Distribution System Planning Workgroup

Final Report

Facilitated by:

EnerNex

A CESI Company

Final Report Version Control

Version	Date	Author	Change Description
1.0	11/18/19	NPlacer	Initial Draft
1.1	11/26/19	NPlacer	Initial Draft — Revised Structure & Formatting
1.2	12/04/19	NPlacer, ASnyder	Initial Draft — Additional Revisions to Structure & Formatting, Interconnection Summary update
1.3	12/09/19	NPlacer, PCentolella, SMorash	Initial Draft — Additional Revisions to Conclusion and Recommendations by Section, Executive Summary refinement
2.0	12/11/19	NPlacer	Initial Draft — Finalization for Initial Stakeholder Release
2.1	12/31/19	NPlacer, MMcBeath, RChebra, KStefferud ASnyder, PCentolella	Near-Final Draft — Incorporation of stakeholder feedback from Initial Draft, additional EnerNex and external edits
3.0	01/03/20	NPlacer	Near Final Draft — Finalization for 2nd stakeholder release
3.1	01/13/20	NPlacer, RChebra, SMorash, KStefferud ASnyder, BRankin, PCentolella NPlacer	Final edits to document following 2nd stakeholder review and review team edits
4.0	01/15/20	EnerNex	Finalization of Final Report for Commission Filing

Table of Contents

Section 1.0 Introduction

In 2017, the Public Utilities Commission of Ohio (the Commission or PUCO) announced a program entitled PowerForward to advance a comprehensive grid modernization strategy. PowerForward was built upon the pairing of two pillars: (i) innovation and (ii) service that enhances the Customer electricity experience.[1] PowerForward consisted of three open meeting phases:

Phase 1: A Glimpse of the Future
Phase 2: Exploring Technologies
Phase 3: Ratemaking and Regulation

Over the duration of the three phases of the program, 127 industry experts provided approximately 100 hours of education to the PUCO Commissioners, members of PUCO Staff (Staff), industry stakeholders, and interested members of the public regarding a variety of grid modernization topics.

On August 29, 2018, the Commission released "PowerForward: A Roadmap to Ohio's Electricity Future" (Roadmap).[2] The Roadmap makes several recommendations about the future of the distribution system and further recommends the creation of a PowerForward Collaborative (Collaborative) along with two additional workgroups, the Distribution System Planning Workgroup (PWG) and the Data and Modern Grid Workgroup (DWG). The Collaborative, PWG, and DWG will continue robust discussions related to the PowerForward program, will address specific tasks articulated in the Roadmap, and will make recommendations to the Commission following discussions between Staff and interested stakeholders.

By entry issued on October 24, 2018, the Commission established the PWG[3] to identify issues that currently exist or that may arise in the integrated distribution planning (IDP) process. The PWG stakeholder group assembled for 13 meetings between March 27, 2019 and January 10, 2020. Meetings were attended by approximately 40 participants across four identified stakeholder groups:

1) Electric distribution utilities (EDUs)
2) Customers and Consumer Groups
3) Competitive retail electric service (CRES) providers
4) Third Parties[4]

All stakeholders were given an opportunity to voice their views and to consider the perspectives of other stakeholders. EnerNex's role was to serve as an independent consultant to facilitate and coordinate group meetings and to provide recommendations to the Commission based on stakeholder discussion and EnerNex's independent expertise.[5] This report captures the key elements, discussions, and recommendations gathered as a result of these meetings and the ongoing work of the Staff and EnerNex. Nothing in the PWG Final Report shall be binding upon the Commission in this or any future proceeding, nor shall it serve to supersede any previous Commission Order or directive.

1 This draft adopts the convention of capitalizing stakeholder names and defined terms, such as Customer, except when sourcing quoted text
2 https://www.puco.ohio.gov/industry-information/industry-topics/powerforward/powerforward-a-roadmap-to-ohios-electricity-future/
3 http://dis.puc.state.oh.us/DocumentRecord.aspx?DocID=d91dd3b0-5d0e-4f43-ac0f-705a90f66c5c
4 "Third Parties" includes environmental non-profit organizations and vendors of energy-related products and services.
5 http://dis.puc.state.oh.us/DocumentRecord.aspx?DocID=cd5d5659-c3a0-4266-829f-51be34feab56

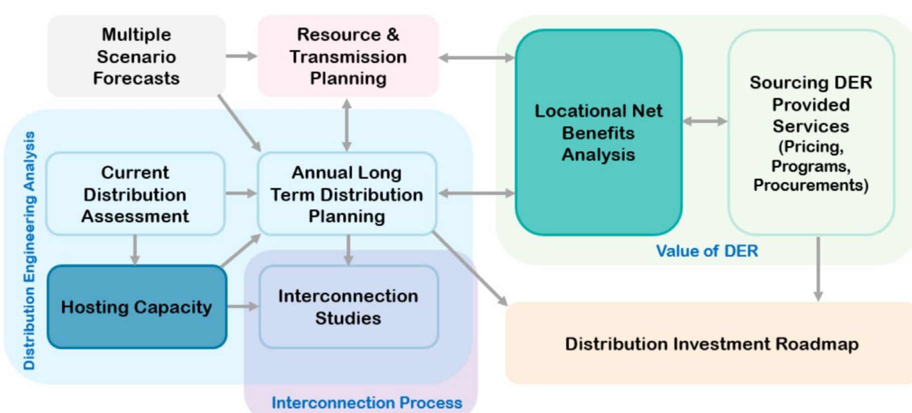
Section 2.0 Executive Summary

Like many other grid modernization topics, distribution system planning (DSP) is evolving across the utility industry and involves a spectrum of activities across multiple jurisdictions. A holistic approach to this type of enterprise planning will be instrumental in shaping the progress of the utility industry and will require a focused and concerted effort between utilities, regulators, and legislative bodies. Best practices from other jurisdictions can and should be leveraged wherever appropriate; however, how these practices can most effectively be adapted to another jurisdiction depends on the local context.

A common strategic planning approach is to classify the jurisdiction's current and desired end states and then define a pathway to close the gaps between these states over a targeted time frame. The Roadmap broadly describes desired grid modernization outcomes. The primary objectives of this transition are to: 1) create a strong distribution grid[6] that 2) utilizes the grid as a secure, open access platform for evolving applications, that 3) creates a robust marketplace for innovative products and services, and 4) enables an enhanced customer experience[7]. In the context of these larger grid modernization objectives, DSP and its transition to an IDP, plays an important role.

IDP is an evolution of DSP that is characterized by "more cohesive and multidisciplinary planning with a wider and more complex range of engineering and economic valuation issues" [8]. Additionally, "stakeholder participation and transparency into the planning process becomes increasingly important,"[9] assuming that data sharing can be done without putting sensitive information at risk. The Roadmap goes further to state that an IDP is "where utility distribution systems will integrate and responsibly accommodate non-utility assets" and "in addition to internal coordination across utility divisions, continuing development of technology and the increased presence of non-EDU stakeholders require collaboration between EDUs and non-EDUs"[10]. A visual representation of these interrelated issues is shown in Figure 1, some of which were addressed within the scope of the PWG (Section 2.2).

Figure 1: Integrated Distribution Planning[11]



[6] A strong distribution grid means reliable, resilient, optimized, efficient, and planned in a manner that recognizes the necessity for change
[7] Based on Roadmap objectives at 9.
[8] See Department of Energy (DOE) Modern Distribution Grid Volume 1 at 41, https://gridarchitecture.pnnl.gov/media/Modern-Distribution-Grid_Volume-I_v1_1.pdf
[9] Ibid
[10] See Roadmap at 18-19
[11] See DOE Modern Distribution Grid Volume 3 at Fig. 16, https://gridarchitecture.pnnl.gov/media/Modern-Distribution-Grid-Volume-III.pdf.

This report is based on a snapshot of the current state of the distribution system in Ohio as well as best practices identified in other jurisdictions. Additionally, it incorporates views from the PWG stakeholders and offers recommendations from EnerNex regarding near-term steps that can be taken to move closer to the suggested Roadmap end state. The intention of this report is to make recommendations to the Commission and to serve as a launch point to help shape future discussion and implementation of distribution planning practices in Ohio. An evolution toward IDP practices requires multiple incremental steps that each employ deliberate processes to effectively achieve the overarching goals.

2.1 Local Context

To begin the PWG stakeholder discussions, each of the Ohio EDUs (Ohio Power Company, Duke Energy of Ohio, Inc., the Dayton Power and Light Company, the Toledo Edison Company, the Ohio Edison Company, and the Cleveland Electric Illuminating Company) provided current-state assessments, filed on April 1, 2019.[12] These assessments included an overview of the distributed energy resources (DERs)[13] interconnected within each EDU territory as well as the non-wires alternatives (NWA) identified and/or considered. The key findings across the EDUs were as follows:

- Although there are differences in DSP capabilities across the Ohio EDUs, each EDU falls within an expected range of traditional planning practices[14]. From an EDU perspective, traditional DSP practices have enabled them to consistently meet distribution service reliability standards.
- The combination of limited smart meter data and traditional DSP practices hinders the ability of EDUs to optimize their system[15].

EnerNex also compared the EDUs' current practices in Ohio to best practices elsewhere in the country. While not every best practice implemented in other jurisdictions may be applicable for Ohio at this time, they suggest a direction in which Ohio planning practices could evolve and develop. For example, DSP processes are sometimes coupled with integrated resource planning in other jurisdictions. As a "restructured" state,[16] Ohio EDUs are not required to file an integrated resource plan (IRP); therefore, this approach is not directly applicable. However, the Commission's intent to establish a more coordinated and comprehensive IDP process can still be pursued at a distribution level.

Some of EnerNex's key observations on the differences between current practices in Ohio and best practices in other states are as follows[17]:

[12] Current state assessments for all four EDUs can be found at http://dis.puc.state.oh.us/CaseRecord.aspx?CaseNo=18-1596.
[13] This report follows the definition of DER used in the Roadmap at 10, footnote 2 (which references a NARUC definition).
[14] Traditional planning practices can be characterized by, but not limited to, the following: DERs are not fully integrated into planning processes, planners have not relied on NWAs, and limited attention has been given to forecasting EV integration requirements or responses to time-of-use (TOU) rates and settlements with competitive suppliers based on individual customers' usage.
[15] Distribution system optimization includes, but is not limited to, the following capabilities: to identify changes to customer demand, to inform areas of needed investment and replacement of aging infrastructure, to integrate beneficial NWAs, to identify where DER, improved distribution efficiency, and responsive demand can provide net benefits.
[16] In 1999, Am. Sub. SB 3, the Ohio Electric Restructuring Act, was passed. It authorized the restructuring of the electric industry in Ohio. Restructuring primarily involved the following components: 1) unbundling of a vertically integrated systems, 2) customers served by a generator of choice, 3) transmission and distribution remained regulated, and 4) the replacement of a rate base construct for a competitive model construct for evaluating the rate of return of generation. From PUCO presentation available at https://pubs.naruc.org/pub.cfm?id=537DA758-2354-D714-51DA-9CEC2371B6EF
[17] Best practices are a compilation of efforts being pursued in other jurisdictions with active grid modernization proceedings. This includes actions pursued in California, Hawaii, New York, Massachusetts, Minnesota (typically by investor-owned utilities, or IOUs).

- **Project Selection**—Ohio EDUs primarily rely on traditional capital investment plans to ensure dependable and safe power delivery, while best practice is to balance capital investments, non-capital expenditures, and DERs and other NWAs to meet system requirements[18] and Customer objectives.
- **Project Justification**—Ohio EDUs consider distribution investments on a project-by-project, simple net present value (NPV) basis, while best practice is to pursue a combination of distribution investment options based on a "least cost, best fit" or a benefit cost analysis (BCA) that considers creating the greatest net value from a system or societal perspective.
- **Forecasting**—Ohio EDUs rely on point-based peak forecasting from historical trending and local knowledge, while best practice is to use AMI-driven load profiling, responsive demand, and DER forecasting at a distribution circuit or feeder level.
- **Analytical Approach**—Ohio's approach is deterministic, meaning that EDUs use specified criteria to analyze for identified system limits; best practice is probabilistic or risk-based, providing a probability of system failures based on best estimates.
- **DERs & Hosting Capacity Analysis**—Ohio has low DER adoption levels compared with some states and therefore has a correspondingly limited impetus for pursing hosting capacity analysis (HCA). For jurisdictions with greater DER adoption, HCA is sometimes published via a web portal and DER value is considered in relation to its location or relationship to other components in the system (i.e., a locational net benefits perspective).
- **Stakeholder Engagement**—The PWG workgroup is currently engaged for a finite period, while best practice is to utilize ongoing stakeholder workgroups to provide input into planning process design and refinement.

A fundamental objective of a modern grid, as indicated in the Roadmap, is to enable Customers to "manage their energy usage, adopt technologies that provide benefits and drive systemic benefits for the grid."[19] DSP across the industry, as well as in Ohio, will need to evolve with the development of DERs, electrification of transportation and other end uses, growth in flexible and price responsive demand, improvements in distribution efficiency, customer demand for greater reliability, and the continued evolution of retail markets. For example, in the Roadmap, the Commission found that "grid modernization plans developed by the EDUs must address how the existing distribution grid will adapt to meet the anticipated energy and power needs of electric vehicles (EVs), so that the societal benefits associated with EV charging can be maximized."[20]

Furthermore, with the deployment of advanced meters, the Commission found that settlements with competitive suppliers should change to enable "the monetization of changes in an individual customer's energy and usage,"[21] and the Commission encouraged each EDU to "propose or amend an existing TOU rate design,"[22] which could include real-time pricing. While questions related to EV integration, wholesale settlements, and rate design will be addressed in other proceedings, it will be important to address their implications as they relate to current and future developments in DSP.

[18] Meeting system requirements includes, but is not limited to: safely serving demand, asset optimization, increasing distribution efficiency
[19] See Roadmap at 31.
[20] See Roadmap at 20.
[21] See Roadmap at 32.
[22] See Roadmap at 31.

2.2 Group Scope & Focus

The PWG was formed to develop recommendations to the Commission on the following tasks[23]:

i. future scenarios for Customer DER adoption in Ohio, and how these scenarios should be incorporated into EDU forecasting and planning processes;
ii. modifications to interconnection standards, including defining required functions and settings for advanced inverters;
iii. development of NWA suitability criteria, processes and a timeline for implementing NWA opportunities; evaluation of options for procuring NWAs;
iv. defining HCA use cases; identifying an appropriate HCA methodology and associated tools and data requirements to satisfy use cases; a timeline for initial HCA analysis and publication of results for each EDU; and development of portals for sharing information on peak load forecasts, capital plans, hosting capacity maps, heat maps reflecting locational value, and other key data;
v. determining a process for identifying where it would be beneficial to deploy storage solutions.

The focus of the PWG was to examine practical and feasible considerations for achieving these five tasks. The tasks were divided into the following sections in this report:

- **Section 3**—NWA summary (tasks i and iii)
- **Section 4**—Energy storage summary (task v)
- **Section 5**—Interconnections standards summary (task ii)
- **Section 6**—HCA summary (task iv)
- **Section 7**—Appendices: Supporting content related to high-level recommendations and each topic area, meeting workshop summaries, and a list of acronyms and definitions

The summaries of these topics are arranged in the order they were presented and discussed in the PWG. Each summary is posted on the PUCO website,[24] along with the agenda, minutes, and presentations for each public meeting. The summary documents provided as part of this final report are reformatted to have a more concise and unified structure.

