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November 24, 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,

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Certificate of Service

*320287

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 24th day of November 2021.

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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 August 12, 2021, at Docket No. M-2020-3022877, the Office of Consumer Advocate (OCA) submits 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 this further opportunity for the OCA and other interested parties to discuss these emerging technologies and their implementation on the distribution system.

In support of these Comments, the OCA has attached a Report prepared by Rakon Energy LLC (Rakon Energy Report), which provides additional details and further responses to the questions contained in the Secretarial Letter.[1]

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.

[1] See attached Appendix A.

The December 3, 2020 Secretarial Letter sought 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 December 3, 2020 Secretarial Letter was published in the Pennsylvania Bulletin setting the due date for comments at 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.

On February 18, 2021, the OCA submitted its Comments.[2] In its Comments, the OCA recommended that 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. The OCA also recommended that the Commission consider initiating a statewide, stakeholder proceeding regarding the adoption of IEEE 1547-2018.[3] This national standard will

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[2] Policy Proceeding – Utilization of Storage Resources as Electric Distribution Assets, Docket No. M-2020-3022877, OCA Comments (Feb. 18, 2021) (OCA Initial Comments).

[3] IEEE 1547 is a national standard regarding the technical specifications for, and testing of, the interconnection and interoperability between electric power systems and Distributed Energy Resources (DERs).

ensure that as Distributed Energy Resources interconnect to the distribution grid, they will have the capability and flexibility necessary to reach their full potential. OCA Initial Comments at 1.

As to the three specific questions set out in the December 3, 2020 Secretarial Letter, the OCA provided that: (1) electric storage has the potential to provide a number of benefits to the distribution grid; (2) there is no clear answer as to every case regarding whether a storage asset is performing a distribution, generation or transmission function and, as such, a statewide collaborative may be needed to further explore this issue; and (3) the inclusion of storage assets in rate base could potentially be permissible, if at all, where the storage asset has been found to perform distribution functions and has been shown to be cost effective. In addition to the OCA, the Commission received a large number of comments from various stakeholders.

On August 12, 2021, the Commission issued a second Secretarial Letter in this docket seeking comments on an additional set of seven questions. The August 12, 2021 Secretarial Letter was published in the Pennsylvania Bulletin on August 28, 2021, and thus comments were due no later than September 27, 2021. On September 1, 2021, the Clean Air Council, Philadelphia Solar Energy Association, POWER Interfaith, the Union of Concerned Scientists, and the Natural Resources Defense Council requested a 60-day extension of the September 27 date. The Commission granted the extension and set the new date for comments as November 29, 2021. In accord with this schedule, the OCA submits the following Comments.

II. COMMENTS

A. Introduction.

In response to the December 3, 2020 Secretarial Letter, the Commission has already received a large amount of comments in this docket. The OCA reasonably expects that responsive comments to the August 12, 2021 Secretarial Letter will be at least equal to and potentially greater in number than what was received during the initial comment period. It is clear that there is a great interest in the subject matter under review here, from a broad and varied group of stakeholders. As such, the OCA submits that the Commission should consider creating a robust, broad-based stakeholder process to collaborate on these issues and to potentially create some guidelines for implementation of electric storage on the distribution network.

In the OCA's view, any stakeholder process that the Commission may create should include three specific areas, *inter alia*, that the OCA submits are vitally important to the topic of electric storage on the distribution network, as follows: (1) the adoption of Integrated Distribution Planning (IDP) for all Pennsylvania EDCs; (2) the adoption and implementation of IEEE 1547 - 2018; and, (3) the creation of guidelines and/or regulations that provide the procedural format, such as an application, petition, or other filing, that a utility would use when seeking to employ electric storage and the appropriate level of data that should accompany such a filing. The OCA submits that the myriad of issues presented in this docket should be thoroughly examined and discussed through a broad-based stakeholder process.

B. <u>Answers To The Commission's Directed Questions</u>.

1. <u>What are the parameters that would allow for the use of energy storage on the distribution grid? For example, what factors should be used in the consideration of the energy-storage project? Should the energy-storage project meet certain thresholds and demonstrate certain requirements, e.g., demonstration of cost-effectiveness as compared to alternate measures, demonstration of need, required RFPs to solicit potential third-party providers, limitations on project size and scope, etc.?</u>

Energy storage has the potential to provide significant benefits on the distribution network, but a more holistic approach to planning should be employed to ensure that any potential storage project is the correct and cost-effective response to the identified concern. As discussed in the Rakon Energy Report, the adoption of Integrated Distribution Planning (IDT) would provide a platform to ensure that the implementation of storage and DERs on the distribution system is done through a transparent planning process. Rakon Energy Report at 6-8.

Part of the question here involves whether there should be limitations on the size and scope of potential energy storage on the distribution system. The OCA submits that no size limitations should be implemented at this time. Battery technologies are changing rapidly, and any limits on sizing of storage may be more location specific and will require more flexibility than a general size limitation could provide. Further, as discussed in the Rakon Energy Report, battery manufacturers already set size limits for solar energy systems and storage as to residential and commercial systems. Rakon Energy Report at 8-11.

There is also the question of cost effectiveness of any storage project and whether a definitive showing must be made to establish a certain level of costs versus benefits. The OCA submits that energy storage is just one possible solution to distribution system upgrade concerns. The costs and benefits of any particular project should be adequately weighed against more traditional infrastructure upgrades. The particular system concern or need, and perhaps more importantly, the location in question relative to other potential system assets could well be a major factor along with any potential cost/benefit analysis. As the Rakon Energy Report provides, part of the IDP process includes a review of locational value as part of a cost-effectiveness test. Rakon Energy Report at 10-11.

2. <u>What EDCs have undertaken energy-storage initiatives as a pilot program and what were the results and lessons-learned?</u>

The Rakon Energy Report provides a review of various energy storage pilot programs from across the country. Rakon Energy Report at 11-14. As expected, several of the pilot programs indicate that battery storage can be effective in responding to outage situations. Beyond just outage response, however, the referenced SCE article provides how battery storage can be combined with limited peaking units to supplement power to the grid when renewables may not be completely available. SCE has discussed the ability of battery storage to contain and control reverse power flows, a situation that occurs when localized renewable output is high yet local consumption is low. Rakon Energy Report at 12, fn. 12.

The Rakon Energy Report also provides a link to the Clean Energy States Alliance Report on energy storage pilots in the New England states. Rakon Energy Report at 13, fn. 17. This Report could be very useful to the Commission and the stakeholders here as the subject of electric storage continues to be reviewed in this docket. Importantly, some of the lessons learned from other battery projects illustrate that safety is a key concern.[4]

The North American Electric Reliability Corporation (NERC) released a report on a battery fire event that contains some recommendations for such projects.[5] Among the key takeaways that the NERC Report provides, adequate communication and training of local fire response units is critical. Local fire companies or other first responders should not first learn of the existence of a battery facility when 911 is called. Rakon Energy Report at 13, fn. 15.

There are valuable experiences from other states that could serve as an important guide for the Commission as to the implementation of electric storage in Pennsylvania. The OCA submits that these resources should be thoroughly reviewed as a part of any further processes that the Commission may create in this docket.

3. Under what circumstances is it appropriate to deploy energy storage as compared to traditional infrastructure upgrades?

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4 See Rakon Energy Report at 13, fn. 15, as to a thermal runaway situation and resulting fire.

5 Lesson Learned - Battery Energy Storage System Cascading Thermal Runaway, available at: https://www.nerc.com/pa/rrm/ea/Lessons%20Learned%20Document%20Library/LL20210301_Battery Storage_Cascading_Thermal_Runaway.pdf

Electric storage should not be viewed as an end, in and of itself. The possible deployment of an energy storage asset should be properly viewed as but one tool in the distribution planning toolbox. As discussed, electric storage can be a beneficial resource to the distribution grid in a variety of manners but traditional infrastructure upgrades should not be overlooked and will continue to play a vital part in a reliable and resilient distribution system.

As noted in the Rakon Energy Report:

> energy storage may be an appropriate solution for reliability issues at the end of a distribution circuit with no projected load growth. But in locations where load growth is expected, a new substation may be a possible long-term fix rather than a short-term battery solution. This logic is reasonable in the distribution planning context.

Rakon Energy Report at 14. One recent example from the UGI Electric case provides an example where the deployment of a battery facility was reasonable based on the specific facts of that matter.[6] That said, the parties to that case engaged in prolonged discussions and analysis before reaching the ultimate conclusion that, in that instance, the deployment of a battery facility was a reasonable course of action.

