

State Engagement in Electric Distribution System Planning

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State Engagement in Electric Distribution System Planning

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Summary

Electric distribution system planning is focused on assessing needed physical and operational changes to the local grid to maintain safe, reliable, and affordable service. While electric utilities have always engaged in this activity, the planning horizon has typically been short and involvement by state utility regulators minimal.

Safety, reliability, and affordability remain top objectives for deeper state engagement in longer-term distribution system planning. Other drivers are proposed utility investments to replace aging infrastructure and modernize grids, opportunities to improve distribution system efficiency, enabling consumers to have greater control over energy costs and sources, and integrating higher levels of distributed energy resources (DERs) such as rooftop solar, distributed energy storage, and price-responsive demand.²

This report provides a snapshot of current state engagement in distribution system planning:

- *Part 1* describes activities in states that have adopted some advanced elements of integrated distribution system planning and analysis (see Figure S-1): California, Hawaii, Massachusetts, Minnesota, and New York.³ It summarizes the impetus for early action, goals, regulatory requirements, additional state activities related to distribution system planning, and next steps.
- *Part 2* covers a broader array of state approaches. For example, some of these states have long-standing distribution reliability and performance codes, requiring regulated utilities to report regularly on poor-performing circuits and propose investments for improvements. Other states require regulated utilities to make filings related to proposed grid modernization investments.

A growing number of states are beginning to consider comprehensive distribution system planning processes. This report documents activities in eight states with statutory or public utility commission requirements for electric distribution system or grid modernization plans, plus four jurisdictions with proceedings on such requirements underway or planned. We also cover activities in several additional states to provide a more accurate picture of the significant variation in approaches, in part stemming from differences in electricity market structure — states with restructured markets versus states where all utilities remain vertically integrated. Table S-1 provides a summary of these approaches.

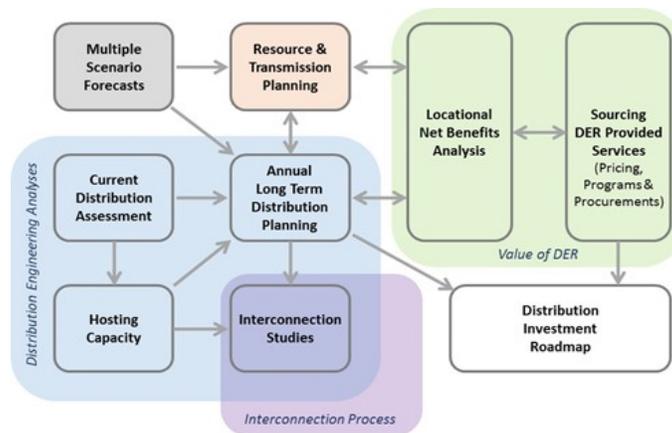


Figure S-1. Integrated planning and analysis: transmission, distribution, and customer/third-party domains⁴

² See U.S. Department of Energy (2017). *Modern Distribution Grid: Volume III: Decision Guide* (www.doe-dsp.org).

³ See ICF International (2016). *Integrated Distribution Planning*. For Minnesota Public Utilities Commission. August.

⁴ Ibid.

Table S-1. State Activities on Electric Distribution System Planning

	States with advanced practices					Other state approaches										
	California	Hawaii	Massachusetts	Minnesota	New York	D.C.	Florida	Illinois	Indiana	Maryland	Michigan	Ohio	Oregon	Pennsylvania	Rhode Island	Washington
Statutory requirement for long-term distribution plans or grid modernization plans ^(a)	✓			✓					✓							
Commission requirement for long-term distribution plans or grid modernization plans ^(a)		✓	✓		✓					✓	✓					
No planning requirements yet, but proceeding underway or planned						✓							✓		✓	✓
Voluntary filing of grid modernization plans								✓			✓		✓			
Non-wires alternatives analysis and procurement requirements	✓				✓										✓	
Hosting capacity analysis requirements	✓	✓		✓	✓											
Locational net benefits analysis required	✓				✓											
Smart grid plans required													✓			
Required reporting on poor-performing circuits and improvement plans							✓	✓			✓		✓	✓		
Storm hardening requirements							✓			✓						
Investigation into DER markets		✓														

(a) For one or more utilities.

Table S-1 provides examples of states with longstanding requirements for utilities to report on reliability and resilience metrics and plans to improve on these measures, as well as states with storm-hardening requirements. Common *emerging* distribution system planning elements include DER forecasting, assessing DER locational value, analyzing hosting capacity, assessing non-wires alternatives, and engaging stakeholders (including third-party service providers) to comment on proposed planning processes and filed utility plans and help identify least-cost solutions to distribution system needs. Some states also are exploring new procurement mechanisms, such as competitive solicitations, to consider DERs as non-wires alternatives for load relief and other distribution system needs.

Among the specific reasons PUCs are adopting these new planning and procurement practices are to facilitate higher penetration levels of DERs, harness these resources to provide grid services for customers, enable greater consumer engagement, and improve review of utility investments in distribution systems, particularly with respect to grid modernization.

States can learn from each other and tailor successful approaches to their unique circumstances. Reviewing the broad range of legislative and public utility commission activities described in this report is a useful starting point.

Acknowledgments

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Acronyms and Abbreviations

AEP	American Electric Power
AMF	advanced metering functionality
AMI	advanced metering infrastructure
BQDM	Brooklyn Queens Demand Management
CAIDI	customer average interruption duration index
CAISO	California Independent System Operator
CEC	California Energy Commission
CGS	customer grid-supply
CSS	customer self-supply
CYME	Cyme International T&D Inc.
DC	District of Columbia
DER	distributed energy resource
DOER	Department of Energy Resources
DPAG	Distribution Planning Advisory Group
DPU	Massachusetts' Department of Public Utilities
DRP	Distribution Resource Plan
DRV	demand reduction value
DSIP	Distribution System Implementation Plan
FPL	Florida Power & Light
FPSC	Florida Public Service Commission
GHG	greenhouse gas
GMP	Grid Modernization Plan
HECO	Hawaiian Electric Companies
ICA	Integration Capacity Analysis
ICC	Illinois Commerce Commission
IEPR	Integrated Energy Policy Report
IOAP	Interconnection On-line Application Portal
IOU	investor-owned utilities
IRP	integrated resource plan(ning)
LBMP	locational based marginal price
LNBA	Locational Net Benefits Analysis
LSRV	locational system relief value
LTIP	Long-Term Infrastructure Improvement Plan
MEDSIS	Modernizing the Energy Delivery System for Increased Sustainability
MTC	market transition credit
MW	megawatt

NEM	net energy metering
NWA	non-wires alternatives
NYISO	New York Independent System Operator, Inc.
NYSERDA	New York State Energy Research and Development Authority
OER	Rhode Island Office of Energy Resources
OPC	Office of the People’s Counsel
PG&E	Pacific Gas and Electric Company
PSC	Public Service Commission
PSIP	Power Supply Improvement Plans
PUC	Public Utility(ies) Commission
PUCO	Public Utilities Commission of Ohio
PV	photovoltaic
Q	quarter
RA	Resource Adequacy
REC	Renewable Energy Certificate
REV	Reforming the Energy Vision
RFP	request for proposal(s)
RPS	renewable portfolio standard
SAIDI	system average interruption duration index
SAIFI	system average interruption frequency index
SCE	Southern California Edison
SDG&E	San Diego Gas & Electric
STIP	Short Term Investment Plan
T&D	transmission and distribution
TOU	time of use
TVR	time-varying rates
VDER	value of DER
WUTC	Washington Utilities and Transportation Commission

Glossary

Advanced metering infrastructure (AMI) uses advanced meters to measure consumption in 5-minute to one-hour intervals and then collect meter data frequently — for example, hourly or daily. Meters are connected to a communications network, which allows the meter to communicate with the utility, in some cases both sending information (like consumption) and receiving messages (like prices or demand response signals). In areas with traditional meters, meter reading typically occurs once a month either through physical reading of the meter or collecting the information through a local radio network.

Distributed energy resource (DER) is a resource sited close to customers that can provide all or some of their immediate electric and power needs and can also be used to either reduce demand or provide supply to satisfy the energy, capacity, or ancillary service needs of the distribution grid. Examples of DERs include solar photovoltaic (PV), wind, combined heat and power, energy storage, demand response, electric vehicles, microgrids, and energy efficiency. Diesel-fired backup generators may also fit in this definition.

Distribution automation enables the monitoring, coordination, and operation of distribution system components in real-time mode, while adjusting to changing loads and failure conditions of the distribution system, usually without interventions. These functions require telemetry, analytics, and control, which in turn require communication and computational resources.

Distribution system is the portion of the electric system composed of medium voltage (69 kV to 4 kV) sub-transmission lines, substations, feeders, and related equipment that transport the electricity commodity to and from customer homes and businesses and link customers to the high-voltage transmission system. The distribution system includes all the components of the cyber-physical distribution grid including the information, telecommunication, and operational technologies and transformers, wires, switches, and other apparatus.

Grid modernization plans are plans made to help advance technology investments to enable improved distribution safety and reliability, operational efficiencies, integration of DERs, and realization of potential DER value. A primary focus for grid modernization plans is expanding distribution investments to replace aging infrastructure to include advanced grid technologies.

Integrated distribution system planning (also referred to as *integrated distribution planning*) assesses physical and operational changes to the electric distribution system necessary to enable safe, reliable, and affordable service that satisfies customers' changing expectations and use of DERs, generally in coordination with resource and transmission planning. Integrated distribution system planning includes stakeholder-informed planning scenarios to support a reliable, efficient, and robust grid in a changing and uncertain future.

Integrated resource planning refers to a utility plan for meeting peak demand and energy needs over a planning period, using a combination of supply-side and demand-side resources that represents the least-cost resource mix, accounting for risk and uncertainty.

Interconnection standards are the technical specifications for, and testing of, the interconnection between utility electric power systems and DERs. Interconnection standards provide requirements relevant to the performance, operation, testing, safety considerations, and maintenance of the interconnection.

Hosting capacity analysis (also called *integration capacity analysis*) is used to establish a baseline of the maximum amount of DERs, an existing distribution grid (feeder through substation) can accommodate safely and reliably without requiring infrastructure upgrades.

Locational net benefits analysis is the systematic analysis of costs and benefits of DERs from a locational perspective. The value of DERs on the distribution system is locational in nature — that is, the value may be associated with a distribution substation, an individual feeder, a section of a feeder, or a combination of these components.

Net energy metering (or simply net metering) is a method that adapts traditional monthly metering and billing practices to compensate owners of distributed generation facilities for electricity exported to the grid. The customer can offset the electricity they draw from the grid throughout the billing cycle. The net energy consumed from the utility grid over the billing period becomes the basis for the customer's bill for that period.

Non-wires alternatives are non-traditional investments or market operations that may defer, mitigate, or eliminate the need for traditional transmission and distribution investments.

Smart inverters are inverters that are capable of actively regulating the voltage of a solar PV installation's output. The inverter switches electricity from direct current to alternating current (AC), as the distribution grid connected to the solar PV uses AC power. Smart inverters address voltage drops before exporting the energy to the distribution grid.

Storm hardening is when physical changes are made to the utility's infrastructure to make it less susceptible to storm damages such as high winds, flooding, ice, snow, or fires. The aim is to allow utilities to withstand impacts from severe weather events with minimal damage and to improve durability and stability of transmission and distribution infrastructure.

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I. Examples of States with Advanced Distribution Planning Practices: Summary and Status

1.0 California

1.1 Introduction

California is a leader in the area of distribution system planning. This section focuses on the Distribution Resource Planning proceeding (R.14-08-013), the Integrated Distributed Energy Resources proceeding (R.14-10-003), and the Integrated Resource Planning proceeding (R.16-02-007).

1.2 Impetus for Early Action

Since 2001, Section 353.5 of the California Public Utilities Code has stated that “[e]ach electrical corporation, as part of its distribution planning process, shall consider nonutility owned distributed energy resources as a possible alternative to investments in its distribution system in order to ensure reliable electric service at the lowest possible cost” (CPUC 2017a). The State Legislature and the California Public Utilities Commission continue to develop laws and policies that support and promote renewable and other distributed energy resources (DERs) located within the utilities’ distribution systems. In recognition that traditional distribution system planning is limited in its ability to support state policies on DERs and emerging technologies, the legislature passed Assembly Bill (AB) 327 in 2013, which requires that Distribution Resource Plans (DRPs) be filed with the Commission (CPUC 2015a).

1.3 Stated Goals

The Commission initiated Rulemaking (R.) 14-08-013 in response to AB 327 to establish policies, procedures, and rules to guide California investor-owned utilities (IOUs) in developing their DRPs. In February 2015, the Commission issued a ruling that laid out the following goals for DRP proposals. The DRPs were expected to support California’s policy of significantly reducing greenhouse gas (GHG) reduction targets, and to

- modernize the electric distribution system to accommodate two-way flows of energy and energy services throughout the IOUs’ networks,
- enable customer choice of new technologies and services that reduce emissions and improve reliability in a cost-efficient manner, and
- animate opportunities for DERs to realize benefits through the provision of grid services (CPUC 2015a).

1.4 Regulatory Requirements

California IOUs were required to file DRP proposals by July 1, 2015, that met the following requirements (CPUC 2015b):

1. Evaluate locational benefits and costs of distributed resources on the distribution system. Evaluation shall be based on 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 electric grid or costs to ratepayers.
2. Propose or identify standard tariffs, contracts, or other mechanisms for the deployment of cost-effective distributed resources that satisfy distribution planning objectives.

3. Propose cost-effective methods of effectively coordinating existing commission-approved programs, incentives, and tariffs to maximize the locational benefits and minimize the incremental costs of distributed resources.
4. Identify additional utility spending necessary to integrate cost-effective distributed resources into distribution planning, consistent with the goal of yielding net benefits to ratepayers.
5. Identify barriers to the deployment of distributed resources, including, but not limited to, safety standards related to technology or operation of the distribution circuit in a manner that ensures reliable service.

To evaluate the IOUs' DRP proposals, the Commission issued a scoping ruling on January 27, 2016 regarding consolidation and deconsolidation of issues and regulatory processes that identified three tracks to address these issues and processes (CPUC 2016c):

1. Track 1 targets the ICA and LNBA methodological issues, including Demo A and Demo B.
2. Track 2 targets Demonstration and Pilot Projects (Demos C, D, and E) to demonstrate DER locational benefits, distribution operation with high DER penetrations, and a microgrid with DERs.
3. Track 3 targets Policy Issues.

1.4.1 Track 1 Integration Capacity Analysis

In Track 1, the Commission directed the three major California IOUs—Pacific Gas and Electric Company (PG&E), Southern California Edison (SCE), and San Diego Gas & Electric (SDG&E)—to convene two working groups: the Integration Capacity Analysis (ICA) Working Group and the Locational Net Benefits Analysis (LNBA) Working Group, to monitor and provide consultation to the IOUs on demonstration projects and provide refinements to ICA and LNBA methods.⁵ In their July 2015 DRP filings, each utility proposed two demonstration projects, later referred to as Demo A and Demo B. Appendix A provides information about the original utility DRP, ICA, and LNBA filings. The Commission issued additional guidance on the DRPs and associated demonstration projects, and authorized the demonstration projects in May 2016 ruling (CPUC 2016a). In an August 2016 ruling, the Commission responded to suggestions from the utilities and revised the guidance on the ICA methodology, recognizing that increased transparency and uniformity are essential (CPUC 2016b).

Pursuant to a May 2016 ruling, Demo A focused on ICA methodologies and was intended to fulfill nine functional requirements (CPUC 2016a):

1. Quantify the capability of the distribution system to host DERs.
2. Use common methodology across all IOUs.
3. Analyze different types of DERs.
4. Conduct analysis down to the line section or nodal level on the primary distribution system within the Distribution Planning Area.
5. Determine thermal ratings, protection limits, power quality (including voltage), and safety standards.
6. Publish the results via online maps.
7. Use time series models.

⁵ ICA is similar to what elsewhere is referred to as *hosting capacity analysis*.

8. Avoid heuristic approaches, where possible.
9. Demonstrate dynamic ICA using two DER scenarios including (a) no backflow beyond the substation bar, and (b) maximum DER capacity irrespective of power flow direction.

The Commission's May 2016 ruling gave the ICA Working Group a list of long-term improvements and short-term work on which to focus. For the longer term, among other things, the ICA Working Group was to consult with the utilities on advancing the ICA methodology to accomplish four goals: expand it to single-phase feeders; make ICA information more user friendly, including interactive maps; develop validation plans; and define quality control measures. For the short term, the ICA Working Group was to work with utilities to achieve six objectives: recommend methods for evaluating hosting capacity; recommend consistent and readable formats for ICA maps; evaluate new methods to improve the efficiency of the ICA tools; evaluate recommendations for establishing reference circuits and use cases for analyzing Demo A results; establish a method for using smart meter and other customer load data for developing localized load shapes (to the extent the utilities were not already doing this); and establish timelines for future work.

The same ruling directs utilities to modify the baseline methodology in Demo A according to the nine functional requirements listed above (CPUC 2016a). Appendix A provides more information about the original utility DRP filings and initial demo projects, as well as the hosting capacity analysis requirements for Demo A.

Interim reports on Demo A projects were issued by PG&E, SCE, and SDG&E in September 2016, and final reports in December 2016. At about that same time, the ICA Working Group submitted an interim report on long-term refinements of their process, and in March 2017 the working group submitted a final report. In March 2017, the ICA Working Group also submitted its short-term final report, which responded to the list of short-term work items and contained a number of consensus recommendations for topics to consider (PG&E 2017a). The Commission issued two rulings on April 19, 2017. One ruling noted the Working Group report and solicited input on a number of related subjects that the Commission believed were ripe for resolution in a forthcoming Commission decision. The second ruling contained a proposal to revise the scope and schedule for the ICA Working Group. On June 7, 2017, the Commission provided finalized guidance to the ICA Working Group and developed a prioritized list of future refinements, including the following:

- Further defining ICA planning use case and methodologies
- Developing standard photovoltaic (PV) profiles for online maps
- Developing methods and tools to model smart inverter functionality
- Performing comparative assessments of the utilities' implementation of ICA methodology on representative reference circuits

The complete list of prioritized future refinements is included in Table 3 of the ruling (CPUC 2017b). The schedule for completion calls for the ICA Working Group to submit a final report on long-term refinements in January 2018.

On August 25, 2017, the Commission issued a proposed decision addressing near-term issues the Commission noted in its April ruling. The proposed decision included a finding that each utility's Demo A met the requirements of the May 2 and August 23, 2016, rulings and provided guidance to the utilities for ICA use cases for online maps. Under the proposed decision, utilities would

- use the iterative methodology for calculating available capacity shown on the maps,

- update ICA results monthly for circuits that have been upgraded or that have new DER interconnections,
- employ 576 hourly profiles in the calculation (a minimum and a maximum day for each month of the year),
- display six ICA results in the maps and downloadable data sets, and
- model regulating devices in the systemwide rollout, as done for Demo A.

The proposed decision would further direct that ICA be limited by preexisting conditions when adding DER degrades the condition, but not when adding DER improves the condition.

