COMMONWEALTH OF PENNSYLVANIA

OFFICE OF CONSUMER ADVOCATE
555 Walnut Street, 5th Floor, Forum Place
Harrisburg, Pennsylvania 17101-1923
(717) 783-5048
800-684-6560

@pa_oca
/pennoca

FAX (717) 783-7152
consumer@paoca.org

February 18, 2021

Rosemary Chiavetta, Secretary
Pennsylvania Public Utility Commission
Commonwealth Keystone Building
400 North Street
Harrisburg, PA 17120

Re: Policy Proceeding – Utilization of Storage Resources as Electric Distribution Assets
Docket No. M-2020-3022877

Dear Secretary Chiavetta:

Attached for electronic filing please find the Office of Consumer Advocate's Comments in the above-referenced proceeding.

Copies have been served per the attached Certificate of Service.

Respectfully submitted,

/s/ Phillip D. Demanchick
Phillip D. Demanchick
Assistant Consumer Advocate
PA Attorney I.D. # 324761
E-Mail: PDemanchick@paoca.org

Enclosures:
cc: Office of Administrative Law Judge **(email only)**
Office of Special Assistants (**email only**: ra-OSA@pa.gov)
Aspassia V. Staevska, Law Bureau **(email only)**
Joe Cardinale, Law Bureau **(email only)**
Eric Matheson, Office of the Executive Director **(email only)**
David Edinger, Bureau of Technical Utility Services **(email only)**
Certificate of Service

*304118

CERTIFICATE OF SERVICE

Re: Policy Proceeding – Utilization of Storage Resources as Electric Distribution Assets	: : :	Docket No. M-2020-3022877

I hereby certify that I have this day served a true copy of the following document, the Office of Consumer Advocate's Comments, upon parties of record in this proceeding in accordance with the requirements of 52 Pa. Code § 1.54 (relating to service by a participant), in the manner and upon the persons listed below:

Dated this 18th day of February 2021.

SERVICE BY E-MAIL ONLY

Richard A. Kanaskie, Esquire
Bureau of Investigation & Enforcement
Pennsylvania Public Utility Commission
Commonwealth Keystone Building
400 North Street, 2nd Floor
Harrisburg, PA 17120

John R. Evans, Esquire
Office of Small Business Advocate
555 Walnut Street
1st Floor, Forum Place
Harrisburg, PA 17101-1923

Charis Mincavage, Esquire
McNees Wallace & Nurick LLC
100 Pine Street
P.O. Box 1166
Harrisburg, PA 17108-1166

Donna M.J. Clark, Esquire
Vice President & General Counsel
Energy Association of Pennsylvania
800 North Third Street, Suite 205
Harrisburg, PA 17102

Mark C. Szybist, Esquire
Natural Resources Defense Council
1152 15th Street NW
Suite 300
Washington, DC 20005

Devin McDougall, Esquire
Clean Energy Program
1617 John F. Kennedy Blvd.
Suite 1130
Philadelphia, PA 19103

Jeffrey W. Mayes, Esquire
Monitoring Analytics, LLC
2621 Van Buren Avenue
Suite 160
Eagleville, PA 19403

/s/ Phillip D. Demanchick
Phillip D. Demanchick
Assistant Consumer Advocate
PA Attorney I.D. # 324761
E-Mail: PDemanchick@paoca.org

Darryl A. Lawrence
Senior Assistant Consumer Advocate
PA Attorney I.D. # 93682
E-Mail: DLawrence@paoca.org

Counsel for:
Office of Consumer Advocate
555 Walnut Street
5th Floor, Forum Place
Harrisburg, PA 17101-1923
Phone: (717) 783-5048
Fax: (717) 783-7152
Dated: February 18, 2021
*303596

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Policy Proceeding – Utilization of Storage Resources as Electric Distribution Assets	: :	Docket No. M-2020-3022877

COMMENTS OF
THE OFFICE OF CONSUMER ADVOCATE

Pursuant to the Secretarial Letter issued on December 3, 2020, at Docket No. M-2020-3022877, the OCA hereby files these Comments regarding potential future regulatory policies related to the utilization of electric storage within electric utility distribution planning. The OCA appreciates the Commission providing a forum for the OCA and other interested parties to discuss these emerging technologies and their implementation on the distribution system.

Through these Comments, the OCA submits that while the utilization of electric storage in electric distribution planning will be critical in the future to meet the needs of the distribution system, the Commission must take certain steps before such value can be realized. That is, the Commission should consider moving to integrated distribution planning (IDP), which is a comprehensive planning framework that requires, among other things, behind-the-meter resource forecasting, hosting capacity analysis, and benefit/cost analysis of non-wires alternatives. Moreover, the OCA recommends that the Commission consider initiating a statewide, stakeholder proceeding regarding the adoption of IEEE 1547-2018. This national standard will ensure that as Distributed Energy Resources interconnect to the distribution grid, they will have the capability and flexibility necessary to reach their full potential.

In support of its Comments, the OCA has also attached a Report prepared by Rakon Energy LLC (Rakon Energy Report), which explains in more detail how to approach and implement IDP, statewide adoption of IEEE 1547-2018, and the various distribution benefits associated with battery storage.

I. PROCEDURAL HISTORY

On December 3, 2020, a Secretarial Letter was issued on behalf of the Commission seeking comments from utilities and other stakeholders on potential future regulatory policies related to the utilization of electric storage within electric utility distribution planning. The Secretarial Letter invited interested parties to submit written comments for the Commission's consideration within 30 days of publication in the Pennsylvania Bulletin. The Secretarial Letter was docketed at Docket No. M-2020-3022877.

As stated in the Secretarial Letter, the Commission is seeking input from various stakeholders on the following issues: (1) what applications can electric storage provide as a distribution asset for utilities that would facilitate improved reliability and resilience, (2) what are the defining characteristics of electric storage used for distribution asset planning as distinguished from generation resources and what would classify electric storage as a generation resource and therefore outside permitted distribution ratemaking and recovery, and (3) is it prudent for utilities to include electric storage in their distribution resource planning and, if so, where and under was circumstances and is it appropriate for utilities to include such investments in rate base?

On Saturday, December 19, 2020, the Secretarial Letter was published in the Pennsylvania Bulletin setting the due date for Tuesday, January 19, 2021. On December 28, 2020, the OCA filed a Motion for an Extension of Time for Comments seeking a 30-day extension to submit Comments. A Secretarial Letter was issued on December 30, 2020, extending the due date for comments until February 18, 2021.

II. COMMENTS

As stated above, before the OCA responds directly to the questions presented in the Secretarial Letter, the OCA submits that there are threshold issues that must be addressed by this Commission before it can fully consider the utilization of electric storage as an electric distribution asset. The OCA will discuss these preliminary matters first before responding directly to the Commission's questions.

A. Integrated Distribution Planning.

While the OCA commends the Commission for taking a proactive approach to address potential future regulatory policies related to the utilization of electric storage within electric utility distribution planning, there are threshold issues that must be considered before stakeholders can fully evaluate the benefits of electric storage. More specifically, traditional approaches to utility distribution planning are not equipped to properly evaluate the benefits of non-wires alternatives compared to traditional investment in aging infrastructure. Accordingly, the Commission should consider a more comprehensive planning process, such as IDP.

In Pennsylvania, Electric Distribution Companies (EDCs) are required to evaluate the needs of their system to meet federal and state requirements. As the Secretarial Letter indicates, one of the ways in which Pennsylvania EDCs meet these requirements is through their Long-Term Infrastructure Improvement Plans (LTIIP), which are evaluated by the Commission every five years. Much of this process, however, is focused on the need to replace, upgrade, or add distribution infrastructure to enhance the safety, reliability, and security of the grid.

Recently, however, new technologies and non-wires alternatives have emerged to potentially address the reliability and resiliency needs of the distribution system. As noted in the Rakon Energy Report:

> In more recent years, energy efficiency, expanded demand response, distributed generation and energy storage — all of which can be located where load relief is most valuable — have expanded the utility's options to meet load growth or reduce demands on aging assets without building transmission, distribution or central generation facilities." Chapter 9, Lazar, J., Chernick, P., Marcus, W., and LeBel, M. (Ed.). (2020, January). *Electric cost allocation for a new era: A manual*. Montpelier, VT: Regulatory Assistance Project

Rakon Energy Report at 11. Consideration and evaluation of these emerging technologies and resources must be considered in a holistic manner to meet the needs of future electric distribution systems. LTIIPs, for example, are not necessarily designed to compare and evaluate the benefits of non-wires alternatives against traditional replacement of electric distribution infrastructure.

Thus, moving to an IDP model would better accommodate resources such as energy storage. The Rakon Energy Report compares and contrasts the differences between traditional distribution planning and IDP. See Rakon Energy Report at 11-15. Generally, IDP is additive to traditional distribution planning in that additional requirements are placed on utilities, in addition to their existing obligations. This includes, but is not limited to, (1) DER forecasting based on interconnection requests, (2) performing a hosting capacity analysis to determine the thresholds at which DERs will trigger upgrades or changes to the electrical distribution system, and (3) evaluating non-wires alternatives against traditional solutions. Rakon Energy Report at 12-14.

A more robust planning process will allow this Commission, EDCs, and interested stakeholders the opportunity to better evaluate emerging technologies, such as electric storage, to determine the value of these resources and the benefits they provide ratepayers. The Rakon Energy Report provides additional information on this topic that will be useful to the Commission and other stakeholders. Rakon Energy Report at 7-21. The OCA submits that the Commission should consider implementation of IDP for its EDCs.

B. <u>Interconnection Rules and IEEE 1547-2018</u>.

The OCA submits that the Commission should also consider initiating a statewide, stakeholder proceeding regarding implementation of IEEE 1547-2018.[1] IEEE 1547-2018 represents a considerable shift from the prior standard by requiring that newly installed inverters or interconnection technology be able to provide specific grid supportive functionalities, including voltage and frequency ride-through and voltage and frequency regulation. Moreover, while the Commission's regulations do provide the ability for EDCs to incorporate amendments and revisions to IEEE 1547, the most recent changes contain a menu of options that need to be considered and selected by regulators and interested stakeholders. As indicated by the Interstate Renewable Energy Council (IREC):

> Rather than a single package of default settings that work in all instances and for all technologies, IEEE Std 1547-2018 adds new features and requirements and includes more flexibility and options. Utilities and state regulatory commissions will need to evaluate, select and assign different "performance categories" for different DERs. In addition, as applicable, states and utilities will need to consult and coordinate with the Regional Reliability Coordinator and Regional Transmission Organization (RTO), Independent System Operator (ISO), or other transmission operator on certain issues within IEEE Std 1547-2018 relating to reliability and performance.[2]

As indicated in the Rakon Energy Report, there are several reasons why statewide implementation of this standard and 'smart' inverters will help unlock the full potential for DERs on the system, including electric storage:

1. Smart inverters provide much better voltage and frequency capabilities to interconnect behind-the-meter resources.

---

[1] IEEE 1547 is a national standard regarding the technical specifications for, and testing of, the interconnection and interoperability between electric power systems and DERs.

