Joint Clean Energy Group Comments, RIPUC Docket 24-34-EL,[1] Development of Tariffs Applicable to Energy Storage Systems Connected to the Electric Distribution Systems

December 23, 2024

Stephanie De La Rosa, Commission Clerk
Rhode Island Public Utilities Commission
89 Jefferson Blvd., Warwick, RI 02888

Dear Ms. De La Rosa,

On behalf of the Alliance for Climate Transition ("ACT"), RENEW Northeast ("RENEW") and Advanced Energy United ("United"), thank you for the opportunity to provide these written comments to support the design of tariffs in docket 24-34-EL.

Our members include companies based in Rhode Island, doing business, and hoping to make future investments in the state. The work done in this docket will set the ground for developing a more robust energy storage network in Rhode Island. We look forward to bringing together the voices of our members to help the RI Public Utilities Commission ("PUC") develop tariff frameworks that will enable the development of energy storage in the state.

For Rhode Island to continue to advance its clean energy and climate goals, the development of energy storage must be a key component of the state's policies and programs.

Following is a summary of some of the many benefits of energy storage:

Storage makes the grid more flexible - which we need as we move to distributed generation and the electrification of buildings and vehicles. As more electric vehicles and heat pumps are deployed to reduce emissions, electricity use is projected to more than double by 2050.

Storage makes the grid more reliable - in times of extreme heat and severe weather, and especially when exacerbated by climate change.

Storage helps states meet their clean energy and decarbonization goals - pairing with intermittent resources like wind and solar.

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[1]https://ripuc.ri.gov/Docket%20No.%2024-34-EL

Storage makes energy more affordable - by reducing the need for expensive peak energy resources.

Storage can reduce air pollution by avoiding the need to bring polluting peaker plants online. Historically-overburdened communities benefit when we turn to storage instead of fossil fuel generators in times of high electricity demand.

Environmental justice communities stand to gain with storage deployment - As of 2021, lower-income communities represent 69% of the population living near a peaker plant. This is especially concerning since average emissions of nitrogen oxides—which are linked to serious respiratory and cardiovascular illnesses— increased by over 50% between 2019 and 2021.[2]

Investing in storage creates economic opportunity - providing good-paying jobs at all levels, and benefiting local communities.

Storage and the clean energy transition go hand-in-hand. Storage is key to the clean energy transition and to meeting Rhode Island's goal of 45% greenhouse gas reductions by 2030. The energy storage systems ("ESS") goal of 600 MW by 2033 set in the 2024 Energy Storage Systems Act will improve the state's chance of meeting its emission reduction goals, but only if storage goals are also taken seriously. Currently the state hosts only one major storage facility in the state: the 3 MW system in Pascoag.[3]

In summary, energy storage can deliver a multitude of benefits and should be treated as a resource. In order for ESS to thrive, storage developers need regulatory certainty, access to planning data, and pricing signals that are aligned with state public policy objectives.

Following is general storage policy input from our organizations, with answers to specific questions posed by the PUC staff, below.

Strong engagement by Rhode Island Energy ("RIE") is vital - While the PUC is overseeing a stakeholder process to develop model tariffs, it will ultimately be the state's electric distribution company ("EDC") that will be responsible for filing tariffs related to ESS interconnection and terms and conditions. We urge RIE to assign regulatory experts and senior technical staff to Docket 24-34-EL, as that will lead to a model tariff that is well integrated with other tariffs and the company's rate design processes.

Need for data access - In Rhode Island, similarly to other states, the level of data asymmetry and lack of access hampers progress for storage developers. We ask that both the PUC and RIE consider how to provide better insights into planned infrastructure

[2] https://www.cleanegroup.org/peaker-power-plant-data-show-persistent-economic-and-racial-inequities/
[3] https://agilitasenergy.com/portfolio/ocean-state-btm-ri/

upgrades, distribution circuit capacity as well as electric system load profiles. A regularly updated portal would help provide insights for the industry parties working to help deliver storage assets to Rhode Island. While RIE has a heat map and hosting capacity map, our members attest that the data reliability and frequency of update is less than optimal.

