Distribution planning regulatory practices

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Integrated Distribution System Planning Training
for MISO/Midwest Region
October 13-15, 2020
In this presentation

► Electricity planning activities and drivers
► State objectives, requirements and filing elements
► Selected regulatory issues
  ◼ Non-wires alternatives (NWAs) procurement strategies
  ◼ Hosting capacity analysis
  ◼ Data-related requirements
  ◼ Stakeholder engagement
  ◼ Getting started with an integrated distribution planning proceeding
  ◼ Emerging issues
► Resources for more information
► Extra slides: State-specific approaches
Electricity planning activities and drivers
Electricity planning activities

► Distribution planning - Assess needed physical and operational changes to local grid
   ■ Annual distribution planning process
     • Identify and define distribution system needs
     • Identify and assess possible solutions
     • Select projects to meet system needs
   ■ Long-term utility capital plan
     • Includes solutions and cost estimates, typically over a 5- to 10-year period, updated every 1 to 3 years

► Integrated resource planning (IRP)* - Identify future investments to meet bulk power system reliability and public policy objectives at a reasonable cost
   ■ Consider scenarios for loads and distributed resources; impacts on need for, and timing of, utility investments

► Transmission planning – Identify future transmission expansion needs and options

Also: energy efficiency, demand-side management, electrification and climate plans

*For states with vertically integrated utilities
One reason states are increasingly interested in distribution planning is because distribution system investments account for the largest portion (29%) of capex for U.S. investor-owned utilities: $39B (projected) in 2019.

Source: Edison Electric Institute
States are responding to a variety of drivers for improved distribution planning.

- More DERs deployed — costs down, policies, new business models, consumer interest
- Resilience and reliability (e.g., storage, microgrids)
- More data and better tools to analyze data
- Aging grid infrastructure and utility proposals for grid investments
- Need for greater grid flexibility in areas with high levels of wind and solar
- Interest in conservation voltage reduction and volt/VAR optimization
- Non-wires alternatives to traditional solutions may provide net benefits to customers
Other potential benefits from improved distribution planning processes

- Makes transparent utility plans for distribution system investments holistically, before showing up individually in a rider or rate case
- Provides opportunities for meaningful PUC and stakeholder engagement
  - Can improve outcomes
- Considers uncertainties under a range of possible futures
- Considers all solutions for least cost/risk
- Motivates utility to choose least cost/risk solutions
- Enables consumers and third-party providers to propose grid solutions and participate in providing grid services

*Figure from De Martini and Kristov (2015), for Berkeley Lab*
State objectives, requirements and filing elements
Example state objectives for distribution planning

► **Michigan**: Safety, reliability and resiliency, cost-effectiveness and affordability, and accessibility (order in U17990 and U-18014 dockets)

► **Nevada** ([SB 146](https://www.nvlegislature.gov/lvgateway/BillDetail.aspx?BillNumber=SB146-2019)): “reductions or increases in local generation capacity needs, avoided or increased investments in distribution infrastructure, safety benefits, reliability benefits and any other savings the distributed resources provide to the electricity grid for this State or costs to customers of the electric utility or utilities.”

**Minnesota** ([Stat. §216B.2425](https://www.leg.state.mn.us/law/statues/216B.2425)): “…enhancing reliability, improving security against cyber and physical threats, and by increasing energy conservation opportunities by facilitating communication between the utility and its customers through the use of two-way meters, control technologies, energy storage and microgrids, technologies to enable demand response, and other innovative technologies.” [emphasis added]

► **PUC objectives** ([8/30/18 order in Docket 18-251](https)):

- Safety, security, reliability, and resilience of the grid, at fair and reasonable costs, consistent with state energy policies
- Greater customer engagement, empowerment and options
- Efficient, cost-effective, accessible grid platforms for new products and services; opportunities for adopting new distributed technologies
- Ensure optimized use of grid assets and resources to minimize total system costs
### State legislative and regulatory activities

<table>
<thead>
<tr>
<th>Common Components</th>
<th>Range of Requirements</th>
</tr>
</thead>
<tbody>
<tr>
<td>Data Sharing and Transparency</td>
<td>Share a broad range of data including feeders, substations, operating voltages/ratings, load assumptions/forecasts, etc.</td>
</tr>
<tr>
<td>Hosting Capacity</td>
<td>Defining methods and tools, sharing maps, leveraging in planning and interconnection analysis. The granularity requested varies from requiring a node-level to feeder-level analysis. The frequency of updates ranges from monthly to annually.</td>
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<tr>
<td>Non-Wires Alternatives (NWAs)</td>
<td>Develop screening processes or criteria that can be used to identify when a grid need should be reviewed as a potential for NWAs. The consideration and assessment of NWAs in the investment plans varies by state – from being required to evaluate a NWA on every infrastructure investment to infrastructure projects of $1 million or greater.</td>
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<tr>
<td>Distribution System Plan Requirements</td>
<td>Provide annual documentation of the planning process and outline their distribution system investment plans to provide the scale of grid needs over a 5-year period. Some utilities are also required to define changes to the planning process in order to better incorporate DER.</td>
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<tr>
<td>Locational Value</td>
<td>Discussions are still in the early stages on this as is a longer-term component of the overall efforts. Some states like CA and NY are beginning to develop methods to assess locational value.</td>
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States with distribution planning requirements

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Example state requirements*

► Distribution system plans
  California, Delaware, Indiana, Hawaii, Maine, Maryland, Michigan, Minnesota, Nevada, New York, Rhode Island, Virginia

► Grid modernization plans
  California, Hawaii, Massachusetts, Minnesota, Ohio
  - Utilities in other states have filed grid modernization plans even absent requirements (GA, NC, SC, TX).

► Hosting capacity analysis/maps
  California, Hawaii, Michigan, Minnesota, Nevada, New York

► NWA/locational value
  CA, CO, DE, DC, HI, ME, MI, MN, NV, NH, NY, RI

► Benefit-cost handbook or guidance
  California, Maryland, Nevada, New York, Rhode Island

*This list is not all-inclusive and is growing.