Further, the proposed decision would direct the utilities to use the same methods for node reduction and limitation category reduction as those as used in the utility’s Demo A and the same methods to develop localized load shapes as those used in Demo A. The utilities were directed to work toward a standardized mapping structure and functionality while using what they developed for Demo A for initial systemwide rollouts. The Commission listed the attributes each map should display, and set an implementation schedule giving the utilities nine months for the initial systemwide rollout (CPUC 2017g).

1.4.2 Track 1 Locational Net Benefits Analysis

The second demonstration project, Demo B, focused on LNBA. In each utility’s original DRP filings in July 2015, they were to include a common locational net benefits methodology based on a Commission-approved E3 DER Avoided Cost Model (E3 2016).⁶ As an example, Appendix A in this report contains a summary of the value components considered in PG&E’s LNBA. The Commission directed that value components in the DER Avoided Cost Model that were not location-specific should be modified to reflect more location-specific information, particularly

- avoided sub-transmission, substation, and feeder capital and operating expenditures;
- avoided distribution voltage and power quality capital and operating expenditures;
- avoided distribution reliability and resiliency capital and operating expenditures; and
- avoided transmission capital and operating expenditures.

The IOUs submitted a detailed implementation plan for project execution, including metrics, schedule, and reporting interval. IOUs were instructed to, at a minimum, evaluate one near-term (zero to three-year project lead time) and one longer-term (three or more years lead time) distribution infrastructure project for possible deferral. The Commission’s May 2016 guidance expanded on original guidance and required demonstration of at least one voltage support / power quality or reliability/resiliency-related deferral opportunity in addition to one or more capacity-related opportunity(ies) (CPUC 2016a).

The Commission’s May 2016 ruling provided a list of short-term work for the LNBA Working Group and a list of long-term refinements to the LNBA methodology. Short-term work was to focus on Demo B, particularly recommending a format to make LNBA maps consistent and readable to stakeholders, and to consult with utilities on further definition of grid services. Long-term work was to focus on four efforts:

- evaluating location-specific benefits over a long-term horizon,

⁶ E3 is a consulting company that has developed a methodology for estimating the value of avoided costs for use in evaluating DER programs.

- valuing location-specific benefits provided by grid services that are provided by advanced smart meter capabilities,
- considering alternatives to the avoided-cost method, and
- considering a method for evaluating the effect on avoided cost of DERs working “in concert” in the same electrical footprint of a substation.

The Demo B project reports were completed in December 2016. An interim report that documented progress on the long-term refinements was issued in November 2016 (CPUC 2016d), and in March 2017 the short-term final report was issued. The short-term report contained a number of consensus and non-consensus recommendations for long-term refinements (CPUC 2017c).

On April 19, 2017, the Commission issued two rulings. One ruling noted the LNBA Working Group report and solicited input on a number of subjects related to the report that the Commission believed were ripe for resolution in a forthcoming Commission decision. The second ruling contained a proposal to revise the scope and schedule for the LNBA Working Group. The Commission’s June 7, 2017, ruling included a finalized list of prioritized long-term LNBA refinements, including the following:

- Methods for valuing location-specific grid services provided by smart inverter capabilities
- Methods for evaluating the effect on avoided cost of DER working “in concert” in the same electrical footprint of a substation
- An improved heat map and spreadsheet tool
- Incorporating additional location granularity into avoided-cost values
- Forming a technical subgroup to develop methodologies for nonzero location-specific transmission costs (with the California ISO)

The finalized schedule in the June 2017 ruling calls for the LNBA Working Group to submit a final report in January 2018 (CPUC 2017b).

In the Commission’s August 25, 2017, proposed decision, it found that each utility’s Demo B met the requirements of the May 2 and August 23, 2016, rulings. The proposed decision also would adopt the two use cases on which the Working Group reached consensus—the Public Tool and Heat Map use cases to enable customers and developers to identify optimal locations for installing DERs, and using LNBA for prioritizing candidate distribution deferral opportunities for the Distribution Investment Deferral Framework. The Commission also adopted use cases for which the Working Group could not reach consensus, including providing location-specific inputs to the integrated DER (IDER) avoided cost calculator for cost-effectiveness evaluation, informing DER incentive levels, and for other applications. The decision gives the utilities 60 days to file proposals for modeling and/or methodological approaches to calculating location-specific avoided transmission and distribution values for the avoided cost calculator following the requirements laid out in the decision. The proposed decision also would require utilities to publish a systemwide LNBA for the Distribution Investment Deferral Framework-related Public Tool and Heat Map use case by May 31, 2018. The proposed decision included additional instructions for utilities related to scheduling, progress reporting, and mechanisms for tracking the incremental costs of implementing the ICA and LNBA work (CPUC 2017g).

1.4.3 Track 2 Demonstration Projects

Rulemaking (R.) 14-08-013 directed the IOUs to propose DER-focused demonstration projects that serve to demonstrate how specific types of DER can be integrated into distribution planning and operations to

produce ratepayer benefits. The Commission’s 2015 DRP ruling provided the utilities with criteria for the Demonstration Projects (CPUC 2015a). The project proposals were filed in July 2015, and updated June 1, 2016. Modifications to some of the projects were filed in March and April 2017. The projects are:

- Demo Project C—demonstrate DER locational benefits. Project C will validate the ability of DERs to defer or avoid investments in traditional distribution infrastructure and achieve net ratepayer benefits as estimated by the Locational Net Benefits Analysis.
- Demo Project D—demonstrate distribution operations and high penetrations of DERs. Project D calls for the utilities to integrate high penetrations of DER into their distribution operations, demonstrate the operations of multiple DER in concert and coordinate operations with third parties and customers.
- Demo Project E—demonstrate a microgrid where DERs (both customer-owned and utility-owned) serve a significant portion of customer load and reliability services. Project E will demonstrate the use of a DER management system for controlling both third-party-owned and utility-owned resources.

The overall aim of Demonstration Projects C, D and E is to learn how DERs can provide benefits to ratepayers and the electric grid, and how DERs can be managed by the utilities. Each utility had different projects approved through Commission decisions issued in February and June 2017 (CPUC 2017h). Each utility’s demonstration projects are at various stages of development.

1.4.4 Track 3 Policy Issues

The January 27, 2016, Commission scoping ruling identified 22 Track 3 issues. An October 21, 2016, ruling identified three “sub-tracks” in which 8 of the original 22 Track 3 issues were combined. The remaining 14 issues were either determined to belong in a different rulemaking or there were no issues identified (CPUC 2016e). The recombined Track 3 issues include

- DER Adoption and Distribution Load Forecasting,
- Grid Modernization Investment Guidance, and
- A Distribution Investment Deferral Process (CPUC 2016f).

1.4.4.1 DER Adoption and Distribution Load Forecasting

As directed under the DRP proceeding (R.14-10-003), the utilities developed and proposed plans for their approach to developing DER growth scenarios (Sub-track 1) via a stakeholder process. For the near-term 2017–2018 integrated resource planning (IRP) process, PG&E proposed using its DER forecast from the California Energy Commission’s (CEC’s) last biennial statewide Integrated Energy Policy Report (IEPR) process, which results in using a projection that is two years old but that has been thoroughly vetted by the CEC. SCE and SDG&E proposed using the draft DER projection for the ongoing 2017 IEPR process. This would result in up-to-date projections, but projections that have not been vetted. In the utilities’ plans, each proposed their own system-specific methods for disaggregating their systemwide DER forecasts to the feeder levels.

In August 2017, the Commission issued a ruling adopting assumptions for the 2017–2018 planning cycle, using an approach similar to the PG&E proposal and approving proposed methodologies for disaggregating to the feeder level. The utilities have the option to adjust their projections for policy changes since 2015 and to update electric vehicle projections. The Commission provided guidance for the development of future assumptions, including addressing the issue of producing a DER forecast in the off-years (i.e., the years between CEC biennial IEPRs), high and low DER growth cases, and several

other issues (CPUC 2016g). The next steps will be determined in a Track 3 proposed decision and will address longer-term issues through a working group at the discretion of Commission Staff.

1.4.4.2 Grid Modernization Investment Guidance

In May 2017, Commission Staff produced a white paper on the Grid Modernization Investment Guidance sub-track, which was issued by Commission ruling with a request for party comments (CPUC 2016h). The Grid Modernization white paper proposes a framework for evaluating grid modernization investments that may be needed to increase DER penetration and integration and value maximization. The white paper proposes a planning process that would integrate with the IOUs' existing distribution planning processes and general rate cases, but would provide additional information to review through the Grid Needs Assessment (GNA) and Grid Modernization Plan (GMP). The Staff proposed the GNA as an annual report (discussed in the Distribution Investment Deferral sub-track below) to identify needs that may need to be addressed through grid modernization. Commission Staff proposed that the GMP be more of a planning vision for grid modernization investments out to 10 years, and would consider specific investments to address the needs to be authorized in the triennial general rate case. The Staff proposal presents options for the process and poses questions for stakeholders to address. The proposal calls for the development of grid modernization guidance to be adopted by the Commission.

1.4.4.3 Distribution Investment Deferral

In June 2017, Commission Staff produced a proposal on the Distribution Investment Deferral Framework sub-track, and an administrative law judge issued a ruling requesting that parties comment on the stakeholder questions included in the report, as well as the report in general (CPUC 2016i). The comment and reply comment periods ended in August 2017. In the proposal, Staff proposes a process in which the utilities' annual distribution resources planning processes would incorporate new steps to seek DER-based options to defer traditional facility and wires-based solutions. In the Staff proposal, when the utility completes the basic assessments, they would identify candidate deferral projects for presentation in a Grid Needs Assessment and an LNBA. The Grid Needs Assessment would be published and submitted. Utilities would then launch a Distribution Planning Advisory Group to evaluate candidate deferral opportunities and planning process results from the Grid Needs Assessment and LNBA. The advisory group would then recommend final distribution deferral projects, at which time the utilities would request Commission approval to launch solicitation processes.

1.5 Other Related Activities

Following are other activities in California that relate to distribution system planning.

1.5.1 Integrated DERs Proceeding

The Integrated DERs (IDER proceeding (R.14-10-003) proposes utility shareholder incentives for deployment of cost-effective DERs that displace or defer a utility expenditure (through all-source request for offers). On December 15, 2016, the Commission approved a competitive solicitation framework in this proceeding (CEM 2016).

Although the IDER proceeding was originally intended to address utility business model and regulatory framework issues more broadly, it has started with a pilot program to test the competitive solicitation process including exploring and updating the Commission's cost-effectiveness framework and incentivizing deployment of cost-effective DERs (CPUC 2016j).

In December 2016, the CPUC approved an interim regulatory process to pilot the competitive solicitation process and the effect of incentives on utility sourcing of DERs as non-wires alternatives. As parties worked together to develop the pilot, it was recommended the incentive be set at the high end of the range of the estimated value of the utility's return on equity minus the cost of equity. In the framework for the pilot approved December 15, 2016, the Commission established a 4 percent pre-tax incentive on annual payments made to third-party DER providers (customers or vendors) to cost-effectively displace or defer traditional distribution system investments that were previously planned and authorized. To test the competitive solicitation process, utilities are required to pursue at least one project. To test the incentive mechanism, utilities are encouraged to select up to three additional projects (CPUC 2016k). Utilities were required to issue solicitations for projects by mid-2017. Solicitations were to be crafted with input from a newly formed Distribution Planning Advisory Group (CEM 2016).

In June 2017, the utilities issued Advice Letters requesting approval to launch DER incentive pilot solicitations. To varying extents and levels of detail, the utilities' Advice Letters explained the regulatory background of the solicitation, how the utility would identify distribution infrastructure that could be deferred through the DERs acquired through the solicitation, and how the utilities plan to evaluate proposals received through the solicitation (PG&E 2017b; SCE 2017; SDGE 2017). Following the advice letter filing, pursuant to Decision 16-12-036, the Commission's Energy Division hosted a workshop to discuss the utilities' Advice Letters (CPUC 2017d).

Also under this proceeding, the Commission and stakeholders worked on the selection of appropriate cost tests and cost-test-adders for emissions. A Staff report was developed recommending a societal cost test, and the administrative law judge issued a ruling releasing the report and requesting comments (CPUC 2017e). There has been significant discussion about how to properly account for greenhouse gas emissions in cost-effectiveness tests. The rulemaking remains open (CPUC 2017f).

1.5.2 Southern California Edison General Rate Case Grid Modernization Request

On September 1, 2016, as part of a general rate case filing, Southern California Edison presented a plan for modernizing and strengthening its distribution grid to automate and reinforce the grid in order to support increased safety, cybersecurity, and reliability, and to enable DER adoption, promote customer choice, and realize DER benefits. SCE forecasted \$1.875 billion in capital expenditures between 2016 and 2020 for automation, planning, communications, and information technology improvements (SCE 2016). Public testimony on the rate case closed in mid-August 2017 (CPUC 2017g). The final record for the proceeding is expected to be submitted by the full Commission for their deliberation and decision by the end of September 2017 (CPUC 2016m). Public participation hearings are set for locations within SCE territory in November (CPUC 2016l). A CPUC decision on the final rates is expected sometime late in 2017 in order for the new rates to be effective January 1, 2018.

1.5.3 Energy Storage Mandates

Pursuant to Assembly Bill 2514 (2010), the California PUC established energy storage mandates. A target of 1,325 megawatts (MW) of energy storage was set for all three California investor-owned utilities. Utilities submit energy storage procurement plans to the CPUC for approval every two years, with the first procurement period beginning in 2014. Procurements increase incrementally every two years. SCE, PG&E, and SDG&E must procure a combined capacity of 1,325 MW by 2020, with an on-line deadline of 2024 (ORA 2016). Three classes of storage are defined: transmission connected, distribution connected, and customer side. Utilities are not allowed to own more than half of the energy storage they procure, which should pave the way for high levels of growth in merchant storage and customer-sited and

-owned energy storage systems (St. John 2013). In 2016, Assembly Bill 2868 was signed into law. This bill adds up to 500 MWs of additional storage procurement interconnected to the distribution system, with up to 25% located behind the utility meter (CA Legislature 2016).

1.5.4 Multi-Entity Report on Improving Transmission and Distribution System Coordination

In June 2017, staff of the California Independent System Operator (CAISO), PG&E, SCE, and SDG&E released a paper that was developed with support from the organization More than Smart titled, “Coordination of Transmission and Distribution Operations in a High Distributed Energy Resource Electric Grid” (MTS 2017). The paper addresses the shift from a highly centralized system power with large generating plants to a more decentralized system with a diversity of resources, technologies, and connectivity levels. It emphasizes the importance of connectivity between the transmission and distribution systems, particularly if DERs are to participate in wholesale markets or provide services to the distribution system. The paper examines three scenarios: where DERs are participating exclusively in the ISO market; where they provide services to the distribution operator or end-use customer, but do not participate in the ISO market; and where they engage in “multiple-use applications” by offering services from the same facility to the ISO, the distribution operator, and end-use customers. Initial coordination steps are recommended and medium-term coordination possibilities suggested (MTS 2017).

1.6 Next Steps

Table 1.1 shows due dates for ongoing proceedings.

Table 1.1. Upcoming Due Dates

Activity	Date
Ruling on distribution load and DER adoption forecasting	Q3 2017
Staff proposal on distribution load and DER adoption forecasting for 2018	Q3 2017
Proposed decision on distribution load and DER adoption forecasting	Q3 2017
Status report on remaining long-term refinements to the ICA and LNBA methods	Q4 2017
Proposed decision on grid modernization guidance	Q4 2017
Proposed decision on distribution investment deferral process	Q4 2017
Proposed decision on grid modernization guidance	Q4 2017
Final ICA and LNBA reports	Q1 2018

2.0 Hawaii

2.1 Introduction

Hawaii's unique circumstances (high imported oil use for electricity generation, isolated island grids, and rapid growth of rooftop solar) spurred the state's early adoption of regulatory reforms to upgrade the electric grid and better integrate renewable energy and distributed energy resources (DERs). The Hawaiian Electric Companies (HECO), which includes Hawaiian Electric, Maui Electric, and Hawaii Electric Light, serve 95 percent of Hawaii's electricity load. The remaining 5 percent is served by Kauai Island Utility Cooperative (KIUC). This section focuses primarily on the Hawaii Public Utilities Commission's Distributed Energy Resources Docket (2014-0192) and HECO's Grid Modernization Plan filing (2017-0226).

2.2 Impetus for Early Action

In 2014, regulators in Hawaii opened Docket 2014-0192 to investigate DER policies and modernize the electricity regulatory framework in the island due to the unprecedented growth of renewable energy in general and, more specifically, distributed generation.

Hawaii's reliance on oil to produce electricity⁷ prompted an ambitious push to increase the island's share of renewable generation. In 2015, Hawaii set a 100 percent renewable portfolio standard for 2045, with a statutory goal of 30 percent for 2020 (Hawaii State Legislature 2016a). High electricity rates and progressive policies including net energy metering policies⁸ stimulated a remarkable growth of distributed PV (Hawaii State Energy Office 2016). By April 2017, 16 percent of Hawaii's electric utility customers had a rooftop solar system (HECO 2017a). High distributed PV penetration levels and remuneration rates contributed to the increase in technical and financial issues for utilities, which prompted regulators to open the aforementioned Docket 2014-0192. In 2015, the Hawaii PUC closed net energy metering for new customers and approved two new interconnection tariffs as part of Phase I of Docket 2014-0192 (HPUC 2015a).

2.3 Stated Goals

In its document, *Commission's Inclinations on the Future of Hawaii's Electric Utilities*, the Hawaii PUC listed the following goals as essential principles for the future strategic business direction of electric utilities in Hawaii (HPUC 2014a):

- Lower, more stable electric bills
- Expanding customer energy options
- Maintaining reliable energy service in a rapidly changing system operating environment

⁷ Some 68 percent of electricity produced in the island in 2014 used oil as fuel (Hawaii State Energy Office 2016).

⁸ Though not specifically discussed in the reference, Hawaii currently has an income tax credit of up to 35 percent of the cost of a solar installation (Hawaii State Legislature 2016b), which when combined with the U.S. tax credit of 30 percent provides additional incentive.

The Commission also offered three guiding pillars for future business strategy, energy resource planning, and project review:

- *Creating a 21st Century Generation System.* According to the PUC, Hawaii’s unique challenges require the state to act early in modernizing the electric system to integrate renewable energy.
- *Creating Modern Transmission and Distribution Grids.* This pillar outlines priorities in upgrading Hawaii’s grid infrastructure to better integrate DERs and expand customer options to manage their energy consumption.
- *Policy and Regulatory Reforms to Achieve Hawaii’s Clean Energy Future.* This pillar sets the priorities for new regulatory policies and rate structures consistent with the principles listed above.

2.4 Regulatory Requirements

This section describes regulatory requirements in Hawaii related to distribution system planning.