[2] BRIAN LYDIC & SARA BALDWIN, INTERSTATE RENEWABLE ENERGY COUNCIL, MAKING THE GRID SMARTER: PRIMER ON ADOPTING THE NEW IEEE 1547-2018 STANDARD FOR DISTRIBUTED ENERGY RESOURCES 4 (2019) (MAKING THE GRID SMARTER), *available at* https://irecusa.org/publications/making-the-grid-smarter-state-primer-on-adopting-the-new-ieee-standard-1547-2018-for-distributed-energy-resources/

2. More hosting capacity on the distribution system is possible leading to better utilization of the distribution system infrastructure.

3. Inverter-based resources are positioned to provide grid services compared to conventional generation resource types such as coal, natural gas and nuclear.

Rakon Energy Report at 23-24.

For these reasons, the OCA supports a robust, stakeholder proceeding to discuss statewide implementation of IEEE 1547-2018. The OCA notes that other states have or are working towards adoption of IEEE 1547-2018 and its accompanying standards. Accordingly, there are models that the Commission and interested stakeholders could follow to expedite the process. See Rakon Energy Report at 22.

C. Responding to the Commission's Directed Questions.

1. Applications Electric Storage Can Provide as a Distribution Asset to Improve Reliability and Resiliency.

Electric storage can provide several benefits to the distribution grid ranging from peak demand reduction to avoidance of costly upgrades on the distribution system. Rakon Energy Report at 32-34. As set forth in the Rakon Energy Report, battery storage can provide the following benefits to the distribution system:

1. Reducing peak demand charge - the industrial facility reduces their "peak" by discharging stored energy during peak demand time. This reduction is the primary benefit of electric storage application on the distribution system for a customer facing peak demand charges.

2. Integrating more renewables – if a Commercial and Industrial (C&I) or a residential customer wants to consume renewable energy; storage can charge when solar is generating and discharge when needed.

3. Providing grid services such as power factor correction, reactive and voltage control, and backup power.

   a. Power Factor Correction – by injecting VaRs as needed, storage can correct for power factor. The power factor is the ratio of active power and reactive power. Unless the power factor is within a range, power does not transfer.

b. Electric storage provides reactive support and voltage control - maintaining voltage is vital for avoiding severe damage to the generation, transmission, and distribution system. Reactive power is critical to preserving voltage levels.

c. Providing back-up power – the storage device instantly provides power during an outage.

4. Direct Distribution system benefits - Electric storage resources can reduce or entirely avoid distribution system losses. Additionally, electric storage increases distribution capacity, and reduces O&M costs.

5. Distribution system upgrade deferral benefits – Electric storage can defer the need for a substation upgrade, especially if the need on the distribution feeder is only for a number of hours in a year.

6. Electric storage at wastewater treatment and water pumping stations – During natural disaster events, additional stress is imposed on the electric grid due to outages on the distribution system. Wastewater treatment and water pumping stations electric load on the distribution system does not rise to a MW scale, but, if batteries are installed at these locations – during natural disasters, the electric motors won't be drawing energy from the distribution system. The appendix provides some of the locations where batteries are installed.

See Id.

2. Defining Characteristics of Electric Storage as Distinguished from Generation Resources and the Thresholds that would Classify Electric Storage as a Generation Resource and Therefore Outside Permitted Distribution Ratemaking and Recovery.

Electric storage is unlike any other electric asset in that it can often perform any of the three traditional functions: (1) generation, (2) transmission, and (3) distribution. Thus, to determine whether a battery storage asset is considered a generation asset and thus outside permitted distribution ratemaking and recovery depends wholly upon the function the battery is performing.

At this point, it is premature and often difficult to categorically state when a battery may fit into one function or another. In the past, such decisions have been made on a case-by-case basis.[3] This question is made further difficult by the fact that battery storage can often serve dual-functions, *i.e.* distribution and generation.[4]

Accordingly, a comprehensive planning process that identifies the specific needs and use cases for an electric storage asset would be needed before the Commission could determine if it is a distribution or generation asset. Moreover, a statewide stakeholder process may be needed to define a 'value stack' for energy storage, to determine the benefits provided by these assets and when to classify an energy storage asset within the distribution function. See Rakon Energy Report at 38.

3. The Prudency of Utilities Including Electric Storage in Distribution Resource Planning and Including Such Investments in Rate Base.

The OCA submits that it would only be prudent and lawful to include electric storage investments in rate base where the storage asset has been found to perform distribution functions and has been shown to be cost effective.[5] Otherwise, it would be impermissible to include such

---

[3] Western Grid Development, LLC, Docket No. EL10-19-001, 133 F.E.R.C. ¶ 61,029, 61,119 (FERC Oct. 12, 2010) ("Because…electricity storage devices do not fit neatly into one of the traditional categories of generation, transmission, or distribution, the [Federal Energy Regulatory Commission] has addressed the classification of these devices on a fact-and-circumstance-sensitive, case-by-case basis.").

[4] See also NATALIE MIMS FRICK, *ET AL.*, LAWRENCE BERKELEY NATIONAL LABORATORY, LOCATIONAL VALUE OF DISTRIBUTED ENERGY RESOURCES 23 (2021), *available at* https://eta-publications.lbl.gov/sites/default/files/lbnl_locational_value_der_2021_02_08.pdf ("To be economically viable, many DERs rely on capturing both locational value—for example, from utility programs—and other value streams such as bulk power system capacity, energy, and ancillary services, which fall within the domain of federally regulated RTOs and ISOs").

[5] As stated above, electric storage assets are unique in that they may provide both distribution and generation benefits to the electric grid. Rakon Energy Report at 39, fn. 43. That is, certain electric storage assets may serve dual purposes. In such instances, it may be prudent to develop a method to allocate electric storage costs that reflects how it is used on the system. For example, it would not be prudent to include in rate base all capital costs associated with an electric storage asset if it is performing some generation or transmission functions.

investments in distribution rate base in Pennsylvania as generation assets are not given traditional rate base/rate of return treatment. See 66 Pa.C.S. §2802(14).

To determine the cost-effectiveness of DERs, including electric storage, the OCA would suggest reviewing the National Energy Screening Project's (NESP) National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources (NSPM).[6] Within the NSPM, it details the types of costs and benefits that should be considered when evaluating electric storage and DERs in general.[7] This will be a valuable resource going forward that may help shed light on how to determine whether an electric storage asset is cost-effective within a non-wires alternative framework.

---

6 NATIONAL ENERGY SCREENING PROJECT, NATIONAL STANDARD PRACTICE MANUAL FOR BENEFIT-COST ANALYSIS OF DISTRIBUTED ENERGY RESOURCES (2020), *available at* https://www.nationalenergyscreeningproject.org/wp-content/uploads/2020/08/NSPM-DERs_08-24-2020.pdf.

7 Id., at 9-1 to 9-13.

III. CONCLUSION

WHEREFORE, the OCA submits these Comments regarding the utilization of electric storage within electric utility distribution planning.

Respectfully Submitted,

/s/Phillip D. Demanchick
Phillip D. Demanchick
Assistant Consumer Advocate
PA Attorney I.D. # 324761
E-Mail: PDemanchick@paoca.org

Darryl A. Lawrence
Senior Assistant Consumer Advocate
PA Attorney I.D. # 93682
E-Mail: DLawrence@paoca.org

Counsel for:
Tanya J. McCloskey
Acting Consumer Advocate

Office of Consumer Advocate
5th Floor, Forum Place
555 Walnut Street
Harrisburg, PA 17101-1923
Phone: (717) 783-5048
Fax: (717) 783-7152

DATE: February 18, 2021
304124

APPENDIX A

RAKON ENERGY REPORT

For Commonwealth of Pennsylvania's Office of Consumer Advocate

Abstract

This report answers the three questions posed by Commonwealth of Pennsylvania's Secretary in the policy proceeding - Utilization of Storage Resources as Electric Distribution Assets

Rao Konidena

Rakon Energy LLC

Contents

List of Figures

List of Tables

Executive Summary

The Commonwealth of Pennsylvania's Office of Consumer Advocate has engaged Rakon Energy LLC to support OCA's response to the three questions posed by the Pennsylvania Public Utility Commission's Secretary in the policy proceeding - Utilization of Storage Resources as Electric Distribution Assets. There are six key takeaways in this report.

First, electric storage has multiple applications on the distribution system, including reducing peak demand, integrating more renewables, providing grid services (such as power factor correction, supporting voltage), and direct distribution system benefits such as distribution upgrade deferral and reduction in distribution system losses. These applications address the reliability and resiliency challenges faced by the electric distribution companies.

Second, this report recommends initiating a stakeholder process to explore moving to integrated distribution planning that enables behind-the-meter resource forecasting, hosting capacity and scenario analysis and provides better value for DERs. IDPs provide for consideration of non-wire alternatives in distribution planning because, before settling on a traditional solution such as a distribution feeder upgrade or a new substation, the distribution planning engineer would ask: is there a non-wires solution to the need on the distribution system?

Third, consideration and implementation of the IEEE 1547-2018 standard on a statewide basis would allow Pennsylvania to realize the full benefit of DERs and electric storage, based on other state's experience.

Fourth, electric storage can function both as a generation asset and a distribution asset. But the question is, how do we distinguish when a battery is being used for distribution needs vs. generation? The best practice is to initiate stakeholder discussions to define "value stack" benefits for electric storage.

Fifth, electric storage has both positive and negative differences relative to conventional generation sources. On the positive end, batteries do not need hours to move from one capacity level to another. Batteries and battery controls manage output in seconds and minutes, not hours. Another positive is, batteries do not have a fuel cost. The O&M costs are relatively low, and if some of the cells in the battery pack fail, only those cells are replaced, not the entire battery system.

On the negative end, batteries are dependent on another source of energy to charge. Hence, batteries draw from the distribution system, and restrictions can be placed on charging times so that there is no conflict with peak distribution hours.

Finally, it may be prudent to include electric storage costs if EDCs demonstrate that the related electric storage assets are providing purely distribution services and are cost-effective. Since electric storage can serve dual purposes, such as providing distribution and generation benefits, it may be prudent to develop a method of allocation to determine what costs should be attributed to the distribution system and what costs should be excluded from ratemaking recovery.

One example of this, would be if the EDC were to tie those infrastructure improvements to feeders with high distribution circuit peaks and historical substations peaks. This hourly substation and distribution circuit peak data can help EDCs restrict electric storage charging during those peak times.

In summary, this report recommends a regulator must take some first key steps before full utilization of battery storage can be realized. This would include IDP because traditional current distribution planning was not designed or implemented to be a comprehensive planning tool, nor was it designed to incorporate emerging technologies or non-wires alternatives. This report also recommends consideration and implementation of IEEE 1547-2018 through a statewide-stakeholder process to realize the full benefit of DERs and electric storage.

I. Introduction

Rakon Energy is retained to assist the Commonwealth of Pennsylvania's Office of Consumer Advocate (OCA) in the Policy Proceeding "Utilization of Storage Resources as Electric Distribution Assets," Docket No. M-2020-3022877.

