Valuation of Distributed Energy Resources

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DERs can impact system costs and reliability

- Impacts on the bulk power system
  - Variability and uncertainty of wind and solar
  - Generation not aligned with demand
  - May lead to overbuilding of capacity and oversupply in real-time
  - Typically provision of energy only (may not include capacity or ancillary services)
  - Operational reliability – visibility, controls and communications

- Impacts on the distribution system
  - Depends on DER profile compared to feeder loading
  - Depends on location (feeder characteristics, existing DERs)
  - Depends on DER capabilities and functionalities

- Deployment is optimized on customer economics. Customer economics and utility cost drivers often do not align.
Passive DER planning can be a mess

Autonomous DER deployment with little information/guidance

◆ Customer decides what DER to install, how big, where, and how to operate it
  - Utilities must manage integration
  - Unfavorable locations lead to expensive interconnection with no one happy
◆ If the next DER requires upgrade or mitigation, that next customer is responsible, even though it might enable future DERs
◆ Utility compensates customer (e.g., net metering, fixed tariff)
  - Compensation may not reflect actual net value that DER brings
◆ Does utility need generation at that time and place? What is the value of demand flexibility at that time and place?
Proactive DER planning is more effective

Tell customers where the grid needs help. Tell customers what services the grid needs. Incentivize them.

- Load/DER forecasting helps resource planners avoid overbuilding and feeds into analysis of which feeders may be stressed by DER in the near-term.
- Hosting capacity shows how much more DER can be managed on a given feeder easily, or where interconnection costs will be low/high.
- Together, these can identify feeders that are likely to see DER growth and may need proactive upgrades.
- Locational net benefits analysis (LNBA) determines the benefits of specific services at a specific location to guide developers.
- Defer some traditional infrastructure investments through cost-effective non-wires alternatives (NWA) that provide specific services at specific locations.
- Leverage customer and third-party capital investments.
- Inform rates and tariffs.
Why locational net benefits analysis?

- What is the value of providing this service at this time at this location?
- Compensation for DER
  - Inform compensation such as value of solar tariff or net metering; programs and incentives; and rate design
- Non-wires alternatives (NWA)
  - What are the costs of the traditional upgrades that the utility would otherwise undertake?
  - What is the suitability of NWAs to distribution system needs?
  - Public tool and heat map
  - Prioritization of candidate distribution deferral opportunities
  - Determine cost-effectiveness, compare projects
Benefits of DERs

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

Calculate the localized impacts first

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

- As more MW of solar are added, the value of the energy and capacity decline.
- Tariffs can be locked in for the long-term or vary over time. There are pros and cons of a variable tariff.
- 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 graph]

<table>
<thead>
<tr>
<th>Year</th>
<th>$/kWh</th>
</tr>
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<tbody>
<tr>
<td>2013</td>
<td>0.15</td>
</tr>
<tr>
<td>2014</td>
<td>0.10</td>
</tr>
<tr>
<td>2015</td>
<td>0.09</td>
</tr>
<tr>
<td>2016</td>
<td>0.08</td>
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<tr>
<td>2017</td>
<td>0.07</td>
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</table>
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; distributed PV 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
Simulations and experience in distribution deferrals

- **APS’ Solar Partner Program results:**
  - Adding PV did not reliably reduce peak load at house or secondary transformer, but did at the feeder level. ¼ of houses produced less than 5% at time of peak load.
  - Aggregated PV reduced peak net load by 15-41% of PV nameplate capacity.
  - West-facing PV produced 2-3x the power at peak than south-facing PV.
  - Correlation between high feeder loading and high PV output

- **Cohen et al. analysis of PG&E feeder upgrades shows:**
  - 90% of feeders would receive no deferral benefit
  - Remaining feeders would receive $10/kW-yr to over $60/kW-yr at very low penetrations
  - Benefits decline as PV increases: at 50% penetration, value is halved

https://www.epri.com/?_sm_byp=iVVwLTjLRHskw6RL#/pages/product/000000003002011316/
Enhanced Valuation Methods - Seven Considerations*