2.3 Limitations & Challenges

Given the current state assessments of EDUs, the existing energy landscape in Ohio, and the limited time to convene as a workgroup, some of the tasks listed above were ambitious. For example:

- **DER Forecasting and Planning (task i)**—This task is heavily dependent on DER adoption rates, which are currently relatively low in Ohio. Moreover, future planning requirements related to the adoption of EVs, changes in wholesale settlements, and the use of TOU rates in Ohio are uncertain. Ultimately, the responsibility falls on each EDU and the Commission to determine the appropriate degree of DER forecasting required over time. EnerNex recommends that the EDUs track and report data to help identify when and where enhancements to forecasting and

[23] See https://www.puco.ohio.gov/industry-information/industry-topics/powerforward/powerforward-collaborative-and-workgroups/distribution-system-planning-workgroup/
[24] Ibid

planning for Customer DERs should be piloted and adopted. As data forecasting of greater DER adoption becomes available, it will be valuable to develop additional forecasting scenarios.

- **NWA (task iii)**—NWA suitability criteria, evaluation frameworks, approaches to NWA procurement, and NWA examples were presented to the workgroup, but EDU-specific suitability criteria, evaluation frameworks, and procurement strategies were not developed. In the absence of a well-defined process for Commission review of utility DSP, the development of NWAs will involve policy decisions by the Commission and further coordination with the EDUs. The NWA Summary provides foundational content for the Commission and the EDUs to consider in terms of advancing the topic of NWA in Ohio.

- **Energy Storage Deployment (task v)**—EnerNex presented information on processes for identifying the location-specific value of storage. The value of distributed energy storage is application specific (i.e., grid need, location, time, technology, customer). Given the multiple potential applications for energy storage that would need to be considered, identifying the location-specific value of storage is currently ahead of the local context. Further, developing a process for identifying optimal locations for energy storage deployment would require complex and case-specific analysis.

2.4 High-Level Conclusions

The benefits of grid modernization to both utilities and customers are growing in importance, as can be attested to by related actions occurring in nearly every U.S. jurisdiction. According to the North Carolina Clean Energy Technology Center "50 States report," 90% of U.S. jurisdictions took grid modernization actions in the third quarter of 2019.[25] From a legislative, regulatory, and utility implementation perspective, the signals are clear: the utility industry is headed toward a more integrated, multi-directional energy system that incorporates more intelligent devices, controls, analytics, and customer service options. The complexity of this integration effort will continue to evolve and will require ongoing and careful consideration, deliberation, and funding over a long-term planning horizon.

The PowerForward program resulted in a Roadmap for Ohio's electricity future that seeks desired outcomes based on certain grid modernization objectives[26]. Like any multifaceted decision-making process that involves multiple perspectives and pathways, it will most effectively be pursued by establishing a long-term vision that is tied to a tactical plan that enables gradual and measurable progress. To move ahead with grid modernization in an orderly and thoughtful manner, the optimal approach is to proactively begin planning and to take incremental "bites of the elephant" over a reasonable time horizon.

[25] See https://nccleantech.ncsu.edu/wp-content/uploads/2019/10/Q32019_gridmod_exec_final.pdf. Nationally, 45 states (including the District of Columbia) took actions related to grid modernization during Q3 2019, with the greatest number of actions relating to energy storage deployment, data access policies, distribution system planning, integrated resource planning, and deployment of smart grid technologies.
[26] See Roadmap at 9.

2.5 High-Level Recommendations

While the primary focus of this report is recommendations on distribution planning, stakeholders should not lose sight that this is but one component, albeit important, of a larger grid modernization effort.

Based on this assertion, EnerNex recommends the following high-level grid modernization actions:

1. **Establish Strategic Clarity in Grid Modernization Efforts** —Ensure multiple grid modernization components are identified, defined, and pursued in a strategically logical, cohesive, and time-sequenced manner that is achievable.

2. **Establish Tactical Alignment in Grid Modernization Efforts**—Ensure grid modernization components are rooted in tactical goals which concurrently align technical, financial, and customer concerns. The alignment of these goals should span across topical areas and throughout project development lifecycles (i.e., front-end strategy, tactical planning and process development, project deployment, and project tracking and optimization).

Further, EnerNex recommends the following high-level distribution planning actions:

1. **Complete the Deployment of Advanced Metering Infrastructure (AMI)[27]**—EnerNex concurs with the Roadmap AMI guidance[28] and agrees that AMI is a foundational grid modernization effort. AMI plays a role in i) enabling more efficient market structures for EDUs and their Customers and ii) providing grid operations benefits. Examples are provided in Appendix A.

2. **Advance Distribution Planning Processes and Generate Annual Reports to Commission**—The objective is to advance distribution planning processes in Ohio, and this can be accomplished via regular reporting that details improvement efforts and related issues. Reports by the EDUs should include data to assist the Commission in identifying potential pilot programs, developing procedures, and/or formulating recommendations that assist in the transition towards IDP. Examples of potential reporting items are included in Appendix A.

3. **Pursue IDP Pilot Programs Directed by EDUs**—The objective is for EDUs to propose IDP pilot programs that utilize industry best practices to proactively advance IDP in Ohio. Projects should start on a small scale, involve a collaborative process with participation by Staff, and include Customer and Third-Party options. The pilot programs should include an evaluation of the process to capture lessons learned.

4. **Pursue Specific NWA, Energy Storage, Interconnection Standards, and HCA Actions—**Sections 3 through 6 of this report provide recommendations for each of the four topical areas covered as part of the PWG's investigation of distribution planning. One recommended approach for accomplishing the recommendations is for subsequent working groups to continue to proactively target and pursue specific topics in a prioritized and orderly manner.

[27] AMI or comparable interval metering and real-time distribution monitoring technology.
[28] The Roadmap considers AMI to be a fundamental component for advancing grid modernization at 31.

EnerNex A CESI Company

Section 3.0 Non-Wires Alternative (NWA) Summary

3.1 Background

As described in the Roadmap, when evaluating a distribution system improvement, the EDU is encouraged to consider the use of NWAs as an option to defer or avoid more expensive distribution system investments. The PWG was tasked with developing recommendations to the Commission on the following topics:

- NWA suitability criteria
- Processes and a timeline for implementing NWA opportunities
- Evaluation of NWA procurement options

3.2 Key Considerations

DEFINITION, OBJECTIVES, AND APPLICATIONS

Non-wires alternatives (NWAs) are defined as electricity grid investments or programs that use non-traditional distribution solutions (e.g., technologies, pricing, markets, tariffs, and contracts) to achieve one or more of the following:

- To defer or eliminate the need for distribution grid capacity equipment upgrades (e.g., distribution lines, transformers)
- To increase distribution grid reliability
- To increase distribution grid resilience
- To increase operational efficiency and optimization of the distribution grid (e.g., volt-var optimization)
- To enhance or maintain safety for utility workers and the public

In relation to DSP, the primary objective for considering NWA options is to identify solutions that mitigate grid risks[29] or that enable grid-operating efficiency at a lower total cost, as compared to traditional grid solutions. The PWG stakeholders agreed that NWA options should include a broad set of technologies as well as approaches to their integration. Adopting a broader definition of NWA increases the range of suitable opportunities and enables adoption of emerging technologies, maximizing potential benefits. Some NWA technology examples may be deployed individually or concurrently and may be either in front of or behind the meter; these include, but are not limited to, the following:

- Distributed generation
- Energy storage (including vehicle to grid or V2G)
- Energy efficiency
- Demand response
- Intelligent end-use devices[30]

---

[29] Distribution grid risks include requirements to provide adequate capacity, reliability, and resilience.
[30] Intelligent end-use devices are devices utilized by electric consumers at or near the end-use premise that assist or optimize energy utilization.

- Voltage optimization (VO)[31]
- Grid topology[32] and power flow control[33]
- Microgrids[34] and fractal architecture[35]

NWA technologies can be integrated with the distribution grid and controlled in various ways:

- **Automatic—**Some technologies may provide NWA functions simply through their inherent characteristics. These would include energy efficiency end uses or non-adjustable devices.
- **Autonomous or Semi-autonomous—**Some technologies (e.g., intelligent end-use devices) may respond to local conditions or follow schemes that are based on programmed set points, often with sub-second latency, that can be adjusted according to grid needs.
- **Coordination (Markets/Pricing)—**Some technologies can be coordinated through markets or pricing signals to manage dynamic loads and/or resources within network constraints.
- **Dispatch/Direct Control (Tariff/Contract)**—Some technologies enable an operator to specify or direct quantities of supply or demand reduction from specific resources at varying intervals.
- **Outsourcing (Aggregation)**—A Third Party may coordinate or dispatch DERs (e.g., demand response resources, virtual power plants or VPP) with limited grid operator control over specific resource locations.

DEVELOPMENT OF NWA SUITABILITY CRITERIA

To narrow the set of potentially viable NWA solutions, each EDU should define, publish and adopt appropriate NWA suitability criteria. These suitability criteria would establish guidelines for consideration of NWA solutions such as a minimum (traditional wires) investment threshold and a minimum planning horizon timeframe. To better understand the viability of NWA solutions within the distribution system, EDUs should consider tracking and reporting to the Commission, on an ongoing basis, the number of NWA opportunities meeting the suitability criteria that are formally evaluated and the number implemented.

PROCESSES FOR IDENTIFYING AND IMPLEMENTING NWA OPPORTUNITIES

Consideration of NWA options begins with the identification of a specific grid need that an NWA solution may address. DSP can include a variety of analyses and forecasts, such as:

---

[31] Typically, VO involves two components: 1) conservation voltage reduction (CVR)—the intentional operation of the transmission and distribution system to provide Customer voltages in the lower end of the acceptable range, with the goal of achieving energy and demand reductions for Customers, and 2) volt-var optimization (VVO)—when utilities manage and optimize voltage and reactive power simultaneously, combining the voltage management associated with CVR with reactive power management. Definitions based on Energy Star reference at 2: https://www.energystar.gov/sites/default/files/asset/document/Volt%20Var%20and%20CVR%20EMV%20Best%20Practice%2006-01-17clean%20-%20508%20PASSED.PDF

[32] Grid topology refers to the physical configuration or structure of the grid system. NWA can allow for grid topology adjustments by unlocking capacity in certain areas where the topology configuration would otherwise violate a given threshold.

[33] Power flow control refers to the ability to change the way that power flows through the grid by actuating line-switching hardware or by controlling high-voltage devices connected in series or in shunt with transmission lines (DOE definition); FLISR (fault location, isolation, and service restoration) technology is one example.

[34] Microgrids are a group of interconnected loads and DERs within clearly defined electrical boundaries that acts as a single controllable entity with respect to the grid. A microgrid can connect and disconnect from the grid to enable it to operate in both grid-connected or island mode (microgrid exchange group definition).

[35] Fractal architecture refers to the design of a fractal power system, which includes individual regions, zones, circuits, and microgrids that each contain supply resources and demand and control systems capable of operating autonomously or collaboratively optimizing their operation based on system conditions.

- Forecasting of load growth
    - Seasonal peak loads at substation distribution transformers
    - Historical trending and local input
- Equipment/asset loading analysis
- System modeling and simulations
- Reliability assessments
- Asset condition assessments

Through these analyses and assessments, specific distribution grid needs can be identified that may be suitable for an NWA project. Grid needs represent specific locations on the grid where concerns exist relative to capacity, reliability, resilience, operational efficiency, and/or safety. Table 1 classifies various grid needs that may warrant NWA consideration and the corresponding DSP inputs and metrics that would need to be explored by EDUs.

Table 1: EnerNex's Classification of Various Grid Needs, DSP Inputs, and Performance Metrics

GRID NEED	DISTRIBUTION SYSTEM PLANNING INPUTS	PERFORMANCE METRICS
Defer or eliminate need for distribution grid capacity equipment upgrades (e.g., distribution lines, transformers)	1. Forecast of distribution circuit peak loads 2. Forecast of distribution feeder capacity constraints 3. Distribution system modeling and simulations 4. Projected asset life 5. Asset management data (e.g., historical loading information, asset condition/life) 6. Load duration curves	7. Peak load as a percentage of circuit design load 8. Duration of peak load exceeding circuit design load 9. Transformer overloads exceeding equipment ratings (defined by loading and duration)
Increase distribution grid reliability	10. Utilization and tracking of traditional reliability indices and metrics (see metrics) 11. Worst-performing-circuit analysis 12. Establishment of non-traditional reliability indices and metrics (e.g., Customer outage cost metrics, value of lost load)	13. Circuit-level SAIDI (system avg. interruption duration index) 14. Customer minutes interrupted (CMI) per circuit 15. Circuit-level SAIFI (system avg. interruption frequency index) 16. Customers interrupted (CI) per circuit 17. Circuit-level MAIFI (momentary avg. interruption frequency index) 18. Non-traditional metrics (Customer outage costs, value of lost load)
Increase distribution grid resilience	19. Customer/public need for increased resilience (e.g., number of critical facilities) 20. External data sources and initiatives such as Ohio State University Sustainability Institute[36] and municipal resilience planning[37]	21. Extent and duration of major outages 22. Cost of major outage recovery 23. Socio-economic impact of major outages 24. Service retention and restoration times for critical facilities

[36] See Ohio State University Sustainability Institute: https://sre.osu.edu/smart-and-resilient-communities.

[37] Ohio State and Municipal Resiliency Planning initiatives include Lakewood (http://www.onelakewood.com/resiliency/), Cleveland (http://www.clevelandnp.org/resilientcleveland/), and the Ohio Department of Transportation (http://www.dot.state.oh.us/Divisions/Planning/Environment/NEPA_policy_issues/Pages/Infrastrucutre-Resiliency-Plan.aspx).

GRID NEED	DISTRIBUTION SYSTEM PLANNING INPUTS	PERFORMANCE METRICS
Increase operational efficiency of the distribution grid	25. Distribution circuit monitoring (incl. SCADA) 26. Advanced metering infrastructure (AMI) voltage readings 27. AMI power characteristic violation alerts 28. Voltage violations extent and duration (actual, simulated) 29. Distribution system modeling 30. Volt-var optimization	31. Customer energy savings (from lower voltages) 32. Voltage violation occurrences, extent, and duration 33. Voltage performance, as measured by the statistical distribution of voltage readings within the ANSI C84.1 band 34. Power quality metrics 35. Customer energy savings
Enhance or maintain safety for utility workers and the public	36. Asset management (remote monitoring data) 37. Distribution circuit monitoring (incl. SCADA) 38. Outage and fault monitoring equipment (momentary outages, ground fault sources) 39. High-impedance fault detection	40. Improvements in existing safety measures (utility and public) due to increased situational awareness and/or ability to isolate/mitigate safety risks automatically (e.g., avoided manual switching, truck rolls, reduced outage duration) 41. Definition of new safety metrics based on a greater public benefit (i.e., reduced power theft, bill threshold and anomaly use warnings)

EVALUATION OF OPTIONS FOR PROCURING NWA SOLUTIONS

An EDU can pursue three primary approaches[38] to meet an identified grid need:

- Traditional infrastructure (i.e., wires) investments
- Utility-owned and managed NWA solutions
- Third Party-owned and managed NWA solutions supplied to the utility

The following factors can help EDUs determine the viability of an NWA solution over a traditional wires approach:

- Nature of the grid need (e.g., capacity, reliability)
- Scale or scope of the grid need (e.g., MW of capacity required)
- Time frame to meet the grid need
- Time frame to implement a solution

SOLICITATION GUIDANCE FOR NWA SOLUTIONS

The EDU may decide it wants to pursue a utility-owned and -managed NWA solution over a traditional wires solution to meet a specific grid need. Alternatively, the EDU may choose to issue a request for proposal (RFP) or request for offer (RFO) for the solicitation of a Third Party NWA solution to address the

[38] Other potential alternative approaches to NWA solutions exist, such as the utilization of dynamic distribution rates. As smart and Internet of Things (IoT) devices become more common, utilities may be able to use narrowly tailored, revenue-neutral distribution pricing as a means to shift the timing of demand as an alternative to capital investment.

grid need. A recent NWA solicitation by Con Edison[39] (June 2019), to provide demand side management for sub transmission and distribution system load relief, serves as one useful reference for pursuing NWA solicitations and associated concerns with public data sharing.