This report is organized according to the Pennsylvania Public Utility Commission's (PUC) Secretarial Letter questions. Before answering the questions individually, this report first provides background information and context.

The Secretarial Letter references two specific challenges to the Electric Distribution Companies (EDCs) from the increase in behind-the-meter resources such as rooftop PV solar, microturbines, electric vehicles, and electric storage in Pennsylvania. The first is, referring to the reliability challenges and increase in distribution grid utilization due to electric vehicles,

> "*potentially lower capacity utilization through increased peak demand*[1]*,*"

which shows that the traditional distribution planning model lags in the valuation of behind-the-meter resources that send energy back to the grid during peak demand hours.

The second challenge posed by an energy transition from central station power to a distributed generation model is

> "*reliability and resiliency more challenging than ever,*"

[1] The Secretarial Letter

which acknowledges this bi-directional energy is happening at the same time the EDCs are experiencing vegetation management and distribution system outages due to an increase in the frequency of natural disasters.

These two challenges are mentioned here because the report refers to those central themes while answering the questions on utilizing electric storage on the distribution system.

Additionally, the Secretarial Letter asserts the following regarding electric storage but maintains the focus on reliability and affordability:

*"advances in technology appear to offer the potential to utilize novel resources which provide **affordable** customer rates and better utility service "*

*"Of specific focus here is the Commission's interest in exploring the viability of utility investment in electric storage as a distribution asset utilized for the purposes of enhancing or maintaining **reliability**"*

*"Exploring this topic is warranted since utilization of batteries on the distribution grid, in appropriate circumstances, may offer an option to foster **reliability** that will have a less significant rate impact than other more conventional utility restoration or improvement investments"*

This report will be coming back to the goalposts of affordability and reliability. All of the recommendations in this report keep these goalposts as a reference.

II. Integrated Distribution Planning is the logical evolution for Distribution System Planning

Several states have instituted stakeholder proceedings and Integrated Distribution Planning (IDP) orders. These best practices provide good reference materials for understanding the distribution planning evolution.

If we take the state of Michigan as an example, the Michigan Public Service Commission (MPSC) recognized the importance of mentioning resiliency and reliability risks in making a case for distribution plan alignment with other planning efforts, as shown in the following statement[2]:

"With increased adoption of electric vehicles and distributed energy resources such as solar and energy storage, the Commission recommends utilities ***better align electric distribution plans with integrated resource plans*** *to develop a cohesive, holistic plan and optimize investments considering cost,* ***reliability, resiliency,*** *and risk."*

The MPSC ordered its staff to initiate a stakeholder working group process to guide distribution investment plans, as shown below:

"The report shall summarize the stakeholder workgroup process, including discussions conducted on the value of resilience, and shall also provide recommendations for the Commission to include as ***guidance for the next round of distribution investment*** *and maintenance plans".*

Without going into detail on other state examples such as California[3], Nevada[4], it is noted that the Center for Partnerships & Innovation (CPI) at the National

---

[2] Michigan PSC. 2019 Integrated Distribution Planning Order. Michigan Public Service Commission. Case No. U-20147. September 11, 2019. Courtesy – NARUC Comprehensive Electricity Planning Library.

[3] CPUC. "Decision on Track 3 Policy Issues, Sub-Track 1 (Growth Scenarios) and Sub-Track 3 (Distribution Investment and Deferral Process." Order Instituting Rulemaking Regarding Policies, Procedures and Rules for Development of Distribution Resources Plans Pursuant to Public Utilities Code Section 769, Decision 18-02-004. California Public Utilities Commission. February 8, 2018. Courtesy – NARUC Comprehensive Electricity Planning Library.

[4] NV Energy. Docket No. 19-04003 - Joint application of Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy for approval of First Amendment to 2018 Joint IRP, a Distributed Resource Plan. Courtesy – NARUC Comprehensive Electricity Planning Library .See NV Energy Original Filing dated April 1, 2019 and Public Utility Commission of Nevada Order dated August 1, 2019

Association of Regulatory Utility Commissioners (NARUC) released a framework[5] for PUC stakeholders engagement. The framework notes the following 3 points as best practices for defining the scope of PUC initiated stakeholder working groups:

1. *"Clearly define the scope of the proceeding early in the process.*
2. *Communicate the purpose and goals to stakeholders early in the process.*
3. *Assess commission capacity and identify where capacity may be limited. Consider the possibility of needing to invest in increased staffing and/or additional resources to accommodate needs."*

In addition to scope definition, the NARUC CPI Framework for stakeholder engagement has best practices and key questions for facilitating and engaging stakeholders, the meeting format and schedule, and what to expect for outcomes and follow-up after the process is complete.

Additionally, the Lawrence Berkeley National Laboratory (LBNL) has published an overview of distribution planning and state activity in a report[6] under the Grid Modernization Laboratory Consortium funding by the U.S. Department of Energy (DOE). This illustration, Figure 1, shows which states have advanced practices in distribution system planning and how other states, including Pennsylvania, are approaching distribution planning.

---

[5] Jasmine McAdams, Public Utility Commission Stakeholder Engagement: A Decision-Making Framework, January 2021, https://pubs.naruc.org/pub/7A519871-155D-0A36-3117-96A8D0ECB5DA

[6] LBNL presentation to MADRI, Overview of Integrated Distribution Planning Concepts and State Activity, March 2018, https://eta-publications.lbl.gov/sites/default/files/schwartz_madri_dsp_presentation_20180313_fin.pdf

State Engagement in Distribution System Planning

GRID MODERNIZATION LABORATORY CONSORTIUM U.S. Department of Energy

New report: *State Engagement in Electric Distribution Planning*, Pacific Northwest National Laboratory, Berkeley Lab, and National Renewable Energy Laboratory, December 2017

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

(a) For one or more utilities.

Figure 1: State Engagement in Distribution System Planning

II.A. Why the current distribution planning won't work?

An EDC's approach to replacing aging infrastructure alone would not address the reliability and resiliency challenges faced by the EDCs.

While replacing old equipment coming to the end of the asset life with newer equipment leads to better outage metrics such as System Average Interruption Duration Index[7] (SAIDI), current distribution planning was not designed or

[7] Table 1: 4kV SS Eliminations Outage Information based on 2009-2019 data, Duquesne Light Company Long Term Infrastructure Improvement Plan (LTIIP) Midterm Review, June 2020, SAIDI of 17.09 before the 4 kV substation elimination project compared to a SAIDI of 14.69.

implemented to be a comprehensive planning tool, nor was it designed to incorporate emerging technologies or non-wires alternatives.

As the Regulatory Assistance Project (RAP) report notes, prudent distribution investments are needed because utility options have increased[8]. And customer-owned generation requests are mostly at the distribution system level. These two developments of increase in technology choices at the distribution node where demand occurs and increase in customer-owned generation – should lead to questions on whether the current distribution planning framework applies? If not, what are the changes needed, and how soon should those changes be enacted?

The graphic Figure 2 below illustrates why traditional distribution planning should lead to the latest integrated distribution planning[9].

In traditional distribution planning, there are 6 steps:

1. Step 1 – Load Forecasting: Each EDC estimates the load growth in its service area, and a 10-year load forecast is put together to feed the distribution needs assessment. The forecasts for demand-side options such as energy efficiency and demand response are conducted separately and accounted for in the final load forecasts. Load forecasts without demand-side program impacts are "gross load forecasts," and with DR and EE impacts are "net" load forecasts.

---

[8] "In more recent years, energy efficiency, expanded demand response, distributed generation and energy storage — all of which can be located where load relief is most valuable — have expanded the utility's options to meet load growth or reduce demands on aging assets without building transmission, distribution or central generation facilities." Chapter 9, Lazar, J., Chernick, P., Marcus, W., and LeBel, M. (Ed.). (2020, January). *Electric cost allocation for a new era: A manual*. Montpelier, VT: Regulatory Assistance Project.

[9] Mid-Atlantic Distributed Resources Initiative (MADRI) report, Integrated Distribution Planning for Electric Utilities : Guidance for Public Utility Commissions, released October 2019, https://www.madrionline.org/wp-content/uploads/2019/10/MADRI_IDP_Final.pdf

   a. It is relevant to note that traditional distribution planning does not include annual energy and peak demand savings from behind-the-meter generation such as batteries, solar, microturbines, and electric vehicles because behind-the-meter generation was negligible until recently.
2. Step 2 – System Assessment: Load forecasts are input into the EDC's system assessment, including distribution system planning criteria. In general, the utility is running load flow studies to understand and prep the study for the next step. Any distribution generation requests that come through the utility's distribution interconnection department are input at this step.
3. Step 3 – Grid Needs Identification: In this step, the distribution planning engineer seeks to identify what upgrades are needed on the distribution system to accommodate increased load or replace aging infrastructure or approve the new DG interconnection request.
4. Step 4 – Solution Identification: In this solution identification step, distribution planning engineers are looking for traditional solutions such as replacement, upgrading, relocations, and some voltage class eliminations.
5. Step 5 – Project Design and Construction: Once the EDC's plan is approved, the design and construction departments at the EDCs take over. The focus is sequencing projects according to capital spending, labor availability, supply materials, and the distribution system's need.
6. Step 6 – System Monitoring and Control: In this final step, once the projects are in-service, they are monitored for preventive maintenance and general asset life monitoring to protect the investment from weather elements and vandalism.

Most states have started an "Integrated Distribution Planning" (IDP) for the same reasons this report has mentioned so far – rise in customer-owned generation and increase in technology options at the distribution system. This IDP is different than distribution planning in the following manner:

1. Step 1 – Load <u>and DER</u> Forecasting: In addition to the load growth impacts and DR & EE impacts, the customer-owned generation, i.e., Distributed

Energy Resource (DER) forecasts, is also developed based on the DG interconnection requests and survey data. Hence, load forecasts without demand-side program impacts are “gross load forecasts,” and with DR, EE, and DG impacts are “net” load forecasts.

2. Step 2 – Hosting Capacity Analysis / System Assessment: This entire step 2 is now undergoing a major change in the distribution system planning. Since not all distribution feeders have the same capacity to accommodate customer requests, a Hosting Capacity Analysis[10] (HCA) is run by the distribution utility to assess how much capacity is available at each distribution system substation to accommodate a new customer request without impacting reliability. An example from Potomac Electric Power Company (PEPCO) in New Jersey is mentioned here[11] to show the hosting capacity map.
3. Step 3 – Grid Needs Identification and Locational[12] Value: In this step, in addition to the steps outlined under traditional distribution planning, states such as New Hampshire[13] are conducting Locational Value of Distributed Generation (LVDG) studies to understand and quantify where distribution system improvements are needed (the locational value of the distribution system). The implication here is high population density - urban feeders, for example, serving city centers would be higher in locational value given their

---

[10] See Table “Example State Requirements for Hosting Capacity Analysis”, page 32 of the LBNL report, February 2021 , Locational Value of Distributed Energy Resources, https://eta-publications.lbl.gov/sites/default/files/lbnl_locational_value_der_2021_02_08.pdf

[11] PEPCO Hosting Capacity Map link, https://www.pepco.com/SmartEnergy/MyGreenPowerConnection/Pages/HostingCapacityMap.aspx

[12] Locational value is defined as the value of electric storage based on its location on the distribution system. A February 2021 LBNL report titled, “Locational Value of Distributed Energy Resources”, defines, “*locational value of DERs, which is their value at a specific point on the electric system*”. https://eta-publications.lbl.gov/sites/default/files/lbnl_locational_value_der_2021_02_08.pdf

[13] NHPUC Docket No. DE 16-576, Order Approving Scope of Locational Value of Distributed Generation Study, Order No. 26,221 (February 20, 2019) 16-576_2019-02-20_ORDER_26221.PDF (nh.gov)

impact on customer outages than a low population density – rural feeder, feeding farms, and cabins.