1. Account for *all electric utility system economic impacts* resulting from demand flexibility
2. Account for variations in value based on *when* demand flexibility occurs
3. Account for the *impact of distribution system* savings on transmission and generation system value
4. Account for variations in value specific *locations* on the grid
5. Account for variations in value due to *interactions between DERs* providing demand flexibility
6. Account for benefits across the *full expected useful lives* (EULs) of the resources
7. Account for variations in value due to *interactions between DERs and other system resources*

### Applicability of Enhanced Valuation Methods to Distribution, Generation, and Transmission Planning Analyses

<table>
<thead>
<tr>
<th>Enhanced valuation methods to account for:</th>
<th>Distribution System Planning</th>
<th>Generation Planning</th>
<th>Transmission Planning</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. All electric utility system economic impacts resulting from demand flexibility</td>
<td>![most applicable]</td>
<td>![least applicable]</td>
<td>![most applicable]</td>
</tr>
<tr>
<td>2. Variations in value based on when demand flexibility occurs</td>
<td>![most applicable]</td>
<td>![least applicable]</td>
<td>![most applicable]</td>
</tr>
<tr>
<td>3. Impact of distribution system savings on transmission and generation system value</td>
<td>![least applicable]</td>
<td>![most applicable]</td>
<td>![least applicable]</td>
</tr>
<tr>
<td>4. Variations in value at specific locations on the grid</td>
<td>![most applicable]</td>
<td>![least applicable]</td>
<td>![least applicable]</td>
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<tr>
<td>5. Variations in value due to interactions between DERs providing demand flexibility</td>
<td>![most applicable]</td>
<td>![least applicable]</td>
<td>![most applicable]</td>
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<tr>
<td>6. Benefits across the full expected useful lives of the resources</td>
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<td>![most applicable]</td>
<td>![least applicable]</td>
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<tr>
<td>7. Variations in value due to interactions between DERs and other system resources</td>
<td>![least applicable]</td>
<td>![most applicable]</td>
<td>![least applicable]</td>
</tr>
</tbody>
</table>

- ![most applicable]: Most applicable
- ![least applicable]: Least applicable

Stacking the value stream for rooftop PV

25-year levelized Value of Solar

<table>
<thead>
<tr>
<th></th>
<th>2017 DPV</th>
<th>Low</th>
<th>Medium</th>
<th>High</th>
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<tbody>
<tr>
<td>DPV</td>
<td>7.1MW</td>
<td>20MW</td>
<td>50MW</td>
<td>100MW</td>
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<tr>
<td>UPV</td>
<td>19MW</td>
<td>89MW</td>
<td>89MW</td>
<td>89MW</td>
</tr>
</tbody>
</table>

GE, Solar Program Design Study, 2017
TOU periods don’t manage spring season well

Revised TOU peak months and hours

TOU rates have a similar arbitrage impact as storage but without the losses. A value stream approach can be used.
TOU rates can be valued like storage – example from CO

Value in year 1

Value

$9,000,000
$8,000,000
$7,000,000
$6,000,000
$5,000,000
$4,000,000
$3,000,000
$2,000,000
$1,000,000

DPV 7.1MW 20MW 50MW 100MW TOU1 TOU2
UPV 19MW 89MW 89MW 89MW

- Fuel Price Risk
- Emissions
- RECs
- Reserves
- T&D Upgrades
- Distribution Losses
- Transmission Losses
- Capacity
- Energy

Lew, GE, “DER Compensation”, ESIG Fall workshop, Oct 2017
PG&E example: Distribution Investment Deferral Framework (DIDF)