As discussed herein and in the Rakon Energy Report, however, energy storage may not be the right solution to every distribution system concern. Rakon Energy Report at 14. As such, the OCA submits that the Commission should consider the implementation of IDP. IDP provides a platform to incorporate a variety of responses to distribution planning, as the Rakon Energy Report provides:

> … as Rakon's February report noted, the Commission will continue to face these questions on an ad hoc basis in traditional distribution planning without the IDP process. The IDP is the logical evolution for Distribution System Planning.
>
> The current distribution planning won't work because an EDC's approach to replacing aging infrastructure alone would not address the reliability and resiliency

[6] See Pa. PUC v. UGI Utilities Inc. – Electric Division, Dock. No. R-2021-3023618, (Order entered Oct. 28, 2021) (UGI Electric).

> challenges faced by the EDCs. This EDC challenge is true even in a load growth scenario because, as the Regulatory Asset Project (RAP) report notes, the EDC options have increased. Hence this report recommends that the Commission adopt a stakeholder driven IDP process.

Rakon Energy Report at 14 (footnote omitted).

IDP has the ability to incorporate energy efficiency, demand response, DERs and electric storage, among other possible tools, in order to create a more transparent and efficient distribution planning process. The OCA submits that the Commission should consider the benefits and efficiencies to be gained through the use of IDP.

4. <u>Who should own an energy-storage asset? EDCs, third-party vendors, or some combination of both?</u>

The OCA submits that third-party vendors should be viewed as the preferred ownership structure for energy storage assets. In the OCA's view, the rapidly evolving and complex technologies at issue here are best left to the competitive marketplace. That said, however, the OCA is open to the possibility that in some situations EDC ownership could be reasonable and in the public interest.

In some instances, the ownership structure of any energy-storage asset could turn on the specific facts of the case at hand. As a general proposition, however, third-party ownership is preferable as the Rakon Energy Report provides:

> EDCs are not well-positioned to own battery technologies; they will have to evaluate different technology vendors and enter into long-term contracts that may miss the next wave of cost-effective battery chemistries. The EDCs know their distribution system and have data on reliability and resiliency needs on the system. If EDCs stick with what they know best and leave the battery chemistry to aggregators, then Pennsylvania consumers will be better served.

Rakon Energy Report at 19. Although, third-party ownership of a distribution system asset does raise some reasonable concerns.

Any battery that is a part of the distribution system must be available when called upon to either release power into the system or potentially serve as a sink for any excess or reverse power flows. Accordingly, third-party ownership models would need to include rules governing the permitted uses and availability of these distribution resources. As discussed in the Rakon Energy Report, a review of what other states and utilities have implemented in this regard could provide a useful framework for such governing rules and regulations. Rakon Energy Report at 17-18.

Some combination of third-party ownership and EDC ownership may turn out to be the model that provides the greatest level of flexibility in this area. In general, however, the OCA submits that the competitive market is likely to return the best outcomes in the way of products and services.

5. <u>What processes should the Commission use to review requests to utilize energy storage as a distribution asset and recover associated costs?</u>

As a starting point, the IDP process should be employed to ensure that any project being put forth to the Commission for possible authorization has already been thoroughly studied. Further, utilities seeking Commission review of an energy-storage project should have to supply a baseline of data to support any such request, including but not limited to a description of the concern, the alternatives reviewed, the cost/benefit analyses and other necessary supporting documentation. The procedural vehicle, such as an application or a petition proceeding, may depend on the exact proposal being put forth – EDC ownership, third-party ownership, outright purchase, lease, or potentially another arrangement. A base rate case, however, with the already tight timelines and myriad of issues generally present should not be the preferred way forward.

As the Rakon Energy Report provides, there are a number of cost, prudency and incentives questions that will need to be examined in any such proceeding. Rakon Energy Report at 20-22. The statutory timelines of base rate cases do not lend themselves well to such inquiries. The OCA submits that whatever process or processes that are eventually adopted must be suitable for the participation and input of a broad category of stakeholders.

6. <u>What cost recovery mechanisms should be implemented for the ownership and operation of energy-storage assets?</u>

Numerous possibilities exist as to cost recovery mechanisms, including either Section 1308 base rate recovery, Section 1307 automatic adjustment clauses, or some combination of both. As the OCA is primarily recommending that energy storage ownership should fall to third parties, cost recovery should align with the provision of a service rather than the purchase of an asset that may be afforded base rate treatment. Again, on a case-by-case basis the potential costs of either approach could be vastly different.

As the Rakon Energy Report provides:

> To answer the first part of the sixth question, the Commission should note that the battery system's capital costs vary due to the interconnection costs. The range is $200-$2000 per kWh, depending on where the battery is interconnected. Closer to the interconnection point, the less need for distribution upgrades to accommodate the battery.
>
> The Commission should consider additional costs for installation, commissioning, construction, permitting, site remediation, de-watering sites, and regrading landscape depending on the site location. Electricity consumption needs for station power, maintenance, and warranty must be factored into the costs also.
>
> The O&M costs are lower than the capital costs because there is not much maintenance of the battery systems after installation. However, some battery owners take an augmentation package. If a battery cell fails, the manufacturer replaces the cell instead of replacing the entire system.

Rakon Energy Report at 23 (footnote omitted). In addition to the cost categories listed above, salvage, recycling and all other end-of-life costs must also be adequately considered. Rakon Energy Report at 24. Accordingly, in an EDC-owned scenario, the total costs of ownership must be accounted for and it must also be recognized that the battery itself has a limited lifespan and decommissioning costs at this point in time may not be well settled.[7]

As an additional component of question six, the Commission requests comments on whether the Commission should allow EDCs' storage systems to participate in the PJM wholesale markets. As the OCA is recommending a third-party ownership model, participating in PJM markets could be beneficial to consumers. As the Rakon Energy Report provides:

> Yes, the Commission should allow EDCs storage systems to participate in the PJM wholesale markets. Since we have already established that storage systems provide multiple services, not allowing wholesale market participation would limit the revenue streams of battery storage systems, increasing the cost to the ratepayers.
>
> Storage revenues should be treated similarly to the revenue treatment of Pennsylvania's Demand Response programs that participate in the PJM markets.

Rakon Energy Report at 27.

To be clear on this point, the OCA is recommending that storage facilities that are owned by third parties should have the ability to participate in providing market services as administered by PJM, to the extent that such activities do not lessen the ability of the storage facility to fulfill its primary obligation to reliability and resilience of the distribution system. In the OCA's view, however, participating in PJM markets denotes more of a generation activity and should not be considered for EDC-owned systems.

7. <u>What are the appropriate models and limitations necessary to allow energy storage to participate in wholesale power markets?</u>

Energy storage assets can provide a wide array of ancillary services. Rakon Energy Report at 28-29. Depending on the size and the location of energy storage facilities, these ancillary

[7] The Rakon Energy Report also provides some important transparency issues that should be addressed, in the event that the EDC owns the storage asset. Rakon Energy Report at 25-26.

services can be a benefit to both the distribution and transmission grid. It is also possible that the presence of batteries can create competing demands on the transmission network, specifically:

> Those batteries are using the transmission system to charge and deliver energy to provide wholesale market services. As a result, batteries end up taking space on the transmission system. This transmission capacity reservation impacts the EDC distribution system operations in situations where the EDC is dependent on the same transmission network to deliver energy to the distribution demand. Hence it is prudent for the Commission to consider rules specifically for peak demand hours on the distribution system so that batteries participating in the wholesale market are not using up the transmission system simultaneously.

Rakon Energy Report at 29. Accordingly, there should be parameters and limits placed on the operation of such wholesale assets.

The EDCs have a part to play here, as the Rakon Energy Report provides:

> … EDCs should place appropriate limits on the operation of batteries participating in the wholesale markets. However, it should be on a case-by-case basis because a fully charged battery can provide reliability and resiliency to the EDC during emergencies on the distribution grid if allowed to do so.
>
> If batteries participate in PJM markets independently or through aggregation enabled by the FERC Order 2222, the Commission must set rules in its role as the Relevant Electric Retail Regulatory Authority (RERRA) to account for double counting of services.
>
> In the latest PJM compliance proposal, PJM is stating clearly that double-counting, meaning providing the same services in wholesale and retail markets, is not permitted and that the EDC must determine if battery storage is providing the same service.

Rakon Energy Report at 30. Further, the Commission and the EDCs have experience in similar wholesale market activities in the area of demand response programs, specifically:

> Within the context of the Commission's seventh question about appropriate models to allow storage participation, it is worth noting that the PJM markets allow retail demand response participation in wholesale markets. FERC has mandated a "net benefits test" in FERC Order 745 on demand response participation in PJM markets.
>
> According to PJM, in a net benefits test, DR is compensated at full LMP when two conditions are met: 1) DR can balance supply and demand, and 2)

> Payment of LMP to DR is cost-effective. PJM calculates annually the monthly values of LMP for this test and posts on the PJM website.
>
> This net benefits test can be a model for energy storage participation in PJM markets because when discharging energy on the distribution grid, batteries generate energy by reducing load. By drawing energy when batteries are charging, they are increasing the load. Similar to DR, batteries can balance supply and demand. And FERC Order 2222 provides a framework for batteries and DR to participate in PJM markets via aggregation.