4. Step 4 – Solution Identification including Non-Wires Alternatives (NWA): In this solution identification step, distribution planning engineers are looking for non-traditional solutions, mainly electric storage, under a broad category called NWA, in addition to traditional solutions as we have seen in DLC's plan.
5. Step 5 – Project Design and Construction: There is no change in this step compared to the traditional distribution planning process.
6. Step 6 – System and DER Monitoring and Control[14]: In this final step, once the projects are in-service, including DERs, they are monitored for preventive maintenance and general asset life monitoring to protect the investment from weather elements.

[14] Active monitoring and control of customer owned DERs by the utility is not the intention behind this final step. This step simply notes the asset owner, who may be from any one of the customer classes (e.g. residential, commercial, industrial) monitors their investment for long asset life.

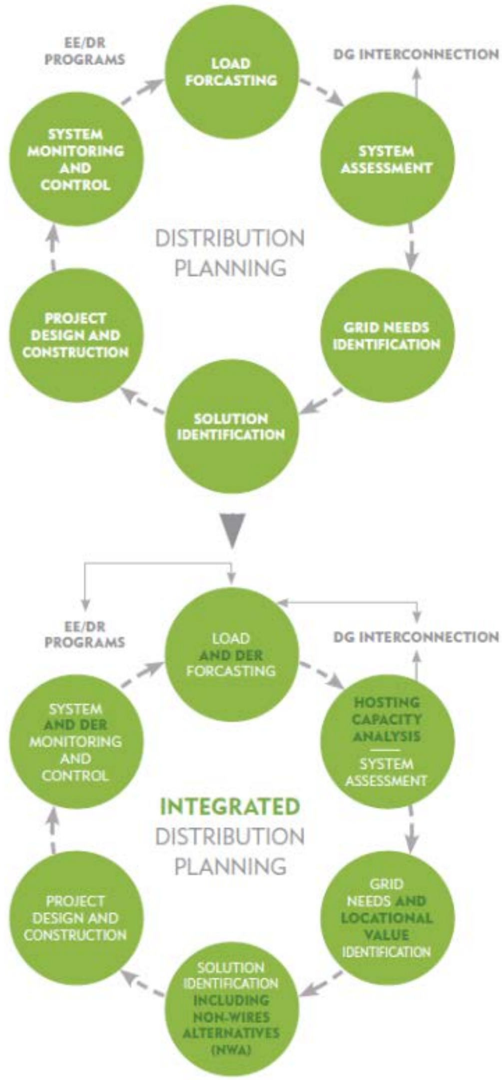


Figure 2: Comparison of Traditional Distribution Planning to Integrated Distribution Planning

II.B. Walk-Jog-Run Framework

Realizing what is happening in Pennsylvania has happened in states like California, Hawaii, New York, and each state and each utility is unique, there are established frameworks that provide a comparison for states or utilities with high distributed energy resources penetration to states that are starting on a pathway to integrated distribution planning tools and process steps. The walk-jog-run pioneered by Paul D Martini[15] is one such framework. This framework in Figure 3 lays time on the X-axis and DER penetration levels on the Y-axis.

A common metric needed to read this framework is the percentage of DER MWs as a function of an EDC's peak demand. Hypothetically, if the peak demand is 10,000 MW for a utility, and the amount of DERs is 500 MW, that utility is in stage 1 because it has only 5% of the DER penetration level. Alternatively, utilities with higher DER penetration percentages (typically more than 10%) are in stage 2.

It is important to mention here that DER penetration levels are rarely spread uniformly across an EDC's distribution system. DERs tend to be clustered at some substations. As a result, a utility could be seeing stage 2 needs in one part of their distribution system, whereas other parts are still in stage 1.

1. Walk – Stage 1: Grid Modernization focusing on reliability and operational efficiency. PA's EDCs and most distribution utilities are at this stage of refreshing distribution assets as they come up for the end of life asset replacement. This initial stage is where discussions on advanced technology options available at the distribution system are happening, as is the Secretarial Letter case.
2. Jog – Stage 2: DER integration. Distribution system and asset optimization happen at this stage, leveraging the foundational elements of stage 1. Advanced Distribution Management System (ADMS), Advanced Metering Infrastructure (AMI), Field Area Network (FAN), and Advanced Grid Intelligence and Security (AGIS) initiative – are typical elements of this stage. Utilities in California, Hawaii, and New York are at this stage.
3. Run – Stage 3: Distributed Markets. Multi-Party energy transactions and market operations are enabled at this stage. Almost everyone acknowledges

[15] Paul D Martini et al, September 2016, http://gridworks.org/wp-content/uploads/2016/09/plug-and-play-report_online_v2.pdf

that none of US utilities are in this stage 3, even though some pilots are on peer-to-peer energy transactions.

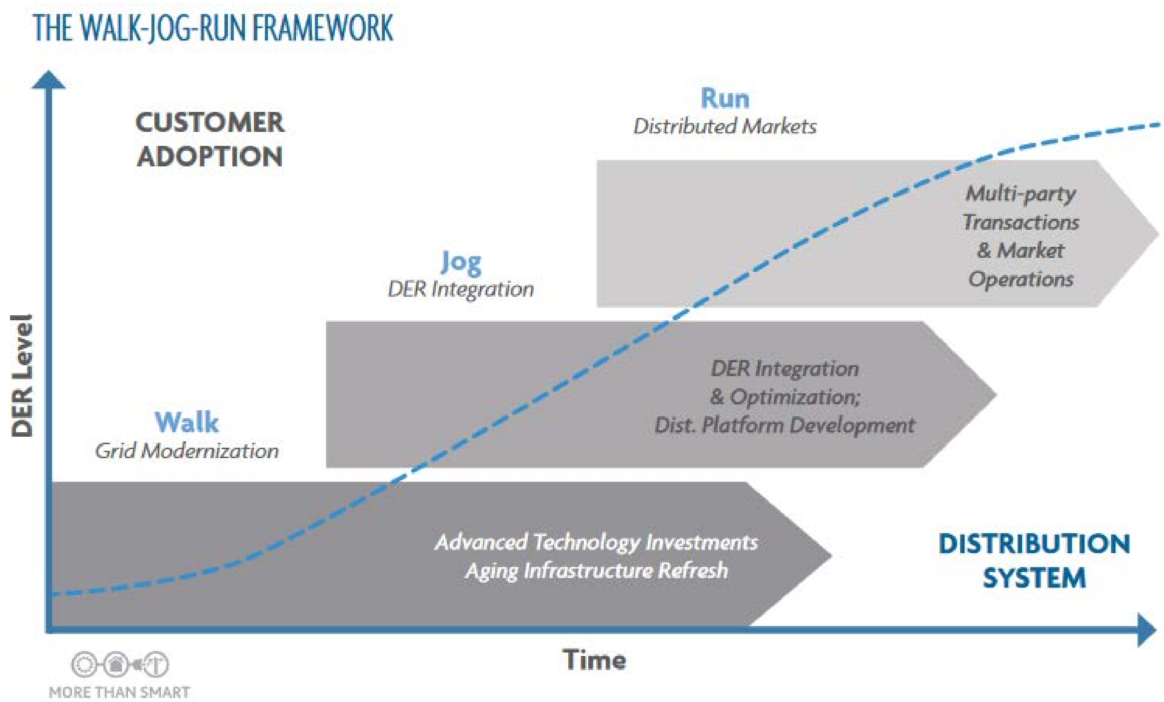


Figure 3: The Walk-Jog-Run Framework to understand DERs growth

One of the drawbacks of this framework is there is no mention of reliability and affordability to the end customer.

II.C. Scenario Analysis in Distribution Planning

Distribution planning involves running several scenarios. A high load forecast, and maximum achievable potential for demand response, are some of the typical scenarios in distribution planning. Within each scenario, a utility increases the percentage of the main variable for sensitivity cases. For example, a utility under a load forecast scenario may model high, medium, and low sensitivity cases for load forecast to assess the distribution system needs.

With the increase in customer owned generation, scenarios in distribution planning could include,

1. Scenarios with high distributed solar penetration
2. Scenarios with high distributed solar + storage penetration
3. Scenarios with high Electric Vehicle penetration

Please note that this list of scenarios is not exhaustive. Neither is the implication that EDCs should study scenarios at all substations or feeders. As the report mentions later, in answer to question 1, EDCs must look at individual feeder hourly peak data and annual substation peak data to shortlist distribution system equipment for scenario development.

Utilities can determine what distribution system upgrades or other improvements need to occur and at what time.

II.D. Consideration of Non-Wires Alternatives in Distribution Planning

The electric industry uses Non-Wires Alternatives (NWA) to refer to all non-traditional solutions to transmission and distribution planning. Some of these NWAs include both traditional demand side options such as EE and DR because they don't involve wires, and innovative technology options such as Smart Wires[16], which is a company with a product called SmartValve™, that claims to increase the transfer capacity on existing wires by thousands of MWs.

Before settling on a traditional solution such as a distribution feeder upgrade or a new substation, the distribution planning engineer should ask: is there a non-wires solution to the need on the distribution system?

Included in the NWA discussion is electric storage because batteries would qualify under this NWA definition. It is worth noting that neither standards associations such as the Institute of Electrical & Electronics Engineers (IEEE) nor regulatory associations such as the National Association of Regulatory Utility Commissioners

---

[16] Website for Smart Wires, https://www.smartwires.com/smartvalve/

(NARUC) have defined NWA[17]. And NWAs do not distinguish between transmission and distribution solutions, even though most innovative and upcoming technologies[18] tend to focus more on the transmission system.

On the NWA topic, New York's utility Consolidated Edison's ("ConEd") Brooklyn-Queens Demand Management Program[19] is often mentioned as an illustrative example of how electric storage was part of a solution to defer large capital outlays. As Figure 4 shows, battery storage is part of the demand management program identified by ConEd to meet peak demand in the summer of 2018.

The key takeaway is electric storage provides options to meet reliability and affordability criteria when combined with other non-wires alternatives such as demand response, energy efficiency, and combined heat & power solutions.

---

[17] National Grid, a utility in Massachusetts, New York and Rhode Island defines "Non-Wires Alternative (NWA) is the inclusive term for any electrical grid investment that is intended to defer or remove the need to construct or upgrade components of a distribution and/or transmission system, or "wires investment". https://www.nationalgridus.com/Business-Partners/Non-Wires-Alternatives/What-is-an-NWA

[18] Companies similar to Smart Wires include, Ampacimon, Lindsey Manufacturing, LineVision, NewGrid, and WindSim.