Source: U.S. Department of Energy
Procedural elements (1)

► Frequency of filing
- Typically annual or biennial
- Every 3 years (e.g., NV)
- *Considerations*: alignment with utility distribution capital planning, IRP filing cycle, workload, making and tracking progress on goals and objectives

► Planning horizon
- 3 year action plan — NV (+ 6-yr forecasts), DE (+ 10-yr long-range plan)
- 5 years – NY, CA (+ 10-yr grid modernization vision), HI (+ plan to 2045), MI (+ 10-15 yr outlooks), MN (+ 10-yr Modernization & Infrastructure Investment Plan)
- 5-7 years - Indiana
- *Considerations*: short- and long-term investments, coordination with IRP, granularity of distribution planning

► Stakeholder engagement
- Covered later in this presentation
Confidentiality for security or trade secrets — for example:

- Level of specificity for hosting capacity maps
- Peak demand/capacity by feeder
- Values for reliability metrics
- Contractual cost terms
- Bidder responses to RFPs
- Proprietary model information
Substantive elements (1)

► Baseline information on current state of distribution system
  - Such as system statistics, reliability performance, equipment condition, historical spending by category

► Description of planning process
  - Load forecast – projected peak demand for feeders and substations
  - Risk analysis for overloads and mitigation plans
  - Budget for planned capacity projects
    - Asset health analysis and system reinforcements
    - Upgrades needed for capacity, reliability, power quality
    - New systems and technologies
    - Ranking criteria (e.g., safety, reliability, compliance, financial)

► Distribution operations — vegetation management and event management

Source: Xcel Energy, Integrated Distribution Plan, Nov. 1, 2019
Substantive elements (2)

► DER forecast
  ■ Types and amounts
► Hosting capacity analysis
  ■ Including maps
► NWA analysis
► Grid modernization strategy
  ■ May include request for certification for major investments
► Action plan
► Additional elements may include:
  ■ Long-term utility vision and objectives
  ■ Ways distribution planning is coordinated with integrated resource planning (if applicable)
  ■ Customer engagement strategy
  ■ Summary of stakeholder engagement
  ■ Proposals for pilots
Evolution in distribution planning practices

NWA procurement strategies
Considering non-wires alternatives

- Non-wires alternatives (NWA) are options for meeting distribution (and transmission) system needs related to load growth, reliability and resilience.
  - Single large DER (e.g., battery) or portfolio of DERs that can meet the specified need
- Objectives: Provide load relief, address voltage issues, reduce interruptions, enhance resilience, or meet local generation needs
- Potential to reduce utility costs
  - Defer or avoid infrastructure upgrades
  - Implement solutions incrementally, offering a flexible approach to uncertainty in load growth and potentially avoiding large upfront costs for load that may not show up
- Typically, the utility issues a competitive solicitation for NWA for specific distribution system needs and compares these bids to planned traditional grid investments (e.g., distribution substation transformer) to determine the lowest reasonable cost solution.
As part of annual capital planning, each utility must routinely identify candidate projects (load relief, reliability) for non-wires alternatives, post information to websites and issue RFPs. Utilities jointly provided suitability criteria (March 2017) for NWA projects and described how criteria will be applied (May 2017) in capital plans and procurement processes.

<table>
<thead>
<tr>
<th>Criteria</th>
<th>Potential Elements Addressed</th>
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</thead>
<tbody>
<tr>
<td><strong>Project Type Suitability</strong></td>
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<tr>
<td>Large Project</td>
<td>36 to 60 months</td>
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<tr>
<td>Small Project</td>
<td>18 to 24 months</td>
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<tr>
<td><strong>Timeline Suitability</strong></td>
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<td>Large Project</td>
<td>&gt; $1M</td>
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<td>Small Project</td>
<td>&gt; $300k</td>
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<tr>
<td><strong>Cost Suitability</strong></td>
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<tr>
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<td>&gt; $1M</td>
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<td>Small Project</td>
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</table>
## Projects, Needs and Default Solutions:
**Example Consolidated Edison RFPs for Non-Wires Alternatives**

<table>
<thead>
<tr>
<th>Project (RFP year)</th>
<th>Need</th>
<th>Default Solution</th>
</tr>
</thead>
</table>
| **Hudson Network (2017)**                  | Amount: 7.1 MW  
Location: West 50th St. Substation  
Overload period: 1-8 pm (5 pm peak)  
When: 2021 (summer) | Feeder upgrades to reduce potential overloads                                |
| **Columbus Circle Network (2017)**         | Amount: 4 MW  
Location: West 42nd St. No. 2 Substation  
Overload period: 2–7 pm (6 pm peak)  
When: 2021 (summer) | Feeder upgrades to reduce potential overloads                                |
| **West 42nd Street Load Transfer Project (2017)** | Amount: 42 MW (total, varies by year)  
Location: W. 42nd St. No. 1 Substation  
Overload period: 9 am–7 pm (2–3 pm peak)  
When: 2021–2027 (starting May 2021) | Transfer 55 MW of load from W. 42nd St. No. 1 Substation to Astor Substation before summer 2021 |

Sources: Con Edison 2017a, Con Edison 2017b, and Con Edison 2017c

See [Joint Utilities NWA Opportunities](#) and [REV CONNECT](#)
Distribution Investment Deferral Framework decision (Feb. 2018) created an annual process for consideration of DERs:

- “The central objective…is to identify and capture opportunities for DERs to cost-effectively defer or avoid traditional IOU investments that are planned to mitigate forecasted deficiencies of the distribution system.”

- Utilities file annually (now consolidated):
  1. Grid Needs Assessment (example GNA) — main driver for Distribution Resources Plan
  2. Distribution Deferral Opportunity Report (DDOR)

- Recommend deferral opportunities for competitive annual solicitations
  - Examples: SCE, PG&E, SDG&E

- May 2019 update modified requirements
  - $/MWh and locational net benefit analysis values for prioritizing projects
  - Additional requirements for GNA narrative and datasets
  - Additional project-specific data required for planned investments and candidate deferral project shortlist
Hosting capacity analysis
Example hosting capacity analysis requirements: Minnesota (1)

- State law (§216B.2425, 2015) requires Xcel Energy to conduct a distribution study to identify interconnection points for small-scale distributed generation and system upgrades to support its development.

- PUC requires analysis of each feeder ≤1 MW and potential distribution upgrades necessary to support expected distributed generation levels, based on utility’s IRP filings and Community Solar Gardens program.