2.4.1 Instituting a Proceeding to Investigate Distributed Energy Resource Policies

Through Docket 2014-0192, the Hawaii PUC intends to spur an electricity sector reform to support the sustainable growth of DERs. Order 33258, the first major Commission order in this docket (HPUC 2015a)

- streamlined the interconnection process and adopted new technical standards for advanced inverters,
- moved away from Hawaii’s net energy metering program (which is closed for new applicants) and grandfathered existing distributed PV users, and
- created three tariffs for new PV owners:
 - customer self-supply (CSS), for customers that do not need to export excess energy to the grid
 - customer grid-supply (CGS), a program similar to net energy metering at a reduced credit rate
 - a time-of-use tariff (described in more detail below) (HPUC 2015b)

The CSS option is intended for customers who plan to consume all energy produced and do not need to export any to the grid. HECO is considering CSS tariffs that encourage “scheduled” exports as needed for the DERs to provide critical grid services, as well as to encourage CSS customers to use grid-supplied energy during low-demand/high-supply periods of the day (10 a.m.–3 p.m.). The option also allows for an expedited (~30-day) interconnection review.

The CGS option is functionally similar to net energy metering (NEM). Customers export excess energy to the grid and receive a credit. The difference between NEM and CGS is that the CGS credit is set to approximate the relative value of the energy to the system and the credit does not need to be tied to retail rates. The net effect of the proposed CGS tariff is to reduce the solar credit that customers receive for self-generation from 30 cents/kilowatt-hour (kWh) under traditional net metering to ~15 cents/kWh, which is closer to HECO’s avoided cost compared to the least cost alternative generation resource. In addition, the minimum residential customer bill was increased from \$17 to \$25.

A third tariff option is a new, expanded time-of-use (TOU) tariff that shifts energy demand to the middle of the day (HPUC 2014b). Phase I of this docket (2014-0192) concluded in September 2016, after the Commission approved HECO’s TOU pilot program for 5,000 customers.

2.4.2 Distributed Energy Resource Policies: Developing DER Markets

- On December 9, 2016, Order No. 34206 established a statement of issues and a procedural schedule for Phase 2 of Docket No. 2014-0192. The order divided Phase 2 into three categories, each with its own specific set of issues and a briefing schedule (HPUC 2016):
 - Priority Issues
 1. What changes, if any, should be made to existing interim DER options (e.g., developing time-varying export credit rates, revising technical requirements to facilitate increased deployment, adjusting tariff features such as duration, eligibility, etc.) prior to resolution of other Phase 2 issues?
 2. What changes, if any, should be made to interconnection standards to facilitate or enable proposed changes to interim DER options, prior to resolution of other Phase 2 issues?
 - Technical Track Issues
 3. How can the utilities' DER integration analyses be improved to more accurately characterize grid capacity for various forms of DER and other renewable resources?
 - a. What measures can be taken to proactively identify and address anticipated technical barriers to safely integrate increasing amounts of DER in a cost-effective manner?
 - b. What measures can be taken to improve the electric utilities' integration capacity at both the circuit and system levels?
 4. How should existing interconnection standards and procedures be modified to promote the safe and smooth integration of increasing levels of DER onto Hawaii's electric grids?
 - a. What modifications or additions to technical requirements should be included in Hawaii's interconnection standards for advanced inverters?
 - b. What revisions should be made to existing processes to improve the resolution of interconnection delays for DER systems?
 - Market Track Issues
 5. How should a longer-term competitive market structure be established to determine compensation for exported energy and services from DER in Hawaii?
 - a. What successor tariff(s) should be developed to replace the current interim DER tariffs?
 6. What alternative rate designs, including unbundled rate designs, should be considered to facilitate the safe and beneficial integration of DER onto Hawaii's electric grids?
 - a. What data and methods are appropriate to provide a cost and value basis for evaluating alternative rate designs?
 - b. How should customer impacts resulting from alternative rate designs be evaluated? Should software tools be developed by the utilities to provide for simplified and meaningful comparison of alternative rate designs?
 - c. How can the costs of DER be reduced and the value of DER be increased, such as through improved integration and aggregation, such that DER provides benefits to Hawaii in general, and ratepayers in particular, as deployment grows over time?

- d. How should the costs associated with DER deployment be allocated among customer classes and recovered through appropriate rate designs, and what data and methods are necessary to make these determinations?
7. Should sunset or expiration dates be established for existing DER tariffs? If so, should participants in those programs be transitioned into other available tariffs? If so, how?

In May 2017, the Commission partially addressed priority items 1 and 2 by approving two stipulation agreements and directing the parties to submit joint proposals (or partial stipulations and position statements) for remaining issues related to the CSS tariff and CSS interconnection agreement. The Commission also established four Working Groups as part of Phase 2 of the DER docket to evaluate

- advanced inverter functions,
- DER integration analyses,
- smart export programs, and
- KIUC-specific issues (HPUC 2017a).

The pressing issues are expected to be resolved in 2017. The technical track issues are expected to be resolved in 2018.⁹ The market track issues will be addressed beginning in August 2018 and are expected to be resolved in late 2018 or early 2019.¹⁰

2.4.3 Smart Export and CGS+ Programs

Responding to one of the pressing issues discussed in the preceding section, in October 2017 the Hawaii PUC approved an Interim Smart Export Program for HECO. The program is designed to give customers incentives to avoid exporting energy to the system during the hours of peak sunlight. Under the program customers receive credits ranging from 11 cents/kWh to nearly 21 cents/kWh for energy exported between 12 a.m. and 9 a.m., or between 4 p.m. and 12 a.m., and no credit for exports between 9 a.m. and 4 p.m. The Interim Smart Export Program was based on a number of ideas and proposals raised by parties responding to the Hawaii PUC's request for input in developing tariffs "to enable a longer-term competitive market structure for DER" (HPUC 2017b).

Related to the Hawaii PUC's desire for options to transition the marketplace and address NEM-related concerns related to uncontrolled export of energy, the PUC directed the establishment of a revised CGS+ program. The intent of the program is to accommodate a movement toward storage-based DER offerings. The compensation rate is to be aligned with the value that the energy provides to the grid and with the prices of other low-cost renewable resources. A core component of the CGS+ program is "the requirement that participating customers implement technology that allows the utility to measure, monitor, and, if necessary, control CGS+ systems" (HPUC 2017b). The Hawaii PUC notes its preference that monitoring and control be effectuated by third parties, but in the alternative, CGS+ customers may elect to have utilities install separate smart meters to accomplish the measurement and control. Finally, the Hawaii PUC specified that the CGS+ participants' generation would be curtailed second to last, and

⁹ Statements of Position on the Phase 2 Technical Track Issues were due August 14, 2017; Information Requests were to be submitted by August 21, 2017; responses to Information Requests were to be submitted within 14 days of the date of service of the Information Requests; and parties' final position statements were to be submitted by September 18, 2017, with a hearing to follow. For the original schedule, see Docket No. 2014-0192, Order No. 34206, and for revisions pursuant to the establishments of the working groups, see Order No. 34725.

¹⁰ Statements of Position on the Phase 2 Market Track Issues are due August 6, 2018; Information Requests are to be submitted by August 20, 2018, and a hearing is anticipated in October 2018. See Docket No. 2014-0192, Order No. 34206.

can be curtailed when other controllable renewable resources have been curtailed and the utility is at risk of violating an operational constraint necessary to maintain reliable service (HPUC 2017b).

2.4.4 HECO Grid Modernization Plan

In 2016, HECO requested the Hawaii PUC approve, in Docket 2016-0087, various smart grid investments and software expenditures. In Order No. 34281, the Commission dismissed HECO's application without prejudice and provided guidance for developing a detailed, scenario-based grid modernization strategy that provides a comprehensive and holistic vision and context to inform subsequent review of discrete grid modernization project applications submitted by the utility. The Commission requested (HPUC 2017c) that at a minimum, the strategy include the following:

1. Current status of electric grid infrastructure pertaining to grid modernization
2. Grid architecture and interoperability
3. Grid-facing technologies
4. Customer-facing technologies
5. Pace of grid modernization implementation
6. Costs and benefits of grid modernization
7. Flexibility and resilience
8. Health, cybersecurity, data access, and privacy

HECO filed a draft Grid Modernization Strategy on June 30, 2017, and a final version on August 29, 2017. Following HECO's submission of the strategy, the HPUC opened a new docket (2017-0226) and a comment period. Stakeholder comments were due September 13, 2017. The Commission will identify any next steps after reviewing comments and the strategy (HPUC 2017d).

2.5 Other Related Activities

2.5.1 Grid Service Tariffs

Hawaii PUC and HECO are developing revised grid service tariffs that aim to more flexibly integrate controllable loads, generation, and storage resources into grid operations and expand the ability of loads to provide key grid services that can help balance intermittent renewable resources and help address some of the concerns surrounding large-scale distributed-generation PV and other renewable energy resources (HECO 2017b). Grid service tariffs complement distribution system and grid modernization planning in Hawaii. HECO has defined four major bulk services that demand response can provide, which HECO envisions implementing through four rate and incentive mechanisms: (1) capacity, (2) fast frequency response, (3) regulating reserve (regulating up and down), and (4) replacement reserve.

HECO has enlisted six vendors to provide demand response services, and they are currently in a pilot phase. HECO provides monthly status reports to the Commission. Vendor final reports are expected to be submitted to HECO between September and December 2017.

According to the HECO companies' filing on February 10, 2017, HECO has, for the four services listed above,

- quantified and valued the services in technology-agnostic terms;

- identified the technical means through which these services can be delivered;
- evaluated the synergy or conflict in the ability of DERs to simultaneously provide identified services; and
- portrayed means and market mechanisms to allow customers to provide these services (HECO 2017b).

The values for services were based on avoided cost for each category of service, determined based on modeling. Capacity and load shift were identified as the most valuable across the board, with the value of fast frequency response and regulating reserve being driven by the amount of renewable energy resources on the system.

2.5.2 Advanced Inverter Functionality

HECO was the first utility in the United States to enable advanced PV inverter functionality, in early 2015. To do so, HECO partnered with the National Renewable Energy Laboratory, the Electric Power Research Institute, and Solar City to perform inverter testing. Based on the testing results HECO concluded it would be reasonable to raise its minimum daytime load threshold for interconnection studies from 120 percent to 250 percent (HECO 2015). In 2015 the Hawaii PUC issued an order requiring advanced functionality including expanded frequency and voltage ride through (HPUC 2015a). In 2017 the Hawaii PUC issued an order instructing the HECO companies to activate the Volt-VAR and Frequency-Watt advanced inverter functions, and to deactivate Fixed Power Factor. The Volt-VAR function is an advanced inverter function in which the inverter measures voltage and “responds by reducing not-in-phase and otherwise reactive power production in response to rising voltage in an attempt to bring voltage in range” (HPUC 2017b). Similarly, the Frequency-Watt function enables the inverter to measure frequency, and if frequency is out of the normal range it adjusts power output to assist the grid in returning frequency to the normal range (HPUC 2017b).

2.5.3 Study on Alternative Utility Regulatory Models

In 2016, House Bill 1700 appropriated funds to the Hawaii Energy Office to commission a study of alternative utility regulatory models that would enable the state of Hawaii to (1) meet its energy goals; (2) maximize consumer savings; (3) enable a competitive distribution system; and (4) eliminate or reduce conflicts of interest in energy resource planning, delivery, and regulation. A request for proposals (RFP) was released by the Energy Office in September 2016. London Economics International, LLC was selected to do the study, which began in the second quarter of 2017. The study is expected to be completed by December 2018 (NCEC 2017).

2.6 Next Steps

Next steps for Hawaii include completion of the technical track and market track of the DER Docket No. 2014-0192, in 2017 and 2018, respectively.

3.0 Massachusetts

3.1 Introduction

Rate pressures, reliability threats from extreme weather, and interest in reforming net energy metering prompted Massachusetts' regulators to modernize the state's electric infrastructure and update utility requirements.

3.2 Impetus for Early Action

Massachusetts has a 25 percent renewable portfolio standard by 2030. State law also requires at least 25 percent of load be met with demand-side resources by 2020. Massachusetts' electricity rates are among the highest in the country (EIA 2017). Additionally, the reliability of the state's electric system is constantly threatened by "increasingly extreme weather" (Walton 2015; Massachusetts 2017a). These factors prompted the Massachusetts' Department of Public Utilities (DPU) to issue Order 12-76-B regarding the Modernization of the Electric Grid in June 2014. DPU listed the benefits that grid modernization could provide, including:

- empowering customers to better manage and reduce electricity costs,
- enhancing the reliability and resiliency of electricity service in the face of increasingly extreme weather,
- encouraging innovation and investment in new technology and infrastructure,
- addressing climate change and meeting clean energy requirements (Massachusetts 2017a).

DPU envisions a modern electric system that is cleaner, more efficient and reliable, and empowers customers to manage and reduce their energy costs. A technologically advanced electric system could maximize the integration of solar and other forms of distributed energy resources (DERs), minimize outages by re-routing power away from damaged lines, and automatically alert the utility when customers lose power (DPU 2014).

3.3 Stated Goals

Order 12-76-B establishes the platform and incentives for utilities and other stakeholders to modernize the electric system by innovating and investing in new technology and upgrading Massachusetts' current infrastructure, and to increase the use and integration of clean generation and other forms of DERs. In this Order, DPU established four grid modernization objectives:

- reducing the effects of outages;
- optimizing demand, which includes reducing system and customer costs;
- integrating distributed resources; and
- improving workforce and asset management (DPU 2014).

The order also requires each electric utility in Massachusetts to submit a 10-year grid modernization plan (GMP). The order lists key elements that a GMP must include, such as:

- timing and priorities for all grid modernization planning and investment over a 10-year period;

- marketing, education, and outreach plans;
- research, development, and deployment plans;
- proposed infrastructure and performance metrics to measure progress in achieving objectives;
- a five-year Short Term Investment Plan (STIP) for capital investments and an approach to achieving advanced metering functionality within five years; and
- comprehensive business case analysis to support capital investments in the STIP (DPU 2014).

Order 12-76-B has two companion orders: time varying rates (D.P.U. 14-04) and electric vehicles (D.P.U. 13-182).

3.4 Utility Filings

Massachusetts regulated utilities filed 10-year GMPs with the DPU in August 2015. The DPU docketed the plan filings as follows:

D.P.U. 15-122	NSTAR Electric Company and Western Massachusetts Electric Company, d/b/a Eversource Energy
D.P.U. 15-121	Fitchburg Gas and Electric Light Company d/b/a Unitil
D.P.U. 15-120	Massachusetts Electric Company and Nantucket Electric Company d/b/a National Grid

The plans presented by the utilities differ substantially from one another. National Grid submitted a GMP that seeks to enhance customer control through advanced metering infrastructure (AMI), time-varying rates (TVR), and investments in grid upgrades. The GMP includes four scenarios with different levels of investment in AMI and grid upgrades. National Grid’s proposal also includes higher fixed charges and lower volumetric rates, which reduce the value of customer-sited PV systems (the request was denied; see Section 3.5.1) (Acadia Center 2017).

Eversource’s GMP is more focused on investments to incorporate DERs. The plan contains one pilot energy storage project to integrate renewable energy resources and proposes TVR for a small set of opt-in customers. Eversource’s GMP also calls for broader rate reforms.

Because Unitil utilities had previously installed some AMI capabilities, they have proposed more modest investments in their GMP. The previously installed meters are unable to measure energy consumption over short time periods (e.g., 15 minutes), which prevents them from being able to facilitate TVR and some other peak demand reduction strategies for those customers. The only rate changes proposed in the GMP are opt-in TVR (Acadia Center 2017).

In October 2016, Eversource filed a petition for approval to implement a demand reduction demonstration in Docket D.P.U. No. 16-178 (DPU 2016). In January 2017, Eversource filed for approval of a performance-based ratemaking mechanism and a general distribution revenue charge through Docket D.P.U. No. 17-05 (DPU 2017c). On November 30, 2017, the DPU approved Eversource’s proposals for both a storage and an electric vehicle demonstration project. The DPU did not approve the utility’s other grid modernization proposals (DPU 2017d).

In March 2017, National Grid filed for approval of cost recovery for its Smart Grid Pilot Program costs in Docket D.P.U. No. 17-53 (DPU 2017b), pursuant to D.P.U. No. 11-129, Smart Grid Adjustment Provision.¹¹

3.4.1 Advanced Metering Infrastructure

Utilities filing their first GMP must include a five-year STIP outlining capital investments and a plan to achieve advanced metering functionality (AMF) within five years. DPU defined *AMF* as technology that enables the following functions (DPU 2014; Walton 2015):

- The collection of customers' interval usage data, in near real time, usable for settlement in the ISO-NE energy and ancillary services markets
- Automated outage restoration and notification
- Two-way communication between customers and the electric distribution company
- The possibility of communication with and control of appliances, subject to the permission of the customer

Capital investments included in the STIP must be justified by a business case analysis. If the analysis does not justify AMF deployment within five years, utilities must include a business case that justifies achieving AMF in a longer timeframe (DPU 2014).

3.5 Other Related Activities

3.5.1 Customer-sited Solar Compensation

In April, 2016, the Massachusetts Legislature passed a bill that raised net metering caps and sought to strike a balance among competing interests from utilities, ratepayers, developers, and other stakeholders (Treat 2017).

Analysis by the state's Department of Energy Resources (DOER) found that tariff-based solar compensation mechanisms for customer-sited mechanisms had several benefits over those provided by Solar Renewable Energy Credits (SRECs):

- long-term revenue certainty to generators,
- the ability to set incentives with more precision,
- predictable incentive levels,
- greater cost certainty to ratepayers, and
- opportunity for greater synergies between incentive and net metering programs (DOER 2016).

3.5.2 Energy Storage

Massachusetts implemented an energy storage initiative aiming at making "Massachusetts a national leader in the deployment and effective use of these innovative energy technology solutions." The initiative includes a study by DOER and the Massachusetts Clean Energy Center to analyze costs and

¹¹ For more on Docket No. 11-129 see <http://web1.env.state.ma.us/DPU/FileRoom//dockets/get/?number=11-129&edit=false>.

benefits of energy storage and develop policies to encourage the deployment of this technology (Massachusetts 2017b).

The study concluded that energy storage could enhance the “efficiency, affordability, resiliency and cleanliness of the entire electric grid” and presented a suite of policies to generate 600 MW of energy storage in Massachusetts by 2025. This level of deployment could result in \$800 million in system benefits, according to the study. Benefits were associated with “reduced peak demand, deferred transmission and distribution investments, reduced GHG emissions, reduced cost of renewables integration, deferred new capacity investments, and increased grid flexibility reliability and resiliency” (DOER, MassCEC, n.d.).

House Bill 4568 in 2016 instructed DOER to analyze whether to set a target for energy companies to deploy energy storage. In June 2017, DOER adopted a target of 200 MWh of viable, cost-effective energy storage for each electric distribution company to procure by January 1, 2020 (DPU 2017a).

In December 2016, Unitil proposed installing as many as six residential battery storage systems in homes that have solar PV systems. The company further proposed to recover the budget for the effort through its energy efficiency surcharges (DPU 2016a). At the same time, Eversource proposed battery and thermal storage projects for its commercial and industrial (C&I) customers, with plans to pay for the projects through its C&I energy efficiency surcharges (DPU 2016b). In May 2017, the Cape Light Compact proposed changes to its three-year plan that included increasing its demand response offerings by deploying five to 10 thermal storage units with commercial customers, also recovering costs through energy efficiency surcharges (DPU 2017b).