Importance of expert consultants to guide the process - We commend the legislature for including a budget for consultants to assist the staff with the two tracks of tariff development under Docket 24-34-EL.[4] We are concerned, however, by the dearth of initial proposals to assist with the interconnection tariff process, particularly given the timeline of developing a model tariff by May 1, 2025. The lack of third-party expert consultants makes it all the more important to have leadership from RIE in this docket.

Ensure diverse siting, size and types of projects - Rhode Island will benefit from a variety of technologies, durations, project sizes and configurations (stand-alone vs. co-located with DER generation, etc). With proper data sharing from RIE, market actors are well-poised to design, develop and operate storage in a way that will maximize an array of benefits. Distribution-connected storage such as the projects that would be subject to this new tariff can help deliver a meaningful impact on electric system reliability.

Lay groundwork for larger projects - Many of our trade group members are working to develop transmission-connected storage. While the reliability of the transmission system is under the jurisdiction of the Federal Energy Regulatory Commission ("FERC") and is managed by ISO New England, the PUC should contemplate future procurements and programs that will facilitate the development of larger scale storage systems as well.

Developers need long-term commitments with credit-worthy counter parties to be able to finance projects. As part of the 2024 storage bill,[5] the Legislature directs the Commission to conduct a periodic market assessment, and ultimately for RIE to conduct a procurement of transmission level or distribution storage. We urge the Commission not to delay work on these two important directives.

Consider a program such as Clean Peak - Many states have developed or are in the process of developing storage incentive programs of various designs. These programs use market forces to support public policy objectives and harness the benefits of storage, as described above.

Standalone front-of-meter (FTM) ESS resources at present still need support from state level programs, in addition to participating in the wholesale markets available to them. As part of this framework tariff development, Rhode Island should establish a robust

[4] Energy Storage Systems Act of 2024, https://webserver.rilegislature.gov/BillText/BillText24/HouseText24/H7811aa.pdf
[5] Ibid, at line 32.

distribution-level incentive program in order to achieve the state's goals, with performance based incentives available through the tariff.

We encourage Rhode Island to assess the overall benefits of implementing a program that can harness the power of storage to reduce costs and emissions created when electricity demand is at its highest. The Clean Peak Standard program in nearby Massachusetts[6] has been lauded as one of the most successful programs in the nation.[7]

Collaborate and learn from other states - On December 18, 2024, Clean Energy Group and the Clean Energy States Alliance (CESA) released a new issue brief, Energy Storage Program Design for Peak Demand Reduction,[8] which outlines best practices and lessons learned for state policymakers and regulators engaged in developing energy storage peak demand reduction programs.

CESA, in collaboration with Sandia National Laboratories, has announced that they will launch a new Energy Storage Working Group for utility regulators and staff. This will be a free, monthly, private online meeting for state regulators to gather, share information, and learn from experts who will address specific topics of interest identified by the group. Participating regulators will have the opportunity to share important updates on their work, and to share resources with their peers from other states. Per CESA, interested regulators should email Olivia@cleanegroup.org to get involved. We encourage the RIPUC staff to consider joining this group in 2025, if you have not already.

Following are our initial responses to the questions issued by PUC staff on November 22, 2024. We look forward to discussing these issues further during forthcoming workshops under Docket 24-34-EL.

24-34-I: Interconnection

1. Applicability

1.a. What constitutes the distribution system?

Our trade group members define the distribution system as all the infrastructure and the operating/control systems required to manage it that is owned by Rhode Island Energy, and any sub-transmission assets that serve distribution customers, or distribution substations from a substation owned by RIE. Transmission lines and substations and related infrastructure and systems that are part of the Pooled Transmission Facilities ("PTF") under the jurisdiction/control of ISO-NE or directly connect RIE assets with the PTF are typically not part of the distribution system.

[6] https://www.mass.gov/clean-peak-energy-standard
[7] https://virtual-peaker.com/blog/clean-the-peak-renewable-energy/
[8] https://www.cleanegroup.org/publication/energy-storage-program-design-for-peak-demand-reduction/

1.b. For storage facilities co-located with facilities subject to existing interconnection tariffs and processes, should the existing tariffs control?