[19] The Utility Business Transformation REV-New York by Michael Gilbert, Business Development Manager at Con Edison.

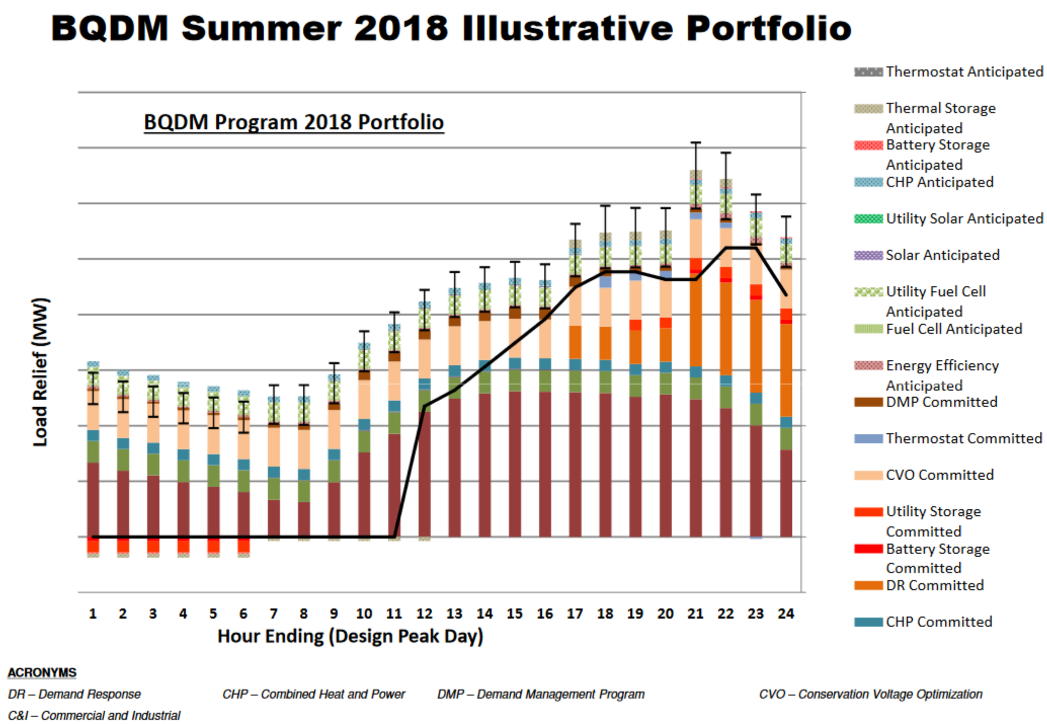


Figure 4: Brooklyn-Queens Demand Management Program to illustrate electric storage as NWA

Hence this report recommends, EDCs look at NWA practices[20] such as,

1. Transparent NWA identification process – EDCs should have publicly posted criteria for NWA opportunities on their distribution system for all projects above a certain cost threshold (example, $500,000).
2. EDCs should issue RFPs for NWA projects – EDCs should issue RFPs for all NWA projects to solicit[21] a portfolio of solutions.

[20] Adapted from Direct Testimony of Melissa Whited, On Behalf of Maine Office of the Public Advocate in Docket No. 2018-00171, https://www.synapse-energy.com/sites/default/files/Testimony-Whited-NWA-Incentive-18-090.pdf

[21] National Grid NWA RFPs are posted here: https://www.nationalgridus.com/Business-Partners/Non-Wires-Alternatives/Opportunities

3. EDCs should have an independent RFP administrator – An independent RFP administrator to oversee the NWA's EDCs RFP process is an important protection.
4. EDCs should perform a Benefit-to-Cost ratio for all NWAs – EDCs should evaluate the B/C ratios of all solutions transparently to proposed NWA projects.

III. Interconnection rules for electric storage on the distribution system

Residential and commercial customers desire to store their renewable energy (mostly PV solar) generated on-site. In addition to their consumption, they might have excess energy to send back to the grid. That excess energy sent to the electric distribution network should be done in a safe and reliable manner for both the customer and the EDC.

The new rules and revisions in IEEE 1547-2018 standard provide that safety and reliability assurance. Hence, inverters to convert the Direct Current (DC) solar to Alternating Current (AC) consumed energy should be IEEE 1547-2018 compliant. A state utility regulator should consider statewide implementation of IEEE 1547-2018 and its related smart inverter requirements, which can allow the benefits of electric storage to be more fully realized.

Commonwealth of Pennsylvania regulations do allow for EDCs to comply with updates and amendments to IEEE 1547. So, in essence a utility could move from IEEE 1547-2003 to 1547-2018 without PUC approval. However, not all stakeholders are familiar with new standards, hence the best practice is, a statewide process for stakeholder participation to learn about what is different in the new standards compared to legacy standards. For example, the benefits of a “smart” inverter compared to an inverter are in its capabilities to sense (be smart about) minor voltage and frequency variations (“ride through”) compared to major interruptions on the electric distribution system.

It is also worth noting here that Commonwealth of Pennsylvania has an opportunity to learn from other state's implementation of IEEE 1547-2018 smart inverter criteria. There is evidence to suggest from a recent report[22] that Hawaii, by mandating smart inverters was able to increase distribution system's hosting capacity[23] and raise the solar interconnection limit from 120% of minimum daily load to 250%.

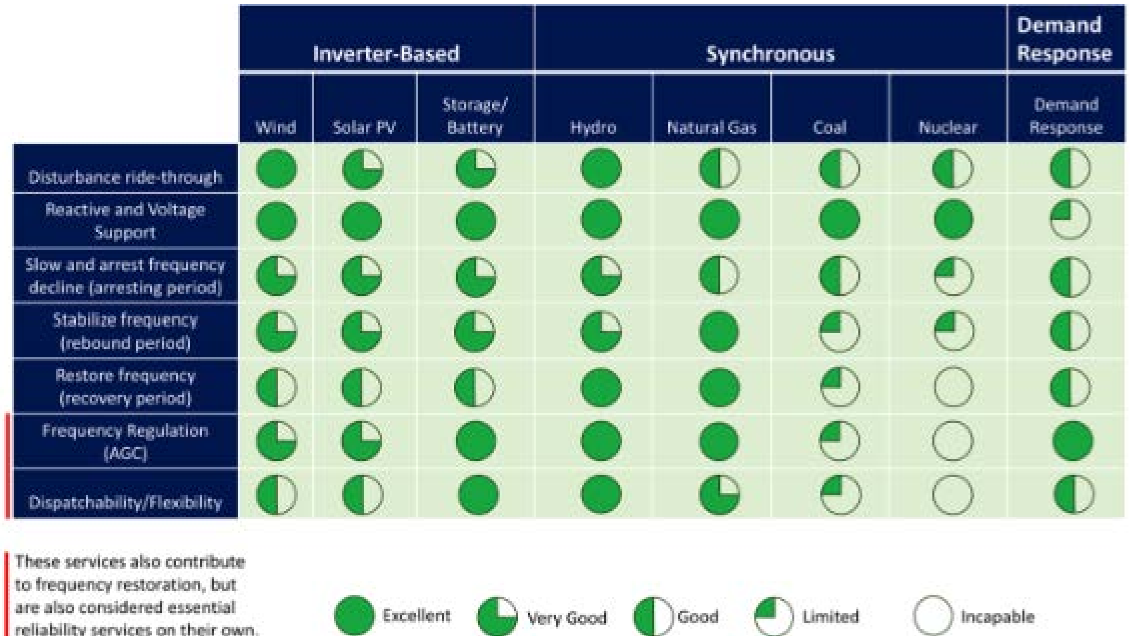
At this stage in the report, it is important to note that inverter-based resources such as PV-solar, battery storage and wind, are much better positioned to provide grid services shown in Table III-1 as suggested by Michael Milligan's paper[24].

[22] Center for Renewables Integration report titled, "It's Time for States to Get Smart About Smart Inverters" released October 2019, https://www.center4ri.org/publications

[23] Hosting Capacity is defined as, "the amount of DERs that can be accommodated on the distribution system at a given time, and at a given location, under existing grid conditions and operations without compromising safety, power quality, reliability or other operational criteria and without requiring significant infrastructure upgrades" https://irecusa.org/publications/optimizing-the-grid-regulators-guide-to-hosting-capacity-analyses-for-distributed-energy-resources/

[24] Source for Electricity Journal paper titled "Sources of grid reliability services" by Michael Milligan, https://reader.elsevier.com/reader/sd/pii/S104061901830215X?token=D0A3F3062FA465B513E0E069B126157F5161004582408B62E83D41D0993C701D1B4B494F38828B68481BAEEDB2CF48EA

Table III-1 - Milligan's Grid Services Summary Table illustrating Inverter-Based resources provide grid services



	Inverter-Based			Synchronous				Demand Response
	Wind	Solar PV	Storage/ Battery	Hydro	Natural Gas	Coal	Nuclear	Demand Response
Disturbance ride-through	Excellent	Very Good	Very Good	Excellent	Good	Good	Good	Good
Reactive and Voltage Support	Excellent	Excellent	Excellent	Excellent	Excellent	Excellent	Excellent	Limited
Slow and arrest frequency decline (arresting period)	Very Good	Very Good	Very Good	Very Good	Good	Good	Limited	Good
Stabilize frequency (rebound period)	Very Good	Very Good	Very Good	Very Good	Excellent	Limited	Limited	Good
Restore frequency (recovery period)	Good	Good	Good	Excellent	Excellent	Limited	Incapable	Good
Frequency Regulation (AGC)	Very Good	Very Good	Excellent	Excellent	Excellent	Limited	Incapable	Excellent
Dispatchability/Flexibility	Good	Good	Excellent	Excellent	Very Good	Limited	Incapable	Good

These services also contribute to frequency restoration, but are also considered essential reliability services on their own.

Excellent | Very Good | Good | Limited | Incapable

Lastly, Energy Storage Association (ESA) also commented in Michigan[25] about the importance of treating energy storage fairly in distribution interconnection rules.

"recommendations to (1)use "net system capacity" as an alternative to aggregate capacity as the study assumption for energy storage systems paired with generation; (2)include a customer's "proposed use" of a distributed generation system; and (3) include rules to govern "inadvertent exports" from distributed generation systems that are permitted to perform this function."

In summary, the best practice is to initiate a statewide process for stakeholder participation to learn about what is different and new in IEEE 1547-2018 for the following 3 reasons:

[25] Energy Storage Association comments to Michigan Public Service Commission, https://energystorage.org/esa-filing/esa-calls-for-fair-treatment-of-energy-storage-resources-in-michigans-interconnection-rules/

1. Smart inverters provide much better voltage and frequency capabilities to interconnect behind-the-meter resources.
2. More hosting capacity on the distribution system is possible leading to better utilization of the distribution system infrastructure.
3. Inverter-based resources are positioned to provide grid services compared to conventional generation resource types such as coal, natural gas and nuclear.