- Utility filed 1st hosting capacity analysis on 12/1/16 (Docket 15-962).
  - Commission’s Aug. 1, 2017 decision requires filing Nov. 1 each year.
  - Provided guidance for future analysis, including reliable estimates and maps of available hosting capacity at feeder level.
    - Details to inform distribution planning and upgrades for efficient integration of distributed generation.
    - Detailed information on data, modeling assumptions and methodologies.

*Example heat map result. Xcel Energy, 2019*
Example hosting capacity analysis requirements: Minnesota (2)

► **Aug. 15, 2019, order** (Docket 18-684) required further improvements
  - Work with stakeholders to improve value of analysis, with more detailed data in maps
  - Provide spreadsheet with hosting capacity data by substation and feeder, with peak load, daytime min. load, installed generation capacity, and queued generation capacity
  - For feeders with no hosting capacity, identify “The full range of mitigation options … including a range of potential costs … and financial benefits….”
  - Identify cost and benefits of replacing or augmenting initial interconnection review screens and supplemental review and automating interconnection studies

► **July 23, 2020, order** (Docket 19-666)
  - Adopts long-term goal to use hosting capacity analysis in interconnection fast-track screens
  - Requirements for analysis due Nov. 2, 2020
    - Estimate costs for more frequent updates
    - Evaluate costs and benefits for other use cases
      - Replacing or augmenting initial interconnection review screens and supplemental review
      - Automating interconnection studies
    - Discuss information and resources required for a *load* hosting analysis and how it could help achieve state energy policy goals for beneficial electrification

Data-related requirements
Data-related requirements

Commissions are addressing data accessibility in distribution planning proceedings, recognizing “limited data visibility could lead to inefficient customer and grid investments” (HPUC 2019).

Two types of data accessibility are being addressed

1. **Customer usage data** - Making AMI interval data available to customers and third parties to support planning and decision-making
   - Some states are requiring utilities to use and/or evaluate feasibility of Green Button framework (Example: DC, NY, CA, HI and IL)
     - **Download My Data** – standard enables customer to download their data
     - **Connect My Data** – data exchange protocol which allows automatic transfer of data from utility to third party on customer authorization
   - Some states requiring “15/15 rule” when sharing aggregated customer data
     - An aggregation sample must have more than 15 customers and no single customer’s data may comprise more than 15 percent of the total aggregated data

2. **System level data** – Making system level data available to support customer and third-party solutions
   - Increasingly common to require hosting capacity maps to be shared online
   - New York, DC and California are examples of states with more detailed system data sharing requirements – see next three slides
System data sharing requirements
Example 1: New York

- New York – Each utility has a **data sharing portal** that includes the following

<table>
<thead>
<tr>
<th>February 2020</th>
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<tbody>
<tr>
<td><strong>LINKS TO UTILITY DATA PORTALS</strong></td>
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<td>National Grid</td>
<td>Orange &amp; Rockland</td>
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<tr>
<td><strong>JOINT UTILITIES OF NEW YORK</strong></td>
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<td>Joint Utilities of New York System Data Portal</td>
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<td>- Distributed System Implementation Plans</td>
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<td>- Capital Investment Plans</td>
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<td>- Planned Resiliency / Reliability Projects</td>
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<td>- Reliability Statistics</td>
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<td>- Hosting Capacity</td>
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<td>- Beneficial Locations</td>
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<td>- Load Forecasts</td>
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<td>- Historical Load Data</td>
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<td>- NWA Opportunities</td>
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<td>- Queued DG</td>
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<td>- Installed DG</td>
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<td>- SIR Pre-Application Information</td>
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System data sharing requirements
Example 2: California

By order, California utilities required to make datasets available as part of Grid Needs Assessments & Distribution Deferral Opportunities filings, including:

► Grid needs
  ■ By circuit, substation, and sub-transmission capacity service
    • Peak load (five years)
    • DER growth (EE, DR, PV, EV, storage)
    • Facility loading %
    • Current year demand
    • 5 year forecasted demand
    • Forecasted percentage deficiency above the existing rating over five years
    • Forecasted MW deficiency over five years
    • Anticipated season or date by which distribution upgrade must be installed

► Distribution deferral opportunities
  ■ Planned investments
    • Project description
    • Distribution service required
    • Type of traditional capital investment equipment to be installed
    • In-service date
    • Deferrable by DERs? Y/N
    • Number and composition of customers
  ■ Candidate deferrals
    • Expected performance and operational requirements
    • Specific locational values
    • Distribution service required
    • Expected magnitude of DER service provision (MW/kWA)
    • Duration and timing of the deficiency and associated DER service requirements
    • Unit cost of traditional mitigation
    • Contingency plans
System data sharing requirements

Example 3: District of Columbia

- Following MEDSIS working group recommendations, DC PSC required dedicated data sharing website.
- Datasets below were requested by MEDSIS Data Information Access and Alignment working group.
- Some data sets require secure access and some requested data sets are not yet available.

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<th>Data Type</th>
<th>Frequency</th>
<th>Granularity</th>
<th>Availability</th>
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<td>Capital Investment Plan – General Overview</td>
<td>Annual, 10 year forecast period</td>
<td>System</td>
<td>Current; Public (Pepco’s Annual Consolidated Report)</td>
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<tr>
<td>Load forecast</td>
<td>Annual, 10 year forecast period</td>
<td>Substation</td>
<td>Current; Public (Pepco’s Annual Consolidated Report)</td>
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<tr>
<td>Reliability statistics (SAIFI, CAIDI)</td>
<td>Annual (ACR)</td>
<td>Feeder level</td>
<td>Current; Public (Pepco’s Annual Consolidated Report)</td>
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<tr>
<td>Planned resiliency/ reliability projects</td>
<td>Annual</td>
<td>Varies by project</td>
<td>Current; Public (Pepco’s ACR and Rate Case Construction Report)</td>
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<td>Feeder level</td>
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<td>Circuit Capacity/ Design Criteria</td>
<td>Static (updated as projects are implemented)</td>
<td>Feeder level</td>
<td>Critical Energy Infrastructure Information (CEII); Secure access required.</td>
</tr>
<tr>
<td>Physical Attributes</td>
<td>Static (updated as projects are implemented)</td>
<td>Node level</td>
<td>Critical Energy Infrastructure Information (CEII); Secure access required.</td>
</tr>
<tr>
<td>Protective devices</td>
<td>Static (updated as projects are implemented)</td>
<td>Feeder level</td>
<td>Critical Energy Infrastructure Information (CEII); Secure access required.</td>
</tr>
<tr>
<td>Voltage profile</td>
<td>Static (updated as projects are implemented and with changes in load information)</td>
<td>Feeder level</td>
<td>Critical Energy Infrastructure Information (CEII); Secure access required.</td>
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<tr>
<td>Circuit impedance models</td>
<td>Static (updated as projects are implemented)</td>
<td>Feeder level</td>
<td>Critical Energy Infrastructure Information (CEII); Secure access required.</td>
</tr>
</tbody>
</table>
Stakeholder engagement
Stakeholder engagement