3.6 Next Steps

Based on lessons learned from the energy storage procurement project, DOER may determine whether to set additional energy storage procurement targets beyond January 2020 (DPU 2017a).

4.0 Minnesota

4.1 Introduction

The Minnesota Public Utilities Commission (PUC) has taken a systematic approach to engagement in distribution system planning, underpinned by direction from the state legislature for the largest utility. While the state does not have high penetration of distributed generation resources, a sizable Community Solar Gardens program supports distributed solar PV systems up to 5 MW. The system size under the program is now capped at 1 MW.

The rationale for PUC engagement is guided by broad changes in the electricity sector: “Aging infrastructure will need to be replaced, distributed energy resources will expand as costs fall, advances will be made in distribution system technology, and customer demands will continue to evolve.” (Minnesota Public Utilities Commission 2016).

4.2 Impetus for Early Action

In May 2015, the Commission initiated an inquiry into grid modernization (Docket No. CI-15-556),¹² with a focus on distribution system planning, citing the evolution already underway for Minnesota’s electric distribution grid (Lange, Twite, and Schuerger 2015, slide 11):

- The grid is at a strategic inflection point, a time of significant change.
- Changing customer demands, new technologies, and evolving public policy will drive increased deployment of distributed resources.
- Tomorrow’s integrated electric grid will be more distributed and flexible, will optimize and extract value through the grid, will operate resiliently against natural disaster and attacks, and will be cleaner, reliable, and affordable.
- Development of tomorrow’s grid is already underway; there is an unprecedented opportunity to invest in a 21st century grid.
- Updates to distribution planning process will be needed to support a reliable, efficient, robust grid in a changing (and uncertain) future; should be coordinated with resource and transmission planning; and could incorporate stakeholder informed planning scenarios.

4.3 Stated Goals

The Commission’s framework for its inquiry focuses on three key questions (Ibid., slide 12):

1. Are we planning for and investing in the distribution system that we will need in the future?
2. Are the planning processes aligned to ensure future reliability, efficient use of resources, maximize customer benefits, and successful implementation of public policy?
3. What commission actions would support improved alignment of planning for and investment in the distribution system?

¹² Minnesota Commerce Department. Docket Number: 15-556.

<https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=eDocketsResult&docketYear=15&docketNumber=556#>

The Commission held a series of stakeholder meetings in 2015. A *Staff Report on Grid Modernization* (Minnesota Public Utilities Commission 2016) summarized the information presented and recommended next steps. The report offered several principles to guide grid modernization (Ibid., p. 14):

- Maintain and enhance the safety, security, reliability, and resilience of the electricity grid, at fair and reasonable costs, consistent with the state’s energy policies.
- Enable greater customer engagement, empowerment, and options for energy services.
- Move toward the creation of efficient, cost-effective, accessible grid platforms for new products, new services, and opportunities for adoption of new distributed technologies.
- Ensure optimized utilization of electricity grid assets and resources to minimize total system costs.
- Facilitate comprehensive, coordinated, transparent, and integrated distribution system planning.

The report also defined grid modernization for Minnesota (Ibid., p. 12)¹³ and laid out a three-phase approach to continue policy development of grid modernization in the state (Ibid., p. 11):

- Phase 1: Adopt definition, principles, and objectives for grid modernization (completed).
- Phase 2: Prioritize potential action items (current phase).
- Phase 3: Adopt a long-term vision for grid modernization (no immediate action).

As stated in the *Staff Report on Grid Modernization*, the threshold question for the Commission is, “how can forward looking planning targeted at the distribution system level, in coordination with other planning (IRP, transmission, etc.), be effectively and appropriately accomplished in order to protect and promote the public interest?” The report states that a “more directed and coordinated approach to grid modernization is warranted,” while acknowledging that some related activities will continue on separate tracks (Ibid., p. 6).

The U.S. Department of Energy sponsored a consultant report on integrated distribution system planning for Minnesota. The Commission held a stakeholder workshop in October 2016 to solicit responses to the report, discuss perspectives of utilities and stakeholders on distribution planning for the state, and identify frameworks for moving the process forward.¹⁴

4.4 Filing and Other Regulatory Requirements

Minn. Stat. §216B.243 requires utilities, when considering a Large Energy Facility—a high-voltage transmission line or generating facility—to evaluate “possible alternatives for satisfying the energy demand or transmission needs including but not limited to potential for increased efficiency...load-management programs, and distributed generation.”

Minn. Stat. §216B.2425 requires Xcel Energy to file Biennial Distribution Grid Modernization Reports that identify “investments that it considers necessary to modernize the...distribution system by enhancing

¹³ Staff proposed the following definition: “A modernized grid assures continued safe, reliable, and resilient utility network operations, and enables Minnesota to meet its energy policy goals, including the integration of variable renewable electricity sources and distributed energy resources. An integrated, modern grid provides for greater system efficiency and greater utilization of grid assets, enables the development of new products and services, provides customers with necessary information and tools to enable their energy choices, and supports a standards-based and interoperable utility network.”

¹⁴ Meeting notice and consultant report (ICF International 2016) at: <https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId=%7bBCE52F21-2497-4F2D-A70D-02614957A012%7d&documentTitle=20169-124836-01>

reliability...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.”

The utility may request that the Commission certify grid modernization projects as priority projects, a threshold requirement for utility to recover costs through a rider, outside of a general rate case.

The legislation also requires Xcel Energy to conduct a distribution study identifying interconnection points on its distribution system for small-scale distributed generation and necessary upgrades to support continued distributed generation development. No formal Commission action is required.

Xcel Energy filed its first Biennial Distribution Grid Modernization Report in 2015¹⁵ (Docket No. E-002/M-15-962).¹⁶ The Commission order¹⁷ on the filing certified the utility’s proposed advanced distribution management system but denied certification of a solar plus storage substation project. The order further required the utility to file its initial hosting capacity analysis by December 1, 2016, with analysis of each feeder for distributed generation up to 1 MW and potential distribution upgrades necessary to support expected distributed generation, based on the utility’s integrated resource plans and Community Solar Gardens process. Xcel Energy recently filed its second Distribution Grid Modernization Report (Docket No. E-002/M-17-776).¹⁸

Xcel Energy’s initial hosting capacity analysis, filed on December 1, 2016,¹⁹ analyzes the ability of individual feeders to accommodate additional distribution generation systems up to 1 MW without the need for distribution system upgrades. PUC staff issued briefing papers²⁰ on the filing for the Commission’s June 15, 2017, public meeting. The Commission’s decision on the filing²¹ requires hosting capacity analyses November 1 each year and provides direction for the utility’s next hosting capacity analysis, to be filed November 1, 2017. Among the requirements are providing reliable estimates and maps of available hosting capacity at the feeder level, information in sufficient detail to inform distribution planning and upgrades needed for efficient integration of distributed generation, and detailed information on data, modeling assumptions, and methodologies. Xcel Energy recently filed its second hosting capacity analysis (Docket No. E-002/M-17-777).²²

In June 2017, the PUC issued a questionnaire²³ to the state’s utilities on their distribution planning practices and asked for stakeholder comments and responses on the following questions:

- How do Minnesota utilities currently plan their distribution systems?

¹⁵ <https://www.xcelenergy.com/staticfiles/xcel/PDF/Regulatory/MN-Filings-Biennial-Transmission-Grid-Modernization-Report.pdf>

¹⁶

<https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=eDocketsResult&docketYear=15&docketNumber=962>

¹⁷ <https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId=%7b6ACF016C-3E0E-4CA7-A52A-35FD0E28D7FB%7d&documentTitle=20166-122702-01>

¹⁸ <https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId=%7BA068795F-0000-C713-BD9C-C4A38A5E5A09%7D&documentTitle=201711-137086-01>

¹⁹ <https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId=%7bD19C7D57-5143-4353-9196-1E89B8622CE9%7d&documentTitle=20176-132648-01>

²⁰ <https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId=%7bD19C7D57-5143-4353-9196-1E89B8622CE9%7d&documentTitle=20176-132648-01>

²¹ <https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId=%7b10EB9E5D-0000-C013-ABB5-F4FA1C04D825%7d&documentTitle=20178-134418-01>

²² <https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={F01C795F-0000-C81D-9319-32CC6BC16E25}&documentTitle=201711-137070-01>

²³ <https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId=%7b307DE9F3-1F36-4CB1-AABA-96F0FCA6B1A8%7d&documentTitle=20174-131044-01>

- What is the status of each utility’s current plan?
- Are there ways to improve or augment utility planning processes?

4.5 Next Steps

The *Staff Report on Grid Modernization* recommends next steps for each topic area related to grid modernization.

- *For near-term consideration:*
 - Integrated distribution planning: Commission Staff envisioned that Minnesota “Distribution Grid Plans” could include scenario planning and hosting capacity analyses, grid data, actions on PV smart inverters, and more. A decision in Docket No. CI-15-556 on distribution planning requirements is anticipated in the first quarter of 2018.
 - Distribution generation interconnection and smart inverters: Staff recommended the Commission monitor progress on finalization of UL and IEEE standards and consider updating interconnection standards with a targeted scope of review. A work group of utility, developer and other stakeholders are participating in educational webinars and in-person meetings to inform and help develop the record. The PUC anticipates adopting updated interconnection process and technical requirements in 2018-19.
 - Hosting capacity analysis: Beyond existing requirements for Xcel Energy, Staff recommended that the Commission consider requiring utility analyses of hosting capacity, either independently or as part of a broader distribution plan. The Commission is considering these issues in Docket No. CI-15-556.
- *Supporting grid modernization technologies:*
 - Advanced metering infrastructure (AMI): AMI penetration in Minnesota is relatively low, compared to national deployment rates. Possible next steps include specifying AMI functionality and development of a business case, including cost-benefit analysis.
 - Volt/VAR optimization: Staff recommended that this technology be evaluated by each utility, either independently or as part of a broader distribution plan.
- *Other policy considerations:* Stakeholders participating in Commission workshops identified several other policy-related areas as important for grid modernization, including making energy usage data easily accessible to customers, enabling third-party aggregation of demand response resources (currently prohibited in the state), and offering consumers time-varying rates. The Commission already is exploring some of these areas in other open dockets.
- *Utility business models and market structure:* Among topics staff recommended for consideration are Distribution System Operator and utility service-based models, and performance-based ratemaking. The Commission recently opened a docket on performance-based ratemaking and issued a notice of comment period.²⁴

²⁴ <https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId=%7B90E0AA5E-0000-C917-912B-461B042A8200%7D&documentTitle=20179-135735-01>

5.0 New York

5.1 Introduction

New York state is a leader in thinking ahead about the operations and planning of electric distribution systems. The focus of this section is New York's Distribution System Implementation Plans (DSIPs), non-wires alternatives (NWA), and what is being called the *Value Stack tariff*.

5.2 Impetus for Early Action

The New York Public Service Commission (PSC or Commission) instituted a Reforming the Energy Vision (REV) proceeding (14-M-0101) in early 2015 to address gaps between advancements in information technology, electronic controls, distributed generation and energy storage, and the ability of utilities and regulators to adopt them, or adapt to them (NY PSC 2015a). The relatively high cost of forecasted distribution system upgrades in New York is also cited as an impetus. As part of the REV proceeding, the PSC is exploring the concept of a distribution system operator and distributed system platform (DSP) and is requiring the utilities to file Distributed System Implementation Plans (DSIPs). A DSIP is a multi-year plan that includes a proposal for capital and operating expenditures to build and maintain the utility's DSP. *DSP* is defined as "an intelligent network platform that will provide safe, reliable and efficient electric services by integrating diverse resources to meet customers' and society's evolving needs. The DSP fosters broad market activity that monetizes system and social values, by enabling active customer and third-party engagement that is aligned with the wholesale market and bulk power system" (NY PSC 2015a).

5.3 Stated Goals

The six stated purposes of the New York REV are:

- enhanced customer knowledge and tools that will support effective management of the total energy bill;
- market animation and leverage of customer contributions;
- systemwide efficiency;
- fuel and resource diversity;
- system reliability and resiliency; and
- reduction of carbon emissions (NY PSC 2014).

The stated goals of the DSIPs are to:

- serve as a source of public information regarding DSP plans and objectives, including specific system needs allowing market participants to identify opportunities;
- serve as the template for utilities to develop and articulate an integrated approach to planning, investment, and operations; and
- enable the Commission to supervise the implementation of REV in the context of system operations (NY PSC 2015b).

Prior to DSIPs, utility distribution system planning was performed in the context of capital planning, and the PSC reviewed distribution plans mainly in the context of rate proceedings, to consider whether they were sufficient to meet the utility's regulatory obligation (NY PSC 2015c).

5.4 Filing and Other Regulatory Requirements

5.4.1 Distributed System Implementation Plans

The DSIP (part of Docket/Case 14-M-0101) is a multi-year plan filed with the PSC. It is subject to public comment and updated regularly. The DSIP must contain (among other things) a proposal for capital and operating expenditures to build and maintain DSP functions, as well as the system information needed by third parties to plan for effective market participation.

In April 2016, the New York PSC issued guidance on DSIPs that required utilities to make the following DSIP-related filings (NY PSC 2016):

- A plan and associated timeline for a **stakeholder engagement process** during DSIP filing development (filed May 2016).
- Individual utility **Initial DSIPs**, each addressing its own system and identifying immediate changes that can be made to effectuate state energy goals and objectives (filed June 2016). This filing also required utilities to provide information regarding their current five-year capital investment plans as a first step toward providing customers and other parties with the information they need to identify and characterize near-term opportunities for distributed energy resource (DER) development in each utility's electric distribution system (NY PSC 2017a, p. 3).
- A joint—and as necessary, individual—**Supplemental DSIP** by the utilities addressing the tools, processes, and protocols that will be developed jointly or under shared standards to plan and operate a modern grid capable of dynamically managing distribution resources and supporting retail markets (filed November 2016).
- **Subsequent DSIPs** will be submitted on a biennial basis beginning in June 2018. Future filings are expected to include increased detail, such as developments in markets and technology capabilities, as well as lessons learned and improvement opportunities.

The Supplemental DSIP provides an initial view of the enhanced planning tools and methodologies that will form the basis of distribution planning in the future and allow for the development of DSP capabilities and integration of higher levels of DERs (JU NY 2016). The Supplemental DSIP filing by the Joint Utilities of New York (Joint Utilities, or JU) included:

- a load and DER forecasting stakeholder engagement process,
- a process for coordination with New York Independent System Operator (NYISO) on short- and long-term forecasting,
- a non-wires analysis suitability framework and forthcoming implementation matrices,
- a detailed roadmap for hosting capacity, and
- an interconnection data platform and process roadmap.

Throughout 2016, the Joint Utilities had a variety of stakeholder engagement activities that were focused on informing the Supplemental DSIP. In 2017, the Joint Utilities formed a 15-organization advisory group along with the following nine implementation teams:

1. Customer Data,
2. DER Sourcing + Non-wires Alternatives Suitability,
3. Electric Vehicle Supply Equipment,
4. System Data,
5. Monitoring & Control,
6. NYISO/DSP,
7. Hosting Capacity,
8. Load/DER Forecasting, and
9. Interconnection - Interconnection Technical Working Group and Interconnection Policy Working Group (JU NY 2017a).

The goals of the 2017 stakeholder engagement process are to inform stakeholders of implementation progress, solicit feedback on implementation progress, achieve alignment for moving forward, and incorporate stakeholder input into implementation plans as applicable (JU NY 2017a).

On March 9, 2017, the PSC issued an order responding to the Supplemental DSIPs filed by the Joint Utilities. The Commission agreed with several commenting parties that the Supplemental DSIP did not provide sufficient details necessary to anticipate, monitor, and evaluate each utility's progress toward implementing a distribution system platform over the next few years. The Commission also noted that the time frame spelled out for utilities' hosting capacity analysis was too long and the details regarding the prioritization of circuits were insufficient (NY PSC 2017a). The Commission praised an initiative to develop an electric vehicle (EV) Readiness Framework within 12 months.

The Commission provided specific guidance on five topics areas where increased focus and tangible results were needed to enable development of DSPs to facilitate the use of DERs. The Commission suggested that focusing near-term actions on the following five areas would have significant benefits:

1. hosting capacity,
2. interconnection portals,
3. non-wires alternatives,
4. aggregated customer data privacy, and
5. energy storage.

Hosting Capacity

The Commission recognized data as a fundamental element for enabling DER development. Therefore, they stressed that utilities must advance the capabilities for calculating and presenting hosting capacity data as quickly as possible. The Commission expressed support for the phased data approach outlined by the utilities, but indicated that progress has been "unacceptably slow and not supportive of industries' needs" (NY PSC 2017a).

The Commission directed that a hosting capacity analysis for all circuits at or above 12 kilovolts (kV) be completed by October 1, 2017, and stated that hosting capacity maps needed to be improved and data provided with maps.

Interconnection Portal

In the REV Track One Order (NY PSC 2015c), the Commission directed the utilities to develop a means for DER developers to apply for interconnection through an online portal. Subsequently named the Interconnection On-line Application Portal, it was intended to automatically perform impact studies, such as load flow and fault potential, and to facilitate the issuance of a utility decision in a timely manner. None of the utilities addressed the portal as required in their Initial DSIP filings, but in September 2016 a functional specification report for the portal was issued by the Joint Utilities to help identify a proposed scope of work and schedule for expected efforts. The report proposed that the portal be developed in three phases over the next two years (NY PSC 2017b):

- Phase 1, to be completed by early 2017, was to include automated application management.
- Phase 2, scheduled for completion by the end of 2017, will automate standardized interconnection requirements technical screening.
- Phase 3, scheduled for completion between 2017 and 2019, will integrate full automation of all processes.

The Commission indicated that while it understands there is still uncertainty in the later phases of the effort, it directed the utilities to ensure that Phase 1 is fully implemented by no later than October 1, 2017, and to submit a compliance filing.

Non-Wires Alternatives (NWA)

The Commission directed the utilities to file additional information and revised matrices within 60 days of the March 9, 2017, order that describe “how the proposed NWA Suitability Criteria will be applied as a standard procedure in the development of transmission and distribution project justifications” (NY PSC 2017b). The Commission further directed utilities to describe “how Suitability Criteria [for NWAs] will be incorporated into the planning procedures, and how and when the Suitability Criteria will be applied to projects in their current capital plans” (NY PSC 2017b). Each utility was also required to identify all projects in its five-year capital plan that meet the criteria and when NWA solicitations will be issued for those projects. The Joint Utilities made a filing on May 8, 2017, to address a common NWA Suitability Criteria framework that utilities throughout New York will use. In appendices to the filing, each individual utility summarized its own planning process, capital work plan, and utility-specific NWA Suitability Criteria.

The proposed Suitability Criteria framework proposed by the Joint Utilities consists of the following *three components*, to indicate whether a project should be considered for an NWA that is more cost-effective than traditional solutions (NY PSC 2017a, p. 19):

- **Project type** points to certain types of projects that better lend themselves to nontraditional solutions. For instance, load relief is such a project type. Load relief would traditionally rely on solutions such as reconductoring, new substations or expansions, or transformer upgrades, but could also be addressed by energy efficiency, demand response, or other DERs.
- **Timeline** is the time needed to complete the procurement process, including developing and issuing requests for proposals (RFPs), vendor response, technical review of proposals, contracting, and implementation.