Energy Storage Systems ("ESS") have distinct operating capabilities that make them different from other types of load. At base level, they are a distributed energy resource that can *export* energy, and a load (if charging from the grid) that imports energy. Existing interconnection standards and electric service bulletins may need to be amended, but it is unlikely that a separate tariff is required to successfully and safely connect ESS.

For new ESS, new rules that guide how the EDC would need to study the proposed system can be helpful in laying out specifics of how schedules, permanent import or export curtailment, or varying curtailment (e.g. flexible connection rights under a distributed energy resource management system "DERMS" capability) would be permitted as study parameters, and when such parameters would be agreed to by the applicant and the EDC.

For existing generation facilities, like a PV array, the interconnection of DC coupled ESS behind existing inverters with no increase in peak power export or new proposed import capacity should not trigger a full study by the EDC. With no change in the AC equipment connected to the grid, a simple amendment of the existing ISA should suffice.

If the proposed storage is AC coupled, or requires changes to the existing inverters at the same AC ratings (but different inverters) then it is reasonable to expect a study by the EDC, or in the later case a review for any issues the new inverters would require, similar to how a repowering of a PV array with new inverters is reviewed today.

For proposed new behind-the-meter ("BTM") ESS projects co-located with existing load customer and wired in series behind the existing load service meter for the customer, the PUC should establish distinct rules that allow simple, expedited and standard reviews if the load is to change outside of what is currently in place and allowed (eg. a service upgrade), or if the system would be proposed to export energy.

RIE should propose export levels (not nameplate but actual export) that would trigger each level of study, along with needed screens, to provide transparency to applicants what will be allowed as expedited, versus what would require a full Impact Study for Renewable Distributed Generation ("ISRDG").

1.c. Should a single interconnection tariff for all export facilities not subject to an existing interconnection tariff be developed, or should the current focus be on storage facilities?

Even though we believe that any interconnection tariff must be comprehensive and technology/facility type/system characteristic agnostic, our members suggest a phased approach to making amendments to the existing interconnection tariff. The adoption of one comprehensive interconnection tariff will ensure fair queueing practices that affect both project interconnection costs and predictability of the interconnection process times.

At this time, a focus on ESS connection and operational issues would be more productive and expedient to the state's legislated goals of having 600MW of storage in Rhode Island by 2033. We also believe such a narrow focus is in alignment with the legislative directive. However, we urge the PUC to consider establishing a schedule for the next phases for other facility types as part of the final order in this docket.

The issues with microgrids, as mentioned in the question, cross from connection issues to operational control, franchise rights for the EDC, and cost recovery that are beyond the scope of the interconnection and terms and conditions rules needed for ESS.

3. Study Process

3.a. What interconnection studies should be required for energy storage resources?

- *i. Should the process allow for the applicant to seek alternative interconnection studies, for example one study without restrictions and one study subject to operational guidelines?*
- *ii. If alternatives are allowed, how should alternatives be initiated and sequenced?*

As indicated above, the DG Interconnection Tariff could be amended to lay out specific conditions and screens for ESS to determine the level of study, and then the parameters of study. Using flexible scheduling that is responsive to the local load curve on the grid will allow the applicants of new facilities to find alignment between maximizing revenues and delivering savings to the load customers by deferral of local peak driven utility infrastructure upgrades. This would require early interaction and iteration between the applicant and the EDC study personnel, especially if a pre-application report shows that a firm interconnection is not possible without system upgrades.

In line with the existing standard study process, an applicant may request a feasibility study to be conducted. A feasibility study report for a storage facility must provide the applicant with a dispatch limiting schedule which takes into account the unique ability of storage facilities to limit charging and discharging capacity in response to the local load curve to avoid triggering excessive upgrades. Such analysis should be limited to thermal constraints only to limit the scope of the feasibility study.

