BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF COLORADO

PROCEEDING NO. 17M-0694E

IN THE MATTER OF THE COMMISSION'S REVIEW OF ITS RULES GOVERNING ELECTRIC RESOURCE PLANNING, IMPLEMENTING COLORADO'S RENEWABLE ENERGY STANDARD, AND ENABLING NEW TECHNOLOGY INTEGRATION.

COMMENTS OF THE ENERGY STORAGE ASSOCIATION

Pursuant to the Public Utilities Commission of the State of Colorado ("Commission") Decision Opening a Repository Proceeding and Soliciting Input from Interested Participants issued on October 26, 2017, the Energy Storage Association ("ESA") respectfully submits these comments for the Commission's consideration in the matter of the Commission's review of its rules governing electric resource planning, implementing Colorado's renewable energy standard, and enabling new technology integration.

ESA's comments focus on recommendations for reforming provisions within the Electric Resource Planning ("ERP") rules, Rules 3600-3619, to better incorporate considerations for energy storage and provide an initial template for the Commission's consideration for new rules for Distribution Resource Planning (DRP).

I. ABOUT THE ENERGY STORAGE ASSOCIATION

Since its inception 27 years ago, ESA has promoted the development and commercialization of safe, competitive, and reliable energy storage delivery systems for use by electricity suppliers and their customers. ESA's nearly 150 members comprise a diverse group of electric sector stakeholders, including electric utilities, energy service companies, independent power producers, technology developers—of advanced batteries, flywheels, thermal energy storage, compressed air energy storage, and other technologies—component suppliers, and system integrators.

II. COMMENTS ON ELECTRIC RESOURCE PLANNING REFORMS

Recently published results of Xcel Energy's All Source Solicitation as part of its 2016 Electric Resource Plan reflect the tremendous price reductions in renewable energy and energy storage technologies. On December 28, 2017, Xcel Energy released findings of an all source solicitation that reflected historically low-priced bids for energy storage, both as a standalone asset and paired with wind, solar, and gas generation.[1] These findings present an immense opportunity for the State of Colorado to deploy low-cost resources at a time when there is a critical need for a more flexible and resilient electric system.

While these results are encouraging, they belie a broader challenge for energy storage in the State of Colorado and elsewhere across the United States. Current rules do not require utilities to model their system need in a way that ensures that energy storage is able to fairly compete with other traditional resources to meet the system reliability needs. In the comments below, ESA provides an overview of important reforms needed in the ERP process to allow effective consideration of energy storage, ensuring that utilities examine the widest set of solutions for prudent use of ratepayer funds.

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[1] Xcel 2016 Electric Resource Plan, 2017 All Source Solicitation 30-Day Report (Public Version), Colorado Public Utilities Commission Docket No. 16A-0396E, 28 December 2017, available at: https://www.documentcloud.org/documents/4340162-Xcel-Solicitation-Report.html.

i. Unique characteristics of energy storage require modifications to ERP process

Advanced energy storage technologies, particularly batteries, have unique characteristics that can serve many of the needs of the grid, if considered appropriately in planning processes. Unlike generation resources, energy storage may both inject and withdraw electricity from the grid; it can respond nearly instantaneously to a control signal and can ramp nearly instantaneously up or down to a precise level of service; and it is "always on" and available for service, even when neither charging nor discharging. Such unique characteristics of storage require a different approach to resource modeling if a utility will realize the full value of storage to its system.

Several basic guidelines will ensure inclusion of storage in ERP processes enhances prudent planning for Colorado ratepayers:

1) Use up-to-date storage cost estimates and cost forecasts to better identify near- and long-term prudency of storage;

2) Employ sub-hourly intervals in modeling to quantify the value of both capacity and flexibility benefits provided by energy storage;

3) Institute a "net cost" analysis of capacity investment options to more accurately compare energy storage with traditional capacity resources;

4) Incorporate system flexibility needs into reliability metrics to better account for the characteristics of the future supply mix; and

5) Analyze demand resources as distinct resource options separate from load forecasts to seek the widest range of cost-effective resources.