The PWG discussed NWA ownership in Ohio, but there was not consensus among the group regarding which option, EDU or Third Party, is preferable or how each option is addressed under Ohio law. Nor was there consensus regarding the financial, operational, and reliability obligations of Third Party owned projects or any associated Commission regulation/oversight of these projects. Specific guidance from the Commission is needed to advance this topic, nevertheless the following general guidance applies:

- If the EDU is procuring an NWA that it will own and operate, the procurement process is similar to procuring traditional infrastructure and would include requirements and specifications for the NWA solution being pursued.
- If the EDU is seeking NWA grid services to be provided by a Third Party, then the solicitation should include the following:
    - A description of the grid need(s), situation, or challenge to be resolved
    - The NWA RFP/RFO evaluation and award criteria
    - The potential for single or multiple awards (portfolio) to address the grid need(s)
    - NWA performance criteria and provisions

When utilizing an RFP/RFO to solicit NWA solutions, the solicitations should describe the technical requirements of the grid need to be met in order to open the solution to a broad range of potential technology options. Although specific technologies may not prevail due to technical or performance concerns, this approach may generate a broader range of market-based solutions for the EDU to consider.

The EDU should establish an agreement with a Third Party that includes a well-defined grid services contract (or with multiple Third Parties in a portfolio of grid services contracts) to address the grid need. For best results, the contract should include performance provisions that specify the grid service to be provided, performance requirements, and penalties for non-performance.

EVALUATION OF NWA SOLUTIONS

Given the EDU's obligation to provide safe and reliable service, the assessment of an NWA's technical adequacy (e.g., ability to consistently perform), commercial adequacy (e.g., creditworthiness, financial efficacy), and feasibility should rest with the EDU. The PWG identified several mechanisms that could be used by EDUs to address potential concerns with proposed Third Party NWA solutions, such as the following:

- Contractual performance provisions for NWA grid services provided by Third Parties
- Derating factors to account for potential NWA performance variables and factors relative to the grid need. For example, to meet a coincidental load/peak load need, the following may apply:
    - Solar PV peak output may occur prior to the circuit peak loading, or cloud cover may affect solar output when it is needed

[39] See https://www.coned.com/-/media/files/coned/documents/business-partners/business-opportunities/non-wires/newtown-energy-rfp.pdf?la=en

    - The charge state of a battery may not be sufficient to provide for capacity needed by the distribution grid in a timely manner
- Interconnection standards and advanced inverter settings

Selection of a Third Party NWA solution should include an evaluation of time, cost, and risk factors compared with a traditional infrastructure approach. "Least-cost, best-fit" is a utility approach to evaluate NWA alternatives (or other utility investments) that combines a competitive procurement process (to ascertain "least cost") with an evaluation of the proposed solution's "fit." The assessment of "fit" is usually performed first in order to narrow the range of acceptable options and includes assessing various risk factors (e.g., Third Party contracting risks). Upon full evaluation, certain instances and corresponding actions may result:

- The NWA is implemented because it meets the "least cost, best fit" criteria for a grid need.
- A combination of traditional EDU infrastructure and NWA solution(s) are considered to achieve a "least cost, best fit" solution.
- The solicitation validates the use of only a traditional infrastructure investment approach because the NWA does not provide a "least cost, best fit" solution to satisfy the grid need.
- An alternative BCA method is pursued in place of "least cost, best fit" criteria, based on various cost-effectiveness tests (mentioned below).

NWA EVALUATION FRAMEWORK

Jurisdictions that have pursued NWA solutions have often adopted a single or a combination of standardized frameworks for evaluating the cost-effectiveness of an NWA. These frameworks typically define and organize potential NWA costs and benefits into the following domains:

- **Bulk Power System**—The value of energy/services provided to the bulk power system, such as from ancillary services, transmission capacity (added or deferred), and the ability to meet future capacity supply commitments
- **Distribution System (and DERs)**—The value of energy/services provided to the distribution system in terms of reductions in operating costs (e.g., by avoiding premature maintenance, reducing marginal losses during distribution peaks, optimizing volt-var), reductions or deferrals in capital spending, and increases in system reliability
- **Customer**—The value of energy/services provided to individual energy consumers, including reductions in costs for electric delivery and energy supply
- **Society**—Potential benefits realized by society (e.g., environmental benefits, economic development impacts)

NWA investments are typically subject to a series of cost-effectiveness tests, each providing a different perspective on the overall impact. Some combination of the following tests is typically applied to justify or support an NWA investment:

- **Rate Impact Measure (RIM)**—This test measures the net impact of the program on Customer rates to determine if average rates will be lowered. The results of this test are, in part, a function of utility rate design. A utility's lost revenue is a key cost component that typically links fixed cost recovery to a volumetric rate design (i.e., reduced consumption impacts the utility's ability to recover fixed costs).

- **Total Resource Cost (TRC)**—This test measures the net cost of the program as a resource option, including both the utility's and the participants' net costs, to determine if resource efficiency is improved.
- **Utility Cost Test (UCT)**—This test measures net program costs, like a TRC test, but excludes participant costs. Instead, its purpose is to determine if revenue requirements are reduced. This test does not include a utility's lost revenue as a cost (which is the primary difference between this test and the RIM test).
- **Societal Cost Test (SCT)**—This test expands upon the TRC to incorporate "external" benefits and costs that might accrue to society rather than to just Customers and utilities. Most commonly, an SCT might include the calculation of environmental benefits and costs associated with an NWA solution. For example, potential environmental benefits, such as reduction in greenhouse gas (GHG) and fine particulate matter emissions, might need to be offset by the disposal costs of storage chemicals. Other societal benefits and costs might include those related to economic impacts or impacts on public safety.[40]
- **Participant Cost Test (PCT)**—This test measures the quantifiable costs and benefits of a program to determine the net impact to the participating energy consumer.

As an example, a sample cost-effectiveness framework adapted from the Rhode Island Public Utilities Commission[41] is included as an appendix. The framework provides an example of cost-benefit categorization, descriptions of costs and benefits relevant to each category, and candidate methodologies for estimating cost and benefit values.

Given the early-stage discussions on the topic of NWA opportunities in Ohio and a lack of statutory requirements related to NWA opportunities that exist in other jurisdictions[42], the PWG stakeholders concluded it was premature to develop a uniform NWA evaluation framework. At this juncture, most of the PWG stakeholders believe it is sufficient for EDUs to continue to evaluate the cost-effectiveness of NWA opportunities as they do currently—by comparing an NWA solution to a more traditional wires solution on a simple NPV basis.[43] However, it should be noted that considering only the costs and benefits that are directly applicable to the EDU leaves out the benefits that might accrue to other parties from an NWA investment. These include customer benefits driven from improved distribution efficiency and resilience (e.g., volt-var optimization, reduced outage costs) or other drivers (e.g., corporate reliability targets or sustainability goals).

NWA PERFORMANCE MONITORING

As part of performance monitoring, EDUs should track the actual time and cost associated with implementing an NWA solution relative to the planned time and cost. In addition, metrics should be defined and tracked to gauge the performance of each NWA relative to the intended grid need and to

---

[40] By their nature, societal costs and benefits can be challenging to quantify. However, various jurisdictions have established methodologies for estimating the environmental benefits. As an example, Consolidated Edison's Benefit Cost Analysis Handbook illustrates the approach the company has adopted toward the calculation of external benefits in New York: https://www.coned.com/-/media/files/coned/documents/our-energy-future/our-energy-projects/coned-bcah.pdf?la=en.

[41] The full Rhode Island benefit-cost framework is available at http://www.ripuc.org/eventsactions/docket/4600-WGReport_4-5-17.pdf.

[42] See "Navigating Utility Business Model Reform" by Rocky Mountain Institute (2018) for examples of recent regulatory statutes and case studies related to NWAs in various states (on 42-43 and 51-52) and broader utility business model topics: https://rmi.org/wp-content/uploads/2018/10/RMI_Navigating_Utility_Business_Model_Reform_2018-1.pdf

[43] The EDUs estimate the capital cost of a traditional wires-based solution to provide needed additional capacity on a circuit through equipment upgrades and/or circuit reconductoring. The cost of an NWA solution that might be able to defer the traditional investment would then be compared to the NPV of deferring that investment.

ensure contractual performance obligations are met. Table 1 above lists some of the performance metrics associated with meeting various grid needs via an NWA solution.

3.3 PWG Conclusions

The following summarizes the primary conclusions of the PWG regarding NWAs, based on themes that emerged from group discussions:

- The EDUs report challenges in finding cost-effective NWA solutions given all the distribution system performance obligations that need to be met.
- Uncertainty around the eligibility of EDUs or Third Parties to own, operate, or realize potential value streams of NWA technologies hinders their consideration and diminishes their potential economic viability in Ohio.
- EDUs have no significant drivers to engage in NWA contracts with Third Party owners, even if Third Party contracts might be less costly to Customers than traditional solutions.
- Given early-stage discussions on the topic of NWA opportunities in Ohio, and a lack of statutory requirements as they relate to NWA opportunities, the PWG stakeholders concluded it was premature to develop a uniform NWA evaluation framework.
- Similarly, the PWG stakeholders concluded it is sufficient for EDUs to continue to evaluate the cost-effectiveness of NWA opportunities using their current method (by comparing an NWA to a more traditional wires solution on a simple NPV basis).
- Some PWG stakeholders expressed interest in increasing the transparency of the EDU planning process so that external stakeholders are more broadly aware of potential NWA projects under consideration. The PWG stakeholders believe that an integrated DSP process should enable Customers to identify opportunities for integrating DERs and maximizing value for those DER investments. The EDUs expressed concern associated with publishing system constraints based on associated confidential and/or trade secret data.
- Some PWG stakeholders urged the EDUs to integrate existing demand response and energy efficiency programs into their planning processes—supporting the idea of using existing resources to develop solutions for grid needs that do not impose new costs.
- The PWG stakeholders encouraged continued collaboration and consideration of the topics included in this document as the EDUs identify appropriate opportunities for NWA solutions on their distribution systems.

3.4 EnerNex Recommendations

The following recommendations are primary actions that can be taken to further NWA development in Ohio. As noted, a lack of clarity related to recommendations 1 through 3 hinders NWA progress in Ohio and should be addressed first:

1. **Define the Role of EDUs Associated with NWA Projects**— The Commission should define the eligibility of EDUs to own, operate, or realize potential value streams of NWA technologies and address optimal approaches to solicit NWA projects to maximize project value.

2. **Define the Role of Third Parties Associated with NWA Projects**— The Commission, EDUs, and Third Parties should work together to define the role of Third Parties to own, operate, or realize

potential value streams of NWA technologies, and address optimal approaches for Third Parties to work with EDUs.

3. **Track NWA Project Evaluations**— To better understand the viability of NWA solutions within the distribution system, the EDUs should track, on an ongoing basis, the number of NWA opportunities that are formally evaluated and the number that are ultimately implemented. The Commission and EDUs should discuss how to balance competing concerns related to public data access and Customer privacy in order to most effectively enable NWA visibility and opportunity.

Subsequently, recommendations 4 through 6 require further discussion and development to be actionable at an individual EDU level. One approach, as recommended above, is for working groups to continue to pursue specific topics in a prioritized and orderly manner.

4. **Develop Initial NWA Suitability Criteria**—To narrow the set of potentially viable NWA solutions, each EDU, in coordination with the Commission, should adopt NWA suitability criteria. These suitability criteria would establish guidelines for consideration of NWA solutions such as a minimum (traditional wires) investment threshold and a minimum planning horizon timeframe.

5. **Define Scope and Timing for an Initial NWA Evaluation Framework**—The Commission and EDUs should determine the collective scope and relative timing for developing an initial NWA evaluation framework in Ohio. Developing an initial evaluation framework, although potentially limited in scope at first, is a proactive measure that will facilitate greater alignment and preparedness of Ohio EDUs regarding future NWA considerations.

6. **Develop an Initial NWA Cost-Effectiveness Framework**—The Commission and EDUs should consider cost-effectiveness frameworks for NWA consideration beyond simple NPV analysis. Developing an initial cost-effectiveness framework, although potentially limited in scope at first, is a proactive measure to begin to assess how associated costs and benefits of various NWA projects could be evaluated.

Section 4.0 Energy Storage Summary

4.1 Background

In the Roadmap, the Commission expressed further interest in the deployment of energy storage as a distribution grid solution. The PWG was tasked with developing recommendations to the Commission on a process for identifying deployment scenarios where energy storage solutions would be most beneficial. An energy storage system is defined as any system that can absorb energy from the grid or Customer on-site generation resource, retain it for a period of time, and then release the energy as needed. Energy storage can be classified as an NWA option or as a standalone technology that can be deployed at various scales. Given the potential of energy storage "to provide operational benefits across the electricity system,"[44] the PWG examined energy storage solutions separate to the topic of NWAs.

4.2 Key Considerations

ENERGY STORAGE TYPES

There are a variety of energy storage technologies, such as electrochemical batteries, mechanical devices (e.g., hydro, compressed air, flywheels), electrical devices (e.g., capacitors), and thermal devices (e.g., water heaters). Energy storage technologies continue to grow as viable deployment solutions in terms of quantity of available solution offerings, technical capability, and maturity. Some energy storage technologies are being developed to meet specific and targeted functionalities, including longer duration grid storage,[45] while others aim to store energy for a wide range of purposes to increase their overall value proposition. Additionally, the increased utilization and functionality of end-use callable demand management devices (e.g., thermostats, building controls) can serve as related alternatives that may work independently or in concert with standalone energy storage technologies.

Energy storage technologies and their potential locations on the distribution system are the topic of many studies[46] and involve the consideration of various factors to optimize deployment. Different types of technologies could be more feasibly deployed at given physical locations and grid interconnection points. For example, some forms of storage require large amounts of land or heavy machinery for installation and may benefit from economies of scale when deployed at a transmission level. Alternatively, behind-the-meter (BTM) solutions or other distribution–focused deployments may be more advantageous when deployed strategically. Defining an approach to energy storage deployment largely depends on the use case under consideration and the associated value streams.

ENERGY STORAGE APPLICATIONS AND VALUE STREAMS

Energy storage systems are uniquely capable of a variety of applications and uses. Like other NWA solutions, energy storage can be used to defer distribution system upgrades. In addition, energy storage can also provide a suite of additional and new Customer services, including demand charge reductions, participation in ancillary market services, and backup power.

---

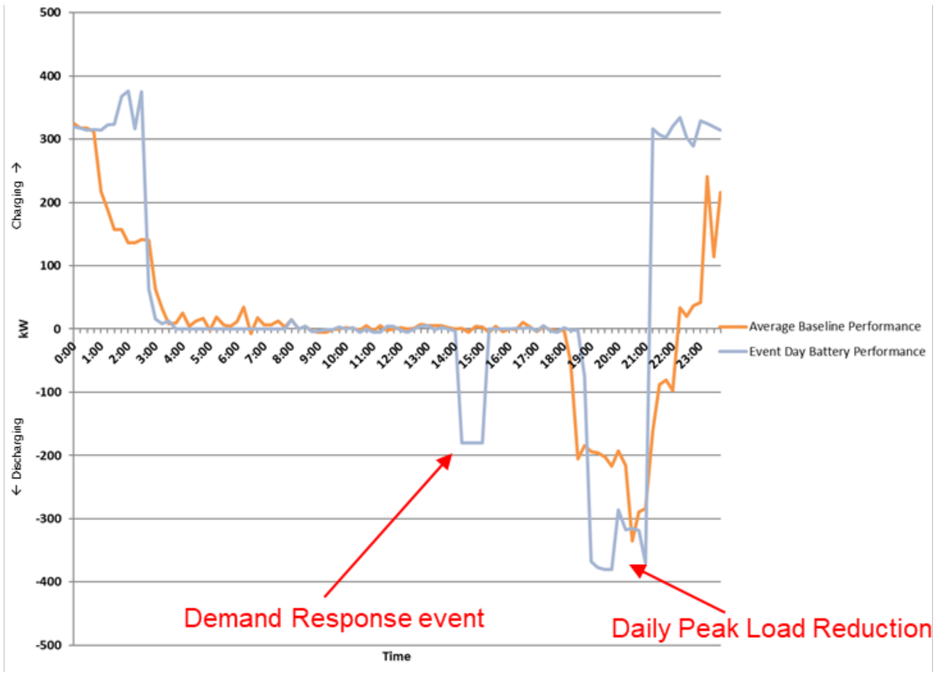
[44] See Roadmap at 21.