Included with the study should be a non-binding unit cost estimate for the avoided upgrades. After the delivery of the feasibility study results, the project applicant may proceed to a full impact study conducted within the constraints of the dispatch limiting schedule or opt to be studied for a firm capacity interconnection.

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In addition, attention should be given to how ESS applicants in the interconnection queue are treated when the utility subsequently receives load customer requests. No additional load customer requests should be allotted circuit or substation capacity ahead of an ESS project after the utility and the ESS developer execute an impact study agreement and the developer provides a study deposit.

ESS developers are likely to make significant investment decisions for further development of projects based on the feasibility study results. Therefore, such a provision is essential to preserve the validity of the feasibility study results and provide projects with regulatory certainty.

The EDC should ensure through any process changes needed that load and export studies are conducted in parallel and are completed simultaneously. To the extent that ESS customers are able and agree to time and size their charging activity to reduce peak load, preserving headroom for other load customers, this is an aspect of the unique flexibility of ESS to avoid increasing distribution system infrastructure and costs, and a reason for the different rate class and structure outlined further on in these responses.

3.b. What characteristics of the facilities, such as size, location, and/or configuration, should determine the study requirements?

Distinction between nameplate, export and import capacity and the ability to set up dynamic scheduling for each are key characteristics of an ESS. If the facility is seeking to provide some type of grid service to the distribution company, such as peak capacity relief, export capacity expansion (at low load times) or voltage support, the timing and characteristics of the proposed system's capabilities for these services should be taken into consideration in the study. At a minimum, a fixed dispatch limiting schedule can be adopted at this time.

As with other inverter-based generators (e.g. solar PV), ESS inverters in the market are now UL1741sb certified. These smart inverters offer interoperability features. The adoption of an overall DER management strategy can provide increased flexibility of operations for ESS and studies should consider these capabilities as the adoption process progresses.

The utilization of interoperability features will require establishing communications protocols, utility requirements for monitoring and controlling, bulk power system data needs and requirements for aggregator applications. Adoption of a comprehensive strategy will avoid unnecessary expenses for equipment, infrastructure, and staff.

4. Costs

4.a. Should there be a payment schedule for interconnection costs?
- *i. What fees can be assessed fairly via a schedule?*
- *ii. Which fees, if any, should depend on project scope and size?*
- *iii. Which other interconnection costs should be collected from applicants and how?*
- *iv. What is reasonable timing for assessment and payment of study costs and construction costs?*

The existing rules of the DG tariff for study and interconnection costs and payment work sufficiently for applying to ESS projects when they are distinct in time and location from other proposed facilities. Ideally, storage projects that are able to be studied with flexible parameters as a stand-alone facility will not create new stresses on the grid, but instead support it and create less demand on existing infrastructure, thus not requiring any system upgrade costs.

Under the current rules for interconnection, the interconnecting customer is eligible for a payment plan for costs exceeding $25,000. It allows the interconnecting customer to request a breakdown of the costs by phases and establish mutually agreed upon construction and payment milestones. This provision should be extended to all ESS customers/projects as well.

4.b. Under what conditions, if any, should a storage facility be eligible for a reduction/credit to the interconnection construction costs?

As described in the last response, ESS operating schedules can often be created to suit local distribution system conditions such that they do not cause violations or constraints on the system, and instead enhance the operation of the distribution grid. If this is the case system upgrades should be negligible as should be interconnection costs, aside from project specific costs.

8. Other Elements

The greatest benefits of ESS can be created with the active control of the distribution system operator, typically through the interaction with a DERMS or advanced distribution management system ("ADMS"). RIE does not have such systems in place at present but, with the advent of storage goals, increased penetration of solar and wind, and increasing electrification in the state, we believe it is time for this to change. RIE should be encouraged by the PUC to implement such systems as utilities in other states, like Massachusetts, are already doing.

To efficiently and cost effectively find locations for ESS and then propose suitable operating plans to be studied, developers need access to more system data from RIE.

This would be an addition to timely and detailed DG Interconnection Queue Reports and Affected System Operator Reports. Enhanced hosting capacity and load maps would be a good initial start, with substation and feeder load profiles an important next step, in the absence of dynamic control.