Rakon Energy Report at 31-32 (footnotes omitted).

The Commission should allow battery systems to participate in both retail and wholesale markets, with the appropriate safeguards. In a similar situation, demand response resources have long participated in wholesale and retail markets. Energy-storage providers can be treated similar to how demand-response providers are held accountable for how much demand they have reduced and for how long. EDCs have the ability to control the limits of such market participation on a case-by-case contractual basis.

III. CONCLUSION

The Office of Consumer Advocate respectfully submits these Comments regarding the utilization of electric storage within electric utility distribution planning, and looks forward to a continuing dialogue on these important issues.

Respectfully Submitted,

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DATE: November 24, 2021
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APPENDIX A

RAKON ENERGY REPORT

For Commonwealth of Pennsylvania’s Office of Consumer Advocate

Abstract

This report answers the seven 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

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Executive Summary

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

There are **seven** key takeaways in this report.

First, this report recommends the Integrated Distribution Planning (IDP) process to conduct a cost-effectiveness test because grid needs should dictate cost-effective solutions, including storage. An IDP also provides a structure to treat energy storage as a distribution asset. On capacity size limitations, this report asserts that the Commission should not consider battery storage size limitations because there already exist limitations for customers due to solar system size and manufacturer battery size.

Second, states on the West and East coasts have undertaken energy storage pilot programs, and the Commission can learn from those experiences. Most utility pilot programs have seen a consistent benefit when batteries are deployed for distribution system outages. The Arizona fire incident also shows a need for fire inspectors to know the locations of batteries on the distribution grid.

Third, energy storage is not ideal for all situations on the grid because we don't want storage to charge during grid emergencies. We expect the batteries to charge during off-peak hours, and those circumstances are appropriate to deploy energy storage compared to the traditional distribution upgrades. This report recommends that the Commission adopt a stakeholder-driven IDP process to address the third question on circumstances that make sense to deploy storage. Emissions should also be considered because storage should discharge when emissions are higher for public health benefits.

Regarding the **fourth** question on energy-storage asset ownership, this report recommends third-party ownership of the storage assets on the distribution grid because it is not in the consumer interests for EDCs to own, operate, and keep track of different battery chemistries. Moreover, with the FERC Order 2222 on distributed energy resource aggregation, aggregators taking on the task of aggregating distributed assets are consistent with how demand response programs operate in wholesale markets.

Fifth, the Commission should ensure electric storage incentives vary by customer class and location, link incentives for electric storage implementation with behind-the-meter solar installations and know that some EDC impacts could go either benefits or costs way.

Sixth, the Commission should allow EDC storage systems to participate in the PJM wholesale markets since storage devices provide multiple services and reduce consumer costs. EDCs can impose limits on the operation of the battery system at feeders with high distribution circuit peaks and historical substation peaks. This hourly substation and distribution circuit peak data can help EDCs restrict electric storage charging during those peak times.

Additionally, the Commission should allow EDCs to enter into distribution-related services provided by third party-owned energy storage systems because the needs on the distribution system are changing with more customers adopting distributed generation.

On the question of whether the Commission should go through §1308 base rate for all costs, or a combination of §1308 and §1307, this report makes no firm recommendation except to state that the Commission must include all cost components including the capital, operating, decommissioning costs and performance metrics.

Finally, on the **seventh** question, the Commission must allow battery systems to participate in both retail and wholesale markets because of the Commission’s experience with demand response programs.

While PJM is working with its stakeholders on compliance rules around FERC Order 2222, demand response resources have long participated in wholesale and retail markets. Third-party aggregators can be held accountable for reliability and resiliency, similar to how demand response providers are held accountable for how much demand they have reduced and for how long. The Commission has experience with retail demand response programs participating in the PJM markets.

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.

Similar to the Feb report, this report is organized according to the Pennsylvania Public Utility Commission's (PUC) August 12, 2021, Secretarial Letter questions.

II. First Question - Parameters that would allow for energy storage on the distribution grid

Based on the comments filed in response to the first set of questions asked in December 3, 2020, Secretarial Letter ("the December Letter"), the Commission acknowledged that electric storage provides reliability and resiliency benefits on the distribution grid on August 12, 2021, Secretarial Letter ("the August Letter").

So, the first question asks about the parameters that would allow for electric storage on the distribution system, such as under what regulatory/statutory framework would energy storage be a distribution asset, size limitations in terms of the nameplate capacity, and elements to inform the cost-effectiveness test.

Regarding the regulatory/statutory framework that allows energy storage as a distribution asset, the key question that distribution planning engineers should ask themselves before settling for a traditional distribution upgrade is, "is there a non-wires solution to the need on the distribution system?".

And the regulatory framework that enables that non-wires solution is an Integrated Distribution Planning (IDP) process. IDP provides a structure to treat energy storage as a distribution asset.

An IDP enables behind-the-meter resource forecasting, hosting capacity, and scenario analysis and provides better value for Distributed Energy Resources (DERs), including battery storage systems.

Several commenters to the December Letter note the importance of a transparent process for distribution planning, similar to this report's recommendations.

For example, the Advanced Energy Management Alliance (AEMA) comments discuss how storage "must be integrated into all aspects of distribution resource planning[1]." An IDP provides this integrated structure.

The Energy Storage Association (ESA) recommends the Commission develop guidelines to treat Non Wires Alternatives (NWAs) to "maximize the value of energy storage in distribution planning[2]. "

Natural Resources Defense Council (NRDC) comments went further than this report's recommendation on the IDP process. NRDC recommends "enacting legislation to create a neutral NWA evaluator role in the Commonwealth of Pennsylvania to increase the success of the NWA framework in the distribution planning process[3]." Consistent with this report's recommendations, NRDC comments note the lack of transparency in distribution planning[4]. An IDP provides transparency in distribution planning.

Finally, the Edison Electric Institute (EEI) mentions that a "dozen states are investigating or have established a process for incorporating storage and DERs into distribution system planning." Hence including the Office of Consumer

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[1] "Storage has the potential to resolve distribution-level issues more cost-effectively than traditional "wires" investments, and therefore must be integrated into all aspects of distribution resource planning." Page 7, AEMA Comments

[2] Page 7, ESA Comments.

[3] Page 20, NRDC Comments

[4] "Pennsylvania's distribution system planning process lacks transparency." NRDC Comments

Advocate (OCA), at least 5 commentators to the December Letter have also recommended the IDP process similar to this report's recommendation.

On the nameplate capacity size limitations, the Commission is providing an example when asking this question, "if an energy-storage system is designed to meet the specific need of voltage regulation, should the capacity be limited only to address this problem, or is it acceptable to size the system to provide additional capacity?".

The answer to this sizing question depends on the size limitations where batteries would likely be deployed, namely for backup power and storing solar energy.

Most residential customers already operate under a size limitation when owning a solar array system. The solar array is sized according to the residential customer's previous years' consumption plus 10%. This limitation ensures that the residential owner is not generating excess solar energy most of the time for the distribution utility. According to PECO's NetMetering website[5], there is a difference in how this 110% limit applies compared to the solar system size depending on whether the customer owns or leases the system.

"Solar energy systems of customers who want to participate in net metering are limited in capacity to no greater than 50kW (residential only) or 3,000kW (non-residential only) in size and so that they generate no more than 110% of the customer's expected annual electricity usage. The 110% limit only applies if the customer leases the system. However, if the customer owns the solar energy system, the 50kW size limit (residential only) or 3,000kW size limit (non-residential only) still applies but not the 110% limit."

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[5] PECO Net Metering website - https://www.peco.com/SmartEnergy/MyGreenPowerConnection/Pages/NetMetering.aspx

Hence, for sizing batteries for residential and non-residential customers, a limit is already placed on solar energy systems, which translates into a de-facto limit for energy storage systems. For example, if a residential customer owns a solar system, they have a size limit of 50 KW. The battery for this residential owner is limited to a 50 kW power rating with a discharge capability of 2 hours translates into a 100 kWh system size.

But most commercial branded residential battery systems are sized smaller than 100 kWh, such as 20 kWh (Sonnen[6]), 19.6 kWh (LG CHEM RESU[7]), and 14 kWh (Tesla Powerwall[8]). Hence a battery size limitation for providing only one service such as voltage regulation versus multiple services does not matter because manufacturer sizes limit consumer choices.