- Transparent process to create candidate deferral shortlist, grid mod investments, & proactive hosting capacity upgrades to accommodate forecasted DER growth
- 5 year planning horizon
- Grid Needs Assessment (GNA)
- Investment projects
- Technical and timing screens
  - Depends on DER profile compared to feeder loading
  - Capacity, reactive power, voltage, reliability (backtie), resiliency (microgrid)
  - Can DER provide required service?
  - Operating date
- Prioritization metrics
  - Cost-effectiveness
  - Forecast certainty
  - Market assessment

Source: PG&E’s 2018 Distribution Deferral Opportunity Report, Sep. 4, 2018
Grid Needs Assessment (GNA) report and spreadsheet:
- 6,994 separate grid needs
- Location
- Distribution service required
- Primary driver of grid need
- Date needed
- Equipment/Facility rating
- Forecasted deficiency over 5 years
- What mitigation options are possible? Can they be mitigated through distribution switching and load transfers?
### PG&E example: Grid Needs Assessment

<table>
<thead>
<tr>
<th>Project Type</th>
<th>Distribution Capacity</th>
<th>Voltage Support</th>
<th>Reliability (Back-tie)</th>
<th>Resiliency (microgrid)</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>Substation/Bank</td>
<td>59</td>
<td>0</td>
<td>10</td>
<td>0</td>
<td>69</td>
</tr>
<tr>
<td>Feeder</td>
<td>107</td>
<td>0</td>
<td>23</td>
<td>0</td>
<td>130</td>
</tr>
<tr>
<td>Distribution Line</td>
<td>631</td>
<td>6153</td>
<td>11</td>
<td>0</td>
<td>6795</td>
</tr>
<tr>
<td><strong>Totals</strong></td>
<td><strong>797</strong></td>
<td><strong>6153</strong></td>
<td><strong>44</strong></td>
<td><strong>0</strong></td>
<td><strong>6994</strong></td>
</tr>
</tbody>
</table>

Grid Needs Assessment

Planned Investment

PG&E Example: Qualitative Prioritization Methodology

- **Cost-effectiveness** – Projects with higher costs or higher LNBA are ranked higher. DER can potentially provide a high value by avoiding expensive solutions.
  - Unit costs
  - LNBA $/kW-yr
  - LNBA $/MWh-yr

- **Forecast certainty** – How certain is the grid need? Near-term needs and locations with SCADA are ranked higher.
  - Forecasted need
  - SCADA available
  - # customers on asset

- **Market assessment** – How likely can DER successfully meet the requirements? Projects that are day-ahead, have fewer grid needs, fewer days/year and lower overcapacity are ranked higher.
  - Real-time or day-ahead notification
  - Days/year
  - Number of grid needs
  - Hours per call
  - Overcapacity

Engineering judgment and experience play into *all* three metrics.
PG&E example: Performance and operational requirements

<table>
<thead>
<tr>
<th>Candidate Deferral</th>
<th>Grid Need Location</th>
<th>Real Time (RT) or Day Ahead (DA)</th>
<th>Offer Size (MW)</th>
<th>Delivery Months</th>
<th>Calls/Year</th>
<th>Delivery Hours</th>
<th>Hours Duration</th>
</tr>
</thead>
<tbody>
<tr>
<td>Alpaugh New Feeder</td>
<td>Corcoran 1112</td>
<td>DA</td>
<td>4.4</td>
<td>Jun-Sep</td>
<td>113</td>
<td>3:00PM-10:00PM</td>
<td>7</td>
</tr>
<tr>
<td>Calflax Bank 2</td>
<td>Calflax Bank 1</td>
<td>DA</td>
<td>4.8</td>
<td>May-Aug</td>
<td>92</td>
<td>4:00PM-8:00AM</td>
<td>16</td>
</tr>
<tr>
<td>Santa Nella</td>
<td>Canal Bank 1</td>
<td>DA</td>
<td>1.2</td>
<td>Jun-Aug</td>
<td>75</td>
<td>5:00PM-8:00PM</td>
<td>3</td>
</tr>
<tr>
<td></td>
<td>Canal 1103</td>
<td>DA</td>
<td>4</td>
<td>Jun-Sep</td>
<td>122</td>
<td>3:00PM-10:00PM</td>
<td>7</td>
</tr>
<tr>
<td></td>
<td>Ortiga 1106</td>
<td>DA</td>
<td>3.8</td>
<td>Jun-Sep</td>
<td>122</td>
<td>4:00PM-10:00PM</td>
<td>6</td>
</tr>
<tr>
<td>FMC 1102</td>
<td>FMC 1101</td>
<td>RT</td>
<td>0.8</td>
<td>Jun-Sep</td>
<td>4</td>
<td>12:00AM-12:00AM</td>
<td>12</td>
</tr>
</tbody>
</table>