24-34-TC: Terms & Conditions Elements

1. Availability

1.a. What types of energy storage resources should be eligible for service under a WDS?

Wholesale distribution service has historically been designed for participants in the wholesale market to reach such markets through the assets of a distribution utility. This is typical for municipal power and light companies or rural co-ops that are entirely surrounded by a distribution company service territory, with no separate transmission company.

With DERs—and ESS in particular—wishing to connect to the distribution system but also access the wholesale markets directly, this need has led to an evolution of WDS tariffs to consider the needs and impacts of ESS specifically, as well as FERC orders pertaining to ESS in wholesale markets.

Specifically, ESS should be eligible for a WDS tariff if it is participating in the ISO-NE wholesale markets. This could be a stand alone ESS that is purchasing power for resale into the wholesale market, or it could be an ESS co-located with generation that is selling its output to the wholesale market (if such co-located ESS charges from the distribution system in addition to charging from the co-located renewable generator).

The WDS tariff would specifically exclude the ESS from being assessed any transmission charges on energy used for charging, as directed by FERC in Order 841. This would include any load used by the ESS for necessary on-site services, such as HVAC for the ESS, which ISO-NE had deemed part of the losses associated with the ESS, and thus also exempt from transmission charges.

1.b. What types of energy storage resources should be eligible for service under a retail service tariff?

If the ESS is not participating in the wholesale market in any way, and still wishes to operate, then it would be served under a retail tariff. For Behind the Meter ("BTM") ESS, where there is a load customer, the ESS would by default be served via a retail tariff. This could be changed in the future as ISO-NE and then RIE implement the tariffs and metering capabilities to submeter ESS that is BTM, thus enabling such resources to participate in wholesale markets, which is the goal and directive of FERC Order 2222.

1.c. Should storage facilities be considered a distinct class of customers because they have unique characteristics, warranting separate cost allocation and rates?

> *i. Are these characteristics different for similarly designed wholesale and retail storage systems?*
> *ii. If storage facilities should be considered a distinct class of customers, should that apply to standalone, generation-sited, or other configurations?*

Storage facilities do have distinct characteristics that warrant different rates, however it may not be possible or prudent to create a new "customer class" for ESS for purposes of cost allocation due to the lack of historical load data for actual operating ESS. Without sufficient historical operating data for ESS, it would be impossible to accurately create an "ESS Customer Class" for purposes of cost of service allocations.

Retail and wholesale ESS will have different characteristics that will warrant different rates. Mainly, wholesale ESS require service to receive power from the regional transmission grid to their ESS and are exempt from transmission charges, and should be exempt from retail customer program charges. A retail ESS project, by definition, will however not be participating in the ISO-NE markets, and will instead rely on the EDC for the provision of charging energy, and is not exempt from transmission service charges.

As noted above, we do not think that storage should be formally designated a new, separate customer class. We do think that new rates, reflective of storage's unique characteristics, should be created and made available to ESS projects. These rates would be made available to any eligible ESS that needs to utilize the distribution system to charge (whether such ESS is co-located with generation or not). As ESS will use the distribution system similarly for similar load and export activities, the structure of ESS rates for wholesale or retail ESS should be similar or identical aside from retail-specific rate components and factors.

ESS facilities that are co-located with generation, do not intend to charge from the grid, and *cannot* do so, due to physical and contractual constraints (e.g., a recloser and terms in its ISA), should not be placed on a rate at their nameplate or other theoretical import level. They are only load customers for parasitic losses for inverter and HVAC power, similar to solar-only facilities.

Furthermore, the PUC should consider establishing the same principles as adopted by FERC Order 841, regarding exempting certain distribution charges for ESS facilities availing a retail service and charging and discharging energy for the purpose of providing a distribution grid service.

1.d. Should the tariff availability depend on concurrent enrollment in net metering, Renewable Energy Growth, or other programs or tariffs?

i. Should availability allow a wholesale storage facility to be paired with generation participating in the retail market?