Several of these recommendations were recently incorporated into planning guidelines in the State of Washington.[2] In October 2017, the Washington Utilities and Transportation

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[2] Washington Utilities and Transportation Commission, *Report and Policy Statement on Treatment of Energy Storage Technologies in Integrated Resource Planning*, October 2017, available at:

Commission ("UTC") issued a Report and Policy Statement on Treatment of Energy Storage Technologies in Integrated Resource Planning and Resource Acquisition in Docket No. U-161024. In the policy statement, the UTC revised its resource planning rules to ensure that utility planning and procurement activities adapt to changing utility needs and availability of new technologies by calling on utilities to incorporate sub-hourly modeling, up-to-date cost data, and a net cost analysis. In addition to the State of Washington, regulators in New Mexico and Michigan have similarly issued rules requiring utilities to consider energy storage in their resource planning exercises.[3] Sub-hourly modeling, net cost approaches, flexibility metrics, and distinct demand resource modeling have been employed in other utilities' IRPs recently.[4] Finally, in 2016 ESA published a primer on including energy storage in integrated resource planning, which discusses some of these topics in greater detail and may be a helpful reference for the Commission.[5]

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https://www.utc.wa.gov/_layouts/15/CasesPublicWebsite/CaseItem.aspx?item=document&id=236&year=2016&docketNumber=161024&resultSource=&page=&query=&refiners=&isModal=&omItem=false&doItem=false.

[3] See New Mexico Public Regulation Commission, Final Order Amending Integrated Resource Planning Rules 17.7.3 NMAC to Include Energy Storage, Case No. 17-00022-UT, 9 August 2017, available at: http://www.nmprc.state.nm.us/general-counsel/docs/17-00022 UT%20Final%20Order%20Amending%20Intergrated%20Resource%20Planning%20Rule17%207%203%20NMAC%20to%20Include%20Energy%20Storage%20Resources.pdf. See also Michigan Public Service Commission, Opinion and Order of the 21 December 2017 meeting of the Michigan Public Service Commission in Lansing, Michigan, available at: https://mi-psc.force.com/sfc/servlet.shepherd/version/download/068t0000001X2Co.

[4] See Chapter 8 in *Portland General Electric 2016 Integrated Resource Plan*, issued 15 Nov 2016, available at: https://www.portlandgeneral.com/our-company/energy-strategy/resource-planning/integrated-resource-planning. See also *Hawaii Electric Companies' Power Supply Improvement Plan*, issued 23 Dec 2016, available at: https://cca.hawaii.gov/dca/files/2016/12/dkt_2014_0183_20161223_companies_PSIP_update_report_1_of_4.pdf. See also *PNM 2017-2036 Integrated Resource Plan*, issued 3 July 2017, available at: https://www.pnm.com/irp. See also *APS 2017 Integrated Resource Plan*, issued April 2017, available at: https://www.aps.com/library/resource%20alt/2017IntegratedResourcePlan.pdf.

[5] Energy Storage Association, *Including Advanced Energy Storage in Integrated Resource Planning: Cost Inputs and Modeling Approaches*, November 2016, available at: http://energystorage.org/system/files/attachments/irp_primer_002_0.pdf.

ii. Use accurate data on cost and performance

ERP rules should require that utilities use updated and accurate cost assumptions for energy storage to ensure that it is fairly evaluated next to traditional resources. ESA recommends that utilities use estimates of advanced storage costs that are not more than one year old. Colorado utilities benefit from having actual data points from Xcel Energy's recent solicitation, and those bid values should inform planning inputs. Additionally, numerous sources report the installed cost of advanced energy storage has declined significantly in recent years, generally faster than market expectations. While estimates of the rate of reduction vary, several sources report cost declines of approximately 10 percent year-on-year.[6] Considering this rapid and recent technical progress, it is critical that planners use up-to-date advanced storage cost estimates and forecasts for ERP model inputs. Not doing so risks basing investment decisions on outdated assumptions.

Utilities should also use a declining cost curve when projecting future costs of storage. Utilities' resource planning typically assume that the costs of conventional supply technologies increase over time, based on inflation, since combustion turbines and other decades-old generation technologies are no longer experiencing significant cost declines. Advanced storage is different in that the rapidly increasing scale of manufacturing capacity and deployment has resulted in significant unit cost reductions, with this trend expected to continue within current resource planning windows.