It is also worth noting that not all residential customers want to back up their entire load as shown in Figure 1, and they only size the battery to back up their critical loads such as freezer, air conditioner, and cooking appliances. It would be difficult for the Commission to guess the critical load size for a consumer. Hence this report recommends that the Commission does not consider size limitations.

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[6] Sonnen website - https://sonnenusa.com/en/eco/#specifications

[7] LG CHEM RESU Datasheet, https://www.lg.com/us/business/download/resources/BT00002151/180830_LG_ESS_Datasheet.pdf

[8] Tesla PowerWall 2 Datasheet, https://www.tesla.com/sites/default/files/pdfs/powerwall/Powerwall%202_AC_Datasheet_en_northamerica.pdf

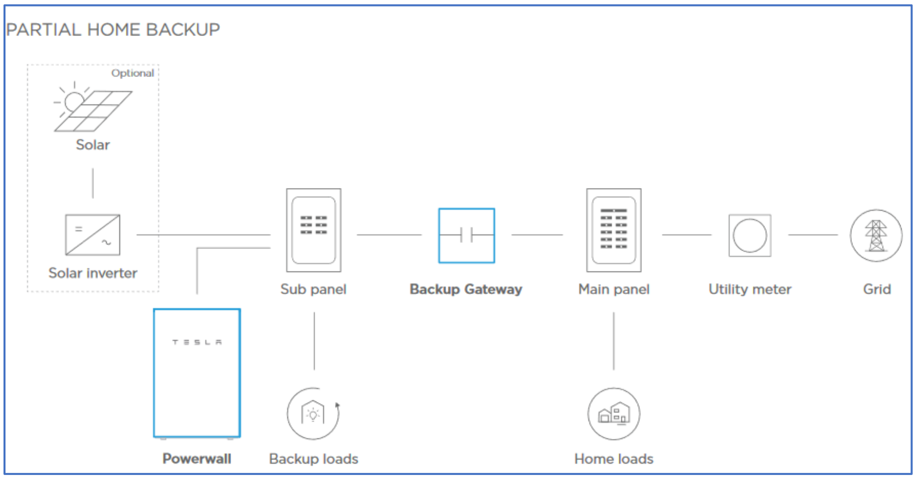

Figure 1: Tesla Home Backup Schematic showing only a subset of the home load is backed up[9]

In conclusion, for capacity size limitations, this report asserts that the Commission should not consider battery storage size limitations because there already exist limitations for customers due to solar system size and manufacturer battery size.

Finally, on the information for the Cost-effectiveness test, yes, energy storage provides more than reliability and resiliency benefits on the electric distribution system. Hence to inform the cost-effectiveness test, the Commission should consider additional factors such as the following that provide the locational value at that substation or feeder on the distribution grid:

- Increase in the distribution system capacity, which is a benefit
- Decrease in the distribution system losses [benefit]

The **electric storage system's location** on the distribution grid is important to inform the cost-effectiveness test. Because as mentioned in Rakon's February report, "If storage is located on the primary distribution circuit and deferring the

[9] ibid

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

The February Rakon report written in response to the December Letter mentions six steps in an IDP. The grid needs identification, and locational[10] value is step 3 of that process. This report recommends the IDP process to conduct a cost-effectiveness test because grid needs should dictate cost-effective solutions, including storage.

III. Second Question – EDCs experience with energy storage pilots

The second question is straightforward, "What EDCs have undertaken energy-storage initiatives as a pilot program, and what were the results and lessons learned?".

The August Letter mentions Maryland, "For example, the Maryland Public Service Commission has approved several pilot projects for EDCs and at least one for a third-party owner," and Maryland's pilot programs are discussed extensively in the NRDC comments. Hence this report summarizes other known pilot programs from the East and West coasts.

[10] 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

Table 1 is a summary of lessons learned. Please note that Table 1 is not exhaustive and does not list all EDCs with energy storage pilot programs.

Table 1: Lessons Learned summary table of Energy Storage Pilots (not exhaustive)

Lessons Learned	EDC/Outcome	Source
The 3 Distributed Energy Storage Initiative (DESI) systems were discharged during the summer peak demand hours, which helped SCE avoid distribution outages[11].	SCE - California/SCE has signed 7 contracts worth 770 MW of battery storage systems to meet future reliability needs.	SCE Blog[12]
Xcel mentions that the Panasonic battery successfully provided islanding and backup power during 2 feeder outages[13].	Xcel - Colorado	Xcel Energy presentation to Colorado Public Utilities Commission[14]
Thermal runaway issue caused battery fire at the	APS - Arizona	March 2021 NERC Lessons Learned report[16]

[11] "The three systems were discharged for two hours starting around 5 p.m. on Aug. 15, when the outages took place, and on Aug. 17, to help avoid further outages. The systems continue to discharge each day starting around 5 p.m." SCE Blog

[12] https://energized.edison.com/stories/battery-storage-helped-power-socal-during-recent-heat-waves

[13] Xcel Energy's 2019 Annual Report to the Colorado Public Utilities Commission Regarding the Innovative Clean Technology Program, Docket # 09A -015E , https://www.dora.state.co.us/pls/efi/EFI_Search_UI.search

[14] Docket # 09A -015E , https://www.dora.state.co.us/pls/efi/EFI_Search_UI.search

[16] https://www.nerc.com/pa/rrm/ea/Lessons%20Learned%20Document%20Library/LL20210301_Battery_Storage_Cascading_Thermal_Runaway.pdf

APS battery system. This fire incident has led to a detailed report that included recommendations such as fire inspectors should not be caught unawares of battery locations on the grid[15].		
Sterling's battery provides backup power for up to 12 days for Sterling's critical facilities.	Sterling Municipal Light Department – Massachusetts	CESA report titled, "Energy Storage Policy Best Practices from New England: Ten Lessons from Six States[17]"
Residential battery pilot program for 250-customers, TOU rate customers save money.	Liberty Utilities – New Hampshire	CESA report titled, "Energy Storage Policy Best Practices from New England: Ten Lessons from Six States.[18]"

It is clear from this sampling of states on the West and East coasts that EDCs have seen a consistent benefit when batteries are deployed for distribution system outages. As the Arizona fire incident in the APS example indicates, fire inspectors

[15] NERC recommendation, "Until NFPA 855 has been finalized, entities owning BESS should consider: The key to managing risk associated with the installation of a BESS focuses on a hazard mitigation analysis. This will identify gaps along with the appropriate control measures like design modifications, suppression, and training. • The fire services should not be seeing a BESS for the first time when 911 is called. Consideration should be given to developing a pre-incident guide which will serve as the mutual platform for future training of utility personnel and the fire services. • Conduct training, familiarization tours and exercises with your local fire department."

[17] Page 38, CESA report https://www.cesa.org/resource-library/resource/energy-storage-policy-best-practices-from-new-england/

[18] Page 13, CESA report https://www.cesa.org/resource-library/resource/energy-storage-policy-best-practices-from-new-england/

must be made aware of the locations of batteries on the distribution grid so that they are not caught off-guard if there is a battery fire incident in the future.

IV. Third Question – Appropriate circumstances to deploy storage

The third question is also straightforward, "Under what circumstances is it appropriate to deploy energy storage as compared to traditional infrastructure upgrades?".

As the August Letter notes, energy storage may be an appropriate solution for reliability issues at the end of a distribution circuit with no projected load growth. But in locations where load growth is expected, a new substation may be a possible long-term fix rather than a short-term battery solution. This logic is reasonable in the distribution planning context.

But as Rakon's February report noted, the Commission will continue to face these questions on an ad hoc basis in traditional distribution planning without the IDP process. The IDP is the logical evolution for Distribution System Planning.

The current distribution planning won't work because an EDC's approach to replacing aging infrastructure alone would not address the reliability and resiliency challenges faced by the EDCs. This EDC challenge is true even in a load growth scenario because, as the Regulatory Asset Project (RAP) report[19] notes, the EDC options have increased. Hence this report recommends that the Commission adopt a stakeholder driven IDP process.

