr>
<td>120</td>
<td>114</td>
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</table>
We don’t know where the PV will be interconnected

There are 4000-5000 nodes on this feeder where PV could be interconnected
PV location makes a huge difference

Feeder voltage profile

PV = 0%

PV location makes a huge difference

Feeder voltage profile

Single PV = 20%

PV location makes a huge difference

Feeder voltage profile

Distributed PV = 20%

Hosting capacity range for overvoltage violation

EPRI, Stochastic Analysis to Determine Feeder Hosting Capacity for Distributed Solar PV, Palo Alto, CA 2012.
### Methodologies

| Detailed Analysis | Power flow simulations conducted at each node until violations occur, e.g., SCE, SDG&E. Stochastic analysis uses many simulations (e.g., different sizes in different locations) to give uncertainty range. |
| Streamlined | Simplified algorithms for each power system limitation to estimate when violations occur, e.g., PG&E |
| Shorthand Equations | Very simple calculation method |
Detailed Analysis

PV Scenario Scripts

Data Filtering Scripts

Time Series Load-Flow Simulations

Post-processing Scripts

Voltage violation with PV=0%

Likelihood of over-voltage 11am – 2pm
Voltage violation with PV=2%

Likelihood of over-voltage
11am – 2pm
Voltage violation with PV=6%

Likelihood of over-voltage 11am – 2pm
Voltage violation with PV=10%

Likelihood of over-voltage 11am – 2pm
Detailed Analysis - Hosting Capacity

Feeder Length is Critical

Hosting Capacity [%] vs. Feeder Length [mi]

Simplified Analysis

Simplified Analysis - Hosting Capacity

Feeder

Hosting Capacity [%]

IS2  JK2  MC4  WA4  BC1  BC2  BC3  CB4  CB5  CB6

Simplified
Detailed

Shorthand Equations – from the California Solar Initiative
Shorthand Equations – Approach

EPRI, *Alternatives to the 15% Rule*, Dec. 2015
SCE Integration Capacity Analysis

Distributed Energy Resource Interconnection Maps (DERiM)

Southern California Edison, Distribution Resources Plan, 2015
Hosting Capacity in SCE for energy producing DERs

Average Discharging Hosting Capacity of the 30 Representative Distribution Circuits by Voltage Class

Higher voltage lines can host more capacity

More DER can be hosted closer to the substation

SCE, DRP, 2015
Locational Net Benefits
Benefits of DERs

Ben Kellison, “Unlocking the Locational Value of DER 2016: Technology Strategies, Opportunities, and Markets,” January 2016,
Why LNBA?

► Public tool and heat map
► Prioritization of candidate distribution deferral opportunities
► Determine cost-effectiveness, compare projects
► Inform compensation or incentives
Beware: Pitfalls of calculating locational net benefits

► Benefits vary
  • By technology
  • By time (of day, season, etc)
  • By location (LMP node, feeder, location on feeder)

► DER may provide many services/benefits – be careful to avoid double-counting

► What are you avoiding? What is the business-as-usual path?

► Average avoided cost estimates are easy and transparent but lack rigor of modeling actual hourly, location-based operations. Get the large value streams correct.
These value streams have ripple effects

If you avoid X distribution losses

Then you avoid Y transmission losses associated with X

A generator avoids producing X+Y

Possibly less capacity is needed to serve X+Y

Possibly even less capacity due to reserve planning margin

Ben Kellison, “Unlocking the Locational Value of DER 2016: Technology Strategies, Opportunities, and Markets,” January 2016,

Calculate the localized impacts first
Avoided energy

DER may avoid fuel and O&M costs from the marginal generator

► DER may avoid the energy it produces plus the T&D losses associated with that production

► Options for calculation:
  □ Assume marginal generator(s), heat rate(s)
  □ Historical LMPs, forward prices
  □ Locational marginal price at a node – production cost modeling simulates unit commitment and economic dispatch for each hour of the year
► As more MW of solar are added, the value of the energy and capacity decline.
► If a tariff is not locked in for long-term, this is risky for solar customers.
► Storage can mitigate the declining value of solar by producing at peak, even as peak shifts to later hours.
► Solar PV production degrades (0.5%/year) over time.

![Austin VOS assessment](attachment:image.png)
Avoided capacity

DER may avoid the need for additional generation capacity

- DER may avoid capacity equivalent to its capacity value plus some amount due to avoided T&D losses. It may also avoid additional capacity that would be needed for the planning reserve margin.

- Options for calculation:
  - Average capacity factor of DER during peak net-load hours
  - Approximations to effective load-carrying capability without iterations
  - Effective load-carrying capability analysis with iterative loss-of-load probability calculation
Transmission losses

DER may avoid transmission losses

► DER may avoid transmission losses associated with the energy production of the DER plus avoided distribution losses

► Options for calculation:
  - Average loss rate – overestimates losses
  - Marginal loss rates with diurnal and monthly profiles – losses are higher during peak flows
  - Power flow modeling – production cost models may estimate transmission losses
Distribution losses

DER may avoid distribution losses since energy is generated at the point of consumption.

► High penetrations of DER could lead to reverse power flow and increased distribution losses

► Options for calculation:
  - Average loss rate – overestimates losses
  - Marginal loss rates with diurnal and monthly profiles – losses are higher during peak
  - Power flow modeling of feeder for selected (peak load, peak PV, etc) periods or time-series simulations. Computationally challenging: where and how big are the DERs; should all feeders or representative feeders be modeled?
Avoided distribution capacity, deferrals of upgrades, distribution impacts

DER may avoid the need for additional T&D capacity or defer the need for upgrades. DER may also incur costs.