Requirements

- **Before plan is filed**: Varies from one timely meeting required (MN) to significant upfront input through working groups (e.g., CA, DC, HI, MI, NH, NY)
- **After plan is filed**: Opportunity to file comments

Examples:

- **Hawaii** - Stakeholder council, technical advisory panel, ad-hoc working groups
- **New Hampshire** - Stakeholder group with specific responsibilities to make recommendations on:
  - Assumptions and metrics
  - Load and DER forecasting methodology
  - Hosting capacity, interconnection, and locational value approach
- **New York** - Surveys, newsletters, webinars, meetings, and designated **website** with links to various sources of information –

The Joint Utilities of New York

- DSP Enablement Efforts
- 2020 DSIP Filings
  - Hosting Capacity
  - Non-Wires Alternatives
  - EV DCFC Incentive Program
  - Webinars: JU DSP Efforts
New York – Joint Utilities stakeholder engagement opportunities summarized in **newsletter**

Recent and Upcoming JU Stakeholder Engagement

- **Stakeholder Survey** released to help inform the 2020 DSIPs
- Quarterly **DSP Enablement Newsletter** published with updated structure based on October survey
- Next quarterly newsletter posted to JU Website
- Company-specific stakeholder meetings on DSIPs (dates TBA)
- **JU Stakeholder Webinar** on Distributed System Implementation Plans (DSIPs)
- Today’s Webinar
- **June 30, 2020**
  - Individual DSIPs are filed
Hawaii – Integrated Grid Planning

Stakeholder Engagement

Hawaiian Electric IGP Process

Education & Information

Input & Feedback

- Forecasting Assumptions
- Resilience
- Distribution Planning
- Market

Industry peer group of experts participating voluntarily to advise on processes, methodologies, & technologies

Integrated Grid Planning
Stakeholder Council Meeting
August 18, 2020

LISTENING+ INTEGRATING+ COLLABORATING
to Reach 100% Renewables
Getting started
Getting starting with an IDSP proceeding: What others have done

► Develop staff report or white paper outlining DSP needs, goals, and vision
  ■ Example: Oregon PUC Staff White Paper

► Issue surveys or targeted questions to utilities and stakeholders
  ■ Example utility survey from Minnesota
  ■ Utility survey, stakeholder survey and follow-up stakeholder questions used in Oregon
  ■ Initial meetings or workshops
    • Review and discuss surveys and questions
    • Understand current processes, data, systems and filings

► Host targeted presentations or trainings for staff and stakeholders, including reviewing DSP guidelines from other states and utility filings
  ■ Examples: Colorado, Oregon

► Require utilities to develop stakeholder engagement plan prior to technical planning
  ■ Example: Joint Utilities of NY stakeholder plan and timeline

► Require utilities to develop initial distribution system plan to report on current system and processes. Example: New York April 20, 2016, order
  1. Develop plan and timeline for stakeholder engagement (May 5, 2016)
  2. File Initial DSIP addressing current planning, operations, and administration and identifying immediate changes to meet state energy goals (June 30, 2016)
  3. File Joint DSIP addressing tools, processes and protocols developed jointly or under shared standards (Nov. 1, 2016)
Emerging issues
Emerging Issues (1)

► Fire risk (see “Extra Slides” for more information)

● CA utilities required to file Wildfire Mitigation Plans that include:
  • ID high risk zones and develop de-energization plans
  • Enhanced inspection, repair/replacement and vegetation management
  • Strategy for sectionalization of lines to minimize areas subject to de-energization
  • Automatic reclosers strategy to prevent possible downed lines from starting fires
  • Identifying maximum wind tolerance of lines and mapping to weather forecasts
  • Significant metric analysis to track plans & performance

► Affordability

● CA PUC recent decision in affordability docket establishes 3 metrics
  • Hours at minimum wage required to pay for essential utility services
  • Vulnerability index of various communities
  • The ratio of utility service charges to household income after deducting housing and other essential utility services (affordability ratio)

● NY PSC is examining low income affordability with a target level of 6% of gross income. May 2016 order directed utility filings and adopted a framework for addressing low income customer needs
Emerging Issues (2)

- DER compensation tariffs based on locational benefit
  - New York Value Stack tariff compensates DER based on location, in addition to energy, capacity, environmental and demand reduction
  - Locational specific relief value (LSRV) zones are identified by each utility based on utility-defined criteria
  - Response to event calls in LSRV zones results in additional DER compensation

Source: Con Edison LSRV Zone Map
Resources for more information

U.S. Department of Energy’s (DOE) Modern Distribution Grid guides


Alan Cooke, Juliet Homer, Lisa Schwartz, *Distribution System Planning – State Examples by Topic*, Pacific Northwest National Laboratory and Berkeley Lab, 2018


Berkeley Lab’s Future Electric Utility Regulation reports

Berkeley Lab’s research on time- and locational-sensitive value of DERs


Forthcoming from Berkeley Lab — email Lisa Schwartz to request a draft:


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Extra Slides: State-Specific Approaches
**AB 327 (2013)** requires utilities to prepare Distribution Resource Plans (DRPs) that identify optimal locations for the deployment of DERs.