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[6] See Lazard, *Levelized Cost of Storage Version 3.0*, Nov 2017, available at: https://www.lazard.com/perspective/levelized-cost-of-storage-2017/. See also GTM Research, *Q4 2017 Energy Storage Monitor*, Dec 2017, available at: https://www.greentechmedia.com/research/subscription/u-s-energy-storage-monitor. See also Bloomberg New Energy Finance, *Lithium-ion Battery Costs and Market*, 5 July 2017, available at: https://data.bloomberglp.com/bnef/sites/14/2017/07/BNEF-Lithium-ion-battery-costs-and-market.pdf.

iii. Employ granular resource modeling to capture storage benefits

Typical utility planning models use three inputs—forecasted demand, the capital cost of available technologies, and those technologies' operating profiles—to calculate economic long-term options for system capacity. These models tend to be simple because they adequately capture the uncomplicated operations of traditional generation units providing capacity. In contrast, current-day advanced energy storage provides high value flexibility services, like frequency regulation or ramping support, in addition to capacity. A large-scale energy storage resource dedicated to providing peak capacity when needed—typically a several-hour period in afternoon and early evening during summer months—can also provide grid services for the many hours when that peak capacity is not needed. Storage resources can do this because they are "always on" and available for service, in contrast to traditional generation units that incur start up and shut down costs to provide services to provide peak capacity and other services. As a result, planners do not have the right tools to estimate the net cost of storage capacity.

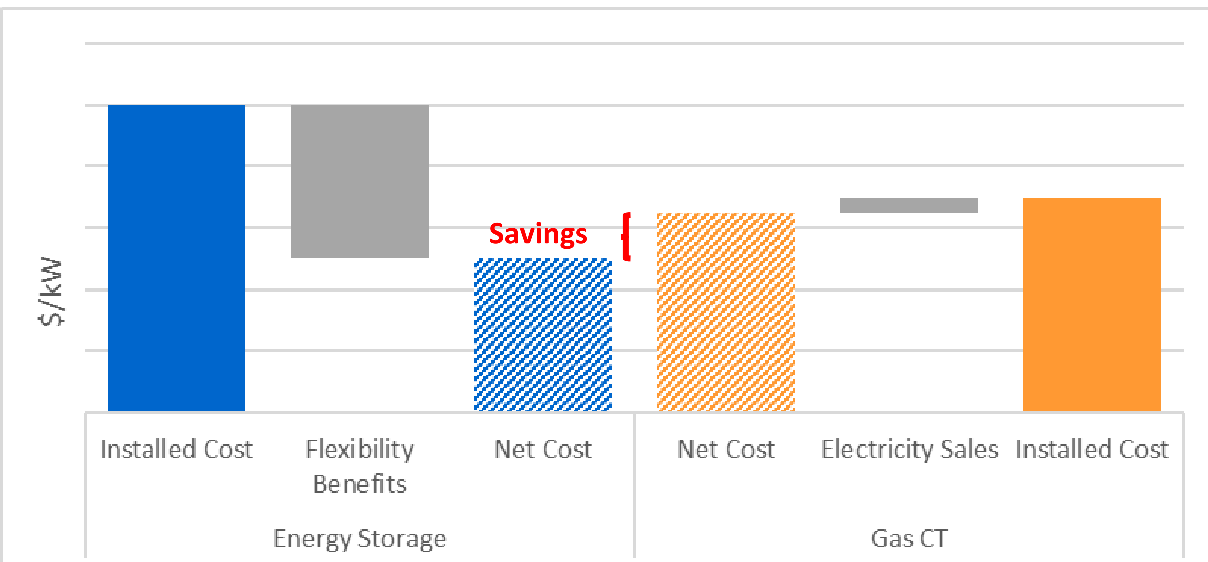
For this reason, ESA recommends that the Commission update ERP methods to accurately model advanced storage. Utilities should employ models that use sub-hourly intervals that capture the flexibility of storage operations to provide both capacity and grid services. Validated commercial models are available that can examine calculate economic resource options including intra-hourly dynamics, such as PLEXOS. If sub-hourly modeling is not considered an option, then at minimum utilities should use an hourly chronological production cost model, rather than sampling a small set of hours from each season.

iv. Compare resource options on a net cost basis

ESA proposes that the Commission call on utilities to incorporate a net cost evaluation methodology within the ERP that better captures the value of flexibility. The flexibility benefits and avoided system costs of advanced storage operations are significant and represent a substantial addition to the capacity value of storage. The simplest method to incorporate such storage benefits into the ERP is to use a net-cost-of-capacity approach, as pioneered by Portland General Electric in their 2016 IRP and the concept of which is illustrated in Figure 1:

Net cost of capacity = Total installed cost – Operational benefits (flexibility operations & avoided costs)

Figure 1 Example of Net Cost of Capacity Calculation



Some of the operational benefits of storage are flexibility services directly provided by the individual unit in question. Among these benefits are (1) regulation, (2) load following, and (3) contingency reserves. When the direct operational benefits of storage are modeled, they can represent as much or more than the capacity value of storage. For example, preliminary findings from Portland General Electric's 2016 IRP found that operational benefits of storage were expected to be approximately two times larger than the capacity value (~$90/kW-yr and ~$40/kW-yr, respectively).