- **Cost** is a “floor” value. Traditional projects with costs exceeding the floor would be considered for a potential NWA solicitation. It is presumed that projects with costs greater than the floor amount would be able to overcome transaction and opportunity costs (NY PSC 2017b).

Each of the utilities that are part of the Joint Utilities in New York conduct transmission and distribution (T&D) planning on an annual basis to identify system needs to meet each utility’s design standards and identify the corrective actions or traditional project solutions that address those needs (NY PSC 2017c). Capital planning includes the selection of T&D solutions as part of the annual capital budget and multi-year capital forecast. The result of applying the NWA Suitability Criteria to the capital plan is a list of traditional infrastructure projects that are candidates for NWA solutions. Starting in May 2017, each of the Joint Utilities began posting on websites the list of potential NWA opportunities, along with preliminary descriptions and expected timing for solicitations (NY PSC 2017c).

Each of the Joint Utilities proposed its own NWA Suitability Criteria to the Commission. In each utility filing, the project types identified were either load relief, reliability, or both.

The utilities noted that all other categories of projects have minimal suitability for NWAs at present and will be reviewed further as suitability changes due to state policy or technological changes (NY PSC 2017c).

Each utility defined large and small projects and identified a timeline suitability and a cost suitability for each of these categories. For example, Con Edison identified large projects as those that are on a major circuit or substation, and a suitable timeline for NWA opportunities of 36 to 60 months. The utility identified small projects as those at the feeder level and below, with timelines of 18 to 24 months.

Con Edison applied NWA suitability criteria to its 2017 capital work plan to determine non-wires alternative opportunities. Because Con Edison does not have a cost floor for large projects, all large projects that had sufficient time to be implemented were selected as potential opportunities for NWA solutions. For small projects, a \$450,000 cost floor was used in addition to the need date to determine NWA opportunities. Con Edison identified nine potential large load relief projects and one small load relief project for its 2017 capital work plan (NY PSC 2017c). Appendix B in this report provides a summary of potential NWA projects for Con Edison.

Another New York utility, National Grid, submitted its most recent capital improvement plan January 31, 2017. National Grid reviewed the projects in its current capital improvement plan for NWA suitability and preliminarily identified 17 projects as having the potential for NWA solutions. These are in addition to the seven NWA projects National Grid is currently processing RFPs for, of which five are large and two are small. All but one of the 24 potential projects are characterized as load relief projects; the other project is characterized as a reliability project. Appendix B provides a summary of the seven projects for which National Grid plans to issue RFP solicitations.

The Joint Utilities, in their proposal, indicated that each utility will follow its own prescribed procurement processes for bidding and determining the winner(s) of the bidding processes. Each utility will examine bids meeting the RFP requirements to formulate a portfolio, or portfolios, of solutions that meet the utility’s needs, and then compare them using the utility’s recent benefit-cost analysis handbook. The utilities will then negotiate final contract terms/awards with the bidders submitting the most cost-effective bid or combination of bids (NY PSC 2017c).

Customer Data Privacy

In the Supplemental DSIP, the Joint Utilities proposed and the Commission agreed to adopt a “15/15” privacy standard that would keep customers’ identities anonymous when reporting aggregated data sets. An aggregated data set would be shared only if it contains at least 15 customers, with no single customer representing more than 15 percent of the total load for the group (NY PSC 2017a). Pursuant to the Commission’s order, the Joint Utilities also reviewed building energy management and benchmarking data privacy standards for providing whole-building aggregated data to building owners or their agents. In a June 7, 2017, filing, the Joint Utilities proposed a “4/50” privacy standard, meaning the utilities would only provide whole-building data when there were four or more customers, with no single customer representing more than 50 percent of the total building load. The standard would apply independently to each fuel type. In cases where the 4/50 conditions do not hold, building owners would need signed authorizations from the building’s customers. The Joint Utilities also proposed exceptions when necessary to comply with local laws and ordinances (JU NY 2017b).

Storage

The Commission states that, “determining optimal locations, types, levels, and uses of storage, either on the system or behind customers’ meters, should become routine, collaborative activities involving the Utilities, customers, storage product vendors, DER developers, and other interested parties” (NY PSC 2017b).

The Commission directed that by no later than December 31, 2018, each individual utility must have energy storage projects deployed and operating at no fewer than two separate distribution substations or feeders. The Utilities should attempt to perform at least two types of grid functions with the deployed energy storage (e.g., increasing hosting capacity and reducing peak load), and utilities are directed to collaborate to ensure a range of productive projects and that duplicative projects are avoided (NY PSC 2017b).

5.4.2 Value of DER Proceeding

The Value of DERs (VDER) proceeding (Case 15-E-0751) is intended to promote the growth of large capacity solar, such as community and commercial installations (Walton 2016). Phase 1 of the proceeding addresses broader system needs than the NWA solicitations described above. The proceeding provides a framework for valuing and developing compensation methodologies for DERs so they can play a more significant role in meeting New York’s energy needs in the future.

5.4.2.1 VDER Phase 1

While the focus of VDER Phase 1 was to create a near-term replacement for net metering, that does not discourage the further development of solar PV. The PSC order issued on March 9, 2017, required utilities to put forward implementation proposals that addressed, at a minimum, the following items (NY PSC 2017a):

1. Calculation and compensation methodologies for a Demand Reduction Value (DRV)
2. Identification of, compensation for, and megawatt (MW) caps for locational system relief value (LSRV) zones
3. Proposed methods and values for providing Capacity Values for the Value Stack

4. Identification of average generation profiles for capacity and demand-reduction value compensation in projects' first year of operation
5. Cost allocation and recovery methodologies for each component of the Value Stack, with emphasis on issues associated with capacity compensation
6. The practicality of allocating and collecting costs associated with DER compensated under Phase 1 net energy metering
7. Proposed accounting transactions and ratemaking treatment
8. Utility processes for managing billing and tracking bill credits
9. Reporting procedures for tracking progress in tranches and any other necessary reporting
10. Draft tariffs stating the Market Transition Credit (MTC) for the residential and small commercial classes, for each tranche (including rules for how the MTC, DRV, and LSRV will be applied to community distributed generation)

The Joint Utilities made a filing on April 24, 2017, that laid out a work plan to consider additional potential sources of value created by DERs through a Value Stack methodology and tariff. Value Stack will be used in lieu of net metering. A Value Stack tariff is a compensation method that takes into account previously unquantified values, including locational and environmental benefits. The Value Stack is based on monetary crediting of net hourly injections, and excess credits can be carried over to subsequent billing and annual periods.

The basics of the Value Stack tariff, as proposed, are summarized below (PowerMarkets Today 2017):

- Eligible projects will be paid for a term of 25 years from their in-service date.
- To be paid through value tariff, projects must have metering that can record net hourly consumption and injection.
- Payments under the tariff are based on the following:
 - ENERGY: Day-ahead hourly zonal locational marginal price inclusive of losses (eventually moving to subzonal prices).
 - CAPACITY: Capacity value is based on retail capacity rates for intermittent technologies. It will be different for dispatchable DER, including intermittent resources paired with storage. Capacity payments for intermittent resources remain similar to those in the old system, based on supply charge for the service class that has a load profile most similar to a solar generation profile.
 - ENVIRONMENTAL: Environmental value is the higher of the latest Tier 1 Renewable Energy Certificate (REC) procurement price established by the New York State Energy Research and Development Authority (NYSERDA) or the social cost of carbon.
 - DEMAND REDUCTION and SYSTEM RELIEF: DRV and LSRV are based on de-averaging the utility marginal-cost-of-service studies, performance during the 10 peak hours, and other factors described.
- Costs associated with new VDER payments will be collected proportionally from the same group of customers that benefit from the savings associated with the DER projects. Where compensation does not reflect a value that has been identified and quantified, recovery will come from customers within the same service class as the beneficiaries.

The DRV and LSRV approach will be refined through revisions to utility marginal-cost-of-service studies over the next year (JU NY 2017c).

On September 15, 2017, the PSC issued an order largely approving the VDER proposals submitted by the IOUs pursuant to the March 2017 PSC order. The PSC ordered several modifications to the utilities' proposals, including their decision that utilities should use existing surcharges and deferred accounting mechanisms rather than creating new, and VDER-specific mechanisms, for recovering VDER costs. The PSC also ordered utilities to use Orange and Rockland's methodology for selecting the Service (customer) class from which the installed capacity (ICAP) credit will be derived. The PSC also ordered that the "Market Transition Credit should be recalculated to account for any change in the three-year average ICAP value when a Service Class (S.C.) different from S.C.1 is used." (NY PSC 2017d).

A significant portion of the PSC's order discussed questions related to how and when utilities provide the VDER credits to customers' bills because long lags between the end of billing periods and the appearance of credits on customer bills has financial impacts on customers. Thus, the PSC's order includes directions for moving forward for identifying steps needed to make sure customers receive their credits no more than two months following the end of the billing cycle; for filing an automation and billing report which includes a timeline for automation implementation and implementation cost; and for working with Community Distributed Generation (CDG) sponsors and others for billing-related issues affecting CDG projects, sponsors, and subscribers. The PSC further directed the utilities and PSC staff to work on issues related to queue management and other considerations related to possibly increasing the size of projects eligible for the VDER tariffs from 2 MW to 5 MW. Related to this issue, the PSC included a list of questions on which they seek public input and comment.

5.4.2.2 VDER Phase 2

The Joint Utilities April 24, 2017, filing proposed initial market enhancements for consideration in VDER Phase 2. These include the following (JU NY 2017c):

- *Distribution-level reactive power and voltage support*: Consider whether the smart inverter requirement proposed under IEEE 1547 should be adopted as a requirement in New York.
- *Expanded Locational Energy, Capacity, and Ancillary Values*: Utilities work with NYISO to assess whether and how DER can adequately provide the following wholesale market ancillary service products:
 - Ten-minute spinning reserves
 - Thirty-minute reserve
 - Regulation
 - Voltage support
 - Black-start capability
- *Enhanced Interconnection Cost Sharing*: Identify alternative structures by which developers could collectively pay for common interconnection costs, either through a "batching" approach to share common costs or by establishing a tariff mechanism where all interconnecting customers would be charged for a share of common investments that increase aggregate hosting capacity.

There are three Phase 2 working groups. Initial scopes of each working group (as of July 2017) are summarized below (NY PSC 2017e):

- Value Stack
 - Expand eligibility, including different technologies and projects greater than 2 MW.
 - Improve existing value stack elements and add new elements to value stack.

- Rate Design
 - Explore mass-market default rate design reforms.
 - Develop a mass-market net energy metering transition plan by December 2018.
 - Develop a framework for development and consideration of grid access charges, non-bypassable fees, or other methods to mitigate costs posed on nonparticipants.
 - Address commercial and industrial rate reform.
- Low- and Moderate-Income Customers
 - Consider Interzonal Community Distributed Generation credits.
 - Consider Low- and Moderate-Income value stack adders.
 - Coordinate NYSEERDA solar program incentives with VDER tariffs.
 - Develop eligibility determination/enrollment mechanisms.
 - Investigate on-bill financing/pay-as-you-save approaches.
 - Utility ownership: investigate circumstances under which utility ownership of DERs should be permitted.

5.5 Other Related Activities

National Grid’s Buffalo Niagara Medical Campus project is a distributed system platform REV demonstration project that will test services based on local and small-scale, but centralized, distribution system planning that will communicate with network-connected points of control. The project is currently under development and expected to continue until fall 2018 (NY PSC 2017c).

Con Edison has implemented a Brooklyn Queens Demand Management (BQDM) program that is avoiding annual carrying costs on a \$1 billion substation through spending \$200 million in NWAs instead. Con Edison originally estimated the substation would be overloaded by 69 MW by 2018. To avoid building the new substation, Con Edison proposed to meet the need with a non-wires solution, including addition of traditional utility infrastructure investments (17 MW) and reducing peak load by 52 MW in the BQDM area through a combination of customer-side solutions (41 MW) and nontraditional utility-side solutions (11 MW). The consumer-side solutions include a range of options targeting demand response, energy efficiency, energy storage, fuel cells, and combined heat and power. A component of the consumer-side solution was a demand-response auction held in July 2016. The result of the auction was more than 22 MW of demand response in a constrained area across afternoon and evening hours provided by 10 firms by 2018 (ConEdison 2016).

5.6 Next Steps

Subsequent DSIPs will be submitted on a biennial basis beginning June 30, 2018. Future filings are expected to include increased detail, such as developments in markets and technology capabilities, as well as lessons learned and improvement opportunities. Utilities must provide hosting capacity analysis for all circuits at or above 12 kV by October 1, 2017, and are expected to complete updated marginal-cost-of-service studies by mid-2018.

Notable activities in the Value of DER proceeding include the following (NY PSC 2017a, p. 151):

- Summer 2017
 - Implementation of VDER Value Stack
 - Staff issues Community Distributed Generation Low Income Proposal
 - Informal update to DSIPs filed
- Q4 2017–Q1 2018
 - Commission considers recommendations on Phase 2 VDER process
 - Commission reviews utilities’ plan and timeline on locationally granular pricing
- Q3 2018
 - Formal update to DSIPs filed by June 30, 2018
- Q4 2018
 - Report and Recommendations for VDER Phase 2 presented to Commission
- Q4 2018–Q1 2019
 - Commission consideration of Report and Recommendations for VDER Phase 2
 - Commission consideration of utility capital expenditure plans related to DSP functions and capabilities presented in rate case filings

II. More State Approaches to Distribution System Planning

6.0 District of Columbia

6.1 Summary of Distribution Planning Activities

In 2011, the Mayor’s Plan for a Sustainable DC set a goal of increasing the efficiency and reliability of the District of Columbia electricity system, as well as integrating cleaner and distributed sources of electricity (DC 2013). In 2015, the Public Service Commission (PSC) opened an investigation to explore how to modernize the city’s grid through the use of innovative technologies and policies. The electric distribution utility serving the District is the Potomac Electric Power Company—commonly known as Pepco.

6.1.1 Modernization of DC’s Electricity Service

In April 2015, responding to a petition of the DC Climate Action and Advisory Neighborhood Commission 6D06,²⁵ the Commission determined that it would open a docket to form a working group to investigate the future outlook for energy growth, the feasibility of deploying more energy storage and increased distribution generation, and the effects on Pepco’s planning and construction plans. In June 2015, the PSC opened Docket FC1130 to investigate avenues for the modernization of DC’s electricity service (MEDSIS), including technology and policy improvements to increase sustainability, reliability, efficiency, and interactivity (DC PSC 2015).

Initial MEDSIS topics identified by the Commission include the following (DC PSC 2015):

- An initial overview of the current energy distribution system in the District and current plans to modernize the system
- An examination of new technologies that will affect the delivery of energy in the District, including but not limited to energy storage, DER, electric vehicles, microgrids, and the integration of identified enabling technologies
- An identification of regulatory and other policies that will enable or inhibit the modernization of the District’s energy delivery system

The PSC hosted three workshops in the MEDSIS case (in October and November of 2015, and in April 2016) and took written input from 39 stakeholders and stakeholder groups. At the first workshop, Pepco, the Washington Gas Light Company, the U.S. General Services Administration, the D.C. Department of Energy & Environment, and the Downtown D.C. Business Improvement District presented an overview of the state of infrastructure and plans to modernize it. At the second workshop, various DER developers shared information about their projects and policy and legal barriers they encountered. The third workshop focused on questions surrounding the legal and regulatory framework and how it might be revised to facilitate DER adoption and promote a more modern energy system.

In January 2017, based on input provided, Commission staff submitted a report that identified a series of regulatory issues to address, recommendations for addressing the issues, and two draft Notices of Proposed Rulemaking (NOPRs) for the Commission to consider. The draft NOPRs propose changes to the DC Municipal Regulations to codify the staff’s recommendations (DC PSC 2017a). On January 25,

²⁵ Advisory Neighborhood Commissions (ANCs) are neighborhood bodies made up of locally elected representatives. ANC 6D06 had asked the DC PSC to establish an expedited working group to review a specific project proposed by Pepco that would affect the citizens represented by ANC 6D06. The PSC denied this request but responded by opening a new docket addressing issues in a more global way.

2017, the Commission issued an order accepting the staff report into the docket and providing opportunities for comment (DC PSC 2017b). Issues identified in the staff report include the following:

- *Relieve uncertainty surrounding the definition of “electrical company.”* Of particular concern was ensuring the definition does not inadvertently treat entities operating microgrids and other DERs as electric companies subject to rules and regulations affecting electrical companies.
- *Address the adequacy of Commission regulations, including a need to define DERs more clearly.* The staff report proposes definitions of DER and 13 types of DERs not clearly defined in existing regulations.
- *Address barriers.* The staff proposal identifies and proposes to address the following: a lack of a streamlined process for certifying solar generation; the definition(s) of generation covered by net energy metering, and a definition of net energy metering facilities; a lack of enforcement provisions related to interconnection regulations; and a proposal to shorten the Commission’s approval time for new renewable energy generation to under 20 days.
- *Define what constitutes retail and wholesale electricity sales.* The staff report proposes revising the definition of “electricity supplier” to add clarity about what type of sale is covered.

Staff also proposed that funds set aside as a result of the Pepco-Exelon merger be used to fund small pilot projects to study DERs. The report sets out qualification parameters for selecting projects. The Commission held a Town Hall Meeting on February 28, 2017, to seek input on this proposal. The staff proposal included the objective of issuing the two NOPRs addressing individual issues within 60 days of the close of comments, so the Commission is expected to follow up with the next phase of the proceeding in the fall of 2017. The Commission recently followed up with a release of a Vision Statement, opening a comment period for public input. See Section 6.2 for a discussion of this order (DC PSC 2017f).

6.1.2 Value-of-Solar Study

A Value-of-Solar study commissioned by the Office of the People’s Counsel (OPC) is in response to a directive from the DC Council. OPC submitted its Value-of-Solar study into the MEDSIS docket (FC 1130) on May 26, 2017, as part of its response to the staff proposal in that proceeding. According to OPC, its study “will be instructive and provide a supportive predicate in advance of local initiatives” (PC-DC 2017). Pursuant to a request by Pepco, the Commission opened a comment period for this study (PC-DC 2017). The OPC submittal occasioned two sets of written comments and two sets of reply comments.

In an October 2017 Order, the Commission noted the receipt of comments in response to the VOS, and indicated the comments will be given appropriate consideration in future solar-related matters. (DC PSC 2017f)

6.1.3 Pepco Rate Case

Several MEDSIS stakeholder issues relate to the ongoing Formal (Rate) Case No. 1139. These issues include a need for better DER planning and forecasting, identifying optimal locations for DER installation, standard tariffs and contracts, and other planning activities. Commission staff declined to make specific recommendations in FC 1130, the MEDSIS docket, until the Pepco rate case is concluded. A final order was issued in the rate case on July 25, 2017 (DC PSC 2017c). The Commission ordered that a workshop be scheduled to discuss questions related to Pepco load forecasting.