IV. Setting up the context for cost prudency

Electric storage has multiple use applications on the distribution system and is unique compared to other generation sources primarily in two ways. One, there is no ramping time for batteries to discharge. Second, batteries are dependent on another energy source to charge. Hence before answering question 3 on costs in rate base, a general overview of other states' approaches with significant electric storage implementation is discussed here.

Additionally, while electric storage might be new on the distribution system, Benefit Cost Analysis (BCA) calculations for distribution utilities are not new. Hence this section recommends a couple of ideas on the benefit to cost ratios and NWAs costs.

IV.A. New York Model

New York state has a target for energy storage implementation of 1,500 MW by 2025 and 3,000 MW by 2030 to meet the state's Climate Leadership Community and Protection Act (CLCPA). New York's utilities and the state are wrestling with the same resiliency challenges as PA's EDCs. And it is worth noting that New York estimates approximately $2 Billion in savings due to the energy storage target[26].

New York has a dual market participation model for energy storage – storage can participate as a resource in both wholesale and retail markets recognizing the dual-purpose of electric storage as a generation asset and a distribution asset. The New York State Energy Research & Development Authority (NYSERDA) offers financial incentives for retail customers in MWh blocks. The state is divided into regions, and each region is further divided into MWh blocks for incentives[27]. For example, the state is divided into:

- New York City commercial storage – Block 2 has an $18 million cap with an incentive of $300/kWh. Block 3 has a $15 million cap with a $240/kWh incentive.
- Long Island commercial storage – Block 1 at $10 million cap and $250/kWh incentive.
- Westchester ConEd commercial storage - Block 1 at $14 million cap and $175/kWh incentive.
- Rest of the state commercial storage – Has 4 blocks with declining incentives. Block 1 has a total $35 million cap, and the incentive rate is $350 per kWh. Block 2 is capped at $31 million at $250/kWh, block 3 capped at $30 million for $200/kWh incentive, and finally, block 4 is capped at $18 million with $125 per kWh.

[26] New York press release, date January 21, 2021, https://www3.dps.ny.gov/pscweb/WebFileRoom.nsf/Web/792C9C672F8901E48525866400617340/$File/pr21007.pdf?OpenElement

[27] NYSERDA MWh blocks for energy storage incentives for retail customers link, https://www.nyserda.ny.gov/All-Programs/Programs/Energy-Storage/Developers-Contractors-and-Vendors/Retail-Incentive-Offer/Incentive-Dashboard

While Pennsylvania is not there yet, like New York in terms of DER penetration, the key takeaway from NY-ConEd's MWh block discussion is that electric storage incentives should vary by customer class and location. High population density areas such as Philadelphia and Pittsburgh perhaps lend themselves to MWh blocks, compared to the rest of the state.

IV.B. Massachusetts Model

Massachusetts Department of Energy Resources (DOER) led the State of the Charge (SOC) study, which led to quantification[28] of

"Ratepayer cost benefits of energy storage associated with reduced peak demand, deferred transmission and distribution investments, reduced GHG emissions, reduced cost of renewables integration, deferred new capacity investments, and increased grid flexibility reliability and resiliency".

The current target in Massachusetts is 1,000 MWh in energy storage by 2025[29]. The state economic development agency, Massachusetts Clean Energy Center (MassCEC™) is the lead agency tasked with implementing the state's clean energy programs, including energy storage.

There are multiple use cases and programs in Massachusetts for energy storage, and some include interaction with the transmission grid operator. Since this report is focused on behind the meter electric storage on PA's distribution system, the following are the services worth noting[30]:

---

[28] Massachusetts SOC study link, https://www.mass.gov/service-details/energy-storage-study

[29] Massachusetts target link - https://www.mass.gov/info-details/esi-goals-storage-target

[30] MassCEC Energy Storage Fact Sheet , https://files-cdn.masscec.com/Energy%20Storage%20Factsheet.pdf

1. Solar Massachusetts Renewable Target (SMART) service – This SMART service specifically targets adding storage to PV solar systems by providing an adder for compensation of electricity generated. This adder range is $0.025-0.076 per kWh, based on the ratio of storage capacity added to the solar capacity. But this service is limited to less than 5 MW systems, solar and storage systems must be installed simultaneously, and adder subscription has limited space.
2. Customer Demand Charge management – This service is only for commercial and industrial customers with greater than 250-300 kW load and is the best service for customers with peaky loads. The facility owner or the project developer owns the system.
3. Utility Demand Response – In this service, the facility owner or the project developer can own the system but must follow the utility's dispatch instructions.
4. Emergency Islanding/Backup Power service – There is no monetary compensation for this service per se, but the facility owner or project developer is eligible for compensation under other services at the wholesale market level.
5. Eversource Variable Peak Pricing – This is only available for customers with a Time Of Use (TOU) rate, and the facility owner should own and operate the storage system. Customers save by using less-expensive electricity at off-peak times.

The key takeaway from the Massachusetts example includes, linking incentives for electric storage implementation with behind-the-meter solar installations.

IV.C. National Energy Screening Project – Benefit Cost Analysis

The National Energy Screening Project (NESP) published a National Standard Practice Manual for Benefit-Cost analysis of DERs (NSPM) in August 2020. This manual guides regulators and stakeholders on how to conduct BCA for DERs including electric storage.

The manual notes the electric utility section of all possible benefits and costs of electric storage should be included in the BCA. A summary Table IV-1 derived from the manual is shown below:

Table IV-1: Benefit Cost Analysis for Distribution system storage[31]

Benefit/Cost/Either	**Specific EDC Impact**	**Explanation**
Benefit	Credit and collection costs	This cost is a benefit because customer payments are made easier especially with low-income customers.
Benefit	Risk	These are benefits depending on the storage used case to the EDC. Electric storage reduces EDC's risk to have an outage on the distribution system due to vegetation management issues. Because electric storage is a non-wires solution.
Benefit	Reliability	
Benefit	Resiliency	
Costs	Financial incentives	Utility program implementation costs
Costs	Program Administration Costs	
Costs	Utility Performance incentives	
Costs	Energy generation	Costs because electric storage requires more energy to charge than discharge
Costs	RPS compliance	
Either	Distribution capacity	These are benefits to the extent electric storage provides these benefits via use case (e.g. increase in distribution capacity, reduction in line losses), and these are costs if the storage device charges during peak demand times on the distribution circuit.
Either	Distribution line losses	
Either	Distribution O&M	
Either	Distribution voltage	

The NSPM includes, identification of all benefits and costs and some impacts to EDCs that could go either way – when performing storage BCA.

[31] Derived from Table 9-1 of the 2020 Manual, https://www.nationalenergyscreeningproject.org/national-standard-practice-manual/

IV.D. Regulatory Assistance Project – Electric Cost Allocation

The Regulatory Assistance Project (RAP) published a manual ("RAP manual") on electric cost allocation in January 2020. The RAP manual is an extensive body of work on cost allocation methods for distributed energy resources. Relevant to this report's scope, a chapter in the RAP manual highlights methods to allocate costs based on distribution system equipment serving residential and commercial customers served by the secondary feeder and industrial customers and others served directly from the EDCs primary feeder as shown in Figure 5.

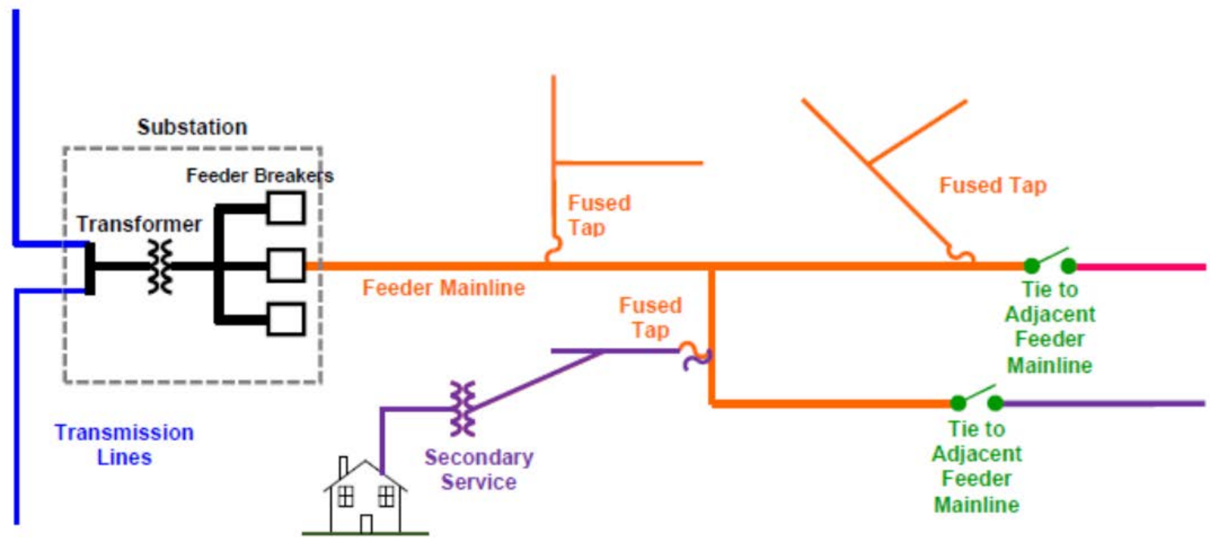


Figure 5: Electric distribution system showing primary (Mainline) and secondary service[32]

The RAP manual classifies all distribution system costs into 2 categories: 1) shared distribution costs and 2) customer-specific costs. Under the shared costs, this includes distribution system equipment commonly shared across all customers such as distribution substations, feeders, transformers, and the distribution system Supervisory Control And Data Acquisition (SCADA) equipment such as

[32] Xcel Integrated Distribution Plan 2019, Figure 16, https://www.xcelenergy.com/staticfiles/xe-responsive/Company/Rates%20&%20Regulations/IntegratedDistributionPlan.pdf

sensors and other communication equipment that links the distribution equipment in the field to a central distribution control center at the utility. This information is relevant to address question 3 on cost prudency because the first question to ask ourselves is – whether storage equipment is commonly shared across all customers based on its location on the distribution system? Or, is it customer-specific?

Customer-specific distribution system costs include service connections from the main feeder line to commercial and industrial customers, metering, street lighting, and connections to individual customers at the end of a radial distribution line[33].

We can further classify the distribution system costs by assigning a portion of costs for customers taking service from the primary distribution feeder versus assigning costs to customers taking service from the secondary service. Once again, to address the cost question, this method indicates that it matters where the electric storage is on the distribution system.

The key takeaways from the RAP manual include identifying customer classes that draw energy from the primary versus secondary distribution feeder and applying costs by distribution equipment classification - distribution substations, primary distribution circuits, and distribution transformers.

A method to allocate electric storage costs depends on where storage is located and its function. If storage is located on the primary distribution circuit and deferring the need for a distribution substation upgrade, a portion of that storage system's costs may be shared across all distribution system customers. On the other hand, if the storage asset is located at the end of a radial feeder and serves

[33] "The vast majority of distribution systems in the United States are configured in a radial, rather than network, format", page 8, February 2021 LBNL report titled, "Locational Value of Distributed Energy Resources", https://eta-publications.lbl.gov/sites/default/files/lbnl_locational_value_der_2021_02_08.pdf

only an industrial customer by reducing their peak demand, the industrial customer bears those costs.