[45] See for example: https://arpa-e.energy.gov/?q=arpa-e-programs/days.

[46] One example study is the EPRI report "Arizona Public Service Solar Partner Program Phase II: Energy Storage Demonstration Results": https://www.epri.com/#/pages/product/000000003002014455/?lang=en-US.

Energy storage solutions can provide benefits to the distribution system in numerous ways, sometimes by providing multiple functions at different times of the day. For example, a Customer-sited battery may charge in the overnight hours to avoid or boost low voltage on the distribution system and discharge in the afternoon to reduce peak load. Figure 3 provides an example of a battery solution responding to a demand response event and helping to reduce a Customer's peak load within the same afternoon.

Figure 2: The Multiple Services of Energy Storage Within a 24-hour Period Relative to a Baseline[47]



Other applications of energy storage pertinent to Ohio are included in the following list, some of which directly align with topics covered in the NWA Summary:

- **Buffering**—Storage can continuously and automatically offset and smooth changes in real power demand and supply from other DERs.
- **CVO**—Storage can assist in actively controlling distribution voltage, in most circumstances, to achieve energy and demand savings/reductions.
- **Microgrids**—Storage can help balance demand and supply in a microgrid when disconnected from the larger power system.
- **Fractal Grid/Fractal Grid Topology**—In a fractal power system, individual regions, zones, or circuits are capable of operating autonomously or collaboratively to optimize their operation based on system conditions. Storage can help balance demand and supply in a specific zone/circuit when disconnected from other portions of the grid system.
- **Power Quality**—Storage can help maintain the wave form in an alternating current (AC) power system that is necessary to ensure reliable and efficient operation of the grid and Customer equipment.

[47] This chart was created from load profiles and battery performance based on EnerNex experience. The 2016 Commercial and Industrial AutoDR with Stationary Battery Storage report serves as a useful reference for real-world battery performance and evaluation relative to baseline performance: https://www.etcc-ca.com/reports/commercial-and-industrial-autodr-stationary-batteries.

- **Congestion Relief**—Storage can help mitigate transmission or distribution congestion and enable more efficient power transfer by increasing demand upstream of a constraint or by supplying energy downstream of a constraint.
- **Ramping**—Storage can help address rapid changes in supply and/or demand over various time periods, from several dispatch intervals to several hours.
- **System Efficiency**—Storage can make load factor improvements by shifting demand from peak to off-peak periods.
- **Topology Optimization**—Storage can provide power or reserves such that the system can be reconfigured while continuing to meet reliability requirements.
- **Capacity Deferral**—Storage can help delay a capacity investment to reduce expected present value costs or gather additional information and preserve options regarding the timing, nature, and scale of the required investment.
- **Backup Supply**—Storage can enable a Customer or group of Customers to maintain some or all electric service when power is not available from the grid.
- **Remote Loads**—Storage can be deployed in locations where significant investment would be required to provide service to the Customer and/or meet reliability requirements. This may include support for various remote EV charging scenarios (e.g., fast charging, fleet charging, transit charging) to smooth spikes in demand.

The above list focuses on potential benefits that energy storage may provide to the distribution system only. It does not consider benefits to the bulk electric system (e.g., transmission deferral, transmission congestion relief) or the full extent of benefits to individual Customers (e.g., demand charge reduction, TOU bill management, participation in ancillary service markets). These additional value streams could play an important role in justifying the economics of energy storage projects for EDUs and Third Parties.

It is also important to note that some energy storage applications may be mutually exclusive or not available at the same time. Therefore, in considering the potential value of an energy storage investment, it is critical to understand its planned operations and constraints, including temporal factors. Finally, as with any DER, energy storage could also negatively impact grid operations (e.g., harmonics) without the implementation of adequate interconnection standards and controls.

ENERGY STORAGE PLANNING AND OPERATIONAL CONSIDERATIONS

Because of its many applications and the broad range of value streams that it offers, energy storage represents a potentially useful and intriguing resource for distribution utilities. Of specific local note, the financial viability of energy storage investments has been demonstrated in a public-private partnership pairing energy storage and PV generation in the Village of Minster, Ohio. However, several issues exist that may limit the proper consideration and adoption of energy storage by EDUs in Ohio, including:

- Uncertainty regarding an EDU's ability to own or operate energy storage as an energy supply resource based on Ohio's regulatory structure
- Uncertainty regarding an EDU's ability to capture or monetize the full range of value streams from energy storage based on Ohio's regulatory structure
- A lack of drivers or requirements for EDUs to make energy storage investments or to contract with Third Party providers for energy storage services
- Financial evaluation methodologies that limit energy storage values to those directly realized by the EDU and exclude consideration of values that might be realized by other entities

The above issues are discussed in greater detail below as they specifically relate to regulatory uncertainty for EDUs and Third Parties and associated financial valuation methods. Additional technical concerns (e.g., round trip efficiency, discharge/charge rates, degradation, life cycles, safety) which vary according to energy storage technology, are generally applicable operational considerations regardless of jurisdiction. The focus of this section is to address primary non-technical barriers in Ohio which should be addressed.

EDU Regulatory Uncertainty—Ownership

One of the chief potential values of energy storage is its ability to provide timely energy on demand to the grid. As stated above, under the current regulatory structure in Ohio and the required Federal Energy Regulatory Commission (FERC) accounting rules,[48] there is uncertainty around the eligibility of EDUs to own and operate energy storage as a supply source. An EDU can own and operate energy storage to provide distribution grid management services, such as discharging the storage to offset peak load on a circuit or to manage voltage on a circuit. However, it remains unclear if the energy storage could be discharged for other purposes, since doing so could potentially be interpreted as providing a competitive source of energy supply. The lack of clarity obfuscates potentially significant value streams, making the energy storage investment reliant on a smaller subset of value streams to justify its economic viability. Under the current NWA evaluation process utilized by the EDUs, value streams that do not provide distribution grid management services are presumed to be unavailable to the EDUs and these value streams are therefore ignored in the evaluation process.

EDU Regulatory Uncertainty—Value Streams

As noted earlier, one common application for energy storage is distribution deferment, whereby energy storage is sited on a distribution circuit to offset peak demand that would otherwise exceed the capacity of the circuit. By maintaining the effective load on the circuit below its design capacity, an energy storage investment may be able to defer the need for a much larger capital investment. However, the peak demand offset scenario may only require utilization of the energy storage resource for a limited number of hours each year. Based on the current regulatory uncertainty mentioned, Ohio EDUs are currently constrained in their ability to extract additional potential values (stacked value of multiple applications) from an energy storage device during the vast majority of hours during the year. As a result, investments in energy storage solutions are currently wholly dependent on the distribution deferral value—which by itself may likely prove insufficient to justify the investment.

Even if the sale of energy from energy storage were permitted, it is not clear if (or how) the EDU would realize this value. For example, if the energy storage investment was added to an existing rider, the revenues from any energy sales would likely be credited back to Customers via the rider mechanism. In this case, the EDU, not benefitting from the energy sale, has minimal incentive to make the investment even if the investment might be entirely justifiable from a broader economic perspective (i.e., TRC test).

[48] Accounting rules according to the FERC uniform System of Accounts apply, specifically Section 363 (Energy Storage Equipment). See also: Utilization of Electric Storage Resources for Multiple Services When Receiving Cost-Based Rate Recovery, 158 FERC ¶ 61,051 (January 19, 2017), allowing multiple uses if separated in time.

Lack of Defined Relationship Between EDUs and Third Parties

At least to some extent, the issues outlined above could potentially be circumvented through Third Party ownership of energy storage. Under this model, the Third Party would not be constrained in monetizing a broader set of value streams from the energy storage investment. However, many distribution-level energy storage applications require close, low-latency integration into grid operations. In this Third Party ownership case, the agreement between the EDU and the Third Party energy storage provider would likely require the utility to have the ability to control the energy storage under defined conditions or time periods—and that the energy storage be available (i.e., sufficiently charged) to meet the grid performance need. At all other times, the Third Party would be able to operate the energy storage in ways to maximize its value to the owner (i.e., the Third Party). Dynamic distribution pricing, such as time-of-use (TOU) or real-time pricing structures, is an additional way to incentivize Third Parties to operate storage in response to distribution system needs. Dynamic pricing options and their potential benefits could be future considerations worth pursuing.

Although the Third Party scenario may result in successful and economic deployments of energy storage, it remains unclear whether the Ohio EDUs would adopt this option. Because the Third Party would presumably have access to other value streams, the utilization of a Third Party energy storage solution could economically meet the operational requirements of the grid need it was intended to solve. However, as noted above, the EDU must be satisfied that the performance risk it would assume by contracting with the Third Party (absent any financial incentive for assuming it) would be preferable to a more traditional solution, even a traditional solution that is more costly.

Additional Value Considerations

Some energy storage applications of potential interest in Ohio have different objectives than the distribution deferment application described above. These objectives may not be adequately assessed using the EDUs' traditional approach based on simple NPV for considering distribution investments. Table 2 was developed to provide examples of energy storage applications where additional value may be realized.

Table 2: Energy Storage Application Examples of Potential Additional Value

Application	Key Objective/Benefit	Challenge	Potential Evaluation Method
Conservation voltage optimization (CVO)	Reduction in Customer energy usage	Customer energy savings not considered in EDU DSP models	Total resource cost (TRC) test
Resilience	Minimize the social and economic costs of extended outages	Social and economic costs of extended outages not considered in DSP models	Societal cost test (SCT)

4.3 PWG Conclusions

The following points summarize the primary conclusions of the PWG regarding energy storage, based on themes that emerged from group discussions:

- It is unclear whether an EDU has the ability to own and operate energy storage as sources of energy supply.
- There is uncertainty around an EDU's ability to capture/monetize the full range of value streams from energy storage.
- The EDUs lack drivers or requirements to make energy storage investments or to contract with Third Party providers for energy storage services.
- Financial evaluation methodologies currently limit energy storage values to those directly realized by the EDU and exclude consideration of values that might be realized by other entities.
- Although the Third Party scenario may result in successful and economic deployments of energy storage, it remains unclear whether this option would be adopted by the Ohio EDUs due to potential performance risks associated with Third Party contracting for critical distribution functions.

4.4 EnerNex Recommendations

The following recommendations are primary actions that can be taken in terms of furthering energy storage development in Ohio. We note that dynamic distribution pricing schemes[49] could incent Customers and Third Parties to provide storage solutions that optimize multiple value streams. However, this alternative would involve policy changes outside of an EDU's current distribution planning process. Additionally, many of the recommendations previously listed in the NWA Summary (Section 3.4) are directly applicable to energy storage and will therefore not be repeated. Beyond the NWA recommendations, the following should also be considered:

1. **Seek Regulatory Direction Regarding Energy Storage (Ownership and Value Stream Realization)—**Under the current regulatory structure in Ohio and required FERC accounting rules, it is unclear whether EDUs are eligible to own and operate energy storage, as it relates to EDU utilization of storage as a supply source. It is recommended that the Commission and the EDUs seek regulatory clarity (federal and state as appropriate) related to ownership and utilization of energy storage by EDUs, Third Parties, and hybrid ownership models. Following regulatory direction and guidance, further legislative input may be necessary.

2. **Pursue Energy Storage Pilot Projects**—It is recommended that Ohio EDUs deploy energy storage pilot projects, whether individually or concurrently with other EDUs or Third Parties. These pilot projects could be conducted to evaluate multiple or preferred technologies that maximize overall value. The application of these pilot projects should align with NWA suitability criteria and grid needs to explore one or multiple (stacked) values that may be realized. Lessons learned from energy storage deployment data could assist in helping to evaluate the efficacy, reliability, and safety of specific energy storage solutions, shape future policy in Ohio, and assist in defining or assessing potential contracting terms with Third Parties.

[49] For example, pricing that reflects the time and location specific marginal value and cost of energy at points on the distribution system.

Section 5.0 Interconnection Standards Summary

5.1 Background

This section is intended to further the objectives of the PWG regarding Ohio's interconnection standards. By charter, the PWG "may develop recommendations to the Commission" for "modifications to interconnection standards, including defining required functions and settings for advanced inverters."

The development of interconnection standards is connected to the escalating deployment of rooftop solar PV nationwide and the development of advanced, or "smart," inverter technology. In 2018, a major revision to the Institute of Electrical and Electronic Engineer's (IEEE's) standard for DERs was published (IEEE Std 1547-2018), and commissions across the country will be considering or already have adopted the new standard in their state interconnection rules. Other relevant interconnection standards include Underwriters' Laboratories (UL) 1741 and FERC's Small Generator Interconnection Agreement (SGIA).

It is important to consider the interplay between the Ohio Administrative Code (OAC) for Interconnection Services (OAC 4901:1-22) and several technical standards used for interconnecting, or integrating, DERs to the EDUs' distribution system. This includes understanding the evolutionary life cycles of both the OAC and the technical standards and how they impact the ability of different stakeholders to meet them in Ohio. In addition, statutory elements, required technical elements, and optional technical elements all have an impact on the approval and operation of DERs in Ohio.

The PWG examined potential concerns related to interconnection standards by exploring the following:

- Key issues surrounding DER integration and interconnection
- Whether particular technical standards from IEEE and UL adequately address these key issues
- Any currently optional elements of technical standards that need to be firmer in Ohio
- Additional requirements or standards needed

In parallel, EnerNex examined the current OAC code (OAC 4901:1-22) in an effort to define recommendations related to the topic. At the present time, there is potential for uncertainty or misapplication of statutory and mandatory standard requirements.

REGULATORY LANDSCAPE

EnerNex's examination of OAC 4901:1-22 revealed several areas of outdated information:

1. The OAC references definitions and language from older revisions of the cited technical standards which may not be present in the latest revision of those standards.
2. The OAC references older revisions of technical standards which may not account for contemporary changes to the underlying technology.
3. The OAC conflates technical capacity limits originally developed for screening purposes. Screening criteria are appropriate for determining if additional analyses may be required, but they should not be used in the same manner as technical capacity limits.
4. The OAC contains no mechanism to account for the out-of-step life cycles between regulations and the technical standards.

One means to address the problem of standard life cycles being out of step is to modify regulation language (as expressed in bold), such as "the XXXX standard or **latest revision thereof** shall be used," and then all parties are legally obliged to accept the specifications of the latest revision. Another means to ensure greater control of the intended requirements is to cite a specific revision; however, that revision may then be deemed out of date or no longer applicable by the issuing organization. As can be seen by these two examples, a tradeoff exists between staying current with the latest standard version versus maintaining certainty of requirements based upon a "time-stamped" standard.

All relevant parties should monitor developments in relevant standards and be willing to adapt to the shifting technology and standards, including being proactively engaged to inform the relevant authority when changes are needed, rather than waiting for fixed regulatory review cycles. This includes making vendors and standards bodies aware, as applicable, of any inconsistencies encountered between intended, standards-based functionality and real-world observation (e.g., certified vs. deployed inverter functionality). Another potential issue can occur when one technical standard involves technology that is dependent upon a different technical standard, as is sometimes the case in a certification process. If a certification standard requires some time to be developed, this time lag can hinder the opportune deployment of various related technologies.