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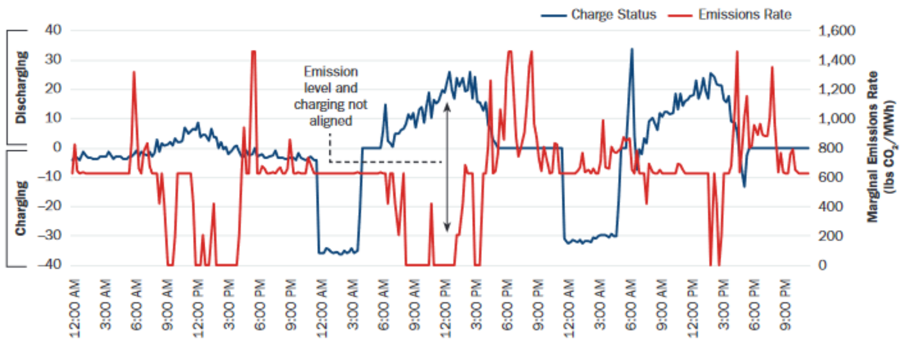
[19] "In more recent years, energy efficiency, expanded demand response, distributed generation and energy storage — all of which can be located where load relief is most valuable — have expanded the utility's options to meet load growth or reduce demands on aging assets without building transmission, 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.

This report also recommends that the Commission consider emissions data as another variable in the IDP process before setting charging and discharging time windows for peak and off-peak demand hours. As the example from California shows, the right incentives for storage discharging would align with hours where emissions are higher compared to charging when emissions are lower. Storage should discharge when emissions are higher for public health benefits.

FIGURE 4A

Misaligned Financial Signals

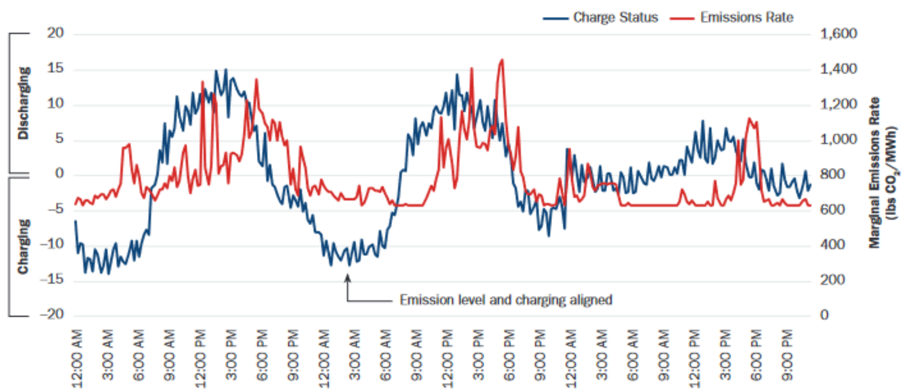


The California SGIP program initially suffered from financial signals that were not aligned with state emissions data. As a result, battery owners frequently discharged their batteries during low emissions periods, rather than charging when emissions were low and discharging when they were high.

Source: WattTime

FIGURE 4B

Emissions Aligned Operation



After program incentives were revised to encourage battery discharge during periods of high emissions, customer battery use became much better aligned with state emissions reduction goals

Source: WattTime

Figure 2: Emissions data should be considered for battery discharging windows[20]

[20] Page 17, CESA report https://www.cesa.org/resource-library/resource/energy-storage-policy-best-practices-from-new-england/

In its comments to the December Letter, AEMA also notes emissions' key role in deploying storage[21]. AEMA comments assert that by reducing emissions, energy storage provides public health benefits.

V. Fourth Question – Storage Ownership

The fourth question concerns ownership of the electric storage system.

The Commission is right in stating that third-party ownership of energy storage should not jeopardize the reliability and resiliency benefits.

For example, in Vermont's Green Mountain Power "Bring Your Own Battery" BYOB program, homeowners have incentives of $850 per kW if enrolled for three-hour discharge and $950 per kW incentive for four-hour discharge. Batteries in Vermont, where extra storage is needed, can get an extra payment of $100 per kW enrolled. This incentive applies to small business owners also.

But the restriction for these incentives is, the battery should only be used for back power. No other applications are possible in this BYOB arrangement[22]. The customer owns the battery, chooses the installer, and chooses the amount to enroll (3-hour or 4-hour discharge) in the BYOB.

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[21] "The peak reduction benefits of energy storage can lower wholesale, transmission, and distribution costs, reduce greenhouse-gas emissions ("GHG") and potential Regional Greenhouse Gas Initiative compliance payments, and increase public health benefits through the reduction of local NOx and SOx emissions." Page 3, AEMA Comments

[22] Green Mountain Power BYOB website, "You may not use the battery system for any controls other than providing backup power for the customer's premises." https://greenmountainpower.com/rebates-programs/home-energy-storage/bring-your-own-device/battery-systems/

Here is an example from New Hampshire[23] SB 498 bill text mandating EDCs do not own Behind-The-Meter energy storage,

"**Utilities shall not own** behind-the-meter battery storage, with the exception of the energy storage pilot approved by the commission in order number 26,209, including phase 2 of the pilot, **unless the commission finds**, after the pilot has been fully implemented, that additional utility ownership of behind-the-meter battery storage would be in the public interest and would not unreasonably encumber the deployment of non-utility behind-the-meter battery storage."

Battery storage chemical technologies are evolving. If Lithium Iron Phosphate (LIP) is effective in some applications, Nickel Manganese Cobalt (NMC) batteries are effective in other instances. Zinc-based batteries are also on the market. Each chemistry differs in the number of cycles, density, applications, and risks that include fire hazards.

A typical home battery might charge during off-peak hours during the night and discharge during peak hours during the day, completing one cycle. That home battery would cycle 365 times during the year, translating into more than 25 years of life cycle warranty. But most battery manufacturers are providing 10 years or 10,000 cycles warranty only.

How deep the charging would be is called Depth of Charge or more popularly referred to as State of Charge (SOC) and how much energy is discharged is the Depth of Discharge (DoD). Most battery manufacturers do not recommend a full 100% discharge[24]. Multiple cycles during the day and close to a 100% discharge reduce battery efficiency and void the manufacturer warranty.

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[23] NH SB 498 text, http://gencourt.state.nh.us/bill_status/billText.aspx?id=2211&txtFormat=html&sy=2020

[24] LG ESS Data Sheet lists 95% DoD, whereas Sonnen lists 90% DoD. Hence DoD's vary by the battery manufacturers.

Each battery cell is stacked in small modular units for residential customers. Those same cells are put in a container for commercial and industrial customers.

Additionally, since batteries are storing energy in Direct Current (DC) and most customers consume Alternating Current (AC) power, batteries are connected through inverters to the distribution grid. Dealing with battery and inverter manufacturers is beyond the scope of an EDC.

EDCs are not well-positioned to own battery technologies; they will have to evaluate different technology vendors and enter into long-term contracts that may miss the next wave of cost-effective battery chemistries. The EDCs know their distribution system and have data on reliability and resiliency needs on the system. If EDCs stick with what they know best and leave the battery chemistry to aggregators, then Pennsylvania consumers will be better served.

Hence this report proposes the third-party ownership model for distributed energy storage. Other **commenters to the December Letter** have commented on similar lines.

For example, ESA comments suggest competitive procurement reduces costs to the ratepayers[25]. NRDC comments suggest a bilateral contract between EDCs and third-party providers of storage services[26]. In their comments, the Solar Energy Industries Association (SEIA) [27] does not object to EDC ownership of storage as a

[25] "when the reliability obligations of the utility do not necessitate ownership, ESS may be excellent candidates for competitive procurement, leveraging third party investment and increasing competition in order to reduce costs for ratepayers." Page 8, ESA Comments

[26] "But the question of utility ownership of those systems must be considered in view of other available alternatives, including bilateral contracts between electric distribution companies and third-party parties for storage services" Page 4, NRDC Comments

[27] "SEIA recommends that any proposal for electric distribution company ownership of electric storage 1) show that it meets the standards to be in a distribution asset according to FERC's uniform system of accounts (Account

distribution asset but provides guard rails for such a treatment. The Advanced Energy Management Alliance (AEMA) [28] also cautioned the Commission on EDC ownership for distributed energy storage.

Additionally, given the FERC Order 2222 implications in the seventh question, third-party ownership would work better with aggregators because the Commission, in its role as a Relevant Electric Retail Regulatory Authority (RERRA), must approve DER Aggregator interconnection requests. The EDCs will still be responsible for conducting distribution system studies that analyze the impact of aggregator requests.

VI. Fifth Question – Prudency Review for Storage

The complexity of the questions starts to increase with the fifth question, which concerns the Commission prudency reviews, certificate of public convenience, and a base rate case review process.

In the August Letter, the Commission asks the question, "If the model of energy-storage ownership is through an EDC, then questions need to be answered as to how the Commission should review the appropriate use and cost recovery of these assets. What form of review and approval process should the Commission utilize to render a determination on the appropriate treatment of a storage system as a distribution asset?".