Other operational benefits of storage accrue to the entire system as avoided costs. Among these benefits are (1) reduced operating reserve requirements; (2) reduced start-up and shut-down costs of all generation facilities; (3) improved heat-rate efficiency of thermal plants; (4) reduced curtailment of renewable resources; (5) reduced risk of exposure to fuel price volatility; and (6) reduced local emissions and ability to run without environmental restrictions on operations. As an example, a Massachusetts state-commissioned study of large-scale energy storage deployment found that the total value of these system benefits was greater than the value of the direct, compensated services of storage. Indeed, because these benefits increase the efficiency of the overall grid, they must be accounted for at a system level, rather than at the level of an individual storage resource.

Taking account of such avoided system costs and flexibility benefits will ensure Colorado utilities take a more accurate view of the cost-effectiveness of energy storage solutions.

v. *Incorporate system flexibility needs into reliability metrics*

The ERP models the ability of different resources to meet resource adequacy in a utility's electric service territory. Resource adequacy traditionally focuses on meeting the single greatest hour of demand in the planning horizon and define an acceptable level of risk for not meeting that demand—called the Loss of Load Expectation (LOLE). Utilities typically plan to an LOLE standard of "1-in-10"—that is, available capacity will only be insufficient to meet system demand just once over a 10 year period. Utilities' ERP modeling combines that LOLE standard with load forecasts and the attributes of existing resources to calculate the extra capacity (“planning reserve margin”) needed in the system—which informed investments in new capacity.

The LOLE convention does not adequately capture needs for system flexibility. As a higher share of Colorado’s electric supply comes from variable renewable generation, utilities will face periods where their electric supply ramps up or down significantly over short intervals. Yet, these fast and sudden changes in supply resulting from higher shares of renewables is not captured in the LOLE convention, which is geared toward evaluating risks only meeting only peak demands. Addressing this shortcoming is not only important to accurately quantifying the benefits of storage in ERPs, but also good practice to ensure prudent use of ratepayer funds.

A method to incorporate flexibility into the resource adequacy of ERPs is to use an LOLE measure geared toward peak rates of change in supply, not simply peak periods of supply. This concept was pioneered by the New Mexico utility PNM in their 2017 IRP,[7] which used two complementary measures: $LOLE_{CAP}$, the conventional reliability standard for events caused by insufficient resource capacity to meet peak demands, and $LOLE_{FLEX}$, a new reliability standard for events caused insufficient resources to respond quickly to meet the volatile nature of renewable resources. Since New Mexico’s utilities are required to meet a Renewable Portfolio Standard, PNM modeled the reliability contributions of various capacity options under scenarios with higher renewables shares in generation, using both $LOLE_{CAP}$ and $LOLE_{FLEX}$ and determined the most cost-effective resources for meeting both metrics adequately.

[7] See *PNM 2017-2036 Integrated Resource Plan*, issued 3 July 2017, available at https://www.pnm.com/irp

vi. Model demand resources as distinct resource options, separate from load forecasts

ERPs begin with a load forecast over the next 10-20 years. Customer demands have traditionally been outside of the control of utilities, and thus load forecasts represent the anticipated needs that a supply portfolio must satisfy. While many utilities have employed demand-side management strategies for years, in general the results of those efforts are factored directly into load forecasts, rather than as distinct dispatchable resources. Similarly, customer-sited generation is forecast and then factored into load forecasts as well. As a result, demand-side resources are generally ignored as options for new capacity investment. Not only does this approach pose a potentially sub-optimal investment result for utilities, but also this approach ignores the critical way utilities can procure customer-sited energy storage for system capacity.

Customer-sited energy storage offers a new way to utilize demand resources as capacity. Unlike traditional demand response or energy efficiency, customer-sited storage can be dispatched and measured directly by utilities for system operations. Unlike generation sources like rooftop solar, customer-sited storage is highly controllable and can be dispatched in a fast and precise manner. Aggregations of customer-sited storage are already being used by utilities in some instances to meet capacity needs, such as in Arizona and New York.