V. Electric storage applications for the distribution system

The first question in the Secretarial Letter is, "*What applications can electric storage provide as a distribution asset for utilities that would facilitate improved reliability and resiliency*?" Several applications are relevant for the distribution system. Some of them are:

1. Reducing peak demand charge - the industrial facility reduces their "peak" by discharging stored energy during peak demand time. This reduction is the primary benefit of electric storage application on the distribution system for a customer facing peak demand charges.
2. Integrating more renewables – if a Commercial and Industrial (C&I) or a residential customer wants to consume renewable energy; storage can charge when solar is generating and discharge when needed. This application is the same as Massachusetts SMART service. This report recommends a statewide process for stakeholder participation to learn about what is different and new with the IEEE 1547-2018 standard compared to legacy standards.
3. Providing grid services such as power factor correction, reactive and voltage control, and backup power.
    a. Power Factor Correction – by injecting VaRs as needed, storage can correct for power factor. The power factor is the ratio of active power and reactive power. Unless the power factor is within a range, power does not transfer.
    b. Electric storage provides reactive support and voltage control - maintaining voltage is vital for avoiding severe damage to the generation, transmission, and distribution system. Reactive power is critical to preserving voltage levels.

c. Providing backup power – the storage device instantly provides power during an outage. In comments submitted[34] in response to the Secretarial Letter, the Pennsylvania Department of Environmental Protection (PA DEP) points out the benefits of electric storage by providing backup power at critical infrastructure facilities during an outage,

“*Energy storage can provide enhanced service to customers by providing backup power, especially at critical infrastructure such as hospitals, government buildings, and food and fueling distribution locations. In particular, energy storage would contribute to emergency preparedness by pairing solar plus storage on police and fire stations and buildings that serve as emergency shelters*.”

4. Direct Distribution system benefits - Electric storage resources can reduce or entirely avoid distribution system losses. Additionally, electric storage increases distribution capacity and reduces O&M costs.
5. Distribution system upgrade deferral benefits – Electric storage can defer the need for a substation upgrade, especially if the need on the distribution feeder is only for a number of hours in a year. PA DEP comments also reference this benefit[35],

“*A business case for energy storage may exist in deferring or avoiding these infrastructure costs altogether and instead strategically deploying energy storage assets within the system, which can reduce the demand and potentially extend the life on traditional distribution infrastructure*.”

[34] Pennsylvania Department of Environmental Protection (PA DEP) comments in Docket No. M-2020-3022877, https://www.puc.pa.gov/pcdocs/1690878.pdf

[35] ibid

6. Electric storage at wastewater treatment and water pumping stations – During natural disaster events, additional stress is imposed on the electric grid due to outages on the distribution system. Wastewater treatment and water pumping stations' electric load on the distribution system does not rise to a MW scale, but, if batteries are installed at these locations, the electric motors won't be drawing energy during natural disasters from the distribution system. The appendix provides some of the locations where batteries are installed.

This list is not an exhaustive list of electric storage applications on the distribution system. But covers the major categories[36].

To address the twin challenges of reliability and resiliency in PA, the best practice is to examine the EDCs data when the distribution circuit peaks occur as shown in Figure 6. The load forecast data in the Electric Power Outlook for Pennsylvania 2019-2024[37] (released August 2020) does not explicitly provide this data to answer the question - when do PA EDCs experience distribution circuit peaks?

---

[36] While this report mentions how battery storage can address reliability and resilience, this report does not recommend that battery storage replace or curtail existing activities that can be effective in addressing reliability and resiliency on the system, such as vegetation management. These are traditional ways to address reliability and resiliency on the system and EDCs should continue these practices.

[37] Electric Power Outlook 2020 report link, [EPO_2020.pdf (pa.gov)]

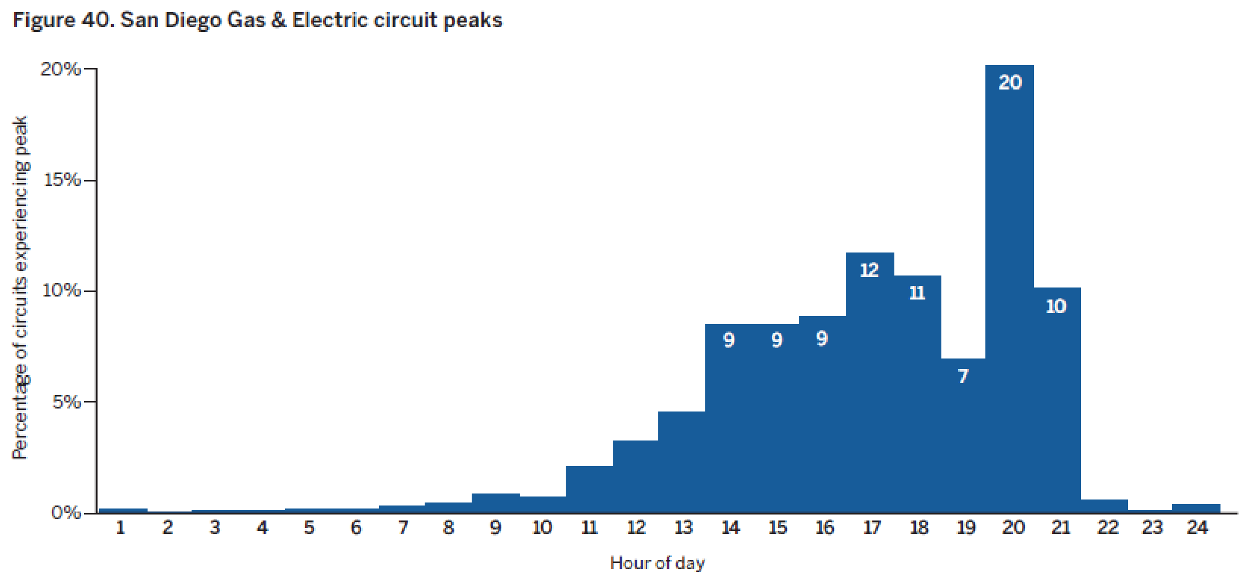


Figure 6: Illustration that shows distribution circuit peaks for a utility feeder, per hour

This data[38] should show percentage of circuits experiencing peak. This hourly granular data at each distribution feeder for an EDC would lead to identifying opportunities where electric storage can address both reliability and resiliency challenges.

Shifting from individual distribution feeder's hourly data to annual substation data shown in Figure 7, EDCs can point to months when distribution substations are stressed the most. The data also points out which substations may need infrastructure improvements. This data could act as a checks and balances system against "prudent" investments by the EDCs.

[38] Figure 40, Chapter 11, Lazar, J., Chernick, P., Marcus, W., and LeBel, M. (Ed.). (2020, January). Electric cost allocation for a new era: A manual. Montpelier, VT: Regulatory Assistance Project.

Figure 41. Month and hour of Delmarva Power & Light substation peaks in 2014

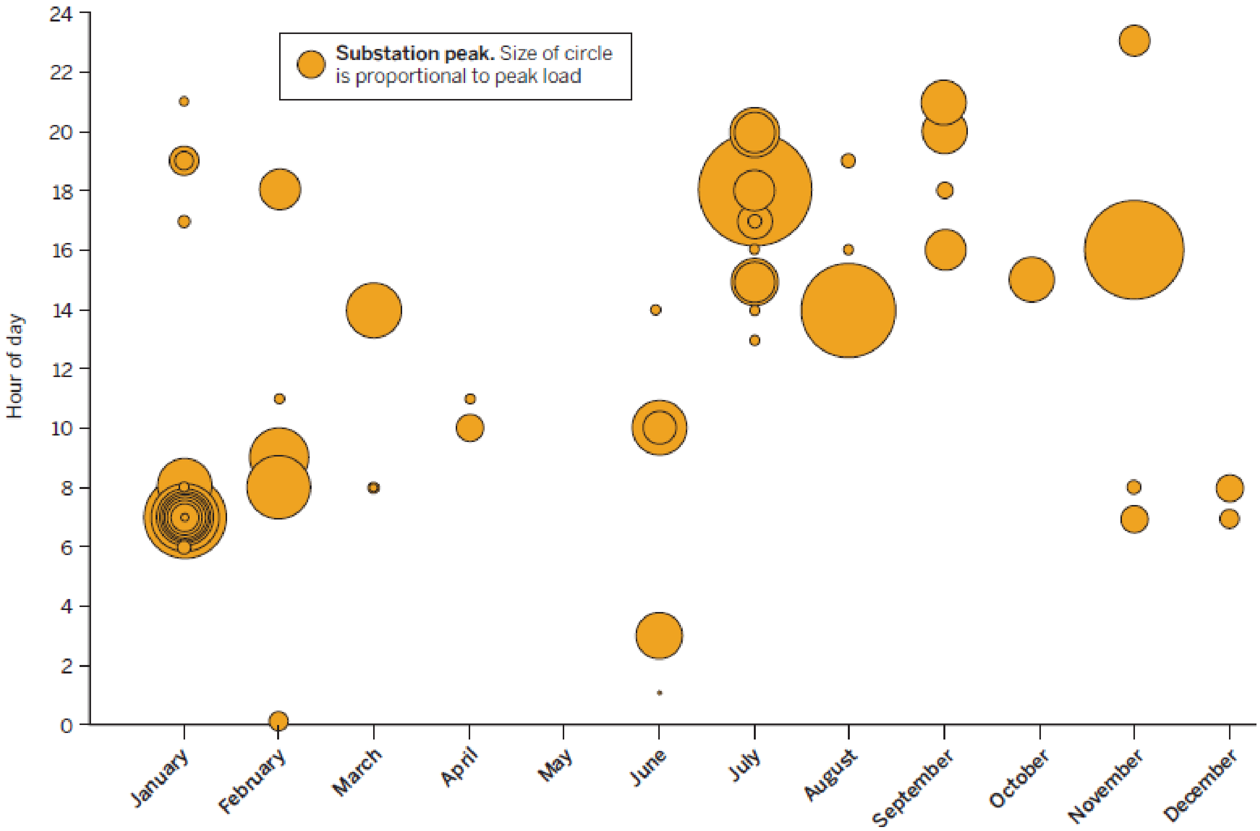


Figure 7: Illustration that shows distribution circuit peaks for a utility substation, per hour for an entire year

If the PUC collects each EDCs historical distribution substation peaks, then the data[39] should show which substations are heavily loaded and at what time of the year. That monthly and hourly data can help PUC mandate qualified electric storage systems to charge only during specific hours in a day during a season, so that charging battery systems do not add to the stress on the distribution circuit.