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363) and 2) be subjected to a Cost Benefit Analysis, comparing it to traditional infrastructure solutions as well as non-wires alternatives and a tariff-based program." Page 1, SEIA Comments

[28] "The storage resources themselves should be procured competitively from third-party providers unless utilities can convincingly demonstrate that utility construction and ownership is less expensive and more reliable." Page 5, AEMA Comments

The answer is the IDP process. If the Commission chooses to allow EDCs ownership of storage, the IDP process provides a transparent stakeholder process to understand grid needs on the distribution system.

For the prudency review question, this report reverts back to the key takeaways from section IV on cost prudency found in the February Rakon report. The summary was,

1. From NY-ConEd's MWh block[29] discussion it is clear that electric storage incentives must vary by customer class and location. High population density areas such as Philadelphia and Pittsburgh lend themselves to MWh blocks than the rest of the state.
2. From the Massachusetts[30] example it is clear that incentives for electric storage implementation must be linked with behind-the-meter solar installations.
3. From the NSPM[31] it is clear that identifying all benefits and utility program implementation costs and some impacts to EDCs that could go either way – is important when performing storage Benefit Cost Analysis.
    a. Benefits include credit and collection costs, distribution outage risk reduction, reliability, and resiliency.
    b. Costs include financial incentives, program administration costs, utility performance incentives, energy generation, and RPS compliance.

[29] 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

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

[31] The National Energy Screening Project (NESP) published a National Standard Practice Manual for Benefit-Cost analysis of DERs (NSPM) in August 2020. https://www.nationalenergyscreeningproject.org/national-standard-practice-manual/

   c. Benefits or Costs include distribution capacity, distribution line losses, distribution O&M, and voltage support.
4. From the RAP manual[32] it is clear that 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 is equally important for cost prudency reviews.

In summary, the Commission should ensure electric storage incentives vary by customer class and location, link incentives for electric storage implementation with behind-the-meter solar installations, and know that some EDC impacts could go either benefits or costs way. Additionally, for prudency review of storage, it is important to identify customer classes that draw energy from the primary versus secondary distribution feeder and apply costs by distribution equipment classification.

VII. Sixth Question – Storage Cost Recovery Mechanism

The sixth question builds upon the fifth question by adding the wholesale market component to the cost recovery dimension. The retail side of the sixth question is similar to the first question. There are individual parts to this major cost recovery question.

First, the Commission is asking, "Should it be through §1308 base rate for all costs, or a combination of §1308 applicable to the capital costs of the battery system and §1307 automatic adjustment for the energy cost associated with running the battery system?".

[32] The Regulatory Assistance Project (RAP) published a manual ("RAP manual") on electric cost allocation in January 2020. https://www.raponline.org/knowledge-center/electric-cost-allocation-new-era/

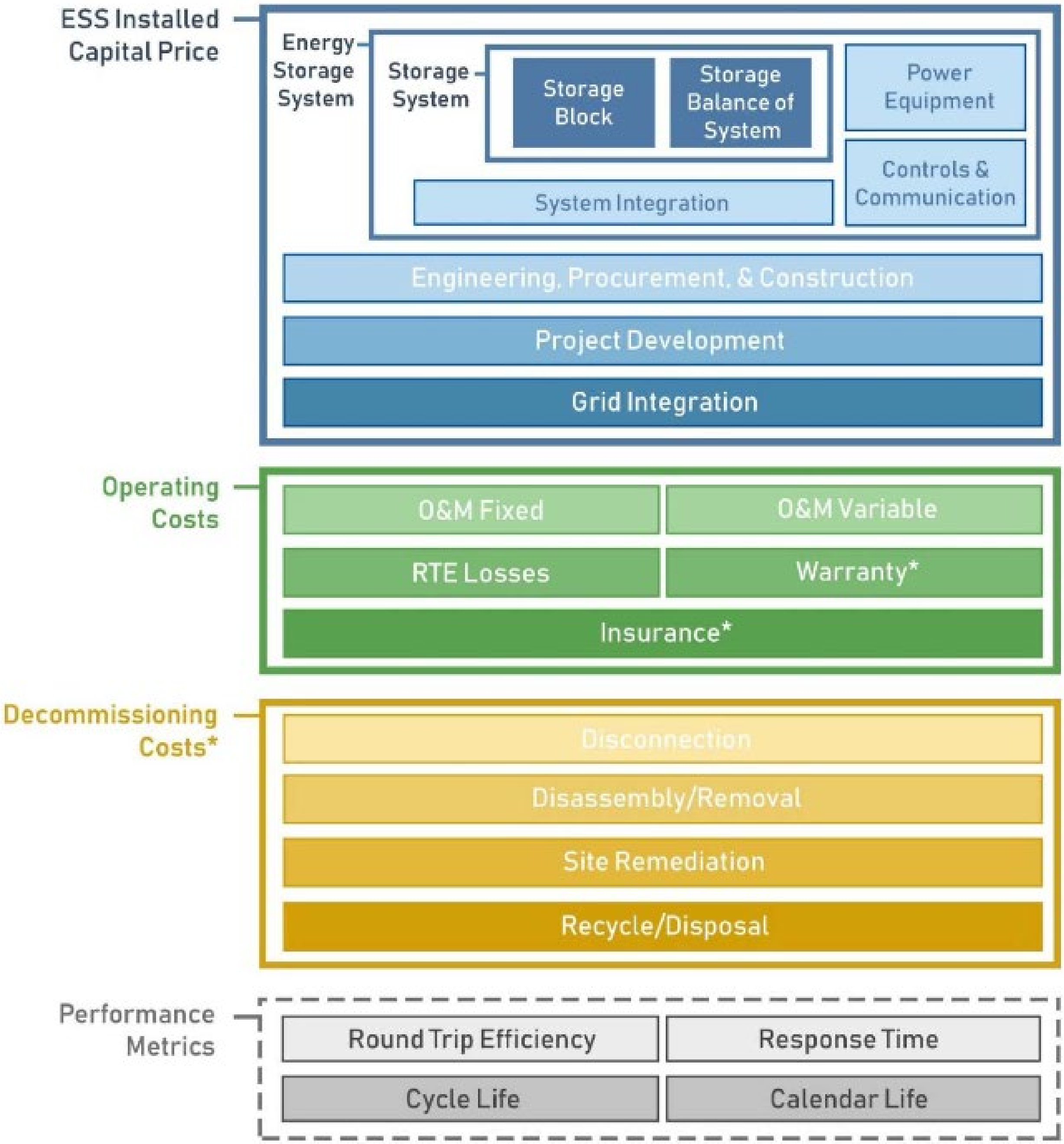
To answer the first part of the sixth question, the Commission should note that the battery system's capital costs vary due to the interconnection costs. The range is $200-$2000[33] per kWh, depending on where the battery is interconnected. Closer to the interconnection point, the less need for distribution upgrades to accommodate the battery.

The Commission should consider additional costs for installation, commissioning, construction, permitting, site remediation, de-watering sites, and regrading landscape depending on the site location. Electricity consumption needs for station power, maintenance, and warranty must be factored into the costs also.

The O&M costs are lower than the capital costs because there is not much maintenance of the battery systems after installation. However, some battery owners take an augmentation package. If a battery cell fails, the manufacturer replaces the cell instead of replacing the entire system. The following Table 2 summarizes the key cost components of energy storage systems.

[33] This consultant research based on interviewing battery four different battery manufacturers.

Table 2: Energy Storage Systems Costs Breakdown Table to illustrate various cost categories[34]



In summary, to answer this question on whether the Commission should go through §1308 base rate for all costs, or a combination of §1308 and §1307, this report makes no firm recommendation except to state that the Commission must include all cost components including the capital, operating, decommissioning costs and performance metrics as illustrated in the Pacific Northwest National Laboratory (PNNL) report[35].

Second, the Commission is asking, "What limits, if any, on the operation of the battery system by the EDC should be established for cost-recovery purposes?", and the answer is[36], any operational limits on the battery system must be based on historical feeder data.

If the Commission mandates EDC ownership of the electric storage system, the EDC must share the data on charging and discharging cycles on a public website in order to be transparent. There is precedent for this at a state commission, namely the Public Utility Commission of Texas (PUCT).

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[34] 2020 Grid Energy Storage Technology Cost and Performance Assessment, Kendall Mongird, Vilayanur Viswanathan, Jan Alam, Charlie Vartanian, Vincent Sprenkle*, Pacific Northwest National Laboratory. Richard Baxter, Mustang Prairie Energy. Technical Report Publication No. DOE/PA-0204 December 2020. Figure 1, https://www.pnnl.gov/sites/default/files/media/file/Final%20-%20ESGC%20Cost%20Performance%20Report%2012-11-2020.pdf

[35] Ibid

[36] "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 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." February Rakon Energy Report

Electric Transmission Texas (ETT), LLC is a joint venture of American Electric Power (AEP) and Berkshire Hathaway Energy Company (BHE). ETT posts the annual data of Presidio Battery which is a 4 MW Sodium Sulphur battery.