Instead of factoring demand resources into ERP load forecasts, utilities could separately analyze controllable customer-sited resources like energy storage as a potential supply option. For example, in its 2017 IRP the utility Arizona Public Service (APS) examined a range of customer resources – energy efficiency, traditional demand response, rooftop solar, and energy storage – as separate supply options from its load forecast, ultimately selecting demand response

& microgrids, energy efficiency, and distributed generation as part of its portfolio.[8] Arizona utility APS is now procuring those resources in part through innovative measures like the Demand Response, Energy Storage and Load Management Program, which proposes the first-in-the-nation "reverse demand response" program that would pay customers for load-shifting with energy storage.

An analysis of demand resource options in ERPs, moreover, could also be informed by the results of distribution resource planning, particularly if utilities analyze the cost-benefit of distributed energy resources in such a setting. ESA elaborates on this topic in the following section.

III. COMMENTS ON DISTRIBUTION RESOURCE PLANNING

ESA is pleased to see that the Commission is seeking input from stakeholders on distribution resource planning for the State of Colorado. ESA believes that distribution resource planning is complementary to the reforms under consideration for the ERP process. Resource planning on the distribution system is fundamentally different process than system resource planning. While the ERP evaluates the costs and benefits of a resource or a portfolio of resources at the system level, distribution planning supplements that analysis by analyzes the costs and benefits of resources on a spatially granular level. Additionally, system resource planning models are unlikely to be able to provide a granular, distribution level analysis that provides locational specific costs and benefits.

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[8] See *APS 2017 Integrated Resource Plan*, issued April 2017, available at: https://www.aps.com/library/resource%20alt/2017IntegratedResourcePlan.pdf

i. Energy storage has a unique role to play in distribution resource planning

Energy storage has a unique role to play in distribution system planning. Distributed Energy Resources ("DERs") such as energy storage can be deployed as a cost-effective solution for deferring or avoiding costlier distribution system upgrades, increasing power quality on distribution circuits, and can serve as a critical resource for increasing circuit and substation hosting capacity to meet the system demands posed by increasing proliferation of DERs, particularly non-dispatchable generation. Several utilities have begun to demonstrate the use of energy storage as a distribution asset. Arizona Public Service purchased two 1-megwatt (MW)/4-megawatthour (MWh) batteries for approximately half the cost of the traditional investment of a wires alternative in August 2017.[9] In November 2017, National Grid proposed a 6 MW/48 MWh (8-hour duration) for Nantucket, Massachusetts to delay the need for the construction of another submarine cable to bring electricity to support the island's growing demand.[10] Finally, New York's Con Edison plans to defer a $1.2 billion substation upgrade through its non-wires alternative program, the Brooklyn-Queens Neighborhood Program, by contracting for 52 MW of demand reductions and 17 MW of distributed resource investments, including energy storage.[11]

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[9] APS Press Release, 9 August 2017, APS Brings Battery Storage to Rural Arizona, available at: https://www.aps.com/en/ourcompany/news/latestnews/Pages/aps-brings-battery-storage-to-rural-arizona.aspx.

[10] National Grid Press Release, 6 November 2017, National Grid Develops Innovative Solution for an Island's Community's Unique Energy Challenges, available at: https://news.nationalgridus.com/2017/11/national-grid-develops-innovative-solution-island-communitys-unique-energy-challenges/.

[11] Con Edison, Distributed System Implementation Plan (DSIP), 30 June 2016, available at: https://www.coned.com/-/media/files/coned/documents/our-energy-future/our-energy-projects/cecony-dsip.pdf?la=en.

ii. Approval for cost recovery should be considered separately and following distribution plan approval

ESA believes that it is appropriate for the utilities to incorporate a rigorous distribution resource planning component to their existing resource planning process. To ensure that distribution plans provide customers with the most cost-competitive and flexible resources, the plans should be seamlessly integrated with utility rate cases and other planning processes at the Commission. To that end, ESA proposes the following format for distribution planning at the Commission.

Distribution resource planning is the vehicle by which utilities review their distribution system needs and identify areas where investment is needed that could be replaced through deployment of DERs. This should be submitted to the Commission separately from any request for spending in upgrading assets on the distribution system. The Commission, along with stakeholder input, may choose to outline for the utilities the appropriate criteria that would trigger a review of the ability of DERs to serve any of the distribution needs identified in the plan. New York's non-wires alternatives suitability criteria is a useful model to lean on for this proceeding.[12] Of the areas where the utility identifies a needed distribution system network upgrade that meet the threshold test, the utility would describe in its distribution plan which distribution investment need can potentially be filled by DERs, including both utility-owned and customer- or third-party owned DER assets on the distribution grid. The Commission would then review the DRPs to determine that the utility has sufficiently considered non-wires alternatives.