As an example, consider how inverter technology can be affected by differing time cycles. Inverter technology comes under the jurisdiction of IEEE Std 1547-2018, but this standard is affected by the publication of IEEE Std 1547.1 (Standard for Conformance Test Procedures) and subsequently on UL certification standard 1741, both of which are currently under revision. UL 1741 determines whether a product meets the 1547-2018 requirements with the companion UL certification, certificate, or sticker. In other words, although the current state of the industry for inverter technology already supports, or will be supporting, the technical capability of IEEE Std 1547-2018, those technologies cannot be deployed until the forthcoming IEEE Std 1547.1 and UL 1741 standards are complete (see Table 3).

Table 3: Relationship Between Inverter Technical Standards

Core Standard (Requirements)	Conformance Test Procedures	Companion Testing to IEEE
IEEE Std 1547-2003	IEEE Std 1547.1-2005	UL 1741
IEEE Std 1547a-2014 (Amendment 1)	IEEE Std 1547.1a-2015	UL 1741SA
IEEE Std 1547-2018	IEEE Std1547.1-xxxx (~2020)	UL updates to 1741 (~2021)

Since OAC 4901:1-22 is currently open for revision, it is expected that these points will be addressed through the normal code revision procedures, and not debated in the PWG.

TECHNICAL LANDSCAPE

Due to the variety and types of DER sources and equipment, connecting these resources to the grid is anything but uniform. This section lays out some of the considerations around how to integrate different technologies such that they both effectively and, more importantly, safely integrate into the grid.

DER integration and interconnection are accomplished through two common means. When the output of a DER matches the grid in terms of voltage (alternating current, or AC), that connection may be direct or made through a protective element such as a fuse. An example of this type of connection is a gasoline

AC generator or an inverter generator, which could be connected directly to the service panel in a residence or business at a standard AC service voltage level (240/208/120V). An alternative type of connection is used when the native output of a DER is direct current (DC). This output is transformed into AC through an inverter to match the connection. Solar PV panels and batteries are types of DERs that generate or consume DC power, requiring such a transformation through an inverter. The inverter is an important control and protective element in a DER system, and the technical standards related to DERs take this into account.

A gas generator functions similarly to a larger grid-scale generator: it is designed to operate at an optimal run speed. If the generator is connected to the grid, it is critical to add protective elements to ensure the safety of the devices under operation. DERs that are constantly operating are expected to have performance parameters that permit (or even mandate) operation during small disturbances while providing limits to ensure safety (i.e., ride through). Under IEEE Std 1547-2018, DERs are expected to ride through small deviations in voltage from the nominal value, or even large deviations due to grid loss. In addition, a DER may have the ability to be regulated (i.e., controlled) to match grid perturbations or variations within its performance parameters and contractual obligations. All DERs have protective circuitry to ensure the maximum safety possible.

A summary of some of the key technical topics related to standards for DERs are described below:

- **Anti-Islanding**—In order to prevent injury to utility workers, the ability of the DER equipment/system to prevent feeding of electricity into a circuit that the utility has ceased energizing.
- **Ride-Through**—The ability of the equipment/system to withstand voltage or frequency disturbances inside defined limits while continuing to operate as specified by IEEE Std 1547-2018 without stopping operation or tripping. The latest revision shifted several requirements from optional to mandatory for the equipment/system.
- **Voltage Regulation**—The ability of equipment to maintain voltage within a certain band either inherently or by command. For DERs, it is important whether the equipment/system can self-regulate, regulate on command, or operate in some other mode.
- **Protection**—Devices that provide protective functions (i.e., a behavior whose purpose is to maintain safe operations/conditions) to protect itself or the distribution grid.
- **Inverter Settings**—The attributes of an inverter that define its operation or relate to its mode of operation. Based on 1547-2018, the EDU can establish options regarding a set of "default attributes," or a default mode, for DER operation.

The initial IEEE standard for DERs was published in 2003, amended in 2014,[50] and published as a major revision in 2018. The evolution of key grid support functions is summarized in Table 4. This report adopts the definitions taken from an international standard[51] for the terms below. Testing regimes and standards reflect this language when equipment and performance is evaluated; therefore, it is critical for the standard to provide this type of clarity and consistency in language.

- **Shall:** "This word means that the definition is an absolute requirement [of the specification]." *We use this to indicate an item is an absolute requirement to satisfy a need.*

[50] The revision in 2014 modified three clauses: 4.1.1 Voltage Regulation, 4.2.4 Frequency, and 4.2.3 Voltage.
[51] https://www.ietf.org/rfc/rfc2119.txt

- **Should:** "This word, or the adjective "RECOMMENDED", means that there may exist valid reasons or circumstances to ignore a particular item, but the full implications must be understood and carefully weighed before choosing a different course." *We use this to indicate an item is recommended to satisfy a need where other approaches exist.*
- **May:** "This word, or the adjective "OPTIONAL", means that an item is truly optional." *We use this to indicate an item is optional to satisfy a need.*

Table 4: IEEE Std 1547 Grid Support Function Comparison by Revision

IEEE Std 1547-2003	**Shall NOT** actively regulate voltage
	Shall trip on abnormal voltage/frequency
IEEE Std 1547a-2014 (Amendment 1)	**May** actively regulate voltage
	May ride through abnormal voltage or frequency
	May provide frequency response
IEEE Std 1547-2018	**Shall be capable of** actively regulating voltage
	Shall ride through abnormal voltage/frequency
	Shall be capable of frequency response

IEEE Std 1547 has evolved grid support functions. Earlier DERs were considered more of a pure load, where no regulation was permitted and the resource could not stay connected during grid disturbances. Today DER is an active participant in grid operations with capabilities to help the grid during those same types of disturbances. The importance of this type of change cannot be overstated. From the standpoint of the technical standard, the 2018 standard is the version "in force" and against which technologies will be evaluated. Therefore, technologies must conform to the performance characteristics of the 1547-2018 standard in order to be certified (e.g., UL certified).

Restricting through administrative rule the performance of a DER to the 2003 functionality when it was developed under the 2018 standard may not even be possible (e.g., clearly *shall trip*, *may trip*, and *shall ride through* are designed and tested differently). The equipment cannot satisfy two mutually exclusive conditions (e.g., *shall trip* and *shall ride through*) unless the technical parameters for when those two conditions occur are different. Finally, as noted above, because of the timeline to develop and put in place the testing and certification regimes, no 1547-2018–compliant DER equipment is expected on the market until the 2021–2022 time frame.

5.2 Key Considerations

ALIGNMENT CHALLENGES

IEEE Std 1547 and UL 1741 continue to be widely supported by the industry; there appears to be no reason to deviate from their use in Ohio. The standards appear to adequately address the issues and stakeholder concerns in other jurisdictions with respect to the interoperability, operation, testing, maintenance, safety, and security of DERs on the distribution and bulk grids (noting that the latest 1574 revision now applies to the latter). Taking this approach will require the PUCO and other Ohio stakeholders to closely monitor the standards' evolution to ensure the OAC remains up-to-date.

As a preliminary matter and as requested by the Commission, the PWG discussed several issues presented by IEEE Std 1547-2018, including the following:

RIDE-THROUGH

PJM, as the regional transmission provider, is subject to FERC's requirements to coordinate with "all affected systems" for small generators and their interconnections.[52] As such, PJM participated in the PWG regarding the ride-through provisions of the revised standard and provided the following guidance:

1. PJM seeks to coordinate with distribution utilities on the ride-through provisions of IEEE Std 1547-2018. Coordination with the Reliability Coordinator is consistent with the IEEE Std 1547-2018 standard.[53]
2. PJM is working with utilities and other stakeholders in the DER Ride-Through Task Force to issue a voluntary guidance document in Q4 2019. This non-binding guidance is intended to broadly apply across PJM's territory under varying distribution grid designs and varying approaches to integrating DERs.
3. PJM recognizes that utilities may currently be in the evaluation stage with respect to IEEE Std 1547-2018 and that it may be premature to commit to a ride-through approach that is consistent with the PJM voluntary guidance document. Regardless, PJM intends to closely coordinate with utilities on this issue.

PJM's guidance on the ride-through provisions of IEEE Std 1547-2018 is consistent with FERC's SGIA[54] which requires that interconnection customers shall ensure "frequency ride though" and "voltage ride though" capabilities for small generation facilities. This input from PJM was helpful and appreciated given the low penetration of DERs in Ohio and the lack of experience in defining and operating relatively new functions defined in IEEE Std 1547-2018.

DEFAULT AND OPTIONAL FUNCTIONS

As described in the Technical Landscape section above, another element of IEEE Std 1547-2018 is the concept of default inverter functions and/or parameters for voltage regulation, as well as several optional inverter settings. Given the timing referenced above, the PWG did not conclude how to address these issues in a future revision of Ohio's interconnection rule.

COMMUNICATION PROTOCOLS

Similarly, IEEE Std 1547-2018 identifies three communication protocols,[55] of which one is required to be supported by a DER for its utility communication interface. At this time, the PWG was in general agreement that no single communication protocol of the three shall be mandated for all DERs in Ohio.

---

[52] Clauses 1.5.6 and 1.5.7 of the Small Generator Interconnection Agreement (SGIA) Appendix D, RM16-8-000 (revised), available from https://www.ferc.gov/industries/electric/indus-act/gi/small-gen.asp

[53] Clause 6.4.1 of IEEE Std 1547-2018, Mandatory Voltage Tripping Requirements, states, "Area EPS operators [i.e., distribution utilities] may specify [voltage trip clearing time] values within the specified range subject to the limitations on voltage trip settings specified by the regional reliability coordinator [e.g., PJM]."

[54] See SGIA Clause 1.5.7.

[55] IEEE Std 2030.5, IEEE Std 1815, and SunSpec Modbus.

TECHNOLOGY EVOLUTION

As discussed, the current state of the industry for inverter technology already supports, or will be supporting, the technical capability of IEEE Std 1547-2018 and UL 1741 SA (for advanced inverter testing) and will evolve to match the forthcoming IEEE Std 1547.1-xxxx and UL 1741 testing and certification standards when revised.

By way of example, the California Public Utilities Commission's Rule 21 tariff specifies smart grid implementation in three phases:

- Phase 1 involves advanced features such as voltage and frequency ride-through
- Phase 2 involves inverter communications
- Phase 3 involves advanced features (i.e., DER scheduling[56]) possibly beyond IEEE Std 1547-2018

The three California IOUs have incorporated IEEE Std 1547-2018 capabilities into their interconnection handbooks. Similarly, the Hawaii PUC approved two new DER programs: Smart Export and Customer Grid Supply+ (CGS+)[57] that require advanced smart inverter features. Both California[58] and Hawaii[59] certify inverters (and other devices) that meet their advanced requirements and currently provide weekly updates to their lists of inverters and vendors that support the 1547-2018 standard and advanced grid functions.

5.3 PWG Conclusions

The following points summarize the primary conclusions of the PWG regarding interconnection standards, based on themes that emerged from group discussions:

- Review cycles for the OAC, IEEE, and UL technical standards are out of step. At the present time, there is potential for uncertainty or misapplication of statutory and mandatory standard requirements.
- The current state of the industry for inverter technology already supports, or will be supporting, the technical capability of IEEE Std 1547-2018, but those technologies cannot be deployed until the forthcoming IEEE Std 1547.1 and UL 1741 standards are complete.
- Some of the key technical topics related to interconnections standards are related to ride-through, voltage regulation, protection, and inverter settings.
- Word conventions for requirements in standards should apply consistent language across standards to avoid misalignment between requirements that impact the ability of various technologies to be certified (e.g., two mutually exclusive conditions).
- At this time, the PWG was in general agreement that no single communication protocol of the three cited in IEEE Std 1547-2018 shall be mandated for all DERs in Ohio.

---

[56] https://www.cpuc.ca.gov/Rule21/
[57] https://puc.hawaii.gov/wp-content/uploads/2017/10/Hawaii_PUC_Smart-Export_CGS_Fact_Sheets_FINAL.pdf
[58] https://www.gosolarcalifornia.org/equipment/inverters.php/documents/documents/documents/documents/Utility_Interactive_Inverter_List_Simplified_Data.xlsx
[59] https://www.hawaiianelectric.com/documents/clean_energy_hawaii/qualified_equipment_list.pdf

5.4 EnerNex Recommendations

The following recommendations are primary actions that can be taken to further the development of interconnection standards in Ohio. Some of these recommendations are contingent upon each other and do not necessarily need to be addressed in the order given.

1. **Pursue Modifications to OAC 4901:1-22**—It is recommended that the Commission and EDUs work to modify OAC 4901:1-22 in a fashion that clearly identifies the adoption and application of IEEE Std 1547-2018 into rule, including that new installations support[60] advanced functions for voltage regulation and ride-through capabilities, even if those functions may not currently be used. The OAC should also adopt by reference IEEE Std 1547.1 and UL 1741.

2. **Pursue Modifications to EDU Interconnection Language**—It is recommended that the Commission and EDUs work together to address the IEEE Std 1547-2018 categories below in their interconnection applications and agreements per OAC 4901:1-22-05(A)(2)[61]:
    - *Categories I–III for Ride-Through:*
        - At this time, EDUs can elect to apply any of the three categories as appropriate and have category set points that vary from PJM's.
        - EDUs should define parameters (inverter- vs. non-inverter–based DER, voltage connection level, nameplate capacity) to clarify which ride-through category is applicable to DER installations in their service territories.
        - Exceptions may exist due to distribution or transmission constraints.
    - *Categories A & B for Voltage Regulation Functions:*
        - At this time, the enabling of voltage regulation functions should not be required at the statewide level.
        - EDUs should clearly specify the allowance (enabled) or prohibition (disabled) of each voltage regulation function listed in IEEE Std 1547-2018 and UL 1741 SA.
        - New interconnection agreements should not grandfather voltage regulation function status and should specifically indicate that mandated use of voltage regulation functions could occur in the future.
        - As penetration of DERs increases, it may be appropriate to recommend/mandate the use of voltage regulation functions and to consider increasing EDU monitoring of voltage levels on feeders where DERs are located.

3. **Pursue EDU Testing and Piloting**—It is recommended that the EDUs pursue testing and piloting related to the IEEE Std 1547-2018 categories previously mentioned:
    - EDUs should have a goal of testing or piloting ride-through set points to eventually align with PJM and the best practices of the industry.
    - EDUs should test and pilot voltage regulation functions to determine effectiveness and gain operational experience.

[60] The standard requires equipment to support the functions. Whether a jurisdiction or an EDU requires the use of such equipment is a different matter.
[61] The interconnection forms posted on the PUCO website are out of date.

Section 6.0 Hosting Capability Analysis (HCA) Summary

6.1 Background

The PWG was tasked with developing recommendations to the Commission on the following:

- Defining HCA use cases
- Identifying an appropriate HCA methodology and associated tools and data requirements to satisfy use cases
- A timeline for initial HCA analysis and publication of results for each EDU
- The development of portals for sharing peak load forecasts, capital plans, hosting capacity maps, heat maps reflecting locational values of distributed generation (DG) sites, and other key data

6.2 Key Considerations

The Interstate Renewable Energy Council (IREC) defines the term *hosting capacity* as "the amount of DER that can be accommodated on the distribution system at a given time and at a given location under existing grid conditions and operations, without adversely impacting safety, power quality, reliability, or other operational criteria and without requiring significant infrastructure upgrades."[62]

HCA has been increasingly discussed over the last five years, but to date it is not prevalent in most U.S. state jurisdictions.[63] In approaching its investigation of HCA, the PWG looked to lessons learned from leading jurisdictions[64]. These jurisdictions have higher penetrations of DERs (2%–16% of Customers) than Ohio, where approximately 0.125%[65] of Customers have DERs, and/or have state policies that have led to the development of hosting capacity maps.