[39] Figure 41, ibid

As illustration from Commonwealth of Massachusetts Clean Peak Standard eligibility criteria[40] is shown in Figure 8:

	Energy Storage Charging Windows	
Clean Peak Season	*Wind-Based Charging Hours*	*Solar-Based Charging Hours*
Spring	*12am - 6am*	*8am - 4pm*
Summer	*12am - 6am*	*7am - 2pm*
Fall	*12am - 6am*	*9am - 3pm*
Winter	*12am - 6am*	*10am - 3pm*

Figure 8: MA Clean Peak Standard eligibility criteria for electric storage charging windows

Another benefit of having this granular data is, it helps EDCs run scenario analysis under an Integrated Distribution Plan for substations that matter the most. Hence this report points out the best practice of collecting hourly individual distribution feeder peak data and substation peak demand data.

VI. How is electric storage different than other generating sources?

The second question is, "What are the defining characteristics of electric storage used for distribution asset planning as distinguished from generation resources? What thresholds, if any, would classify electric storage as a generation resource and therefore outside permitted distribution ratemaking and recovery?". There are 5 main points to consider in response to this question.

First, as we saw in the New York dual-purpose discussion, electric storage can function both as a generation asset and a distribution asset. But the question is,

[40] Massachusetts Clean Peak Standard eligibility criteria, https://www.mass.gov/doc/clean-peak-resource-eligibility-guidelines/download

how do we distinguish when a battery is being used for distribution needs vs. generation?

The best practice is to initiate stakeholder discussions to define "value stack[41]" benefits for electric storage. For example, the New York Public Service Commission (NY PSC) defined a Locational[42] System Relief Value (LSRV) adder to incentivize the consideration of DERs at locations with distribution system needs. An additional value, a Demand Reduction Value (DRV), shows electric storage's benefit in reducing peak demand. Similarly, for electric storage functioning as a generation asset – there are values assigned for energy, capacity, and other grid service benefits.

Second, electric storage lifecycle costs are dependent on how utilities contract with the Battery Energy Storage System (BESS) vendor. This cost point is brought up here to link question 2 to the answer for question 3 on appropriately categorizing NWA costs. If a single cell does not function properly, then the entire BESS must not be replaced. Similarly, for warranty purposes of hypothetical 10,000 cycles, the distribution utility may choose to enter an "augmentation plan" to assure themselves of warranty benefits. This augmentation plan would replace some of the battery cells on a pro-active basis extending the BESS life.

Third, in Pennsylvania, large industrials and commercial customers contract with the Electric Generation Suppliers (EGSs), so EGSs would offer their customers electric storage. As the example from non-vertically integrated electric distribution utilities in a state like Massachusetts – the EGS can function as the storage project developer and work with the facility owner, either a residential utility customer or a commercial & industrial customer.

---

[41] NYSERDA link for value stack benefits, [the Value Stack - Value of Distributed Energy Resources - NYSERDA]()

[42] Locational value is defined as the value of electric storage based on its location on the distribution system.

Fourth, electric storage is limited by the amount of charge from a charging resource. A restriction can be imposed when the resource is charged; for example, distribution planners would restrict the charging during peak hours on the distribution system. Otherwise, charging electric storage would increase the stress on the distribution feeder.

Finally, electric storage is different because it has no fuel and depends on another energy source. Instead of the fuel costs, electric storage has the cost of distribution system delivery charges. The EGS in their role as the storage project developer would be drawing upon EDC distribution equipment to meet retail customer demand.

VII. Prudent to recover electric storage costs in distribution resource planning?

The third and final question in the Secretarial Letter is, "Is it prudent for utilities to include electric storage in their distribution resource planning and, if so, where and under what circumstances? Further, is it appropriate for utilities to include such investments in rate base?"

To answer the prudency question, this report recommends initiating a stakeholder discussion to find out more about batteries benefits and costs. Batteries should be included as a utility asset only if they serve purely distribution benefits and are proven to be cost beneficial[43]. And the key for addressing the benefit-cost ratio is, the distribution planning engineer asking the question: is there a non-wires solution to the need on the distribution system before settling on a traditional solution

[43] Since electric storage can serve dual purposes, such as providing distribution and generation benefits, it may be prudent to develop a method of allocation to determine what costs should be attributed to the distribution system and what costs should be excluded from ratemaking recovery.

For example, it may be prudent to include electric storage costs in distribution assets if EDCs tie those infrastructure improvements to feeders with high distribution circuit peaks and historical substations peaks. This hourly substation and distribution circuit peak data can also help EDCs restrict electric storage charging during those peak times.

We know by this time in the report that not all distribution equipment is equal. Not all distribution equipment peaks at the same time as the hourly distribution data would show. Hence EDCs should classify equipment, accordingly, providing a base for cost allocation of electric storage implementation.

Just like not all distribution equipment is the same – not all EDCs have the same reliability. Hence it is relevant to ask if EDCs with above average reliability metrics should take the lead in implementing electric storage on a case by case basis where there is a need on the distribution system.

Finally, states like New York that have a higher DER penetration and hence in "Jog – Stage 2" of the Walk-Jog-Run framework have Value of DER (VDER) programs. EDCs in New York use VDER programs to qualify battery energy storage systems. These VDER programs are a result of a stakeholder process, led by state agencies[44].

VIII. Summary

The Commonwealth of Pennsylvania's Office of Consumer Advocate has engaged Rakon Energy LLC to support OCA's response to the three questions posed by the Pennsylvania Public Utility Commission's Secretary in the policy proceeding -

[44] Table 5. Approaches to Estimate the Locational Value of DERs for Regulated Utilities, page 31 in the LBNL report summarizes current approaches of several states. https://eta-publications.lbl.gov/sites/default/files/lbnl_locational_value_der_2021_02_08.pdf

Utilization of Storage Resources as Electric Distribution Assets. There are six key takeaways in this report.

First, electric storage has multiple applications on the distribution system, including reducing peak demand, integrating more renewables, providing grid services (such as power factor correction, supporting voltage), and direct distribution system benefits such as distribution upgrade deferral and reduction in distribution system losses. These applications address the reliability and resiliency challenges faced by the electric distribution companies.

Second, this report recommends initiating a stakeholder process to explore moving to integrated distribution planning that enables behind-the-meter resource forecasting, hosting capacity and scenario analysis and provides better value for DERs. IDPs provide for consideration of non-wire alternatives in distribution planning because, before settling on a traditional solution such as a distribution feeder upgrade or a new substation, the distribution planning engineer would ask: is there a non-wires solution to the need on the distribution system?

Third, consideration and implementation of the IEEE 1547-2018 standard on a statewide basis would allow Pennsylvania to realize the full benefit of DERs and electric storage, based on other state's experience.

Fourth, electric storage can function both as a generation asset and a distribution asset. But the question is, how do we distinguish when a battery is being used for distribution needs vs. generation? The best practice is to initiate stakeholder discussions to define "value stack" benefits for electric storage.

Fifth, electric storage has both positive and negative differences relative to conventional generation sources. On the positive end, batteries do not need hours to move from one capacity level to another. Batteries and battery controls manage output in seconds and minutes, not hours. Another positive is, batteries do not have a fuel cost. The O&M costs are relatively low, and if some of the cells in the battery pack fail, only those cells are replaced, not the entire battery system.

On the negative end, batteries are dependent on another source of energy to charge. Hence, batteries draw from the distribution system, and restrictions can be placed on charging times so that there is no conflict with peak distribution hours.

Finally, it may be prudent to include electric storage costs if EDCs demonstrate that the related electric storage assets are providing purely distribution services and are cost-effective. Since electric storage can serve dual purposes, such as providing distribution and generation benefits, it may be prudent to develop a method of allocation to determine what costs should be attributed to the distribution system and what costs should be excluded from ratemaking recovery.

One example of this, would be if the EDC were to tie those infrastructure improvements to feeders with high distribution circuit peaks and historical substations peaks. This hourly substation and distribution circuit peak data can help EDCs restrict electric storage charging during those peak times.

In summary, this report recommends a regulator must take some first key steps before full utilization of battery storage can be realized. This would include IDP because traditional current distribution planning was not designed or implemented to be a comprehensive planning tool, nor was it designed to incorporate emerging technologies or non-wires alternatives. This report also recommends consideration and implementation of IEEE 1547-2018 through a statewide-stakeholder process to realize the full benefit of DERs and electric storage.

Appendix – List of wastewater treatment and water pumping station locations where batteries are installed

Please note – the following is adapted from Rakon Energy's comments to Minnesota's Dakota Electric Association, a utility company, in their IDP proceeding at the Minnesota Public Utility Commission (PUC).

Not everyone thinks about energy storage for water pumping stations. But people who have experienced natural disasters have taken steps to avoid a repeat of their difficulties. The six recent installations below are implementing battery energy storage at their water and wastewater treatment facilities.

1. Irvine Ranch Water District (IRWD) in Irvine, California 40 miles south-east of Los Angeles International Airport is installing 6.25 MW/35.7 MWh Tesla batteries, owned, and operated by Advanced Microgrid Solutions, at water pumping stations, water treatment stations and water recycling plants[45]. The primary driver is the $500,000 energy cost savings per year for the water district.
2. Caldwell Wastewater Treatment Plant in Caldwell, NJ, half-hour north-west of Newark International Airport installed 250 kW/1MWh Eos battery storage with 896 kW of solar for backup power. Here the primary driver is to "keep untreated wastewater from entering local waterways during extended (upto 10 days) power outages[46]".
3. Paul R. Noland Wastewater Treatment Facility (east Fayetteville) and the Westside Water Treatment facility in Fayetteville, Arkansas 200 miles east of Oklahoma City, have recently installed 10 MW of solar and 24 MWh of energy storage. This is a joint project between the City of Fayetteville, Ozarks Electric Cooperative, and Today's Power Inc. (TPI). The primary

---

[45] https://www.irwd.com/home/liquid-news/money-saving-tesla-batteries-arrive-at-irwd-s-michelson-plant

[46] https://www.cleanegroup.org/caldwell-wastewater-treatment-plant/

driver is climate change but there are cost savings of $180,000 per year as well[47].

4. Village of Wappingers Fall Water Treatment Facility two hours north of New York City in New York has a 250 kW, 1000 kWh zinc hybrid cathode battery storage technology for its microgrid. The primary driver here is resiliency and continued operation of this facility[48].
5. Atlantic County Utilities Authority, ten miles away from casinos in Atlantic City, New Jersey, is also installing 1 MW battery energy storage system. The primary driver is, not to see a recurrence of raw sewage spilling into New Jersey's rivers and bays and the ocean[49].
6. City of Eugene, Oregon realized the benefit of energy storage to provide this resiliency benefit at an elementary school designated for a water well in the community to improve clean drinking water availability during power outages, “This project is also part of EWEB’s long-term resiliency planning efforts to establish community points of water distribution around the city of Eugene to be used by its customers during restoration following a large-scale disaster .” Additional information on Worley website is available[50].

---

[47] https://www.solarpowerworldonline.com/2019/09/arkansas-boots-up-10-mw-solar-24-mwh-storage-facility-in-fayetteville/

[48] https://microgridknowledge.com/new-york-microgrid-demonstration-project-uses-low-cost-storage/

[49] https://www.njspotlight.com/2018/04/18-04-16-acua-s-battery-storage-system-first-financed-by-clean-energy-fund/

[50] https://www.worleyparsons.com/our-work/eweb-power