**PUC proceeding** on DRPs includes 3 tracks (order instituting rulemaking):

- **Track 1** – Hosting capacity and locational value methods and initial pilots
- **Track 2** – Additional demonstration pilots related to a) location benefits, b) distribution operations with DERs, and c) microgrids
- **Track 3** – Three policy issues
  - DER Adoption and Distribution Load Forecasting
  - Grid Modernization Investment Guidance
  - A Distribution Investment Deferral Process

**Series of Working Groups formed** – all materials available online:

- Locational Net Benefits Analysis (LNBA) **Working Group**
- Integration Capacity Analysis (ICA) **Working Group**
- DER Growth Scenarios and Distributed Load Forecasting **Working Group**
- Integrated Distributed Energy Resources Competitive Solicitations Framework **Working Group**
California (2)

- LNBA method consistent across IOUs, based on Avoided Cost Calculator enhanced to include location-specific values
  - Staff proposed major changes to DER Avoided Cost Calculator in Nov. 2019
  - CPUC adopted recommendations in Staff Proposal on Avoided Cost and Locational Granularity of Transmission and Distribution Deferral Values
    - Specified T&D values will be estimated through Distribution Investment Deferral Framework and CAISO planning processes
    - Unspecified distribution deferral value will be estimated through updates to the Avoided Cost Calculator considered in Integrated DER rulemaking (14-10-003)

- Integration Capacity Analysis (ICA)
  - 9/9/19 workshop on long-term refinements, culmination of a request for comments on ICA data and online map functionality
  - Utilities request that interconnection use case be the top priority (relative to policy and planning use cases) because CA Rule 21 is currently under revision. Utilities want ICA to be highly accurate for generation sources.
Integration Capacity Analysis (ICA) – incorporation of results into the tariff governing DER integration (CA Rule 21)

- The CPUC assigned commissioner issued a proposed decision, which the full commission voted to sign on 9/24/2020, revising CA Rule 21 and giving guidance on hosting capacity issues.
  - Eliminates the Fast Track eligibility size cap – any size project up to the ICA value (i.e., hosting capacity limit) may use Fast Track interconnection process; projects may require supplemental study if they fail a screen not included in the ICA
  - Gives utilities guidance on updating the ICA values and tracking the information outside of required monthly updates, and for labeling ICA values that need to be updated
  - Gives utilities guidance on developing/updating screens including short circuit contribution, projects potentially causing issues at transmission facilities, and other screens
In response to the growing severity and risk of forest fires, California moved to mitigate and address the risks of fires started by utility infrastructure.

- R.18-10-007 requires and approved wildfire mitigation plans (WMPs).
  - SB 901 (2018) listed mitigation plans contents, gave CPUC short window to approve plans
  - Between June 3 and June 6, 2019, CPUC approved first round of mitigation plans
  - In December 2019 CPUC staff issued draft, revised guidelines for WMPs
  - By resolution, in January 2020 the CPUC ordered utilities to file 2020 WMPs
  - In June 2020, the CPUC ratified the CPUC Wildfire Safety Division’s approvals with conditions of the 2020 WMPs

- WMPs include considerable public outreach. The CPUC ordered that a language is prevalent if 1,000 or more people speak it within the utility’s service territory, and outreach must be in any language that is thus designated as prevalent. By statute, outreach must be in English, Spanish, and the top 3 primary languages regardless of prevalence.
The CPUC WMP template requires plans and 5 years of historical data on:

- Historical number of fires started by utility plant/equipment, no. of injuries and deaths due to fires, and various measures of the no. and value of assets and structures damaged or destroyed
- Historical “near misses” – where equipment failure could have started a fire but did not
- Steps taken to assess and reduce fire risk – equipment inspections, replacement or repair of equipment at risk of causing fires and plant hardening steps such as undergrounding
- Number of public safety power shutoff (PSPS) events and number of customers affected
- Type and number of steps taken to reduce the number of PSPS events and no. of customers affected, e.g., line sectionalization, assistance with backup generation, and pursuing microgrid opportunities
- Vegetation management steps including hazard tree management, expanded clearances around facilities, brush management around poles and drought related inspections
- Weather monitoring and forecasting – the plans detail steps and granularity of forecasting particularly in high fire-risk area and includes assessment of fire risk accounting for how dry the forests and vegetation are.
The CPUC wildfire mitigation roadmap includes 4 priority items:

- Utility WMPs – focus on understanding risk; continued improvement, including the use of a maturity model
- Metrics - developing / tracking metrics to assess progress and performance
- Detailed risk assessment – modeling risk to support resource allocation
- Data and analytics
**SB 19-236** (2019) requires PUC to promulgate rules establishing filing of a distribution system plan (DSP), including:

- Methodology for evaluating costs and net benefits of using DERs as NWAs
- Threshold for size of new distribution projects
- Requirements for DSP filings, including:
  - Consideration of NWAs for new developments (>10,000 residences)
  - Load forecasts from beneficial electrification programs
  - Forecast of DER growth
  - Planning process for cyber and physical security risks
  - Proposed cost recovery method
  - Anticipated new investments in distribution system expansion
  - Economic impacts of NWAs
  - Estimated year when peak demand growth merits analysis of new NWAs
- Public interest in approval of NWAs
- Ratepayer benefits from NWAs
- Benchmarks or accountability mechanisms

*Xcel Energy* hosting capacity map (Denver area)
In Proceeding No. 17M-0694E, initiated through Decision No. C17-0878 (Oct. 26, 2017), the Commission examined implementation of an Integrated Distribution System Planning process and invited comments on:

- “...initial regulatory steps that the Commission should take to ensure that investor-owned electric distribution systems have the capability to handle increased penetration of distributed generation, storage, and certain load building technologies such as electric vehicles.”
- Stakeholder engagement, including Distribution System Planning work group
- Pre-rulemaking proceeding recently completed (No. 19M-0670E)
  - Decision No. C19-0957 seeks comments and information on initial regulatory steps to meet requirements of SB 19-236
  - Series of informational workshops
- Rulemaking forthcoming
HPUC rejected piecemeal investment proposals and required Hawaiian Electric Companies (HECO) to file a comprehensive Grid Modernization Plan.

Order No. 34281 provided guidance for a holistic, scenario-based grid modernization strategy to inform review of discrete projects submitted by utility.