PG&E example: Candidate projects

- PG&E identified 18 candidate deferral opportunities totaling 83 MW
  - Tier 1: four projects totaling 19.3 MW that are more likely to be deferrable with DER
  - Tier 2: two projects totaling 2.1 MW that have some red flags; monitor status
  - Tier 3: 12 projects totaling 62 MW with multiple, major red flags; unlikely that DER can be successfully sourced

### PG&E example: Candidate projects

<table>
<thead>
<tr>
<th>Tier</th>
<th>Candidate Deferral</th>
<th>Unit Cost ($k)</th>
<th>LNBA ($/kW-yr)</th>
<th>LNBA ($/MWh/yr)</th>
<th>In-Service Date</th>
<th>SCADA Avail. (Y/N)</th>
<th>Customers</th>
<th>Real Time (RT) or Day Ahead (DA)</th>
<th>Market Assessment</th>
<th>Days/Year</th>
<th># of Grid Needs</th>
<th>Hours/Call</th>
<th>Over-capacity (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Alpaugh New Feeder</td>
<td>$3,600</td>
<td>$89</td>
<td>$88</td>
<td>2022</td>
<td>Y</td>
<td>2650</td>
<td>DA</td>
<td></td>
<td>113</td>
<td>1</td>
<td>9</td>
<td>38%</td>
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<tr>
<td>2</td>
<td>Calflax Bank 2</td>
<td>$6,070</td>
<td>$88</td>
<td>$60</td>
<td>2023</td>
<td>Y</td>
<td>228</td>
<td>DA</td>
<td></td>
<td>CC</td>
<td>1</td>
<td>CC</td>
<td>CC</td>
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<tr>
<td></td>
<td>Santa Nella New Bank &amp; Feeder</td>
<td>$7,256</td>
<td>$55</td>
<td>$78</td>
<td>2022</td>
<td>Y</td>
<td>973</td>
<td>DA</td>
<td></td>
<td>122</td>
<td>4</td>
<td>7</td>
<td>36%</td>
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<tr>
<td></td>
<td>Camp Evers 2107</td>
<td>$1,720</td>
<td>$202</td>
<td>$2,100</td>
<td>2022</td>
<td>Y</td>
<td>6370</td>
<td>RT+Islanding</td>
<td></td>
<td>8</td>
<td>1</td>
<td>12</td>
<td>3%</td>
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<tr>
<td></td>
<td>FMC 1102</td>
<td>$1,700</td>
<td>$232</td>
<td>$4,830</td>
<td>2023</td>
<td>Y</td>
<td>3422</td>
<td>RT</td>
<td></td>
<td>4</td>
<td>1</td>
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<td></td>
<td>Brentwood 2105</td>
<td>$640</td>
<td>$59</td>
<td>$612</td>
<td>2022</td>
<td>Y</td>
<td>2841</td>
<td>RT+Islanding</td>
<td></td>
<td>8</td>
<td>1</td>
<td>12</td>
<td>6%</td>
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<tr>
<td></td>
<td>Estrella Substation (hypothetical)</td>
<td>$18,500</td>
<td>$209</td>
<td>$293</td>
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<td>Y</td>
<td>2738</td>
<td>DA</td>
<td></td>
<td>122</td>
<td>3</td>
<td>9</td>
<td>21%</td>
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<tr>
<td>3</td>
<td>Pueblo Bank 3</td>
<td>$6,936</td>
<td>$21</td>
<td>$110</td>
<td>2022</td>
<td>Y</td>
<td>9952</td>
<td>RT</td>
<td></td>
<td>8</td>
<td>1</td>
<td>24</td>
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<tr>
<td></td>
<td>Oceano 1106</td>
<td>$425</td>
<td>$18</td>
<td>$64</td>
<td>2022</td>
<td>Y</td>
<td>6811</td>
<td>RT+Islanding</td>
<td></td>
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<td>1</td>
<td>24</td>
<td>8%</td>
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<td>Rosedale 2102</td>
<td>$400</td>