On the question of program enrollment as a condition for availability, at present, ESS are not allowed to be enrolled by themselves in net metering or RE Growth. The controlling condition for ESS to enroll in a WDS tariff would be its participation in a wholesale market. For ESS that are co-located with eligible resources for net metering or RE Growth, RIE and the PUC should consider adding provisions that would allow an ESS to charge from the grid and export along with the eligible energy, and not negate the generator's ability to participate, by netting the charging energy from the exported energy.

Further, RIE should be required when settling energy and other market payments created by such systems to separate out all ancillary service revenues paid to the asset by ISO-NE and transfer those revenues to the ESS owner/operator. While the energy produced by the solar, wind and hydro facilities are transferred to RIE in such programs in exchange for compensation, the activities of ESS in the ancillary markets (namely through the reserve market and the frequency regulation market) can *only* be provided the ESS, and should be remitted to the ESS owner/operator, unless such services are compensated via some as yet-to be-designed grid services retail/state-jurisdictional program.

1.e. Should other facility types, like microgrids, be considered at this time or should a storage tariff be the priority?

As stated above, a focus on ESS connection and operational issues would be more productive and expedient to the state’s legislated goals of promoting the installation of 600 MW of storage in Rhode Island by 2033.

2. Costs

2.a. Once the interconnection costs for a storage facility have been incurred, do storage facilities generally create ongoing costs to the distribution system?

i. Operations costs?

ii. Maintenance costs?

iii. Ongoing capital investment? If so, related to what?

After initial interconnection-related expenses are incurred, storage facilities will create a small amount of gross costs by virtue of needing the utility to conduct meter reading/billing, operations and maintenance, and other general costs related to serving these customers.

Regarding capital investment costs, if ESS are operating so as to charge off-peak and discharge on-peak, the ESS should lower the overall distribution system costs such that ESS result in a net decrease in ongoing costs to the distribution system over time. For example, ESS assets in Massachusetts are incentivized to operate as such through the MA clean peak program program. The share of utility revenue that is from primary and secondary distribution system assets built to serve peak demand thus should not increase at the margin due to increased connections of ESS that operate in such a way as to not increase peak load.

2.b. Do responses to part a on cost causation depend materially on any of the following:

i. *Wholesale versus retail participation*
ii. *Metering/wiring configuration*
iii. *Whether the interconnection relies on existing distribution system capacity*
iv. *Timing of charging and discharging*
v. *Electrical location of the facility*

Yes, as mentioned, if ESS avoids adding to peak load, and operates on a schedule that supports grid needs, they can avoid causing new peak related costs, and can also avoid peak export related costs that would be reflected in the needed upgrades and cost to interconnect.

2.c. All retail customers are assessed certain mandatory charges per various laws. Are there any configurations under which storage connected to the distribution system would or should be able to avoid those charges?

Yes, due to their unique nature, any stand-alone or FTM ESS should not pay charges for energy efficiency, renewable energy programs and other system benefit charges.

4. Other Comments

Storage is a unique resource - As previously illustrated, energy storage resources are operated differently from other interconnected entities. To be consistent with the Renewable Energy Growth Program statute, it is necessary to ensure that electric rate design and distribution cost allocations are adapted to align with the beneficial capabilities and associated costs. Rhode Island Gen. Laws § 39-26.6-24(b) defines the core principles that were finalized from the Docket 4600 process intended to guide the PUC in rate design review. Core principles include ensuring Rhode Island rate design appropriately captures the benefits of distributed-energy resources, equity regarding allocation of costs of the distribution system, and a fair rate structure, among other factors.

Thank you for taking into consideration the input of the storage industry members represented by ACT, RENEW and United. We look forward to ongoing discussions as part of the stakeholder meetings and subsequent opportunities for written comments.
Sincerely,

/s/ Natalie Hildt Treat
Director of Public Policy
The Alliance for Climate Transition
ntreat@joinact.org

/s/ Kat Burnham
Senior Principal
Advanced Energy United
kburnham@advancedenergyunited.org

/s/ Francis Pullaro
President
RENEW Northeast
fpullaro@renew-ne.org

CC: Docket 24-34-EL service list