Integrated Grid Planning process (Order 35569)
1. Develop forecasts and assumptions that will drive planning
2. Collectively identify needs - resources, T&D
3. Identify solutions - resource, T&D that can be achieved through procurement, pricing and program options
4. Evaluate and optimize resource and T&D solutions, submit 5-year plan to PUC with proposed investments, pricing and programs

Hawaiian Electric Companies (HECO) Integrated Grid Plan incorporates procurement into planning itself and merges G, T & D planning processes:
- Integrates solution procurement
- Identifies gross system needs, coordinates solutions, and develops an optimized, cost-effective portfolio of assets
- Allows a variety of distributed and grid scale resources to provide power generation and ancillary services
- Stakeholder council, technical advisory panel, ad-hoc working groups
Hawaii (2)

- Collection of Historical Data
- Load & DER Forecasts
- Load & DER Profiles

Forecast

Analysis

- Distribution Planning Criteria
- Hosting Capacity
- Contingency Analysis
- Grid Needs Identification

Solution Options

- Solution Requirements
- Wires Solutions
- Non-Wires Solutions

Evaluation

- Evaluation of Solutions
- Solution Sourcing
- Solution Selection

Solution Implementation

Source: HECO presentation to Puerto Rico Energy Bureau, Jan. 10, 2020
HRS § 269-145.5(b) – In advancing the public interest, the commission shall balance technical, economic, environmental, and cultural considerations associated with modernization of the electric grid, based on principles that include but are not limited to [emphasis added]:

- Enabling a **diverse portfolio of renewable energy resources**;
- **Expanding options for customers** to manage their energy use;
- **Maximizing interconnection of distributed generation** to the State's electric grids on a cost-effective basis at non-discriminatory terms and at just and reasonable rates, while maintaining the reliability of the State's electric grids, and allowing such access and rates through applicable rules, orders, and tariffs as reviewed and approved by the commission;
- **Determining fair compensation for electric grid services** and other benefits provided to customers and for electric grid services and other benefits provided by distributed generation customers and other non-utility service providers; and
- **Maintaining or enhancing grid reliability and safety** through modernization of the electric grids.

**Order 32491** – The Commission adopted additional principles related to:

- **Grid platforms** for new products, services, opportunities for distributed energy resources
- **Optimization of grid assets** and resources to minimize total system costs
- Greater **customer engagement** and options for consuming and providing energy services
- Enhancing **safety, security, reliability, and resilience** at fair and reasonable costs
- **Comprehensive, transparent and integrated distribution system planning**
Indiana

- Commission required 3 IOUs to establish stakeholder collaboratives to develop performance metrics, incl. for distribution planning and operations
  - First raised in [IURC Order in Cause 44602](#) for Indianapolis Power and Light (IPL) (3/16/16), then in an [IURC order in Cause 44967](#) for Indiana Michigan Power Company and its [compliance filing](#)
  - Also see NIPSCO (Cause 44688) and I&M (Cause 44967)
- **IRP rule** requires utilities to consider effects of distributed generation on distribution system planning (and other types of planning)
- Transmission, Distribution, and Storage System Improvement Charge (2013 legislation) to encourage T&D investments for safety, reliability, modernization; amended in 2019 by [HB 1470](#) in part to include advanced technology investments
  - 5-7 year plans for Indiana URC approval; detailed project descriptions all yrs
  - For capital projects only (e.g., *not* for vegetation management)
  - Charge limited to 80% of “approved capital expenditures and TDSIC costs”; remaining 20% addressed in general rate case
Maryland

- Distribution planning is one of **six topics*** addressed in [PC 44 - Transforming Maryland’s Electric Grid proceeding](#).
  - PC-44 working group progress: proposing a statewide EV program, refining interconnection rules and processes, developing and proposing retail supplier regulations, and designing both time varying rates and storage ownership pilots
  - [Benefits and Costs of Utility Scale and Behind the Meter Solar Resources in Maryland](#) - Final report November 2018:
    - Presents benefits and costs as they accrue to (1) the bulk power system, (2) local power distribution systems, and (3) society and the economy
    - [Original RFP](#) for consultant to study benefits & costs of distributed solar in IOUs’ service areas
- Orders in [Case No. 9406 (BGE rate case)](#) and [Case No. 9418 (Pepco rate case)](#) required a five-year distribution investment plan within 12 months
  - [BGE distribution investment plan](#) and [Pepco plan](#) filed
- [Senate Bill 573](#) required an energy storage pilot program. [PUC order](#) August 2019 established energy storage pilot.
  - In December 2019, working group [proposed metrics and value streams](#) that energy storage applications should consider.

*Other topics: rate design, EVs, competitive markets/customer choice, interconnection process and energy storage
Massachusetts

► **Requirements** for each electric distribution company to submit grid modernization plans every three years that include (next due July 2020):
  - A three-year short-term investment plan that the Department will review to determine which investments are eligible for preauthorization, and
  - A five-year strategic plan outlining how the company intends to meet the DPU’s grid modernization objectives.

► DPU ruled on Grid Modernization Plans in [May 2018 Order](#)
  - Denied AMI requests but approved reliability/resilience-related requests for ADMS, automation and Volt/var optimization – mentioned recent frequency of large storms
  - Required utilities to file performance metrics, a joint utilities proposed evaluation plan, a model Grid Modernization Factor tariff
    - In April 2019, joint utilities filed [Grid Modernization Plan Performance Metrics](#) for each utility to use to measure progress towards grid modernization.
  - Required utilities to file Annual Grid Modernization Reports with updated projections, and metrics (feeder and substation, system level infrastructure, performance)

► [House Bill 4857](#) (August 2018) – Established Clean Peak Standard and requirements for *Annual Resiliency Reports* for distribution systems with heat maps of congested/constrained areas
PSC initially ordered utilities (in rate cases) to file 5-year distribution investment & maintenance plans “to increase visibility into the needs of maintaining the state’s system and to obtain a more thorough understanding of anticipated needs, priorities, and spending.”