DEFINING BENEFITS & LIMITATIONS

HCA is primarily intended to serve as an indicator for specific static-state (snapshot) conditions of individual or multiple portions of the grid system. HCA provides an additional degree of analytical sophistication beyond traditional grid "rules of thumb." Additionally, HCA provides awareness of potential grid conflicts before a more detailed and site-specific interconnection study can be conducted. HCAs can also be used by utility distribution planning groups to identify areas where additional DERs can be supported or would benefit from DERs and as inputs to distributed resource plans.[66] For example, HCA methods may identify if any grid violations occur when a new solar PV facility is interconnected to a circuit based on several criteria (e.g., voltage, thermal, or protection limits). HCA can also be used to identify distribution circuits that are approaching criteria limits, thus assisting both utility planners and

[62] See IREC's "Optimizing the Grid: A Regulator's Guide to Hosting Capacity Analysis for Distributed Energy Resources," 2017, at 6: https://irecusa.org/2017/12/tools-to-build-the-modern-grid.

[63] Only a few states (California, Hawaii, Minnesota, and New York) are characterized as having "advanced activity" related to HCA based on a map from the NARUC State Commission Staff Surge Call: Hosting Capacity Analysis Summary, November 26, 2018.

[64] States mentioned in previous footnote, along with North Carolina and Pepco (an EDU in the DC/Maryland area).

[65] Ohio has approximately 6,000 DERs and 4.8 million Customers.

[66] Examples of HCA as part of distribution planning in other jurisdictions include: 1) the Nevada PUC which issued a proposed decision to require that distribution resource plans include an HCA that is updated bi-annually according to a Proposed Temporary Regulation of the Public Utilities Commission of Nevada (NAC Chapter 704), LCB FILE NO. T001-18I, 08/09/2018, 2) the Minnesota PUC issued an order that a utility Integrated Distribution Plan (IDP) will require a hosting analysis, and Xcel Energy has stated in their IDP that "in the longer term, investments like more advanced control schemes coordinating action with smart inverters and utility devices will improve the hosting capacity of circuits with voltage threshold constraints" according to XCEL Integrated Distribution Plan, Docket No. E002/CI-18-251 November 1 2018 at 211.

developers to identify areas where equipment additions or upgrades would be needed to support further DER deployment. HCA could also help utilities identify areas where new DER could be deployed to eliminate or reduce the need for additional generation or distribution feeders.

HCA is not a substitute for a comprehensive interconnection study; it serves as a functional tool that can be used before a more detailed analysis is conducted. HCA does not specifically address dynamically changing electrical conditions that may occur and it does not address all criteria that distribution planners use when evaluating an interconnection request.

Currently, interconnection requests in Ohio are typically evaluated on an individual basis, with databases adapted to capture DER information. The process of developing a comprehensive HCA at a circuit level and sharing this information publicly would require significant additional effort and coordination between various functional groups within each EDU. As has been identified in other jurisdictions, performing system-wide HCA could require additional data from deployed assets that currently have limited or no tracking capability.

HCA METHODS & APPROACHES

Various HCA approaches are being utilized by utilities and are likely to continue to evolve, especially as the demand for DERs increases. Each of these HCA approaches require similar forms of input data (e.g., circuit characteristics, current state, loads, DER levels) to produce meaningful outputs.

The three approaches to HCA are as follows:

- **Stochastic**—DERs are added at random points on a circuit at increasing penetration levels. A power flow model is run at each penetration level, and the results are analyzed to identify corresponding hosting capacity values.
- **Iterative**—DERs are added at specific points on a circuit at increasing size. A power flow model is run at each penetration level, and the results are analyzed to identify corresponding hosting capacity values.
- **Streamlined**[67]—A complex method that uses characteristics about the circuit as well as probabilistic modeling on realistic DER locations to provide a range of hosting capacity values.

In addition, many proprietary tools, such as EPRI's DRIVE (distribution resource integration and value estimation) tool,[68] combine these approaches and refine them based on detailed analysis of results and experience. It is also useful to note that HCA is not currently intended to provide financial guidance (e.g., location-specific value) of DERs.

HCA EXTERNAL PORTALS

The process of developing portals for sharing HCA information has benefits to both EDUs and external shareholders interested in the capabilities of the distribution system to support DERs. External stakeholders could include end-use Customers considering interconnecting generation at their home or place of business, developers identifying a multitude of potential locations suitable for larger generation projects, and others seeking current data related to DER adoption rates and the infrastructure to

[67] M. Rylander, et. al. "Streamlined Method for Determining Distribution System Hosting Capacity," *IEEE Transactions on Industry Applications*, Vol. 52, No. 1, January/February 2016.
[68] https://www.eaton.com/us/en-us/products/utility-grid-solutions/software-modules/epri-drive-software.html

support it. The benefits to EDUs are generally related to enhanced data and system awareness. Through greater visibility and awareness, utilities have improved foresight related to their grid system's ability to support (i.e., host) varying levels of DERs.

6.3 PWG Conclusions

Stakeholders generally agreed that the current status of DER adoption and lack of associated policy in Ohio does not create an urgent need for system-wide HCA deployment and associated data portals. However, workgroup stakeholders had differing opinions on the value of considering HCA more deliberately and proactively, especially in terms of near-term actions related to HCA. A contributing factor is the difficulty in identifying a trigger point for more thorough consideration of HCA in the future. The PWG generally agreed that the trigger point would likely be associated with an increase in DER adoption rates and interconnection requests reflecting growing consumer interest.

The following points summarize the primary conclusions of the PWG regarding HCA, based on themes that emerged from group discussions:

- The current Pre-Application Review process for interconnection of distributed generation (DG) in Ohio and associated application/processing fees cover the analysis and provide low-cost guides for developers considering DG projects.[69] In considering a similar issue, the North Carolina Utilities Commission (NCUC) identified that Pre-Application Reports[70] currently meet the needs of Customers or developers at a lower cost than system-wide HCA.
- Other jurisdictions have spent significant effort defining HCA methods to be used by their distribution utilities; however, prescribing a specific approach when multiple approaches are valid seems to overstate the intent of HCA. As mentioned above, HCA is intended to be an indicator of a circuit's hosting capacity rather than a tool to identify precision hosting capacity under all scenarios and conditions.
- Stakeholders expressed interest in some level of transparency and visibility into the distribution system and planning process. HCA and portals are one option that other jurisdictions have identified to fill this stakeholder desire. Currently, no incentives or mechanisms exist in Ohio for EDUs to provide that level of transparency.
- As was the case in New York, it may not be appropriate in Ohio to pursue highly functional portals from the outset. Some activities can be done to effectively move toward more transparency on the status of the distribution grids in Ohio to support distribution-sited generation, including those listed in the recommendations that follow.
- As Ohio EDUs deploy AMI and associated analytics more widely, their ability to more quickly characterize each circuit will likely improve.
- When HCA for a set of circuits is pursued by the EDUs, associated information that is shared publicly should be updated frequently by the EDUs to ensure current indicators are provided.

[69] More information on the Major Ohio Application Requirements for Distributed Generation Interconnection for various system sizes can be found at https://www.puco.ohio.gov/be-informed/consumer-topics/distributed-generation-generating-your-own-electricity/major-application-requirements-for-distributed-generation-interconnection/.

[70] North Carolina's Pre-Application Report is a similar process to Ohio's current Pre-Application Review process. Details of the Report and fees can be found in NCUC Order Approving Revised Interconnection Standard and Requiring Reports and Testimony, issued on June 14, 2019, in Docket No. E-100, SUB 101, at 3. At 58, it specifically notes that Pre-Application Reports are "targeted to Points of Interconnection of actual interest to specific Interconnection Customers".

EnerNex
A CESI Company

6.4 EnerNex Recommendations

The following recommendations are primary actions that can be taken in terms of furthering HCA development in Ohio. Some of these recommendations are contingent upon each other and do not necessarily need to be addressed in the order given.

1. **Pursue Initial HCA-Related Evaluations**—Recognizing that Ohio is not at the same level of DER penetration as other states and that interconnection processes differ, it is recommended that the Commission consider the value of EDUs evaluating their system to identify:
    - The quantity of circuits where HCA might hold value in the 5- to 10-year horizon to determine the near-term merits of developing HCA capability
    - The cost of performing/publishing HCA for varying degrees of HCA capability, in terms of comprehensiveness and level of detail
    - The efficacy of the current interconnection queueing system to support varying levels of interconnection applications

2. **Pursue Initial HCA-Related Activities**—It is recommended that resources and effort be focused initially on activities that fall under a general theme of HCA-related activities, capturing some of the benefits without requiring a comprehensive implementation of HCA at this time. Such activities include:
    - Piloting HCA on a few circuits that either likely have lower hosting capacity as the result of existing DERs or circuit characteristics, or where future DER adoption is anticipated
    - Conducting studies to improve EDU understanding of the capabilities of the existing distribution system to support various futures, which could include:
        - Granular load profile analysis and forecasts that incorporate changes due to shifts in end use utilization and responses to time-of-use or dynamic pricing
        - Impact studies to review the effects of siting new EV charging infrastructure
    - Improving any current interconnection queueing process limitations
    - Proactively identifying locations and times where DER could provide distribution system benefits. If shared, this data could enable greater transparency on distribution system capabilities for various Third Party solutions providers (e.g., solar PV, EVs, data centers)

Section 7.0 Conclusion and Summary

The PWG effort undertaken and the participation by stakeholders, including the Staff, has been effective and collaborative. This forum provided a facilitated means to provide education, reference material and meaningful dialogue and interchange among all parties.

Within the context of the vision articulated in the PowerForward Roadmap and trends in the industry, Ohio has once again demonstrated a leadership role in this topic and has established a strong foundation to move forward to the "very bright future where we embrace innovation and change for the betterment of Ohioans."[71] We applaud the Commission for taking a proactive step forward, especially in a landscape that is in the early stages of grid modernization. In our experience, that is an ideal environment for pursuing grid modernization actions in a deliberate, collaborative, and orderly manner. This not only establishes a vision for Ohio, but also serves as an example for other jurisdictions that are grappling with establishing greater clarity and alignment related to grid modernization.

To ensure that Ohio keeps moving the "power forward", deliberate and incremental action is essential. Grid modernization topics are both expansive and complex and will continuously and dynamically adapt over time. In the early stages, staying in tune with best practices from other jurisdictions with more pronounced drivers, whether legislative, regulatory, or Customer-centric, is a good ongoing practice. However, the goal should not merely be to remain current with developing trends, but to identify what can be specifically extracted and applied within the local context. Essentially, Ohio and other jurisdictions, can learn from "early adopters" to cultivate and form their respective vision and direction along a grid modernization continuum. There is no single "silver bullet" for grid modernization, therefore, each jurisdiction will need to establish their desired end state and corresponding pace of development and deployment. This report serves as an example of specific recommendations and steps that can be taken in Ohio with respect to one component of grid modernization, namely, distribution planning.

EnerNex wishes to thank all parties who participated in this effort. EnerNex has been pleased to play a role in helping guide Ohio to take another incremental step forward and we look forward to the continuing ripple effects that may occur locally and in other jurisdictions based on these collective efforts. As stated previously, grid modernization is here to stay and each jurisdiction plays a role in contributing towards the overall national and global landscape. We hope this serves as a useful guide to advance distribution planning and the broader grid modernization discussion in Ohio and beyond.

[71] Roadmap at 6.

Appendix A: High-Level Recommendation Details

The following provides a more detailed explanation of the first two distribution planning recommendations presented in Section 2.5 (High-Level Recommendations).

1. **Complete the Deployment of Advanced Metering Infrastructure (AMI)[72]**—EnerNex concurs with the AMI guidance provided by the Roadmap[73] and agrees that AMI is a foundational grid modernization effort. AMI plays a role in i) enabling more efficient market structures for EDUs and their Customers and ii) providing grid operations benefits as follows:

   i. AMI plays a key role in enabling more efficient market structures. The interval data provided by AMI is needed for financial settlements with competitive suppliers based on the energy used by their customers, the development of TOU rates, and efficient dynamic price signals. The ability to manage demand in response to price signals is a fundamental capability of an efficient market structure. AMI also enables better Customer forecasting, development of Customer load profiles, and the ability to provide the data to Customers and authorized Third Parties for the development of additional products and services.

   ii. Advanced meters and distributed sensor technology provide several benefits in terms of grid operations, such as:
      - Providing information to improve outage management and to accelerate grid service restoration
      - Supporting power flow analysis leading to early identification of potential distribution constraints
      - Enhancing voltage optimization to minimize distribution losses and maximize customer energy and bill savings
      - Avoiding high-transformer loads that shorten equipment life
      - Identifying power quality problems
      - Enabling efficient DER integration and valuation

2. **Advance Distribution Planning Processes and Generate Annual Reports to Commission**— The objective is to advance distribution planning processes in Ohio, and this can be accomplished via regular reporting that details improvement efforts and related issues. Reports by the EDUs should include data to assist the Commission in identifying potential pilot programs, developing procedures, and/or formulating recommendations that assist in the transition towards IDP. The following list contains examples of potential data reports[74] that EDUs could supply the Commission to help further DSP efforts in Ohio. These examples reflect both data collected in the EDU current-

[72] AMI or comparable interval metering and real-time distribution monitoring technology

[73] The Roadmap considers AMI to be a fundamental component for advancing grid modernization by stating that the "Commission has identified AMI, including advanced meters, as a core component of the platform and believes that [Customer Energy Usage Data] needs to be better utilized by the EDUs as well as made available to Third Parties in a way that will lead to an enhanced customer experience." Also, "the deployment of AMI, including smart and advanced meters, enables the provision of the type and granularity of data needed to align retail charges with the wholesale market costs for generation."

[74] Other jurisdictions have required EDUs to file their 5-10 year plan alongside or within these data reports. For the purposes of this list, we have assumed that such plans would be filed as part of a rate case or separate rider, rather than within these context-setting reports.

state assessments and IDP data reporting requirements from other jurisdictions[75] adapted for the local Ohio context.

i. Number and percentage of customers and delivered energy served by AMI or other interval data recorders, a summary of the available functionality, and an updated plan to complete deployment
ii. Percentage of substations and circuits with SCADA or with other monitoring and control technologies (please specify)
iii. Description of installed distribution sensors, communication networks, and controls, and the type and degree of automation installed, including the percent of substations that have been fully or partially automated to IEC 61850 or a comparable standard, and of planned improvements in these network sensors, controls, and automation capabilities
iv. Existing DERs (by type and capacity) interconnected to the EDU's distribution system and a description of the real-time data collected on DER operation
v. Identification of any existing and potential DER clusters and their impacts on DSP
vi. Forecasts of Customer DER adoption (by type and capacity) and potential distribution impacts and a description of forecasting methods
vii. Description of how the application interconnection standards, including interoperability and advanced inverter functionality, impacts distribution planning and any opportunities for improving the integration of DER into distribution planning and operations
viii. Number of units and MW and MWh ratings of energy storage
ix. Number and type of electric vehicles (e.g., light duty, heavy duty, mass transit) registered or estimated to operate in the EDU's service territory
x. Number and capacity of EV fast-charging locations, fleet-charging hubs, public charging stations, and other clusters of EVs in each EDU's distribution system and the related distribution impacts
xi. Estimated annual average and peak system loss percentages
xii. Number of circuits and percentage of delivered energy for which the EDU has implemented upstream and low-voltage (grid edge) volt-var optimization and the corresponding estimated energy and demand savings realized
xiii. The statistical distribution of service voltages within the ANSI C84.1 band measured at or near customer locations (e.g., from regular interval readings at smart meters or distribution voltage sensors, wherever available) for circuits on which the EDU has implemented and not yet implemented voltage optimization (as means of comparison). Relevant information should be provided from each voltage data point (e.g., date, time, circuit data).
xiv. Number and percentage of critical customer facilities for which the EDU has implemented enhanced reliability measures (e.g., separately located redundant service feeds, automated fault location isolation and service restoration [FLISR] systems, microgrids with backup generation or storage) and avoided service interruption estimates associated with these facilities

[75] In assembling this list, EnerNex reviewed materials within (1) the Minnesota Public Utilities Commission's Docket No. E002/CI-18-251, including the Order dated August 30,2018 and Xcel's subsequent Integrated Distribution Plan filed November 1, 2018, (2) the Colorado Revised Statute § 40-2-132 and CPUC Decision No. C19-0957 within Proceeding No. 19M-0670E filed in December 2019, (3) the California Public Utilities Commission proceeding R.14-08-013 (Distributed Resource Plan) and associated working group materials, (4) other industry experience.

xv. Number and percentage of total circuits for which the EDU has implemented enhanced reliability measures (e.g., integration of AMI and/or distributed sensor data into the utility's outage management system, ability to support the circuit from multiple substations, FLISR systems, microgrids) and any estimates of reduced outage times, avoided service interruptions, and related reductions in Customers' value of lost load

xvi. Forecasts of distribution constraints, upgrade requirements, and new developments or neighborhoods that might be suitable NWA candidates, including DER, demand response, and/or price-responsive demand, together with a description of the EDU's NWA suitability and benefit – cost criteria

xvii. A description of the forecasting, modeling, mapping, and power flow analysis software currently used in distribution planning and any planned improvements

xviii. A description of forecast scenarios and methodology used in distribution planning and any planned improvements to that methodology

Appendix B: Topical Scoping Questions

In its role as facilitator for the PWG, EnerNex developed a series of questions, the goal of which was to aid stakeholders in building a shared understanding of the issues under consideration and to create a framework for group deliberations. The questions used in the stakeholder sessions are provided below.