This Figure 3 chart is helpful to understand at what times is the battery charging and discharging and for how long. This public data provides transparency into battery operations for other EDCs and third party service providers.

Summary of Presidio Battery Operations for 2020

The Presidio Battery installation in Presidio, Texas, is a four ("4") Megawatt sodium, Sulphur battery installation. The discharge of the battery will enable it to supply power continuously over an eight-hour period. In addition, it will address voltage fluctuations and momentary outages in the area.

In 2020, the battery discharged and recharged 36 times in a 12 month period.

The longest discharge duration time was 5 hours and 30 minutes.
The longest charge duration time was 6 hours and 45 minutes.

The shortest discharge duration time was 30 minutes.
The shortest charge duration time was 2 hours.

The earliest discharge occurrence began at 5:45 a.m. and lasted 4 hours and 15 minutes.
The earliest charge occurrence began at 8:45 a.m. and lasted 3 hours and 30 minutes.

The latest discharge occurrence began at 9:00 p.m. and lasted 30 minutes.
The latest charge occurrence began 11:30 p.m. and lasted 2 hours.

The following charts are the Kwh discharges and charges per month.

Month	kWh Discharge		kWh Charge
January	27,322.25		31,638.50
February	39,655.00		46,741.00
March	32,539.50		37,250.75
April	4,543.75		8,738.00
May	6,365.00		7,431.00
June	24,179.25		28,384.25
July	13,968.75		16,048.50
August	32,174.25		37,279.25
September	-		-
October	7,474.50		6,581.50
November	29,886.75		35,019.25
December	23,983.00		27,260.75
TOTAL	242,092.00		282,372.75

Figure 3: Summary of Presidio Battery Operations for 2020 in Texas to illustrate EDC data requirements

<u>Third</u>, the Commission is asking whether it should "allow EDCs to enter into distribution-related services provided by third party-owned energy-storage systems, and, if so, how should the EDCs recover these costs?".

Yes, the Commission should allow EDCs to enter into distribution-related services provided by third party-owned energy storage systems because the needs on the distribution system are changing with more customers adopting distributed generation. We have already established that storage provides wide variety of services in addition to reliability and resiliency such as, disturbance ride-through capability, reactive and voltage support, frequency support by reducing frequency deviations, and dispatchability[37].

As the 2016 NARUC DER Rate Design and Compensation Manual[38] note, the EDC, a third party, or the customer could need these distribution services. To prepare for a future in which distributed storage can provide all possible services, EDCs enter into contractual agreements with third parties for their current needs.

Finally, the last part in this sixth question is, "Should the Commission allow EDCs' storage systems to participate in the PJM wholesale markets and how should those revenues be treated? Should the PJM revenues be used to offset the costs of the electric storage system and be credited to customers? Would such a participation model alleviate competition concerns?".

Yes, the Commission should allow EDCs storage systems to participate in the PJM wholesale markets. Since we have already established that storage systems provide multiple services, not allowing wholesale market participation would limit the revenue streams of battery storage systems, increasing the cost to the ratepayers.

Storage revenues should be treated similarly to the revenue treatment of Pennsylvania's Demand Response programs that participate in the PJM markets.

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[37] Table III 1 - Milligan's Grid Services Summary Table illustrating Inverter-Based resources provide grid services in Rakon February report.

[38] Page 140, “these services and values could be sought by the utility, a third party, or another customer. In other words, the customer or DER could bilaterally contract with another customer, resource, aggregator, or the utility for the product or service it is offering. This would allow DER to have wider benefits than simply to the utility or grid, but to other customers directly connected to the grid seeking additional services or products.” NARUC Manual on Distributed Energy Resources Rate Design and Compensation, Prepared by the Staff Subcommittee on Rate Design 2016 https://pubs.naruc.org/pub/19FDF48B-AA57-5160-DBA1-BE2E9C2F7EA0

When a battery storage system charges from the distribution grid, it is similar to a load on the system.

VIII. Seventh Question – Storage participating in PJM Markets

The seventh question is wholesale market-centric. And it contains a generic component, "what role does energy storage participating only in the wholesale markets have on the EDC distribution system operations?".

If batteries participate only in wholesale markets, they benefit the energy, capacity, and ancillary services markets administered by PJM operators. We know this by the annual battery services chart from California ISO, which has 1,300 standalone storage registered in that wholesale market.

Figure 1.21 Average hourly battery schedules (2020)

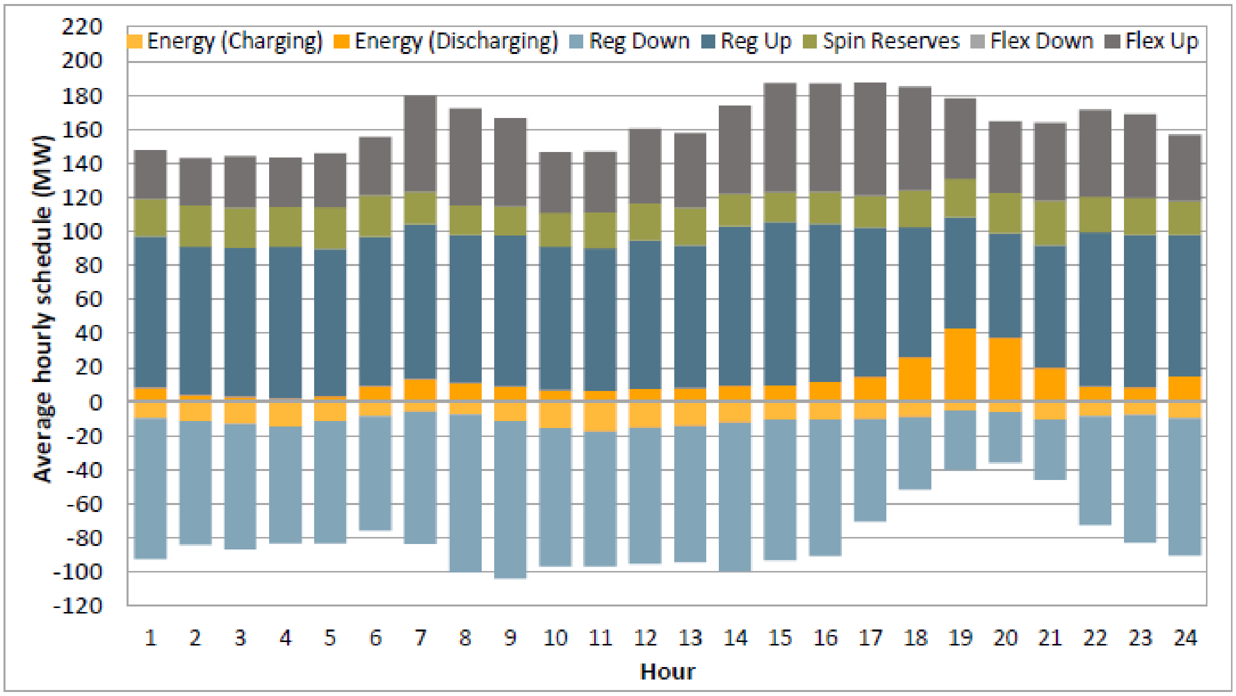

Figure 4: CAISO Average hourly battery schedules for 2020 to show batteries provide multiple ancillary services[39]

Those batteries are using the transmission system to charge and deliver energy to provide wholesale market services. As a result, batteries end up taking space on the transmission system. This transmission capacity reservation impacts the EDC distribution system operations in situations where the EDC is dependent on the same transmission network to deliver energy to the distribution demand.

Hence it is prudent for the Commission to consider rules specifically for peak demand hours on the distribution system so that batteries participating in the wholesale market are not using up the transmission system simultaneously.

[39] CAISO 2020 Market report, http://www.caiso.com/Documents/2020-Annual-Report-on-Market-Issues-and-Performance.pdf

The last question also asks a **specific question**, "Are there appropriate limits for the EDCs to place on the operation of such wholesale assets? Does this depend on whether the energy-storage asset participates in wholesale markets independently or through Order 2222 Distributed Energy Resource aggregation?".

Yes, EDCs should place appropriate limits on the operation of batteries participating in the wholesale markets. However, it should be on a case-by-case basis because a fully charged battery can provide reliability and resiliency to the EDC during emergencies on the distribution grid if allowed to do so.

If batteries participate in PJM markets independently or through aggregation enabled by the FERC Order 2222, the Commission must set rules in its role as the Relevant Electric Retail Regulatory Authority (RERRA) to account for double counting of services.