Commission consolidated all 3 utility filings into Case No. U-20147 (April 2018)

Following comments on draft plans, utilities filed final plans:


PSC 2018 Staff Report - Distribution Planning Framework for an “open, transparent, and integrated electric distribution system planning process”

PSC Order on staff recommendations: “framework … is to be used as a guide for the next iterations of distribution plans….” “Unconventional solutions, including targeted EE, DR, energy storage, and/or customer-owned generation, that could displace or defer investments in a cost-effective, reliable, and timely manner should be considered and evaluated.”
Sept. 2019 order in docket U-20147:

- Utilities must file their next distribution investment and maintenance plans by June 30, 2021.
- PSC staff will examine the value of resilience (and its role in cost-benefit methodologies for rate cases and alignment of distribution plans with IRPs) for the next phase of distribution plans. Staff will file a summary of the stakeholder process—including discussions on the value of resilience—for input into distribution plans by April 1, 2020.
- Utilities will “continue to develop detailed distribution plans over a five-year period, but also include in the plan their vision and high-level investment strategies 10 and 15 years out. This approach is consistent with the planning horizons used in IRPs.“

Stakeholder workshops – June-November 2019

MPSC Staff report on stakeholder workshops – April 1, 2020
Michigan Statewide Energy Assessment by PSC staff (Sept. 11, 2019) recommends utilities:

- “better align electric distribution plans with integrated resource plans to develop a cohesive, holistic plan and optimize investments considering cost, reliability, resiliency, and risk. As part of this effort, Staff, utilities, and other stakeholders should identify refinements to IRP modeling parameters related to forecasts of distributed energy resources (e.g., electric vehicles, on-site solar) reliability needs with increased adoption of intermittent resources, and the value of fuel security and diversity of resources in IRPs. A framework should also be developed to evaluate non-wires alternatives such as targeted energy waste reduction and demand response in IRPs and distribution plans.”

- “work with Staff and stakeholders to propose a methodology to quantify the value of resilience, particularly related to DERs. In addition, the value of resilience should be considered in future investment decisions related to energy infrastructure in future cases.”
Michigan (4)

► **MI Power Grid** - Maximize benefits of integrating new energy technologies & optimizing grid investments for reliable and affordable electric service

► MPSC issued Oct. 17, 2019, order launching the initiative:
  - “No later than June 30, 2020, the Commission Staff shall file in this docket a status report on utility pilot projects, summarizing efforts to date, providing recommendations for objective criteria to apply when evaluating proposed utility pilot projects, and identifying potential areas for additional pilot proposals.” Report [here](#).
  - Optimizing grid investments and performance will include quantifying “the value of resilience, particularly as it relates to distributed energy resources”
  - Priority work areas include grid security and reliability metrics (Case Nos. [U-20629](#) and [U-20630](#))

  - The plans will articulate the utilities' decision criteria to screen projects for NWA analysis and consider pilots for DERs beyond energy efficiency and demand response.
  - PSC staff will file by May 27, 2021, findings and recommendations relating to methodologies or frameworks for evaluating NWAs.
Minnesota (1)

- **Minn. Stat. §216B.2425** (2015) requires largest utility to submit biennial transmission and distribution (T&D) plans to PUC
  - “identify … investments that it considers necessary to modernize the transmission and distribution system by enhancing reliability, improving security against cyber and physical threats, and by increasing energy conservation opportunities by facilitating communication between the utility and its customers through the use of two-way meters, control technologies, energy storage and microgrids, technologies to enable demand response, and other innovative technologies.”
  - May ask Commission to certify priority projects and approve costs through a rider — a finding that the project is consistent with requirements of this statute, not a prudency determination
  - Analyze hosting capacity for small-scale distributed generation resources and to identify necessary distribution upgrades to support [their] continued development

PUC initiated inquiry on Electric Utility Grid Modernization in 2015 with a focus on distribution planning (Docket No. CI-15-556)

- Series of stakeholder meetings
- Questionnaire to utilities on utility planning practices with stakeholder comments
  - How do Minnesota utilities currently plan their distribution systems?
  - What is the status of each utility’s current plan?
  - Ways to improve or augment utility planning processes?

- Staff Report on Grid Modernization defined grid modernization for Minnesota, proposed a phased approach, and identified principles to guide it:
  - Maintain and enhance safety, security, reliability, and resilience of electricity grid, at fair and reasonable costs, consistent with state’s energy policies
  - Enable greater customer engagement, empowerment, and options for energy services
  - Move toward creation of efficient, cost-effective, accessible grid platforms for new products, new services, and opportunities for adoption of new distributed technologies
  - Ensure optimized use of grid assets and resources to minimize total system costs
  - Facilitate comprehensive, coordinated, transparent, integrated distribution system planning
In 2018, the Commission set **Integrated Distribution Planning (IDP) requirements for Xcel Energy** (Docket No. 18-251) and **requirements for smaller regulated utilities**

- Docket Nos. 18-253 (Otter Tail), 18-254 (Minnesota Power), 18-252 (Dakota Electric)

Most requirements are the same across utilities

Fundamental provisions

- 10-year Distribution System Modernization and Infrastructure Investment Plan
  - Including a 5-year action plan, based on internal business plans and DER future scenarios
    - Base case, medium and high — specifying methods and assumptions
  - Coordination with Integrated Resource Planning (except for Dakota Electric, a distribution coop)
  - Utility holds at least one “timely” meeting prior to filing; PUC staff can convene a stakeholder meeting during public comment period
- Data specified for filing - Baseline distribution system, financial data, DER deployment
- For projects >$2M, analyze how non-wires alternatives (NWAs) compare with traditional grid solutions in terms of viability, price and long-term value
  - Specify project types (e.g., for load relief or reliability), timelines and cost thresholds
Xcel Energy filed its **1st IDP** Nov. 1, 2018 (Docket 18-251)

- **2nd IDP** filed Nov. 1, 2019 (Docket 19-666)
  - Grid modernization report required by statute now filed in combination with IDP filing
  - Commission’s [July 23, 2020, order](#) in Docket 19-666
    - Approved certification requests for AMI and Field Area Network - “All future cost recovery will be based upon the Company accomplishing Commission-approved metrics and performance evaluations for the certified projects.”
    - Also certified Advanced Planning Tool, with enhanced capabilities for DER adoption scenarios, hosting capacity, NWA, load forecasting, and integration with other planning
    - Required [Xcel to file rate design roadmap](#)

Next Xcel IDP due Nov. 1, 2021, with continued *annual* updates of baseline financial data and NWA analysis

Filing by other regulated utilities

- MN Power (19-684), Dakota Electric Association (19-674), Otter Tail Power Co. (19-693)
SB 146 (2017) requires utilities to file distributed resource plans (DRPs) to evaluate locational benefits and costs of distributed generation, energy efficiency, storage, electric vehicles and demand response technologies.