6.1.4 Distribution Automation

The Commission is overseeing upgrades to the city's grid to increase the use of information and control technology to improve the grid's reliability, security, and efficiency. The technologies being integrated into Pepco's network include automatic sectionalizing restoration systems, remotely operated switches, and remote monitoring systems (DC PSC 2017d). The features of automatic sectionalizing restoration systems include fault isolation, automatic feeder switching, automatic repair of grid faults, and circuit protection (DC Systems 2013). Remotely operated switches allow for quicker identification of fault locations and switching circuits remotely. Remote monitoring systems provide increased transformer protector performance monitoring and control and allow network operators to isolate faulty transformers (DC PSC 2017d).

6.1.5 Load Research Plan

The Commission ordered Pepco to provide a load research plan detailing how it will use digital grid information, including advanced metering infrastructure data, in its network expansion and rate design plans. Information included in the load research plan includes cost of service, pricing and rate design, demand and energy forecasting, energy efficiency and load management, and distribution and substation planning (DC PSC 2017e).

6.2 Next Steps

In response to the January 2017 staff report in the MEDSIS docket FC1130, the Commission received written comment, and as indicated in the staff report, is expected to follow up in 2017. Also ongoing are the Pepco load forecast quality discussions from the recently concluded rate case, and the proceeding related to the advanced metering infrastructure data access by third parties. As of October 2017, there are no open comment periods or requirements for stakeholder action in these dockets.

7.0 Florida

7.1 Summary of Distribution Planning Activities

Florida's distribution planning-related policies include the Florida Public Service Commission's (FPSC) authorization of utility investment in grid storm hardening and investments in advanced metering infrastructure and reporting requirements for progress on these investments. The state also recently amended its constitution to exempt certain renewable energy and energy storage systems from property tax.

7.1.1 Reporting on Distribution System Reliability

Florida Administrative Code Rule 25-6.0455 requires utilities to file annually a Distribution Service Reliability Report with the FPSC. The reports include total number of outages, identification of the top 3 percent of primary circuits in terms of interruptions, and actual and adjusted reliability metrics including system average interruption duration index (SAIDI), customer average interruption duration index (CAIDI), and system average interruption frequency index (SAIFI) (Florida Department of State 2006).

7.1.2 Reporting on Storm Hardening

With exposure to frequent and strong storms, hardening the electric grid is important for utilities in the state. Grid hardening can include improving the current strength of feeder lines to conform to the National Electrical Safety Code's Extreme Wind Loading (EWL) guidelines; following EWL design standards for new construction of feeders, pole lines, and other planned work; replacing wooden transmission structures with steel and concrete; and undergrounding (i.e., burying power lines instead of putting them on poles) if it is cost-effective.

In 2006, the FPSC began requiring regulated utilities to file plans for storm preparedness and the associated costs (LaCommare et al. 2017). Florida Administrative Code, Rule 25-6.0342, requires each Florida investor-owned electric utility to file an updated, detailed storm-hardening plan every three years. The report must include a description of the deployment plan and standards and procedures for joint and third-party uses (to ensure that they do not interfere with the utility's storm hardening activities). Utilities must seek input from joint and third-party users when developing the plan. The plan also involves maintaining written safety, reliability, pole loading capacity, and engineering standards and procedures for third parties to attach to utility transmission and distribution poles (Florida Department of State 2007).²⁶

7.1.3 AMI Deployment

The FPSC has authorized Florida Power & Light (FPL) and Tampa Electric Company to invest in advanced metering infrastructure (AMI). In 2010, Dockets 080677-EI and 090130-EI led to Order 0153, which authorized FPL plans to install AMI and requires FPL to report annually on progress on smart meter deployment (FPSC 2010). In 2017 as part of Docket No. 170002-EG, FPL filed its most recent smart meter progress report which includes a description of how the company plans to use smart meters to help customers manage and reduce their electricity consumption (FPL 2017).

²⁶ Nothing in the rule is intended to conflict with Federal Communications Commission jurisdiction over pole attachments (specifically Title 47, United States Code, Section 224).

Docket No. 150213-EI approved Tampa Electric's Advanced Meter Program tariff agreement for three years. The program offers free installation of an advanced meter system for participants and is available for Tampa Electric residential customers that own a solar PV system that is interconnected with the utility's distribution system (FPSC 2015).²⁷

In Docket No. 20170183-EI, the Commission approved a revised and restated settlement for Duke Energy Florida which allowed the utility to transfer the net book value of all Mobile Meter Reading assets and the commercial Silver Springs Network meters to a regulatory asset and amortize these investments at the current level of depreciation until fully recovered. The new AMI assets will be permitted a depreciable life of 15 years. Upon completion of AMI meter deployment, the utility will introduce a residential Time of Use rate.²⁸

7.1.4 Tax Exemption for Renewable Energy

In 2016, Florida voters, through a ballot initiative, passed a constitutional amendment on renewable energy (Florida Senate 2017). The initiative is implemented by Senate Bill 90, which provides commercial and industrial utility customers a property tax exemption for renewable energy and energy storage systems (NC Clean Energy 2017).²⁹

²⁷ Participation in Tampa Electric's Advanced Meter Program is voluntary.

²⁸ Florida Public Service Commission (2017).

²⁹ See Florida Senate. CS/SB 90: Renewable Energy Source Devices. <http://www.flsenate.gov/Session/Bill/2017/00090>.

8.0 Illinois

8.1 Summary of Distribution Planning Activities

Illinois has a number of distribution planning-related efforts and policies, including requirements that IOUs report on electric system reliability, authorization for investment plans for grid hardening and smart meters, studies and stakeholder engagement on smart grid technology and integration of renewable energy and efficiency energy, and an examination of how to best manage access to customer utility data.

8.1.1 Distribution System Reporting

Illinois electric utilities are required by Illinois State Administrative Code Title 83, Section 411.120, to report any single outage event affecting more than 10,000 customers for three hours or more, including the number of affected customers, description of the cause, and the circuit number of the distribution circuit (or circuits) involved (Illinois General Assembly, n.d.).³⁰

The code also requires annual reporting, including the utility's performance on distribution system reliability, a three-year plan for future investments in distribution system reliability, and identification of future distribution system reliability challenges (Illinois General Assembly, n.d.). The Illinois Commerce Commission (ICC) assesses the reports at least every three years.

8.1.2 Utility of the Future Study

In March 2017, the ICC kicked off the NextGrid initiative, which grew out of Illinois' Future of Energy Jobs Act.³¹ NextGrid is a consumer-focused study on topics such as leveraging the state's restructured energy market, investment in smart grid technology,³² and recent law expanding renewable energy and efficiency. A series of workshops kicked off what is planned to be about an 18-month process. The ICC resolution invited stakeholders to comment on an independent facilitator and topics to be considered as part of the initiative (ICC 2017a). The Power and Energy System Area of the Electrical and Computer Engineering Department at the University of Illinois at Urbana-Champaign is the selected facilitator.

Seven working groups will address the following topics:³³

- New technology deployment and grid integration
- Electricity markets
- Customer and community participation
- Regulatory, environmental, and policy issues
- Metering, communications, and data
- Reliability, resiliency, and cybersecurity
- Ratemaking

³⁰ Section 411.120 is based on Illinois Statute 220 ILCS 05 – Public Utilities Act, see <http://www.ilga.gov/legislation/ilcs/ilcs3.asp?ActID=1277&ChapAct=220%26nbsp%3BILCS%26nbsp%3B5%2F&ChapterID=23&ChapterName=UTILITIES&ActName=Public+Utilities+Act%2E>.

³¹ For more on the NextGrid initiative, see <https://nextgrid.illinois.gov/>. For more on the Future of Energy Jobs Act, see <http://www.futureenergyjobsact.com/>.

³² ComEd has installed 3.5 million smart meters, with 100 percent deployment expected by the end of 2018. Ameren has installed 530,000 smart electric meters and 286,000 smart gas modules, with 100 percent deployment (about 2 million smart meters) anticipated by the end of 2019. "Next Grid" presentation by Acting Commissioner Sadzi M. Oliva, National Governors Association Energy Innovation Summit, October 4, 2017.

³³ NextGrid Working Groups. <https://nextgrid.illinois.gov/WorkingGroups.html>

8.1.3 Distribution Modernization Investment Planning

The Energy Infrastructure Modernization Act (Senate Bill 1652) allows utilities of a certain size to voluntarily undertake investments in distribution infrastructure improvements, including smart meters, distribution automation, associated cyber-secure data communication networks, substation microprocessor relay upgrades, and grid hardening (Illinois General Assembly 2011).³⁴ Section 220 ILCS 5/16-108.5 of the Act requires Illinois utilities to file annual Grid Modernization Action Plans requesting formula rates for ICC approval (Illinois General Assembly 2011).³⁵

8.1.4 Managing Customer Data Access

In July 2017, the ICC finalized the Open Data Access Framework, which will govern access to utility customer energy usage data. ComEd and Ameren have begun to address framework requirements by creating “data roadmaps.” In Docket 14-0507, the ICC found that Ameren’s and ComEd’s proposed data roadmaps were sound and appropriate plans and ordered that framework requirements must be considered by the utilities as they design and deploy AMI (ICC 2017b).

In Docket 15-0073, Final Order in March 2016, the ICC authorized specific consent language which customers can agree to in order to release AMI interval usage data to non-retail electric supplier third parties (ICC 2016).

³⁴ Utility grid modernization investment plans are posted at:

<https://www.icc.illinois.gov/electricity/utilityreporting/InfrastructureInvestmentPlans.aspx>.

³⁵ An example of Ameren’s 2016 Grid Modernization Action Plans can be found at

<https://www.icc.illinois.gov/docket/files.aspx?no=16-0262&docId=248656>.

9.0 Indiana

9.1 Summary of Distribution Planning

In 2013, the Indiana Legislature passed a bill that created the Transmission, Distribution, and Storage System Improvement Charge (TDSIC) for plans approved by the Indiana Utility Regulatory Commission (IURC). The charge is intended to encourage investment in transmission and distribution systems for safety, reliability, and modernization projects. The charge is also available to encourage investment in economic development projects. The IURC approved TDSIC plans of Duke Energy Indiana (IURC 2016a) and the Northern Indiana Public Service Company (NIPSCO) in 2016 (IURC 2016b), and the Southern Indiana Gas and Electric Company (Vectren) in 2017 (IURC 2017).

9.1.1 TDSIC Plans

TDSIC plans are seven-year plans for transmission and distribution systems, detailing the utility's roadmap for achieving the objectives of safe and reliable service and system modernization. As illustrated by approval of the Duke Energy Indiana (DEI) TDSIC plan, the IURC goes through several steps:

- Determine whether the utility submittal is in fact a seven-year plan under Indiana Code, Title 8, Article 1, Chapter 39, Section 10(a), or Ind. Code 8-1-39-10(a).
- Determine whether the projects included in the plan are in fact eligible projects under Ind. Code 8-1-39-2.
- Determine whether the cost estimates are in fact the best estimate of the cost of the eligible improvements under Ind. Code 8-1-39-10(b)(1).
- Determine whether the seven-year plan provides incremental benefits justifying the cost of the projects.
- Determine whether the seven-year plan is reasonable. (IURC 2016a)

9.1.2 TDSIC Process

The TDSIC process reflects the results of IURC orders and Indiana Court of Appeals' decisions. Through these orders and decisions, the ground rules for determining whether a plan meets the basic definition of a TDSIC plan include the following:

- The assets and resources included are necessary for the transmission and distribution of energy from generating sources to customers;
- The assets and projects are undertaken for the purposes of safety, reliability, or system modernization;
- The descriptions of projects include sufficient information to evaluate all years of the plan; and
- The detailed description is part of the TDSIC plan filed with the IURC.

TDSIC plans submitted early in the process were rejected by the Indiana Court of Appeals (COA) and, subsequently, by the IURC because they contained very specific information for the first year of the plan, but only high-level summary information for years two through seven. To meet the working definition of a plan with sufficient information to be analyzed and approved as a TDSIC "plan," the submission must include detailed project descriptions for all years. Parties recognize that information for year 1 will necessarily be more certain than information for future years (COA 2015, IURC 2015a and IURC 2015b).

The Court of Appeals and the IURC also determined that the detailed information must be included in the plan itself, and not provided as exhibits during discovery. While there is much greater certainty with projects scheduled for year one than there is for projects projected for years two through seven, neither uncertainty nor the need for flexibility in the plan relieve a utility from the requirement to file plans with sufficient detail (COA 2015, IURC 2015c).

Another key distinguishing characteristic is that the projects must be capital projects used in the transmission and distribution of energy. Projects such as vegetation management/right-of-way widening projects, while important, do not meet this definition and would therefore need to be considered in a general rate proceeding or other, non-TDSIC proceeding (IURC 2015b).

AMI has been a sticking point in proceedings thus far. In both the DEI and Vectren TDSIC dockets, where the utilities included AMI as proposed TDSIC-funded projects, the parties to approved settlement agreements agreed to not oppose the utilities including AMI in general rate cases, subject to normal prudence reviews including a review of project costs. (IURC 2016a and IURC 2017). As noted in the Court of Appeals' 2015 ruling, the TDSIC was not intended to cover all transmission and distribution costs through a tracker, limiting the TDSIC to 80 percent of "approved capital expenditures and TDSIC costs," with the remaining 20 percent handled in the utility's next general rate case (COA 2015). DEI and Vectren agreed to remove the AMI projects from their TDSIC plans, and the parties to the settlements agreed to allow the utilities to pursue such projects through general rate cases.

The TDSIC plans target replacement and upgrades to aging infrastructure. Utilities and Indiana regulators and stakeholders are using the process to incorporate modern smart assets into the distribution system (DEI 2016, IURC 2017).

10.0 Maryland

10.1 Summary of Distribution Planning Activities

In September 2016, the Maryland Public Service Commission (MDPSC) initiated Public Conference 44 (PC44) “to ensure that electric distribution systems in Maryland are customer-centered, affordable, reliable and environmentally sustainable” (MDPSC 2016a). The initial PC44 order raised seven topics as ripe for discussion in Maryland, including distribution system planning (MDPSC 2016a). Based on stakeholder comments, the MDPSC revised and prioritized the list, with this topic to be addressed if sufficient consultant funding remains. These topics are somewhat interrelated. For example, the topic labeled “Interconnection Process” includes utility provision of hosting capacity maps, an activity often associated with distribution planning (MDPSC 2017a).

In addition, the MDPSC required Baltimore Gas & Electric (BGE) and the Potomac Electric Power Company (Pepco) to file distribution system plans as compliance filings pursuant to general rate cases. The Commission also has an ongoing process to address reliability and service quality standards and approved riders to accelerate upgrades to the distribution system to increase grid resilience.

10.1.1 Transforming Maryland’s Electric Distribution Systems (PC44)

The MDPSC identified a set of guiding principles for PC44, In the Matter of Transforming Maryland’s Electric Distribution Systems to Ensure that Electric Service Is Customer-Centered, Affordable, Reliable and Environmentally Sustainable in Maryland:

- Service should be reliable, cost-effective and environmentally sustainable.
- Universal access is a bedrock principle, and evaluating ratepayer impact is a priority.
- New technology is fundamentally changing the distribution systems, and the MPSC want to enable and integrate the new technologies what will result in clear benefits to customers.
- Competitive markets are an integral part of the Maryland electric landscape.
- Electric distribution companies and cooperatives should continue as operators of the Maryland distribution grid.
- Operators of the distribution grid should be impartial, particularly when non-regulated affiliates are market participants.
- Alternative revenue collection methods might be appropriate.
- Collaboration between stakeholders is the preferred method for developing lasting solutions. (MDPSC 2017a)

The MDPSC envisions each topic area to be addressed by workgroups led by a Commission Advisor. The following items are expected to be addressed by June 2018:

- Rate design – The MDPSC wants to investigate whether time-varying rate design for distributed solar will both empower customers and provide appropriate market signals.
- Electric vehicles – The MDPSC wants to investigate numerous issues related to electric vehicles (EVs) including strategies for using EVs for energy storage, addressing the strain EV adoption might put on electric infrastructure as well as the costs of infrastructure, retail choice in the EV market, and other issues.

- Competitive markets and retail choice – Maryland is a retail choice state. The MDPSC wants to further investigate data sharing by utilities that have deployed AMI and possible changes to retail choice “to create a more competitive, transparent and customer-friendly market” (MDPSC 2017a).
- Interconnection process – Continuing an earlier Public Conference (number 40), the MDPSC wants to investigate numerous possible actions including:
 - Completing a rulemaking applying residential solar interconnection standards statewide, using an Exelon-Pepco Holding, Inc. (PHI) standard as a basis;
 - Exploring whether smart inverters should be required or encouraged;
 - Ensuring the interconnection process is timely, electronic and customer-friendly;
 - Developing plans and timelines for each utility to publish hosting capacity maps; and
 - Reviewing cost allocation and capacity upgrade cost issue.
- Energy storage – The MDPSC contemplates a possible rulemaking defining residential energy storage and how it is interconnected and classified in rules, tariffs and policies, and considering possible criteria for utility investment in storage as a distribution grid asset.
- Distribution system planning – The MDPSC notes that Baltimore Gas and Electric (BGE) (described in more detail below) and Pepco are both required to develop distribution investment plans as part of recent rate cases. If funding remains after the consultant retained for the PC44 process addresses the other issues, the MDPSC wants to investigate how visibility into DERs can support reliability and possibly markets (MDPSC 2017a).

10.1.2 Distribution Plans Filed as Rate Case-Related Compliance Filings

In November 2017 Pepco filed a distribution investment plan as a compliance filing related to the 2016 final order in its general rate case proceeding. The document outlines in general terms how Pepco performs transmission and distribution planning. The plan emphasizes how the utility’s AMI investment is used in the distribution planning process — specifically, how the AMI data provide significant levels of information used in detailed studies of load and voltage data and impacts of DERs. The filing documents only in general terms the utility’s distribution planning process (Pepco 2017a).

BGE filed a similar distribution investment-planning document in June 2017. As with the Pepco filing, BGE’s document outlines the planning process (BGE 2017).

10.1.3 Other Related Activities

Reliability and Service Quality Standards - Maryland has an ongoing rulemaking process (RM43) that began in 2011 following weather events causing widespread power outages. In its current stage, this proceeding focuses on vegetation management and metrics for measuring outages and outage durations. The most recent MDPSC decision in RM43 identified SAIDI and SAIFI requirements for the 2016 – 2019 period (MDPSC 2015).

Grid Resilience Riders - Pepco and BGE have used surcharges/riders in effect to recover costs related to accelerated upgrades to the distribution system that are designed to increase grid resilience. For Pepco, the MDPSC first approved a Grid Resilience Surcharge in 2013 to provide an extraordinary rate recovery vehicle for Pepco to recover the costs of accelerated replacement of feeders. The surcharge was established with the provision that it would sunset when Pepco has completed qualifying projects unless reauthorized, and any uncollected and prudent costs would be rolled into Pepco base rates at that time

(MDPSC 2013a). In a 2016 rate case order, the MDPSC determined that Pepco's surcharge had been effective in achieving the intended improvements in reliability and rejected a proposal for an additional resiliency plan surcharge (MDPSC 2016b). The MDPSC first approved BGE's Electric Reliability Investment Initiative Surcharge in 2013 to authorize several grid resilience programs. The BGE surcharge will sunset in 2018 unless it is reauthorized and any uncollected prudent investments will be rolled into base rates (MDPSC 2013b).