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[12] See *Joint Utilities' Supplemental Information on the Non-Wires Alternatives Identification and Sourcing Process and Notification Practices.* (http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7B5DA604B3-9CDA-45D3-8642-92A4C4171787%7D)

The distribution resource planning process is the appropriate forum for the utilities to identify the needs of the distribution system that DERs – and storage in particular – can serve and to propose a mechanism to solicit DERs for that purpose. The utility will develop in their plans a proposal for tariffs, contracts, solicitations, or other mechanisms that would ensure that DERs are able to compete as a distribution grid asset. The Commission and stakeholders should have an opportunity to shape these utility offerings so that they are conducted in a way that results in the most flexible, least costly resources for ratepayers. Within this discussion, developing clear rules around utility ownership and cost allocation of storage is critical. Those guidelines should also provide opportunity for third-party or customer-owned storage to provide grid services.

ESA believes that distribution plans are not an appropriate vehicle for utilities to submit requests for spending on distribution assets. Rather, should the utility desire to rate-base traditional distribution investment or a utility-owned DER solution, then the utility would propose such an investment in its rate case. The utility should be required to leverage information developed in the distribution planning process to build a case for its requested spending in the rate case. Addressing proposals by the utilities to spend money on the distribution system in the rate case is critical to provide an opportunity for a broader and more robust engagement by affected stakeholders to evaluate the request for funding.

Beyond interaction with the rate case, it is imperative that the information developed in the distribution resource planning process be used widely in other proceedings. For example, forecasting of DERs that is conducted in the distribution planning process should then be incorporated into the integrated resource planning process. Ultimately, the information made available through the DRP should animate the interconnection process as well, with the ultimate goal of creating opportunity for dynamic data available on hosting capacity in order to facilitate interconnection with greater ease.

iii. *Utility plans should be assessed on their cost-benefit evaluation of DERs, both as directly-owned assets and procured via tariffs, contracts or other mechanisms*

Laying out a distribution resource planning process that effectively assesses opportunities for distributed resources and conducts an accurate cost-benefit assessment of those resources is critical to providing the lowest-cost solution that provides the greatest benefits to ratepayers. ESA notes that it is critical that the distribution plans not only include a robust analysis of the locational benefits and costs of distributed resources, but also proposals for mechanisms by which the market can provide those benefits to the distribution system, namely through proposed tariffs or contracts. Unless those are done effectively, the distribution planning exercise will not result in savings to ratepayers and a more clean, flexible and resilient grid.

Getting the cost-benefit assessment is particularly important for storage resources, since such resources provide a unique set of benefits to the grid that must be captured correctly. To that end, the Commission should develop a separate valuation methodology for storage that reflects the ability of storage to serve as either a behind-the-meter or a front-of-meter distribution system asset that enables greater integration of DERs. ESA looks forward to providing inputs on how this can be done at a future juncture in this or related dockets.

iv. *Consider demonstration projects to drive learning-by-doing and development of a regulatory framework*

Distributed energy resources, most notably storage, are capable of providing a suite of distribution grid offerings today in a cost-competitive price that is on par with “wire” alternatives that the utilities would propose. However, many of the rules and regulations that are needed to enable the smooth integration of distributed energy systems onto the grid have yet to be updated. One potential consideration for the Commission is the use of demonstration projects for non-traditional distribution infrastructure, such as storage, to drive learning-by-doing and the development of rules and regulations around such investments. Under such a pilot, the utilities would select one or two substation assets to study and propose non-wires alternatives as part of a rate-based asset. For example, New York utilities have piloted all-source solicitations for distribution system capacity, such as in the Brooklyn-Queens Demand Management project.[13] A targeted pilot program can serve as an effective learning ground that aligns with the Commission's objectives in this proceeding. ESA looks forward to providing inputs on how this can be done at a future juncture in this or related dockets.

IV. CONCLUSION

ESA commends the Commission and Staff for working to enhance Electric Resource Planning processes and believes that the reforms recommended in these comments will provide the State of Colorado with a more flexible and resilient electric grid. ESA thanks the Commission for the opportunity to provide these comments and looks forward to further participation in this proceeding.

Respectfully submitted this 31st day of January, 2018.

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[13] See ConEd's BQDM Program website at https://conedbqdmauction.com/. See also similar all-source RFOs for distribution system capacity from NY utility PSEG-LI at https://www.psegliny.com/page.cfm/AboutUs/Proposals/SouthFork and http://psegliwnrfp.com/Index.html