- DRP identifies standard tariffs, contracts or other mechanisms for deploying cost-effective distributed resources that satisfy distribution planning objectives.
- DRP is filed with IRP every 3 years and covers utility's 3-year IRP action plan.

PUC adopted temporary planning regulations in 2018 and permanent regulations in 2019 (D-17-08022)

- 6-year forecast of net distribution system load (down to feeder level) and distributed resources
- Hosting capacity analysis and public access to utility's online distribution maps/data
- Grid Needs Assessment compares traditional and DER solutions for forecasted T&D system constraints
- “A utility may recover all costs it prudently and reasonably incurs in carrying out an approved DRP, in the appropriate separate rate proceeding.”
NV Energy filed its **1st DRP in April 2019 (Docket D-19-04003)**

- Distribution system and distributed resource load forecast
- Hosting capacity analysis
- Grid Needs Assessment identifying distribution system constraints
- NWA analysis
  - Utility’s suitability/screening tool identified 10 distribution system projects and 107 transmission projects for NWA analysis
- Locational net benefit analysis
  - considered 8 costs and benefits; identified 3 projects with similar estimated costs for traditional solutions and NWA

**Stipulation approved by PUC**
New York (1)

► **Reforming the Energy Vision** – Utilities file Distributed System Implementation Plans (DSIP) every two years

► **Hosting capacity maps** required for all circuits ≥12 kV

► **Value Stack tariff** – successor tariff to Net Energy Metering based on value stack of actual costs and benefits

  ■ Location-specific relief zones
  ■ Payments to DER (including storage) projects based on energy, capacity, environmental, demand reduction and locational system relief value

  • NY DPS released an updated [Value Stack Order](#) in April 2019.
    ◆ Demand reduction value is based on a fixed window of peak hours
    ◆ Locational system relief value uses a call system where eligible projects may receive compensation for responding during utility call windows. Calls made 21 hours in advance. At least ten calls windows a year guaranteed for each LRSV zone.

■ **July 2020 order**, the PSC set successor rates that allow NEM to continue, but starting 1/1/2022, new mass market PV must use new Value Stack

  • PV owners must pay a Customer Benefit Charge (CBC) to fund a share of public benefit programs
  • [Solar Value Stack Calculator](#) estimates revenue under value tariff
Updated **NY PSC DSIP Guidance** (April 2018) – Must include sections on:

- Integrated planning, advanced forecasting, grid operations, energy storage integration, electric vehicle integration, energy efficiency integration and innovation, distribution system data, customer data, cyber-security, DER interconnections, advanced metering infrastructure, hosting capacity, beneficial locations for DERs and NWAs, and procuring NWAs
- DSIP also must address governance, marginal cost of service studies, and utility’s most recent Benefit-Cost Analysis Handbook
- Utilities filed their 2nd DSIPs in June 2020; see NYSEG/RG&E; CONED; O&R; National Grid; Central Hudson

Each utility must maintain a Benefit-Cost Analysis Handbook (**BCA order**)

- Common handbook template provides a consistent and transparent methodology and presents general BCA considerations and notable issues on data collection required
- Definitions and equations for each benefit and cost are provided along with key parameters and sources. Where applicable, utilities customize the handbook to account for utility-specific assumptions and information.
- The NYDPS regularly updates a capacity spreadsheet for calculating avoided costs for Installed Capacity auctions.
- The utilities filed their 3rd version of the BCA Handbooks in June 2020; see NYSEG/RG&E; CONED; O&R; National Grid; Central Hudson
New York (3)

- Distribution System Implementation Plans - [Docket 16-M-0411](#)
  - **Pilot Integrated Energy Data Resource** launched 1/1/20 - Database and web analytics platform to help DER developers identify, evaluate and initiate DER development

- **Hosting capacity maps** — e.g., National Grid maps PV >300kW at sub-feeder level

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**Joint Utilities Roadmap for Implementation of Hosting Capacity Analysis**

- **Stage 1** - Distribution Indicators
- **Stage 2** - Hosting Capacity Evaluations
- **Stage 2.1** - Additional System Data
- **Stage 3.0** - Advanced Hosting Capacity Evaluations, Sub-feeder level, Existing DER
- **Stage 3.X** - Additional Enhancements to Advanced Hosting Capacity Evaluations
- **Stage 4** - Fully Integrated DER Value Assessments

**Timeline**
- 2016 - Early 2017
- October 2017 - 2018
- April 2018
- October 2019

**Increasing effectiveness, complexity, and data requirements**
PUCO’s **PowerForward initiative** - reviewed technological and regulatory innovation that could enhance the consumer electricity experience.

- Workshops with industry experts “to chart a path forward for future grid modernization projects, innovative regulations and forward-thinking policies”
- Recommendations will be adapted to each utility on a case-by-case basis in individual proceedings.

**PowerForward Roadmap** released August 2018 - vision for the modernization of Ohio's grid with a series of recommended next steps

- Distribution utilities to file grid architecture status reports & current state planning assessments in April 2019, followed by applications for grid arch investments
- Utilities filed respective grid architecture status reports on April 1, 2019.
- October 2018 - two separate working groups/dockets: Distribution System Planning and Data and the Modern Grid

Distribution System Planning Workgroup (EnerNex) **final report** and Data and Modern Grid Workgroup **final report** issued Jan 2020

OH Commission approves Duke **PowerForward rider** in Dec 2018 to recover capital and O&M costs for new PowerForward related initiatives

**Distribution system reliability code, distribution circuit performance codes** and annual reliability compliance filings
Pennsylvania

- **Distribution System Improvement Charge** can be used to recover reasonable and prudent costs to repair, improve or replace eligible distribution property
  - Long Term Infrastructure Improvement Plans (LTIIPs) must be filed
  - In January 2020, regulators approved grid modernization investments for four FirstEnergy utilities based on LTIIPs (Metropolitan Edison, Penelec, PennPower, WestPenn Power)
  - Investments approved included: ADMS, DMS, Distribution Automation, SCADA

- **Distribution reliability code** directs PSC to regulate distribution inspection & maintenance plans, requires utilities to report quarterly on worst-performing circuits and make annual compliance filings ([2016 PA reliability report](#))