<td>$24</td>
<td>$84</td>
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<td>Y</td>
<td>1378</td>
<td>RT</td>
<td></td>
<td>12</td>
<td>1</td>
<td>24</td>
<td>9%</td>
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<tr>
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<td>Rob Roy 2105</td>
<td>$500</td>
<td>$18</td>
<td>$63</td>
<td>2022</td>
<td>Y</td>
<td>8056</td>
<td>RT+Islanding</td>
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<td>1</td>
<td>24</td>
<td>13%</td>
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<tr>
<td></td>
<td>Peabody 2106</td>
<td>$390</td>
<td>$8</td>
<td>$28</td>
<td>2022</td>
<td>Y</td>
<td>2845</td>
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<td></td>
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<td>1</td>
<td>24</td>
<td>13%</td>
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<td></td>
<td>Madison 2101</td>
<td>$105</td>
<td>$13</td>
<td>$45</td>
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<td>Y</td>
<td>2068</td>
<td>RT+Islanding</td>
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<td>12</td>
<td>1</td>
<td>24</td>
<td>9%</td>
</tr>
<tr>
<td></td>
<td>Martin SF H 1108</td>
<td>$180</td>
<td>$9</td>
<td>$33</td>
<td>2022</td>
<td>Y</td>
<td>6716</td>
<td>RT+Islanding</td>
<td></td>
<td>12</td>
<td>1</td>
<td>24</td>
<td>8%</td>
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<tr>
<td></td>
<td>Martin SF H 1107</td>
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<td>$4</td>
<td>$15</td>
<td>2022</td>
<td>Y</td>
<td>7090</td>
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<td>1</td>
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<td>Avenal 2101</td>
<td>$65</td>
<td>$6</td>
<td>$21</td>
<td>2022</td>
<td>Y</td>
<td>1948</td>
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<td>24</td>
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<td>Edenvale 2108</td>
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<td>$24</td>
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<td>Y</td>
<td>6630</td>
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<td>1</td>
<td>24</td>
<td>7%</td>
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<td></td>
<td>Dairyland 1110</td>
<td>$3,887</td>
<td>$96</td>
<td>$24</td>
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<td>Y</td>
<td>518</td>
<td>DA</td>
<td></td>
<td>168</td>
<td>1</td>
<td>24</td>
<td>34%</td>
</tr>
</tbody>
</table>

Candidate deferral

Considerations for LNBA

◆ What is your use case for LNBA and is the calculation methodology appropriate for that use case?
◆ How are needs screened? Are these screens so restrictive that they eliminate projects that seem viable?
◆ What criteria do you use to prioritize candidate projects? To what extent did engineering (or other) judgment change prioritization of projects and why?
◆ Is there data or infrastructure that could give more certainty to the overall process?
Resources

- NREL on DPV benefits and costs: [https://www.nrel.gov/docs/fy14osti/62447.pdf](https://www.nrel.gov/docs/fy14osti/62447.pdf)
Any Questions?

Contact Debbie Lew at debbie@debbielew.com
303-819-3470