► There are many impacts to consider: Equipment may not be capable of bi-directional power flow; DPV may lessen life of load-tap-changers; smart inverters can regulate voltage, etc.

► Options for calculating benefits:
  □ Value DER contribution at peak hours at average distribution investment costs
  □ Power flow modeling – load growth triggers upgrade that can be deferred by DER

► Options for calculating costs:
  □ Assume zero – assume DERs limited to hosting capacity
  □ Detailed interconnection study for a DER project would cost out a handful of workable mitigation options
Beware: Not easy to defer distribution capacity

Avoided, deferred or incurred costs on distribution feeders/substation to accommodate load growth

► Is there a need for upgrades or new capacity? How much available capacity is there now and in the planning horizon?

► Does the output of the DER match the stressed hours/seasons of the capacity need?

► Is the DER location able to defer that capacity?

► Can the DER consistently/reliably provide power at that time? What happens if it’s cloudy (for DPV)?

► Will the DER be available throughout the deferral period?

► Can the utility monitor/control the DER to meet distribution system needs?

► Calculation is feeder-dependent
Avoided emissions

DERs may avoid CO\textsubscript{2}, NO\textsubscript{x}, SO\textsubscript{2} and other emissions

- DERs may avoid emissions associated with avoided energy use. It may also avoid or incur emissions based on generator cycling (starts, ramps, part loading)

- Options for calculation in order of simplicity:
  - Assume marginal generator(s), emissions rate(s)
  - Correlation of historical LMPs to generator type and associated emissions rate
  - Production cost modeling simulates unit commitment and economic dispatch for each hour of the year. It can also capture cycling impacts.
### Stacking the value stream for DPV

#### 25-year levelized Value of Solar

<table>
<thead>
<tr>
<th></th>
<th>DPV</th>
<th>UPV</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>7.1MW</strong></td>
<td>56.54</td>
<td>25</td>
</tr>
<tr>
<td><strong>20MW</strong></td>
<td>50.53</td>
<td>50.53</td>
</tr>
<tr>
<td><strong>50MW</strong></td>
<td>40.31</td>
<td>40.31</td>
</tr>
<tr>
<td><strong>100MW</strong></td>
<td>37.44</td>
<td>37.44</td>
</tr>
</tbody>
</table>

#### GE, Solar Program Design Study, 2017
Questions to ask utilities

► Scenarios

- How did you select the scenarios? What factors will have the biggest impact on outcomes? How did you take stakeholder input into account?
- Where did the input data for load, energy efficiency, demand response, DPV, storage, and other DERs come from and are those reliable, recent studies?

► Hosting capacity

- How do you plan to use these results?
- What method was used and is that method appropriate for the application?
- Which power system criteria did you evaluate?
- At what level of granularity did you analyze the criteria?
- Do you allow voltage control devices to adjust during iterations or are they fixed?

► LNBA

- What methods were used to quantify each component? Do you think results are optimistic? Conservative?
Resources

- NREL on DPV benefits and costs [https://www.nrel.gov/docs/fy14osti/62447.pdf](https://www.nrel.gov/docs/fy14osti/62447.pdf)
- EPRI on hosting capacity [https://www.epri.com/#/pages/product/1026640/](https://www.epri.com/#/pages/product/1026640/)
- EPRI on shorthand equations [https://www.epri.com/#/pages/product/3002006594/](https://www.epri.com/#/pages/product/3002006594/)
Any Questions?

Contact Debbie Lew at debra.lew@ge.com
303-819-3470
Load growth (including EVs & other new loads)

► Determine system load growth
  • Consider rates of growth for each customer class

► Add impact of EVs (and other new loads)
  • EV charging patterns
Demand modifiers

- Energy efficiency
- Demand management: Peak shaving
- Demand response
- Rate structure

- How is DR dispatched?
- How much does energy efficiency contribute at peak?

Time-varying rates can be a significant demand modifier
Impact of DG on load

- DG includes DPV, storage, fuel cells, etc.
- System Forecast Load less Demand modifiers and DG
  - This is how much utility-scale generation is needed at any time
Streamline Interconnection Processes

Establish Granularity
- Determine Level of Granularity (e.g., Substation, Feeder, Line Section)

Model and Extract Data
- Model Circuits (e.g., Weekly Circuit Model Update from GIS Maps)
- Evaluate Criteria (e.g., Thermal, Voltage, Protection, Safety)
- Extract Dynamic Circuit Data (e.g., Load Profiles, Thévenin Impedance)

Evaluate Criteria
- Publish ICA results (e.g., PG&E RAM Map)

Source: PG&E DRP Webinar, 2015
Benefits of DERs

- **ENERGY**
  - Electricity
  - Line losses

- **CAPACITY**
  - Net change in investments in control generation assets
  - Investment in distributed generation technologies and assets
  - Net change in investments in T&D assets

- **GRID SUPPORT (INTERCONNECTED OPERATIONS SERVICES)**
  - Net change in ancillary service requirements:
    - Reactive supply & voltage control
    - Regulation & frequency response
    - Energy & generator imbalance
    - Synchronized & supplemental operating reserves
    - Scheduling, forecasting, and system control & dispatch

- **CUSTOMER**
  - Market & community transformation, company image, EE/EV adoption, increased electricity options (e.g. Green choice programs)

- **FINANCIAL AND SECURITY**
  - Utility fuel price volatility
  - Customer price protection/elasticity
  - Emergency customer power and incidence of outages

- **ENVIRONMENTAL**
  - Criteria pollutants (SOx, NOx, PM10)
  - GHG emissions (CO2)
  - Water and land use

- **SOCIAL**
  - Net impact on job market, employment taxes, and occupational safety