In the latest PJM compliance proposal, PJM is stating clearly that double-counting, meaning providing the same services in wholesale and retail markets, is not permitted and that the EDC must determine if battery storage is providing the same service.

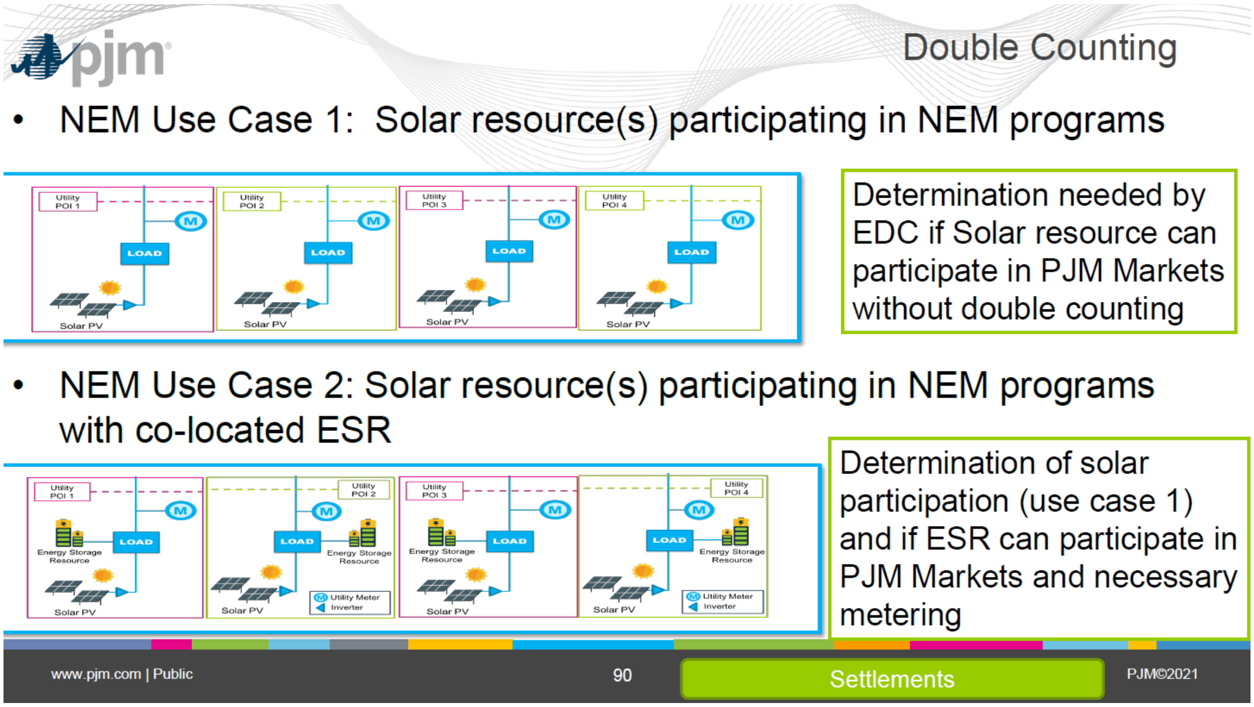

Figure 5: PJM Double Counting Use Case that illustrates PJM defers to EDCs if a storage resource can participate in PJM markets

As the use case in the PJM slide indicates, it is up to the EDC to determine if Net Energy Metered (NEM) solar can participate in PJM markets without double counting. Similarly, if the battery is co-located with solar on the distribution grid, the EDC determines whether the battery can participate in PJM markets.

Within the context of the Commission's seventh question about appropriate models to allow storage participation, it is worth noting that the PJM markets allow retail demand response participation in wholesale markets. FERC has mandated a "net benefits test" in FERC Order 745[40] on demand response participation in PJM markets.

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[40] "when a demand response resource participating in an organized wholesale energy market administered by a Regional Transmission Organization (RTO) or Independent System Operator (ISO) has the capability to balance supply and demand as an alternative to a generation resource and when dispatch of that demand response resource is cost-effective as determined by the net benefits test described in this rule, that demand response resource must be compensated for the service it provides to the energy market at the market price for energy,

According to PJM[41], in a net benefits test, DR is compensated at full LMP when two conditions are met: 1) DR can balance supply and demand, and 2) Payment of LMP to DR is cost-effective. PJM calculates annually the monthly values of LMP for this test and posts on the PJM website[42].

This net benefits test can be a model for energy storage participation in PJM markets because when discharging energy on the distribution grid, batteries generate energy by reducing load. By drawing energy when batteries are charging, they are increasing the load. Similar to DR, batteries can balance supply and demand. And FERC Order 2222 provides a framework for batteries and DR to participate in PJM markets via aggregation.

In its August DERA Compliance framework proposal[43] for meeting FERC Order 2222, PJM states it is "evaluating whether the Net Benefits Test will be performed at the nodal price or the weighted average LMP of the aggregate." Hence, the net benefits test for compensating retail demand response programs in wholesale markets provides the Commission, a model for distribution grid-connected electric storage participation in PJM markets.

IX. Summary

The Commonwealth of Pennsylvania's Office of Consumer Advocate has engaged Rakon Energy LLC to support OCA's response to the seven questions posed by the

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referred to as the locational marginal price (LMP)". FERC Order 745 for Demand Response Compensation in Organized Wholesale Energy Markets, https://www.ferc.gov/sites/default/files/2020-06/Order-745.pdf

[41] Slide 30, PJM training presentation https://www.pjm.com/~/media/training/pjm-demand-side-response-overview-v2.ashx

[42] PJM Demand Response website where Net Benefit Tests historical and current values are posted, https://www.pjm.com/markets-and-operations/demand-response.aspx

[43] Slide 85, PJM DIRS August 2021

Pennsylvania Public Utility Commission's Secretary in the policy proceeding - Utilization of Storage Resources as Electric Distribution Assets. There are 7 key takeaways in this report.

First, this report recommends the Integrated Distribution Planning (IDP) process to conduct a cost-effectiveness test because grid needs should dictate cost-effective solutions, including storage. An IDP also provides a structure to treat energy storage as a distribution asset. On capacity size limitations, this report asserts that the Commission should not consider battery storage size limitations because there already exist limitations for customers due to solar system size and manufacturer battery size.

Second, states on the West and East coasts have undertaken energy storage pilot programs, and the Commission can learn from those experiences. Most utility pilot programs have seen a consistent benefit when batteries are deployed for distribution system outages. The Arizona fire incident also shows a need for fire inspectors to know the locations of batteries on the distribution grid.

Third, energy storage is not ideal for all situations on the grid because we don't want storage to charge during grid emergencies. We expect the batteries to charge during off-peak hours, and those circumstances are appropriate to deploy energy storage compared to the traditional distribution upgrades. This report recommends that the Commission adopt a stakeholder-driven IDP process to address the third question on circumstances that make sense to deploy storage. Emissions should also be considered because storage should discharge when emissions are higher for public health benefits.

Regarding the fourth question on energy-storage asset ownership, this report recommends third-party ownership of the storage assets on the distribution grid because it is not in the consumer interests for EDCs to own, operate, and keep track of different battery chemistries. Moreover, with the FERC Order 2222 on distributed energy resource aggregation, aggregators taking on the task of aggregating distributed assets are consistent with how demand response programs operate in wholesale markets.

Fifth, the Commission should ensure electric storage incentives vary by customer class and location, link incentives for electric storage implementation with behind-the-meter solar installations and know that some EDC impacts could go either benefits or costs way.

Sixth, the Commission should allow EDC storage systems to participate in the PJM wholesale markets since storage devices provide multiple services and reduce consumer costs. EDCs can impose limits on the operation of the battery system at feeders with high distribution circuit peaks and historical substation peaks. This hourly substation and distribution circuit peak data can help EDCs restrict electric storage charging during those peak times.

Additionally, the Commission should allow EDCs to enter into distribution-related services provided by third party-owned energy storage systems because the needs on the distribution system are changing with more customers adopting distributed generation.

On the question of whether the Commission should go through §1308 base rate for all costs, or a combination of §1308 and §1307, this report makes no firm recommendation except to state that the Commission must include all cost components including the capital, operating, decommissioning costs and performance metrics.

Finally, on the seventh question, the Commission must allow battery systems to participate in both retail and wholesale markets because of the Commission's experience with demand response programs.

While PJM is working with its stakeholders on compliance rules around FERC Order 2222, demand response resources have long participated in wholesale and retail markets. Third-party aggregators can be held accountable for reliability and resiliency, similar to how demand response providers are held accountable for how much demand they have reduced and for how long. The Commission has experience with retail demand response programs participating in the PJM markets.