NWA Scoping Questions

DEVELOPMENT OF NWA SUITABILITY CRITERIA

1. What objectives and metrics should exist for considering an NWA application (e.g., objectives: capacity deferral, service to critical facilities, Customer bill reduction)?
2. What are the potential applications for NWAs?
3. What technologies/approaches should be considered eligible as part of an NWA project in Ohio?
4. How can information currently used in distribution system planning be used to demonstrate the need for/net benefits of an NWA project, based on the objectives and metrics established?

PROCESSES AND TIMELINE FOR IMPLEMENTING NWA OPPORTUNITIES

1. How should the process for implementing NWA opportunities be structured/piloted?
2. How should NWAs be evaluated relative to other more traditional utility infrastructure investments (e.g., cost effectiveness and NPV for deferred investments)?
3. How should an NWA that provides multiple forms of value be evaluated?
4. What metrics should be put in place to assess the effectiveness of NWAs and the NWA approach?

EVALUATION OF OPTIONS FOR PROCURING NWAs

1. What type of procurement and contracting models may be utilized for the implementation of NWA projects (e.g., RFP/RFO, options contracts)?
2. What ownership considerations should be addressed, i.e., who can own which components of different NWA projects? Does location impact eligibility for ownership (e.g., front of meter, behind the meter)?
3. If non-utility assets are eligible for an NWA project, how can we ensure they provide safe and reliable service?

Energy Storage Scoping Questions

ENERGY STORAGE APPLICATIONS

1. What functions and uses of energy storage can provide benefits to the distribution system?
2. How does location affect the functions and uses for the deployment of energy storage?
3. Based on the use case, which form(s) of energy storage are best suited to achieve the desired benefits, e.g., mechanical, thermal, chemical, etc.?

ENERGY STORAGE PLANNING CONSIDERATIONS

1. What requirements may be important to consider in ensuring desired benefits are provided?

2. What processes should the utility consider in evaluating where it may be beneficial to deploy energy storage solutions?
3. What role should various stakeholders play in planning, reviewing, implementing, and operating energy storage solutions, including the utilities, Staff, and Third Parties?

Interconnection Standards Scoping Questions

1. What are the key issues surrounding DER integration and interconnection (e.g., ride-through, regulation, protection)?
2. Do the revised IEEE Std 1547 and UL 1741 SA standards adequately address the issues and stakeholder concerns relative to interoperability, operation, testing, and maintenance, as well as safety and security?
    a. Are PJM's recommendations for DER ride-through settings sufficient for Ohio?
    b. Should Ohio require a specific default inverter function and/or parameters for voltage regulation?
    c. Should any of the optional functions within the revised IEEE Std 1547 be part of the interconnection standards in Ohio?
    d. Are additional requirements and/or standards needed?
3. Should Ohio mandate one of the three IEEE Std 1547 eligible communications protocols[76] for DERs?

HCA Scoping Questions

SCOPING QUESTIONS

1. What is HCA?
2. How prevalent is HCA across state jurisdictions?
3. What are the benefits and limitations of HCA?
4. Are there different HCA approaches and methodologies based on different use cases?
5. How are external portals utilized to effectively communicate HCA content?
6. Is HCA relevant to Ohio EDUs?

[76] IEEE Std 1547 requires one of three communication protocols to be supported from IEEE Std 2030.5, IEEE Std 1815, and SunSpec Modbus.

Appendix C: Cost-Effectiveness Framework (Rhode Island)[77]

	Cost or Benefit Category	System Attribute Benefit/Cost Driver	Candidate Methodologies
Bulk Power System	Energy supply: value of energy provided or saved (time- and location-specific)	PJM energy market time and locational marginal pricing (LMP)	Forecasted time- and LMP for the period when the NWA resource is operating
	Forward commitment: capacity value	Whether a PJM Reliability Pricing Model (RPM) Qualified Resource &, if so, prices for RPM Qualified Capacity	Estimate of likely RPM bid capacity from any PJM RPM qualified resources
		Change in demand to the extent reflected in PJM forecasts of capacity requirements	Review of likely future impact on PJM forecasts
	Ancillary services value	If a qualified ancillary service resource, ancillary services prices	Forecast ancillary service prices, subject to the limit of ancillary service requirements
	Renewable energy credit (REC) value	Anticipated REC value	Forecast of REC prices
	Electric transmission capacity costs or value	Change in transmission capacity requirements associated in change in resource mix	Value of avoided transmission capacity associated with any change in net demand
			Forecast cost impacts of resources on increased transmission requirements
	Cost or Benefit Category	**System Attribute Benefit/Cost Driver**	**Candidate Methodologies**
Distribution System and DERs	Distribution capacity avoided and/or increased costs	Generalized change in distribution capacity requirements with change in demand	Annualized distribution capacity value associated with load growth, change in net demand
		Forecasted change in the affected distribution circuit planning requirements	DSP studies
		Location-specific DER hosting capacity	Analysis of capability to host DERs with existing and already-planned facilities
	Distribution operations:	Location-specific impacts on distribution constraints, losses,	Circuit-specific distribution plans

[77] The table is slightly amended from a benefit-cost framework developed by a stakeholder working group for the Rhode Island Public Utilities Commission. The full framework is available at http://www.ripuc.org/eventsactions/docket/4600-WGReport_4-5-17.pdf, Appendix B.

	change in delivery costs	CVO, equipment cycling, distribution locational marginal pricing (DLMP)	Analysis of time-, location-, and product-specific DLMP value
	NWA resource costs	Direct cost of resources including capital and operating costs plus utility program costs (participant recruitment, administrative, incentive, and evaluation, measurement, and verification [EM&V] costs)	Cost estimates
	Distribution system and Customer reliability/ resilience impacts (+/-)	Customer-specific and critical facility outage costs and value of uninterrupted service	US DOE Interruption Cost Estimator
			Customer value of uninterrupted service studies
		Expected performance of DERs	Evaluation of performance reliability of and contractual terms with relevant DER aggregations
		Expected impacts on the probability and duration of outages	Distribution system risk and resilience studies
		Other benefits and costs of distribution improvements or microgrids	Distribution/microgrid planning and costing
	Distribution system safety loss/gain	Changes in risk, improvements in information on system conditions, training costs	Qualitative assessment, tracking and assessment of safety metrics
	Investment under uncertainty: real options cost/value	Irreversible capital-intensive investments under uncertainty may prove to have been unnecessary or uneconomic where new information could alter a decision	Scenario analysis: calculation of real option value associated with different decision times and resources
	Innovation and learning by doing	Experimentation costs	Direct costs of innovation/ demonstration programs
		Rate of cost reduction or performance improvement through greater deployment	Qualitative assessment

	Cost or Benefit Category	System Attribute Benefit/Cost Driver	Candidate Methodologies
Customer	Program participant/prosumer benefits/costs	Direct participant/prosumer technology and program participation costs (not included in NWA resource costs above)	Estimates of net direct costs
		Required behavioral changes and inconvenience costs	Qualitative assessment
		Value of improvements in quality of life	Qualitative value
	Participant non-electricity benefits: oil, gas, waste water savings (or costs)	Value of energy and water savings (or costs)	Estimate of avoided natural gas, oil, and other fuel costs
			Estimate of water savings
	Consumer empowerment and choice	Development of more robust retail and services market	Qualitative assessment
	Non-participant rate and bill impacts **(Rate Impact Measure Test Only)**	Change in rates or costs per kWh	Cost of service studies, bill analysis
	Cost or Benefit Category	**System Attribute Benefit/Cost Driver**	**Candidate Methodologies**
Societal	Environmental externality costs **(Societal Cost Test)**	Marginal environmental externality value	Customer willingness to pay (WTP) for reductions (observation or surveys)
			Societal cost estimates
		Avoided (or additional) net marginal emissions	Forecast of net emissions impacts from change in regional dispatch and resource mix
	Economic development benefits and costs **(Societal Cost Test)**	Estimate of impacts on state product or employment	Qualitative assessment
			Economic modeling (e.g., input/output life-cycle analysis)
	Equity (affordability, low-income energy burden) **(Societal Cost Test)**	Bill impacts on low income and vulnerable Customers, usage patterns, cost allocation, rate design, pricing, assistance programs	Analysis of arrearages, timely payments, uncollectibles, collection expenses, service termination and reconnection costs
			Analysis of bill impacts on low income and vulnerable Customers

	Innovation and knowledge spillover **(Societal Cost Test)**	R&D; strength of innovation eco-system, knowledge capture & sharing from public/utility funded initiatives	Qualitative assessment
	Market/price risk **(Societal Cost Test)**	Variability in price or costs, ability to modify supply or demand, allocation/assumption of cost variability by parties with ability to adapt or absorb variability	Qualitative assessment
			Analysis of volatility in prices, costs, or returns
			Analysis of price elasticity and transparency to price-elastic participants
			Analysis of market liquidity (ability of markets to allocate risks)

Appendix D: Summary of Meeting Workshops

The PWG consisted of eleven group meetings, some conducted in person and some virtually via webinar. The summarized content of each meeting is provided below.

MEETING 1—MARCH 27, 2019

The first PWG meeting laid the foundation for subsequent PWG meetings and was geared toward enabling all participants to operate from a common knowledge base. A draft charter was presented to establish how the workgroup would operate and to establish the discussion topics that would be both in and out of scope for the workgroup. EnerNex provided some context on distribution system planning, including a historical perspective and the current need for both the analytic tools and underlying data to be both appropriate and accurate for the task at hand. This discussion also covered some of the new tools and solutions available to modernize the distribution system, including communications and IT touchpoints.

Paul Centolella (president, Paul Centolella & Associates, LLC) gave a presentation on the evolution of DSP. This presentation covered the core architectural components associated with a modern distribution system and the future scenarios and externalities that should be considered in the planning processes. He also clarified that each of the futures considered are not mutually exclusive; future DSP will consider a broad range of inputs. Each EDU (i.e., AEP Ohio, Duke Energy Ohio, Dayton Power & Light, and FirstEnergy Ohio) presented information on current and near-future DSP processes and plans. These presentations included an overview of DERs interconnected within each EDU territory as well as the NWA projects that have been identified and/or considered.

Consumer Group advocates identified the necessity of ease of use for enrollment in new programs and effective communication to Customers and the need to consider the utility compensatory mechanisms within the context of NWA suitability criteria. Additionally, there were discussions of “masked load,” in which behind-the-meter DERs “mask” the energy usage of the Customer as a whole.

Other topics in this meeting included:

- Holistic planning, including other established reporting/planning mechanisms, such as energy efficiency and long-term forecasts, within the scope of DSP
- The potential of EVs to quickly alter the planning paradigm
- The complexity of modern DSP, which often includes a variety of tangentially related components
- The status of analytic tools within each of the EDUs, including that analytics are required to maximize the value of distribution data—the maturity of analytic tools within the industry was questioned.
- How to maximize the full value of storage by utilizing multiple use cases

MEETING 2—APRIL 23, 2019

EnerNex provided summary comments on the current state assessments of distribution system planning submitted by the EDUs. The key findings were as follows:

- Although there are differences in the development of DSP capabilities, each EDU falls within an expected range of traditional planning practices.
- The absence of smart meter data and a uniform platform will hinder the ability of EDUs to identify and integrate beneficial NWAs.

EnerNex also compared the EDUs' current state practices in Ohio to best practices elsewhere in the country. A summary of the EDUs' current state assessments as they relate specifically to NWA and NWA technologies was presented. Additionally, the scope of the PWG as it relates to its NWA task was reviewed as well as a set of questions that the PWG should attempt to answer as part of the NWA task.

Paul Centolella gave a presentation that covered some background on NWA, including principles, objectives, and guidance for NWA from the Roadmap. EnerNex presented various definitions of NWAs that have been put forward by different entities and summarized how the notion of NWA has been applied in different jurisdictions, including Hawaii, Michigan, California, and New York. Some of the main observations and comments included the following:

- A BCA framework will be beneficial to the economic valuation of NWAs. The BCA framework can be tailored to each EDU dependent on EDU territory characteristics.
- It can be challenging to establish a credible baseline in order to illustrate the performance of NWA projects.
- Forecasts, although beneficial and necessary, are inherently wrong. EDUs need to be innovative in dealing with errors in initial projections. The number of forecast years needed depends on the project.

Each of the EDUs provided comments and perspectives on NWAs, including a presentation by Duke Energy Ohio. Several other stakeholders gave presentations on NWAs, including Enel X (DER aggregator), the Environmental Law & Policy Center (ELPC), and the Office of Consumers' Council (OCC). Some key points from these presentations and subsequent conversations include:

- The EDU is ultimately responsible for the reliability and resilience of the distribution system.
- When NWAs are implemented by Third Parties, technical and legal structures should be put in place to ensure the dependability of NWAs.
- NWAs need to be effective, cost-efficient, and timely.
- The NWA value proposition should be considered at generation, transmission, and distribution levels.
- A fee is included in energy efficiency and demand response costs charged by manufacturers or vendors. The fee is the cost of providing control and reports to the EDU.
- The EDUs are best suited to work with Customers on NWAs because the utilities have a unique understanding of the constraints on the distribution system. The EDUs can work with Customers to develop NWAs that would improve reliability and resilience.
- The absence of AMI meters inhibits NWA deployment.
- NWA accommodation costs (i.e., the cost to facilitate an NWA interconnection) can be significant and should be factored into the evaluation.

MEETING 3—MAY 1, 2019

EnerNex led a discussion on a set of proposed "guiding principles" for NWAs. Following stakeholder discussion, there was general consensus on the guiding principles. EnerNex also led a discussion around the proposed objectives for NWA, an NWA definition, and a set of "candidate technologies." Based on stakeholder discussion, candidate technologies were expanded to include candidate technologies and approaches as well as pricing mechanisms.

The overall NWA approach in Ohio was discussed, including the high-level process around which potential opportunities for NWA would be identified, evaluated, procured, implemented, operated, and monitored. There was general consensus around the proposed approach. There was a request to add the EDUs' current DSP process as an introduction for the NWA process. Some stakeholders expressed a desire to have greater involvement in the EDU planning process, or at least for the process to be more transparent to stakeholders. The EDUs expressed concerns about any stakeholder participation in the distribution system planning process, believing that it would likely be cumbersome. The EDUs also expressed security concerns with making system information public.