Microgrids - In July 2016, the MDPSC denied a BGE proposal to develop two public purpose microgrid projects. The BGE proposal was to construct the microgrids using small natural gas generators and to pay for the projects using a surcharge that would be paid by all BGE ratepayers. Each of the microgrids was designed to power clusters of critical service business establishments. The businesses within the microgrid footprints, such as gas and food retail, would provide the types of services BGE customers need during extended outages on the larger distribution system.

A major reason for the MDPSC's denial of BGE's proposal is MDPSC's view that surcharges are an extraordinary step to be used when the traditional ratemaking process is not appropriate. The MDPSC also found that BGE failed to demonstrate that the proposal was cost-effective to the general customer base, and that BGE did not attempt to secure funding either from businesses that would specifically benefit from the microgrid or from federal or state government sources. Finally, the MDPSC pointed out the ongoing PC44 proceeding and stated that the microgrid proposal might be premature. The proposal was rejected without prejudice, meaning BGE could resubmit a proposal that addresses the shortcomings identified by the MDPSC (MDPSC 2017b).

In September 2017, Pepco submitted a proposal for two public-purpose microgrids. The proposal is in fulfillment of one of the conditions placed on the company for MDPSC approval of the Exelon-Pepco Holdings, Inc. merger. Pepco proposed microgrids in two Maryland counties, each of which would encompass critical services like the BGE proposal, and governmental facilities in these counties. Pepco is still more fully developing the proposals and intends to file supplemental information in February 2018 (Pepco 2017b).

11.0 Michigan

11.1 Summary of Distribution Planning Activities

Michigan requires utilities to operate and maintain distribution systems in a manner that enables the utilities to provide service to customers without subjecting customers to unacceptable levels of performance (MAC R 460.721). Michigan's Administrative Code defines unacceptable levels of performance in terms of the number of customers with service interruption under normal and under catastrophic conditions, and in terms of the percentages of customers whose service has been restored within specific periods (MAC R 460.722).

In 2013, Michigan Governor Rick Snyder laid out a vision for what he called a “no regrets” energy future by 2025. Key components of the Governor's vision include affordable electric service and reducing how often and how long electric customers experience outages (MGO 2013). In response to the Governor's vision and to provide more transparency in utility capital plans, in 2017 the Michigan Public Service Commission (MIPSC) ordered the major investor-owned utilities to develop five-year distribution plans (MIPSC 2017a).

11.1.1 Distribution Plans

In January 2017, the MIPSC issued an order in a DTE Electric Company rate proceeding approving a rate increase and ordering the utility to develop a five-year distribution plan. The Commission noted that it supported the investments needed to ensure that DTE's distribution system was safe, reliable, and resilient, but lacked the appropriate level of information needed to properly evaluate DTE's investment plans that a forward-looking plan would provide. Similarly, in February 2017, the Commission ordered the Consumers Energy Company to develop a five-year distribution plan.

Specifically, the MIPSC ordered DTE to submit a draft distribution plan to Commission Staff by July 1, 2017, and ordered Consumers to submit a draft plan by August 1, 2017 (MIPSC 2017a). Both utilities' draft plans were to be comprised of:

- a detailed description, with supporting data, on distribution system conditions, including age of equipment, useful life, ratings, loadings, and other characteristics;
- system goals and related reliability metrics;
- local system load forecasts;
- maintenance and upgrade plans for projects and project categories including drivers, timing, cost estimates, work scope, prioritization and sequencing with other upgrades, analysis of alternatives (including AMI and other emerging technologies), and an explanation of how they will address goals and metrics; and
- benefit/cost analyses considering both capital and [operations and maintenance] O&M costs and benefits. (MIPSC 2017a)

After submitting the draft plans, the utilities were to meet with Commission Staff and file final, completed plans in early 2018. The MIPSC also invited interested parties to comment on the draft plans.

While the MIPSC's orders directing the utilities to file distribution plans included detailed information on what the Commission wanted to see in the plans, the Commission acknowledged various directions the plans could go in terms of addressing near-term and long-term issues. Thus, after review of the draft

plans, the Commission clarified its expectations that the primary focus of these initial distribution plans should be on priority areas:

- Addressing aging infrastructure and defining the risk assessments needed to prioritize investments
- Identifying and addressing known safety concerns (e.g., third parties coming in contact with electric equipment)
- Improving resilience and mitigating the safety and financial issues related to weather
- Developing objectives and performance metrics to guide the utility's strategy for addressing the Governor's 2013 reliability goals. (MIPSC 2017a)

11.1.2 Related Planning Issues

In 2016 the Michigan Legislature passed two pieces of legislation that could eventually impact the distribution planning process. Public Act (PA) 341³⁶ revised laws related to electric capacity planning and established an IRP process. PA 342³⁷ updated Michigan laws related to renewable energy (MIPSC 2017b). The MIPSC has ongoing processes to implement the legislation.

³⁶ <http://www.legislature.mi.gov/documents/2015-2016/publicact/pdf/2016-PA-0341.pdf>

³⁷ <http://www.legislature.mi.gov/documents/2015-2016/publicact/pdf/2016-PA-0342.pdf>

12.0 Ohio

12.1 Summary of Distribution Planning Activities

Ohio's distribution planning-related policies include a Public Utilities Commission of Ohio (PUCO) grid modernization initiative, utility projects to modernize distribution systems, and state administrative codes focused on the reliability and performance of utility distribution systems.

12.1.1 PowerForward Initiative and Electric Security Plans

PUCO began its PowerForward initiative in April 2017 to “review technological and regulatory innovation to enhance the consumer electricity experience” and outline plans for “a clear path forward for future grid modernization” (PUCO 2017a). A series of workshops with industry experts is intended to assist the PUCO in developing a framework for the evolution of grid modernization in the state and study potential advances to the distribution network, including the following (PUCO 2017a):

- Grid innovation for the benefit of Ohio utility customers
- Key considerations for data integration and interoperability
- Enabling technologies for grid modernization
- Integrating DERs into the evolving grid
- Grid architecture and communications architecture
- Standards development

In recent electric security plan applications, Duke Energy Ohio and Ohio Power Company (American Electric Power, AEP) have included proposals for a rider to implement programs, products and services that advance PUCO's vision for the PowerForward initiative. Ohio Power's (AEP) plan includes, for example, installation of electric vehicle charging stations, microgrid technologies, and smart street lighting controls (AEP Ohio 2016).

12.1.2 Smart Grid Efforts

Ohio law established a state policy for electric service, enumerated in Ohio's R.C. 4928.02, which includes distribution system enhancements such as advanced metering infrastructure (AMI) and smart grid-related programs (State of Ohio 2012).

- PUCO approved an unopposed settlement for Phase 2 of Ohio Power's (AEP) gridSMART project, which lays out plans for AMI expansion, Distribution Automation Circuit Reconfiguration for about 250 circuits, and Volt/VAR optimization for approximately 80 circuits (PUCO 2017b).
- The Grid Modernization Business plan proposal for Ohio Edison, Cleveland Illuminating and Toledo Edison includes three scenarios with full deployment of AMI and advanced distribution management systems, plus Distribution Automation and Integrated Volt/VAR Control to varying degrees.³⁸

³⁸ See <https://dis.puc.state.oh.us/CaseRecord.aspx?CaseNo=16-0481>.

12.1.3 Distribution Modernization Rider

In 2016, PUCO approved a Distribution Modernization Rider (Rider DMR) for Ohio Edison, Cleveland Electric and Toledo Edison. The Rider DMR allows the companies to collect \$132.5 million annually for three years, with the potential for a two-year extension (PUCO 2016a, 2016b), to provide an infusion of capital so the companies will be financially healthy and able to make future investments in grid modernization. A similar Rider DMR was just approved for Dayton Power & Light (\$105 million annually for three years with a possible two-year extension).

12.1.4 State Administrative Codes

Ohio Administrative Code 4901:1-10-10 sets rules for reliability measurement, reliability performance standards, and reliability performance reporting.³⁹ The code requires utilities to develop company-specific CAIDI and SAIFI service reliability indices and minimum reliability performance standards through an open process. Utilities must also file an annual report with PUCO that includes performance data for each reliability and performance index. Each electric utility is also required to periodically (no less than every three years) conduct a customer perception survey. The survey results are to be used as an input to the methodology for calculating new performance standards. Ohio Administrative Code 4901:1-10-11 prescribes methods for determining distribution circuit performance, including provisions for reporting on the utilities worst-performing circuits.⁴⁰ Among others factors, these methods take into account circuit ID number, location, number of customers served, ranking value, SAIFI and CAIDI, and number of safety and reliability complaints. Remedial action must be taken to ensure that no circuit is listed on three consecutive reports of the worst-performing circuits.

Ohio Administrative Code 4901:1-10-26 requires electric utilities to annually file a report with PUCO on performance and reliability of distribution systems. The report must include plans for system investments and improvements.⁴¹ Among other requirements, these plans should look out at least three years into the future, cover the entire service territory, characterize the condition of the system, provide a timetable for improvements, and give details of distribution system budgets and expenditures.

³⁹ Ohio Administrative Code 4901:1-10-10 is at <http://codes.ohio.gov/oac/4901:1-10-10>.

⁴⁰ Ohio Administrative Code 4901:1-10-11 is at <http://codes.ohio.gov/oac/4901:1-10-11>.

⁴¹ Ohio Administrative Code 4901:1-10-26 is at <http://codes.ohio.gov/oac/4901:1-10-26>.

13.0 Oregon

13.1 Summary of Distribution Planning Activities

Several Oregon Public Utility Commission (OPUC or Commission) requirements relate to electric distribution planning, summarized below.

13.1.1 Distribution System Investment Report Filings

Oregon Administrative Rule 860-027-0015 (Oregon Secretary of State 2017) requires regulated electric utilities to submit, by November 1 each year, an annual construction budget for major distribution and transmission investments for Commission review. The utilities report on new construction, as well as extensions and additions to their property, for all projects that cost more than \$10 million. The Commission is not required to take any action on the filings.

13.1.2 Smart Grid Reports

Oregon utilities are required to file smart grid reports with the Oregon PUC every two years. When smart grid report guidelines were originally drafted in 2012 (Order 12-158), plan submittals were required annually. In 2017, the Commission reduced the filing requirements to once every two years (Order 17-290) to allow utilities more time for detailed analysis between cycles (OPUC 2017a).

Smart grid reports must include the following (OPUC 2012):

- Smart grid strategy, goals, and objectives
- Status of smart grid investments in the following categories:
 - transmission network and operations enhancements
 - substation and distribution network and operations enhancements
 - customer information and demand-side management enhancements
 - distributed resource and renewable resource enhancements
 - general business enhancements, including communications and supporting systems
- Smart grid investments and applications it plans to undertake within the next five years, including:
 - how investments fit with the utility IRP
 - how investments fit with the utility's annual construction budget for major distribution and transmission investments
 - how investments will reduce customer costs, improve customer service, improve reliability, and facilitate demand-side resources and renewable resources
- Smart grid opportunities and constraints
- Targeted evaluations
- Related activities

13.1.3 Integrated Resource Plans

Since 1989, Oregon utilities have been required to file IRPs every two years. The goal of the IRP is to identify the best mix of both supply- and demand-side resources that provides an adequate and reliable supply of energy with the best combination of cost and risk to the utility and its customers (OPUC 2016). Currently, IRPs only marginally address distributed resources from a total demand/supply balance perspective. Explicit consideration of distribution system needs and operations needs are not addressed in IRPs.

13.1.4 Proposed Designated Distribution Planning Process

In staff comments on an IRP submitted by Portland General Electric in 2016, Oregon PUC Staff indicated that because costs are declining and interest growing in new technologies such as storage, electric vehicles, communications and controls, and distributed generation, it is time for the utility to create a comprehensive, transparent plan for grid modernization through distribution system planning with a planning horizon of 5 to 10 years. According to PUC Staff, distribution system planning would allow for the evaluation of cost-effective integration of new technologies and encourage the most beneficial placement and efficient use of new DERs. In May 2017, Oregon PUC Staff recommended that a new Distribution System Planning docket be initiated prior to submittal of Portland General Electric's next IRP (OPUC 2017b). On August 8, 2017, the Commission acknowledged Staff's recommendation for the utility to work with Staff to define a proposal for opening a distribution system planning investigation.⁴²

13.1.5 Other Related Activities

Other related activities at the Oregon PUC include a Resource Value of Solar docket (Docket No. UM 1716),⁴³ an energy storage docket (Docket No. UM 1751),⁴⁴ Community Solar Rulemaking (AR 603), three dockets on transportation electrification programs (Docket Nos. UM 1810, UM 1811, and UM 1815), a docket on energy efficiency avoided costs (Docket No. UM 1893), and Portland General Electric's Demand Response cost-effectiveness methodology (Docket No. UM 1708).⁴⁵

⁴² See <http://apps.puc.state.or.us/orders/2017ords/17-386.pdf>.

⁴³ See <http://apps.puc.state.or.us/edockets/Docket.asp?DocketID=19362&Child=action>.

⁴⁴ See <http://apps.puc.state.or.us/edockets/docket.asp?DocketID=19733>.

⁴⁵ See <http://apps.puc.state.or.us/edockets/docket.asp?DocketID=19228>.

14.0 Pennsylvania

14.1 Summary of Distribution Planning Activities

Under Pennsylvania law, utilities under the jurisdiction of the Public Utilities Commission may approve a special charge for recovery of costs for eligible distribution system investments and are required to file distribution system plans as a part of that process. Utilities also must file system reliability reports. Some Pennsylvania utilities have begun to invest in grid modernization technologies.

14.1.1 Distribution System Investment Report Filings

Since 2013, Pennsylvania’s System Improvement Charges Act 11 of 2012 (66 Pa.C.S. § 1353 (a)) has enabled electric distribution companies (as well as natural gas, water, and wastewater utilities) to seek Commission approval to implement a Distribution System Improvement Charge (PA PUC 2012). The charge is intended to provide for timely recovery of costs incurred to repair, improve, or replace eligible property to ensure “adequate, efficient, safe, reliable and reasonable service” (State of Pennsylvania 2012).

The Act requires utilities that wish to implement a Distribution System Improvement Charge (DSIC) to submit a Long-Term Infrastructure Improvement Plan (LTIIP) that includes investment needs and justification of proposed investments. LTIIPs are subject to Commission review at least once every five years.

Utilities with an approved LTIIP and DSIC must submit an asset optimization plan annually. The asset optimization plan describes distribution system investments made in the last year and facilities to be improved in the next 12 months (State of Pennsylvania 2012).

In 2016, LTIIPs were approved for Duquesne Light and the FirstEnergy utilities. PECO Energy’s LTIIP was approved in 2015. PPL has had an approved LTIIP since 2013 and filed for a new LTIIP in 2017, as did UGI Electric. An example of FirstEnergy utilities’ long-term infrastructure improvement plans can be found under Docket Number P-2015-2508936.⁴⁶

14.1.2 Smart Grid Reports

The Pennsylvania PUC has approved smart meter installation plans and recovery of costs for investment in smart meters by PECO, Duquesne, PPL, and FirstEnergy utilities in Docket No. PA M-2009-2092655.⁴⁷ The utilities file annual progress reports for their smart meter initiatives.⁴⁸

14.1.3 Other Related Activities

Pennsylvania utilities are required to maintain minimum reliability standards and report quarterly on their system’s reliability based on four metrics: system average interruption frequency index (SAIFI), customer average interruption duration index (CAIDI), system average interruption duration index (SAIDI), and momentary average interruption frequency index (MAIFI) (PA PUC 2016a; State of Pennsylvania 1998).

⁴⁶ PA PUC (2015).

⁴⁷ See http://www.puc.state.pa.us/about_puc/consolidated_case_view.aspx?Docket=M-2009-2092655.

⁴⁸ See PA PUC (2017) for an example of PPL’s report.

Pennsylvania's distribution reliability code directs the PUC to regulate electric distribution companies' distribution inspection and maintenance plans, requires companies to report quarterly on the worst-performing circuits, and requires them to make annual compliance filings (PA PUC 2016a; State of Pennsylvania 2004).

As part of PECO's 2015 LTIP, the utility expressed its intention to develop one or more microgrids in the five-year plan period (PA PUC 2016b). In 2016, PECO petitioned for permission to initiate and recover costs for a Microgrid Integrated Technology Pilot (Docket No. P-2016-2546452).⁴⁹ The PECO petition was subsequently voluntarily withdrawn, and PECO has undertaken a stakeholder collaborative to further discuss the regulatory and technical issues related to utility microgrids.

⁴⁹ PECO sought to recover pilot costs that could not be recovered through its DSIC.
http://www.puc.state.pa.us/about_puc/search_results.aspx

15.0 Rhode Island

15.1 Summary of Distribution Planning Activities

Rhode Island utilities have been required to develop plans for system reliability and least cost procurement since 2006 (RI PUC 2008). The state is currently taking steps to implement policies to modernize its electric grid.

15.1.1 System Reliability and Procurement Reporting

Rhode Island’s electric and gas utilities⁵⁰ submit System Reliability Procurement reports annually pursuant to the state’s System Reliability and Least Cost Procurement statute, R.I. Gen. Laws § 39-1-27.7. The Comprehensive Energy Conservation, Efficiency and Affordability Act of 2006 forms the basis for the least cost procurement system of reliability in the state (National Grid 2016).

According to the PUC’s Least Cost Procurement Standards (July 2017), “Energy Efficiency procurement, as mandated by §39-1-27.7, is intended to complement system reliability and supply procurement as provided for in §39-1-27.8” (RI PUC 2017). System Reliability Procurement standards set forth guidelines to incorporate non-wires alternatives in distribution system planning. These alternatives include energy efficiency, distributed generation, demand response, and other energy technologies (RI PUC 2017).

15.1.2 Grid Modernization Plans

Starting in 2014, the Rhode Island Office of Energy Resources (OER), the Energy Efficiency and Resource Management Council, the Distributed Generation Board, and National Grid convened a working group to build upon existing energy processes to support future objectives for their electric grid (OER 2016). In 2016, in advance of the state’s grid modernization proceedings, OER released its *Systems Integration Rhode Island Vision*.⁵¹ The document defines systems integration; identifies goals, foundations, and principles; describes existing processes; considers test case scenarios to evaluate; and offers recommendations on how to proceed with Rhode Island’s efforts (OER 2016).

In 2017, the governor requested three agencies—the Rhode Island Public Utilities Commission (PUC), OER, and the Division of Public Utilities and Carriers (DPUC)—to design a new regulatory framework for the state’s electric system, in part toward achieving Rhode Island’s goal of integrating nearly 1,000 MW of renewable energy by 2020 (Proudlove et al. 2017; Raimondo 2017).

Known as the Power Sector Transformation Initiative, it has three objectives: control long-term costs of the system, provide more energy choices for customers, and build a flexible grid to integrate more clean energy generation (RI DPUC and OER 2017). Distribution system planning is one of four work streams (R.I. DPUC, OER and PUC 2017).⁵² This work stream is considering what outcomes should be promoted by distribution system planning, what aspects of utility operations it should address, and how accessible planning should be to third parties.

⁵⁰ The law currently only applies to NGrid.

⁵¹ See OER (2016).

⁵² The other three work streams are utility business models, grid connectivity functionality, and electrification of transportation and heating.

The Rhode Island agencies held technical meetings in spring 2017, facilitated stakeholder engagement with draft proposals over the summer, and requested comments on potential distribution system planning improvements by early September. Proposals are to be presented in fall 2017. The DPUC and OER, with input from PUC Staff, are slated to finish a review of proposals by June 2018 (R.I. DPUC, OER and PUC 2017).

Although the Power Sector Transformation Initiative is currently an undocketed process, OER and DPUC may use National Grid's upcoming rate case, its Annual System Reliability Procurement Plan, or its Annual Infrastructure, Safety, and Reliability Plan as a path for implementation.

15.1.3 Inquiry into Distribution System Planning

In March 2016, the Rhode Island PUC opened Docket No. 4600, Investigation into the Changing Electric Distribution System, and invited stakeholders to submit comments.⁵³ The investigation led to a stakeholder report laying out a set of goals—including rate design principles and a benefit-cost framework for valuing resources on the distribution system—for guidance in regulating National Grid's electric business. National Grid manages the distribution system for 99 percent of the state (RI Division of Planning 2015). The PUC adopted the goals, rate design principles, and benefit-cost framework in the report through Order 22851 in July 2017. Currently, the PUC has issued for public comment draft guidance on how the PUC will apply these adopted elements to National Grid's future regulatory cases.⁵⁴

⁵³ See Docket No. 4600 at <http://www.ripuc.org/eventsactions/docket/4600page.html>.

⁵⁴ See Order 22851 at http://www.ripuc.org/eventsactions/docket/4600-NGrid-Ord22851_7-31-17.pdf.

16.0 Washington

16.1 Summary of Distribution Planning Activities

The Washington Utilities and Transportation Commission (WUTC or Commission) is currently considering two distribution planning-related proceedings. In addition, the WUTC required utilities to file annual smart grid reports through 2016.

16.1.1 Role of Energy Storage in Electric Utility Planning and Procurement (UE-151069)

In May 2015, the WUTC initiated a staff investigation into the role of energy storage in electric utility planning and procurement. A WUTC Commission Staff (Staff) white paper identified barriers to energy storage related to the way Washington utilities modeled storage in IRPs (WUTC 2017). The Staff white paper recommended that the Commission provide structured guidance through a policy statement (WUTC 2017). In response to this recommendation, in March 2017 the Commission issued a draft report and policy statement on treatment of energy storage technologies in IRP and resource acquisition. Eighteen interested parties submitted comments on the Commission report and policy statement. The Commission issued the final policy statement on October 11, 2017.

The policy statement recommended that a stacked benefits approach be considered and that utilities move toward sub-hourly modeling. It also noted that while the policy statement dealt with energy storage at the system planning level, the Commission intends to develop rules guiding the treatment of energy storage and other distributed energy resources in its ongoing integrated resource plan rulemaking. The Commission suggested that detailed work needs to be done to disaggregate the multiple value streams of energy storage and incorporate them into a tariff design.

16.1.2 Integrated Resource Planning/Acquisition Rulemaking

In September 2016, the Commission initiated a rulemaking proceeding (U-161024) to consider revising its rules related to Integrated Resource Planning (WAC 480-90-238 [natural gas] and WAC 480-100-238 [electric]) and its resource acquisition rule (WAC 480-107) (WUTC 2016a). The rulemaking intends to address the following subjects (WUTC 2016b):

- Flexible resource modeling
- Requests for proposals
- Avoided costs
- Transmission and distribution
- Procedural issues

The Commission has held workshops on integrating transmission and distribution planning and considerations associated with Public Utility Regulatory Policies Act (PURPA) and avoided-cost methodologies. Through the rulemaking proceeding, the Commission is exploring whether IRP modeling can be improved to better account for distribution system impacts such as electric vehicles, changes in end use, and distributed generation. The Commission's draft policy paper that addresses energy storage also addresses the IRP rulemaking.

Commission Staff has issued a draft straw proposal for distribution planning in which the rule would identify some subset of the distribution system where there are potential investment needs, based on reliability problems, local load growth, aging equipment, etc. For each of those identified needs, utilities would be required to present an analysis of all investment options for meeting the need—wires and non-wires—and identify the most cost-effective resource.

16.1.3 Smart Grid Report Filings

The State of Washington Administrative Code (WAC) 480-100-505 (2010) includes a requirement for each electric utility to submit periodic reports to the Commission on the utility's evaluation of smart grid technologies that are available or likely to be available soon and on plans for implementing smart grid technologies affecting or applicable to ratepayers of Washington state (WAC 480-100-505 2010). Electric utilities were required to file smart grid technology reports by September 1, 2010, and subsequent reports no later than September 1 of each even-numbered year thereafter through September 2016, unless otherwise ordered by the Commission.⁵⁵ Smart grid reports must include the following (WAC 480-100-505 2010):

- Description of smart grid technologies the utility has considered
- Identification of smart grid technologies that may be cost effective and available for the utility and its customers during the subsequent ten-year period
- A description of the utility's plans and timelines for implementing any smart grid technologies during the two years following submission of the report

In the IRP rulemaking, the Commission is considering whether to extend the smart grid reporting requirement.

16.2 Proposed DER planning requirements

House Bill 1233, proposed in the 2017 Washington state legislative session, would have required utilities to submit an annually updated, 10-year DER plan to the WUTC. The proposed bill stated that the DER plan may inform and be incorporated within the utility's IRP or other resource plan (WA-OPR 2017).

Though HB 1233 did not pass, the legislature directed the UTC to prepare a report and recommendations on distribution planning practices. The report is due to the legislature by December 31, 2017.

⁵⁵ As of the writing of this document, the Commission has not yet ordered that the Smart Grid reports be extended beyond September 2016. WUTC staff indicate that the issue may be addressed in the IRP Rulemaking proceeding (U-161024).

III. Conclusions

While most states have not yet begun to directly engage in longer-term (five to 10 year) planning for electric distribution systems, New York, California, Hawaii, Massachusetts, and Minnesota are early adopters. Several additional states, such as those featured in this report, are beginning to adopt long-term distribution system planning requirements for regulated utilities or are exploring such requirements. These efforts are building on existing distribution reliability and performance codes and PUC reviews of grid modernization investments proposed by regulated utilities.

Beyond universal PUC interest in affordability and reliability, drivers for improved and more transparent distribution system planning processes include interest in more efficient operation of the distribution system, enabling greater consumer engagement, the need to replace aging infrastructure, opportunities to adopt grid modernization technologies for the benefit of consumers, addressing higher levels of DERs due primarily to cost reductions and public policies, and potential net benefits to customers for grid services provided by these resources.

Approaches to state engagement in distribution system planning and grid modernization planning vary widely. They range from a cohesive set of requirements laid out in state statute or PUC orders, to an ad hoc requirement in a general rate case decision for the utility to file an initial long-term distribution system plan or grid modernization plan.

Some PUC distribution planning processes are tied to greater utility assurance of cost recovery for proposed distribution investments that are included in approved plans.

Common *emerging* distribution system planning elements include DER forecasting, assessing DER locational value, analyzing hosting capacity, assessing non-wires alternatives, and engaging stakeholders (including third-party service providers) in proposed planning processes and filed utility plans to help identify solutions to distribution system needs.

Some states also are exploring new procurement mechanisms, such as competitive solicitations, and pricing programs to consider DERs as non-wires alternatives to meet certain distribution system needs (e.g., load relief) and ways to modify the utilities' annual capital planning process to account for these options.

Integration of distribution planning with other electric grid planning processes, including integrated resource planning (in states with vertically integrated utilities), transmission planning, and demand-side management planning, is of increasing interest. Such efforts are still nascent. Some early steps may include consistency in inputs, such as forecasts for loads and types and levels of distributed energy resources, scenarios, and modeling methods—updated in time—across these planning processes. The regulatory landscape is changing rapidly in this area. This report provides a snapshot of the early phase of adoption of new distribution system planning processes.

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Appendix A. California

A.1 Utility Distribution Resource Plan (DRP) Filings

Utilities filed their DRPs in July 2015. This section describes the initial Demo Projects A and B and challenges identified in DRP filings.

In the filings, PG&E, SCE, and SDG&E proposed Demo Projects A and B to utilize integrated capacity analysis (ICA) and locational net benefits analysis (LNBA) as directed.

PG&E proposed the following demo projects in its DRP (CPUC 2016a):

- Demo A (Central Fresno Distribution Planning Area) – The expected load in 2020 is 490 MW and expected DER is 80 MW. This involves approximately 92,500 customers served by four substations.
- Demo B – PG&E is proposing to demonstrate its Optimal Location (Net) Benefit Methodology on the Central Fresno Distribution Planning Area. PG&E is considering one near-term (0–3 years) project involving deferral of increasing distribution transformer capacity and one long-term (greater than 3 years) project, by evaluating whether the distribution transformer capacity can be deferred beyond three years.

SCE proposed the following demo projects in its DRP (CPUC 2016a):

- Demo A – The study will be completed on an “A” level substation in the Orange County area using dynamic modeling techniques using power system modeling software CYME and the transmission modeling tool PSLF.
- Demo B – No specifics are given of the project other than that a project will be developed and the report will be finalized approximately 12 months after Commission approval of the DRP.

SDG&E proposed the following demo projects in its DRP (CPUC 2016a):

- Demo A – SDG&E will undertake a dynamic ICA of each line section—defined as a segment of a circuit, reflecting impedance along the main feeder—in its service territory. Circuits will be analyzed based on thermal, voltage, and protection limits. SDG&E will use Synergi power flow software and its suite of automation tools, including the new dynamic modeling module.
- Demo B – SDG&E intends to analyze the Oceanside area to determine whether a new distribution substation can be deferred.

A.2 Value Components in LNBA

In PG&E’s DRP submittal, it included a detailed list of value components it will include in its locational net benefit calculations. These are listed, with brief descriptions, in A.5, below.

A.3 Challenges Identified

The following key challenges were synthesized from utility DRP filings (CPUC 2015a):

- **Reliability:** Concerns about a number of reliability-related issues associated with increasing DERs were expressed in DRPs. Of particular concern was relying on DERs to address distribution capacity

and reliability needs. Prior Commission decisions required distributed generation to provide physical assurance when acting as an alternative to distribution system upgrades.

- **Markets and T&D interface:** Uncertainty and concerns about the capacity of the system to accommodate and integrate DERs were expressed, and questions were raised as to how to best harmonize DERs to meet market and local reliability needs. Reliability and DER integration were also of concern for utilities at the interface between T&D systems.
- **Safety:** Concerns were expressed with worker safety and a lack information about DER equipment that workers need to safely respond to emergencies.
- **Forecasting and models:** Concerns were expressed about ability to predict DER adoption, lack of detailed modeling of multiple DER technologies and behind-the-meter resources, and lack of a common model of information and processes.
- **Interconnection and tariffs:** It was suggested that the interconnection request process should be revised to handle the growing number of DER interconnection requests, and that interconnection tariffs need to accommodate emerging technologies. Concerns were also expressed about permitting and the flexibility needed for speedy regulatory approval processes for DERs.

A.4 Hosting Capacity Analysis Details

In the Commission’s May 2016 direction in R.14-08-013, a common “baseline” hosting capacity methodology derived from PG&E’s proposed approach was established, and utilities were directed to use it in Demo A (CPUC 2016a). The methodology contains the following four steps:

1. **Establish distribution system level of granularity:** Perform analysis down to specific nodes within each line section of individual distribution feeders. Nodes shall be selected based on impedance factor. Minimum and maximum ranges of results shall be evaluated using lowest and highest impedance.
2. **Model and extract power system data:** A load forecasting analysis tool (e.g., LoadSEER) shall be used to develop load profiles at the feeder, substation, and system levels by aggregating representative hourly customer load and generation profiles. Load profiles must be created for each Distribution Planning Area. Load profiles comprise 576 data points representing individual hours for the 24-hour period during a typical low-load day and typical high-load day for each month (2 days × 24 hours × 12 months = 576 points). A Power Flow Analysis Tool (e.g., CYMEDist for PG&E and SCE and Synergi Electric for SDG&E) shall be used to model conductors, line devices, loads, and generation components that affect distribution circuit power quality and reliability.
3. **Evaluate power system criteria to determine DER capacity:** The Load Forecast Tool and Power Flow Analysis Tool shall be used to evaluate power system criteria for the nodes and line sections that determine DER capacity limits on each distribution feeder. ICA results are dependent on the most limiting power system criteria and could include thermal criteria (equipment ratings), power quality/voltage criteria (fluctuations up to 3 percent), protection criteria (still being developed, but based on amount of fault current fed from sub-transmission due to DER operation), or safety/reliability criteria.
4. **Calculate ICA results and display on online map:** ICA calculations shall be performed using a layered abstraction approach, where each criteria limit is calculated for each layer of the system independently and the most limiting values are used to establish the integration capacity limit. ICA data shall be made publicly available in an SQL server database using the Renewable

Auction Mechanism (RAM) Program Map. The ICA maps shall be available online and shall provide a user with access to the results of the ICA by clicking on a feeder displayed on the map.

In the Commission’s May 2016 Commission ruling, utilities are directed to modify the baseline methodology in Demo A according to the nine functional requirements listed below. In the ruling, details are provided on each of the nine functional requirements (CPUC 2016a):

1. Quantify the capability of the distribution system to host DER.
2. Use a common methodology across all IOUs.
3. Analyze different types of DERs.
4. Conduct analysis down to the line section or nodal level on the primary distribution system.
5. Determine thermal ratings, protection limits, power quality (including voltage), and safety standards.
6. Publish the results via online maps.
7. Use time series models.
8. Avoid heuristic approaches, where possible.
9. Demonstrate dynamic ICA using two DER scenarios, including no backflow and maximum DER capacity irrespective of power flow direction.

A.5 Value Components Considered in PG&E’s Locational Net Benefits Analysis

#	Component	PG&E Definition
1	Sub-Transmission, Substation, and Feeder Capital and Operating Expenditures (Distribution Capacity)	Avoided or increased costs incurred to increase capacity on sub-transmission, substation, and/or distribution feeders to ensure system can accommodate forecast load growth
2	Distribution Voltage and Power Quality Capital and Operating Expenditures	Avoided or increased costs incurred to ensure power delivered is within required operating specifications (i.e., voltage, fluctuations, etc.)
3	Distribution Reliability and Resiliency Capital and Operating Expenditures	Avoided or increased costs incurred to proactively prevent, mitigate, and respond to routine outages (reliability) and major outages (resiliency)
4	Transmission Capital and Operating Expenditures	Avoided or increased costs incurred to increase capacity on transmission line and/or substations to ensure system can accommodate forecast load growth
5a	System or Local Area Resource Adequacy (RA)	Avoided or increased costs incurred to procure RA capacity to meet system or CAISO-identified Local Capacity Requirement (LCR)
5b	Flexible RA	Avoided or increased costs incurred to procure Flexible RA capacity
6a	Generation Energy and GHG	Avoided or increased costs incurred to procure electrical energy and associated cost of GHG emissions on behalf of utility customers
6b	Energy Losses	Avoided or increased costs to deliver procured electrical energy to utility customers due to losses on the T&D system
6c	Ancillary Services	Avoided or increased costs to procure ancillary services on behalf of utility customers

6d	RPS	Avoided or increased costs incurred to procure RPS eligible energy on behalf of utility customers as required to meet the utility's RPS requirements
7	Renewables Integration Costs	Avoided or increased generation-related costs not already captured under other components (e.g., Ancillary Services and Flexible RA capacity) associated with integrating variable renewable resources
8	Any societal avoided costs which can be clearly linked to the deployment of DERs	Decreased or increased costs to the public which do not have any nexus to utility costs or rates
9	Any avoided public safety costs which can be clearly linked to the deployment of DERs	Decreased or increased safety-related costs which are not captured in any other component

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Appendix B. New York

B.1 Potential Non-Wires Alternatives (NWA) Projects

Table B.1. Consolidated Edison Potential NWA Projects as of May 8, 2017 (NY PSC 2017a)

NWA Opportunity Listing	Project Type	Need Date	Project Size	Estimated RFP Timing
Water Street - Install Cooling on all Area Substation Transformers	Load relief	2019	Large	Project is under engineering review; Solicitation expected prior to Aug. 1, 2017
Water Street - Install additional Cooling on Farragut 345/135kV Transformers	Load relief	2019	Large	Project is under engineering review; Solicitation expected prior to Aug. 1, 2017
Cable Crossings (Flushing, Yorkville)	Load relief	2019	Small	Solicitation for Flushing are expected by Jul. 1, 2017
Plymouth Street - Install additional Cooling on Farragut 345/135kV Transformers	Load relief	2020	Large	Project is under engineering review; Solicitation expected prior to Aug. 1, 2017
Plymouth Street - Uprate Feeders 32072, 32076, 32078 and 32710	Load relief	2020	Large	Project is under engineering review; Solicitation expected prior to Aug. 2017
Part of Ridgewood/Brownsville to Glendale (60 MW) BQDM Traditional Solution	Load relief	2019	Large	Solicitation timeline to be determined pending BQDM Extension ⁶
Vernon to Glendale - Replace Limiting Sections of Cable	Load relief	2021	Large	Solicitation timeline to be determined pending BQDM Extension
New 138kV Feeder Vernon-Glendale and Newtown and Install 5th transformer at Glendale	Load relief	2021	Large	Solicitation timeline to be determined pending BQDM Extension
Load Transfer W. 42st No. 1 To Astor	Load relief	2022	Large	Solicitations expected by Aug. 2017
Uprate Syn Bus Sections at W. 65 th Street	Load relief	2026	Large	Project deferred due to decrease in the projected load

Table B.2. Planned Project Solicitations by National Grid (NY PSC 2017b)

Project Name/Description	Project Type	Status	Loading Relief Needed	Voltage Type	Project Size	Estimated RFP Timing	Need Timing
Baldwinsville	Load Relief	Proposal Review	4-6 MW	Distribution	Large	N/A	2023+
Old Forge	Reliability	RFP Posted	13 MW	Distribution/ Sub-Transmission	Large	RFP Posted	2023+
Brooklea Dr.	Load Relief	RFP Development	140 kW	Distribution	Small	May-2017	2020
Gilbert Mills	Load Relief	RFP Development	1.7 MW	Distribution	Small	May-2017	2023+
Van Dyke	Load Relief	RFP Development	6 MW	Distribution	Large	Jun-2017	2020
Golah-Avon	Load Relief	RFP Development	6 MW	Sub-Transmission	Large	Jul-2017	2021
Buffalo 53	Load Relief	RFP Development	1 MW+	Distribution / Sub-Transmission	Large	Aug-2017	2020

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