Other key points and observations made during the discussion were as follows:

- The workgroup aims to establish a uniform approach among all the EDUs for identifying and evaluating NWA projects.
- There are examples of successful, economically viable NWA projects that improve reliability, resilience, and operational efficiency. These examples will be discussed in more detail.
- The NWA procurement process should be a mechanism that will allow for fair competition to identify the lowest cost solution for the chosen application.
- The EDUs expressed concerns that the NWA process might be too lengthy to be useful to respond to unexpected situations. In these cases, an RFP for an NWA solution would not be appropriate.

Finally, EnerNex facilitated a discussion around NWA ownership considerations. In general, the initial framework presented needs modification for increased clarity. Staff agreed to consider how this information might be better presented for future discussion.

MEETING 4—MAY 7, 2019

EnerNex led a discussion that covered analysis of PJM locational marginal prices and how relevant factors (e.g., energy, congestion, losses, real-time analysis) might contribute to the identification of NWA opportunities. Stakeholders felt that this kind of analysis would likely not be useful for assessing current NWA opportunities at the distribution level. EnerNex reviewed NWA evaluation frameworks that have been adopted for use in New York, including the societal cost test (SCT), utility cost test (UCT), and rate impact measure (RIM) test. Stakeholders were generally unfamiliar with these approaches and wanted to defer decisions around adopting this kind of evaluation, pending more information and input. There was discussion about scaling back to a more limited version of the UCT to begin NWA evaluations in Ohio but no consensus on this position.

EnerNex reviewed a case study on the calculation of substation upgrade deferral benefits associated with an NWA investment in Rhode Island (the Tiverton NWA Pilot). Stakeholders had questions on the details of the case study and assumptions used in the analysis, not necessarily on the analytical framework itself. EnerNex reviewed the PWG scoping question language for NWA from the previous meeting, including:

- The development of NWA suitability criteria
- Evaluation options for procuring NWAs

Minor modifications to the language were discussed, and the group agreed that the full NWA summary document would be circulated prior to the next meeting.

MEETING 5—MAY 29, 2019

The meeting began with a discussion of the integration of NWA opportunities into DSP. The definition of NWA was clarified to include intelligent end-use devices and other load-shifting mechanisms. The question was raised as to whether NWAs require real-time pricing or some other distribution market. Stakeholders encouraged EDU distribution engineering groups to work with the EE, DR, and tariff design organizations within each EDU to move toward more IDP.

The EDUs expressed concern about whether NWA efforts such as these would be sufficient in deferring large-scale distribution investments. They further expressed concern about the reliability of these investments and services, particularly in times of high system stress, when the upgrade would be needed. The idea of contracts and service agreements to guarantee performance was provided. Stakeholders also raised the idea for pilot programs to allow for greater confidence in the potential of NWA performance.

EnerNex provided an overview of a cost planning framework. Generally, the PWG seemed receptive to the framework, but there was concern about cost-effectiveness (and/or cost-benefit) evaluations being required for each distribution investment. Stakeholders mentioned that there was no need for such analysis on every investment but that an options analysis providing project justification and rationale would be helpful for large projects.

West Monroe Partners, a management consulting firm, provided a case study of an NWA procurement process that intended to alleviate problems at a substation with poorly performing circuits. The case study details showed that the NWA provided cost-beneficial alternatives to the traditional upgrade, but the NWA was ultimately not pursued, in part because the full cost of the NWA solution was borne by the substation deferment; the NWA was not able to participate in wholesale markets.

The EDUs outlined that the traditional process for distribution upgrades includes no cost-benefit analysis, but it does include an options analysis that optimizes on economics, suitability, and need. Needed distribution investments are made based on an obligation to serve and on reliability. In this light, project justifications may not need a full cost-benefit analysis.

An open discussion was held on the outstanding items, including the NWA Status document that was made available prior to the meeting. EnerNex worked with stakeholders to identify a number of points where clarifications could be made on the document. EnerNex updated the document and made a new version available. Energy storage scoping questions were introduced. Stakeholders and EDUs appeared ready to share thoughts and frameworks for consideration of storage benefits at future meetings.

MEETING 6—JUNE 11, 2019

EnerNex provided an overview presentation on energy storage that included a review of energy storage technologies, applications, potential benefits, and locational considerations. The presentation included case studies from California, Oregon, and the New York Independent System Operator (NYISO).

AEP OHIO presented how it generally considers NWAs and specifically how it considers energy storage as part of its distribution system planning process. The presentation included a simplified economic evaluation of a potential energy storage investment for the purposes of deferring a distribution investment. There was a brief discussion regarding the potential to make energy storage solutions "mobile" by locating them within freight containers.

Duke Energy provided an overview of their enterprise-wide energy storage deployments, including "value stacking" revenues to offset the investment. Additionally, the presentation included notes on the Energy Storage Necessity Identification (ESNI) framework utilized by Duke distribution planning engineers.

Paul Centolella presented on energy storage applications and how those applications operate within varying operational time frames needed for the distribution system. The presentation included defining storage capabilities beyond deferral applications. The presentation concluded with a review of the statutory role of the Commission, Staff, and Third Parties relative to distribution investments.

MEETING 7—JUNE 19, 2019

Stakeholder feedback was solicited on a draft NWA Summary document. Several topics related to the document were discussed, including:

- The intent of specific paragraphs
- Missing items (such as risk and the creditworthiness of potential suppliers)
- Clarification on utilizing an adaptation of the Rhode Island framework as an example of how other jurisdictions are considering the cost-effectiveness of NWAs
- The need for transparency and ongoing collaboration related to NWAs

EnerNex presented on the suitability of behind-the-meter (BTM) storage to perform different distribution applications, particularly relating to the requirements of low latency and precise performance required for certain applications. EnerNex also presented on the Minster, OH, solar PV/storage project, which is a public-private partnership with an expected three-year payback, accomplished through utilization of multiple value streams.

A discussion was held on the process utilities should consider for evaluating applications for storage. A variety of potential issues were identified associated with maximizing the value of storage relative to the regulatory framework in Ohio. Some of these issues included:

- Situations in which storage provides both a distribution service as well as an energy supply or wholesale market service
- The EDUs' incentive to offer storage into the market if all market revenues are credited to Customers

Stakeholders discussed the role of the PWG related to energy storage in terms of identifying the issues and regulatory constraints or to make specific policy or regulatory recommendations. Stakeholders discussed that value stacking is currently required to make energy storage a cost-effective investment. Additionally, the current utility landscape in Ohio and the potential limits for NWA or energy storage were discussed. Different opinions were expressed, but participants tended to agree that certain barriers or challenges could be identified.

MEETING 8—JULY 16, 2019

EnerNex started the meeting with a discussion of the scope of the PWG's task on interconnection standards, including a list of questions that the PWG would attempt to answer. EnerNex gave an introductory presentation describing the purpose of standards and the potential issues that might result from incorporating standards into regulations. The presentation provided a summary of existing interconnection standards in Ohio and potential issues the PWG may want to address in its recommendations.

EnerNex also gave an overview of the IEEE Std 1547-2018 standard, including the evolution of the 1547 standard over the last 15 years. Other relevant interconnection standards were covered, including UL 1741, California Rule 21, and Hawaii Rule 14H.

Jereme Kent of One Energy addressed the group to describe concerns his company, as a DER provider, has with Ohio's interconnection standards and process. Mr. Kent advocated for the adoption of a wireless direct transfer trip (DTT) function that would trigger all large DERs on an affected circuit to trip offline by utilizing a substation protection device and wireless communications. Mr. Kent also advocated against adoption of the low voltage ride-through requirements of IEEE Std 1547-2018.

Andrew Levitt of PJM gave a presentation on PJM's interest in the 1547-2018 standard, namely that distribution-level DERs be required to ride through brief periods of abnormal frequency and voltage in order to avoid the instability of sudden DER generation loss. PJM acknowledged that, given Ohio's current low level of DER penetration, near-term decisions on ride-through are not critical from a reliability standpoint.

Each of the EDUs addressed the group with their concerns relative to interconnection standards. AEP, Duke Energy, and Enel X presented slide deck content related to interconnection standards and held common positions that can be summarized by the following statements:

- DER ride-through should not be mandated.
- Default inverter function settings should not be mandated but instead left to the discretion of the EDU.
- The optional elements of IEEE Std 1547-2018 should not be required but left to the discretion of the EDU.
- DER communications should occur via any of the IEEE Std 1547-2018-approved protocols; no one protocol should be mandated.
- EDU awareness of net load is not sufficient for DSP purposes; DERs should have separate metering for generation and usage.

MEETING 9—JULY 30, 2019

EnerNex established a set of recommendations for stakeholder consideration based on a review of a draft document that summarized the key positions of stakeholders voiced during the previous PWG meeting held on July 16. The proposed recommendations addressed technical considerations as well as considerations related to the current Ohio rule review. Most stakeholder discussion was focused on the following topics:

- Potential unintended consequences of ride-through voltage requirements for inverters
- Ensuring that there are no "mandated" requirements related to ride-through, voltage regulation, and/or inverter settings
- Maintaining flexibility to have the capability to adjust based on experience to be gained and changing grid conditions

Stakeholders are comfortable that the updated IEEE Std 1547-2018 standard can adequately address their needs as long as the focus is on ensuring the availability of advanced functionality, and not on mandating the use of any specific functionality. Issues surrounding the language and timing for the adoption of IEEE Std 1547-2018 were discussed.

MEETING 10—AUG 7, 2019

EnerNex received stakeholder comments and proposed edits to a draft document summarizing the key positions of stakeholders on NWA and energy storage. Stakeholders discussed the need for greater clarification on NWA performance monitoring (e.g., how the number of NWA opportunities were formally evaluated and how the number of NWA solutions implemented could be tracked). Stakeholders appeared open to establishing suitability criteria for NWAs that could be independently established by each EDU. Suitability criteria, for example, could set minimum spending and planning horizon thresholds for consideration of NWAs, which would provide greater definition to "the number of NWA opportunities formally evaluated."

Some additional key stakeholder comments included the following requests:

- Additional explanation of the societal cost test, including identification of potential societal costs and benefits that could be included in this test and how those values might be determined
- Deletion of FLISR (fault location, isolation, and service restoration) as a potential energy storage application
- Noting of two potential issues that may limit the proper consideration and adoption of energy storage technologies by EDUs in Ohio:
  - Potential negative consequences of energy storage on grid operations
  - Energy storage applications that may be mutually exclusive or not available to be performed at the same time
- Additional information regarding how other jurisdictions have dealt with Third Parties providing grid services (e.g., any commission oversight, consequences for failure to perform, etc.)
- Clarification on the prescriptive wording in the document (e.g., *will*, *shall*, *may*, *should*)

MEETING 11—OCT 31, 2019

EnerNex introduced the concept of HCA, including providing a definition and identifying how HCA relates to interconnection studies. The presentation also included an overview of the types of limits (e.g., voltage, thermal, protection) that are considered in HCA and the approaches for deriving hosting capacity. The presentation concluded by outlining the state of the art for sharing this information through online portals.

Steve Steffel, a distribution planning manager with Pepco, provided an overview of Pepco's hosting capacity methodologies, including their online portals. Mr. Steffel also provided insight on methods to increase hosting capacity, privacy and data security, future plans for hosting capacity, and how certain state rules within Pepco's jurisdictions influence HCA methodologies and refresh cycles. EnerNex presented on HCA as an element of advanced distribution engineering. The presentation included the need to improve distribution system circuit awareness and understanding, as loads become more dynamic and Customer expectations shift.

Stakeholders discussed several key topics:

- The merits of performing a formal HCA on every circuit given the current relatively low number of Customers with DERs in Ohio (<1%)
- Lessons learned from Minnesota and other jurisdictions where HCA was required of distribution utilities
- A potential timeline and potential triggers for an HCA on a subset of circuits, which could include detailed forecasting of DER (including EV) deployments

The meeting concluded with a discussion of next steps, including additional information on costs of HCA as borne in other jurisdictions.

Appendix E: Acronyms and Definitions

AC	Alternating current
AEP	American Electric Power
AMI	Advanced metering infrastructure
ANSI	American National Standards Institute
BCA	Benefit cost analysis
BTM	Behind the meter
CI	Customers interrupted
CGS+	Customer grid supply +
CRES	Competitive retail electric service
CVO	Conservation voltage optimization
CVR	Conservation voltage reduction
DER	Distributed energy resource
DG	Distributed generation—A small generator located at or near where the electricity will be used and is attached to the distribution grid. DG can be either a primary or secondary source of power and uses a variety of technologies, such as combustion turbines, solar rooftop panels, and wind turbines.
DLMP	Distribution locational marginal pricing
DNP	Distributed network protocol
DOE	Department of Energy
DR	Demand response
DRIVE	Distribution resource integration and value estimation
DSP	Distribution system planning—Enterprise planning that considers how best to deliver electricity from the grid's transmission system to individual customers
DTT	Direct transfer trip
DWG	Data and modern grid workgroup
EDU	Electric distribution utility
EE	Energy efficiency
ELPC	Environmental Law & Policy Center
EM&V	Evaluation, measurement and verification
ESNI	Energy storage necessity identification
EV	Electric vehicles
FAQ	Frequency asked questions
FERC	Federal Energy Regulatory Commission
FLISR	Fault location, isolation, and service restoration
GHG	Greenhouse gas
HCA	Hosting capacity analysis
IDP	Integrated distribution planning—A holistic approach to shaping the distribution of electric power that considers how to incorporate new technologies and valuation systems in an effort to create a stable and resilient

	modern grid; IDP is considered a further evolution of distribution system planning (DSP)
IEEE	Institute of Electrical and Electronic Engineers
IoT	Internet of things
IOU	Investor-owned utility
IREC	Interstate Renewable Energy Council
IRP	Integrated resource plan
IVVC	Integrated volt-var control
ISO	Independent system operator—an independent, often non-profit, system coordinator that oversees the operation and use of transmission systems and the electricity market generated within its area
kW	Kilowatt
kWh	Kilowatt-hour
LMP	Locational marginal pricing
MAIFI	Momentary average interruption frequency index
MPUC	Minnesota Public Utilities Commission
MW	Megawatt
NARUC	National Association of Regulatory Utility Commissioners
NCUC	North Carolina Utilities Commission
NPV	Net present value
NWA	Non-wires alternatives
NYISO	New York Independent System Operator
OAC	Ohio administrative code
OCC	Office of Consumers' Council
PCT	Participant cost test
Pepco	Potomac Electric Power Company
PJM	An RTO that coordinates the movement of wholesale electricity in all or parts of 13 states and the District of Columbia
PUC	Public Utilities Commission
PUCO	Public Utilities Commission of Ohio
PV	Photovoltaic
PWG	Distribution system planning workgroup
REC	Renewable energy credit
RFO	Request for offer
RFP	Request for proposal
RIM	Rate Impact Measure
RPM	Reliability pricing model (name of PJM's capacity market)
RTO	Regional transmission operator
SAIDI	System average interruption duration index
SAIFI	System average interruption frequency index

SCADA	Supervisory control and data acquisition—a system of remote control and telemetry used to monitor and control the transmission system and substation automation
SEP	Smart energy profile
SGIA	Small generator interconnection agreement
SCT	Societal cost test
TOU	Time of use—a pricing strategy by which the charge for electricity varies by the time of day and the season based on the demand peak on the system
TRC	Total resource cost
UCT	Utility cost test
UL	Underwriters' Laboratories
V2G	Vehicle to grid – The utilization of vehicles to provide energy to and interact with the grid system as a DER
VPP	Virtual power plant
VVO	Volt-var optimization—A software module that accesses the advanced meter data for both operational/situational awareness and system studies; sometimes called integrated volt-var control (IVVC)
WTP	Willingness to pay