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Information for

Applications for Transmission Connected Energy Storage Complying with the Next Generation Energy Act

Presented by

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1. Contract Length

The Maryland NGEA requires at least a 15-year contract term.

a. What is a desirable contract term given the useful life of energy storage equipment, degradation of battery performance over time, augmentation schedules and financing considerations?

Ameresco has contracted over 15-year terms. 20-year terms tend to be more cost-effective due to alignment with industry-standard warranty timelines.

b. Would bidders welcome the opportunity to submit multiple contract term options for one project configuration?

Yes, Ameresco would welcome the opportunity to submit multiple contract term options for one project configuration.

2. Energy Storage Price Schedule

The NGEA specifies that the contract shall be based on a partial toll.

a. How can energy storage project developers manage the risks posed by a partial toll?

Partial toll risk is primarily tied to the necessary response time for offtaker-owned cycling. Revenue not tied to market-fluctuation is highly valued and therefore the Key Performance Indicators (KPI) associated with a partial toll (capacity retention, availability) are high-risk items. One primary component of managing this risk is appropriate lead time from the offtaker as to when they desire their cycles. This gives the project owner time to prepare and ensure the BESS is well positioned to satisfy customer needs. 12 hours is preferable notice prior to a discharge call.

i. What barriers, if any, do you expect with respect to financing the energy storage project with a partial tolling contract?

Partial toll contracts will still require some form of merchant exposure. Financeability of merchant revenue streams vary.

ii. What barriers do you have or foresee with respect to participating in PJM wholesale markets for energy, capacity, and ancillary services with the ESCC partial tolling contract? E.g., existing offtake contracts, market risks, financial risks, etc.

One primary risk factor that may impact financeability of a partial toll is who bears the risk of ELCC percentages shifting throughout the project lifetime. For example, if a 50 MW BESS enters into a toll for $5/kW-m, the contracted revenue would need to stay at $3M/year, regardless of the ELCC percentage ascribed to storage by PJM for capacity market participation throughout the project term. If this is not a fixed number, then market risk is not reduced beyond rate fluctuation and the seller will incorporate a weighted risk into their price.

b. How could a partial toll incorporate indexation?

Toll pricing can be indexed against several factors. These include applicable ITC percentage, interconnection costs, effective tariff percentages, etc. Indexation that occurs after COD (i.e., if rates index in accordance with market variables) would then re-expose the project to market risk and would diminish the effect of the contracted toll revenue, resulting in a risk premium and higher prices. Indexation in the form of hardware risk throughout the project life is certainly acceptable and expected. Contract value should be impacted by BESS performance including capacity retention, and availability.

i. What should be included in an index and over what period should the indexation occur?

Indexation is most effective between contract signing and commercial operation. This allows the project to progress with protection from things like effective tariff rates, interconnection costs, and applicable ITC percentages.

c. How could the contract be structured to best balance project risks between developers and Maryland ratepayers?

One risk mitigation measure is the allowance of re-siting. This allows for, in the event of a site-specific occurrence increasing project costs significantly, the Seller and Buyer to agree to relocate the project to an area that would result in cost efficiencies. This flexibility would require timeline and location flexibility from the buyer but would ensure that above-average cost projects do not progress and impact ratepayer costs negatively.

Additionally, Ameresco has noticed that capacity degradation contracts have allowed for the most competitive system prices. This means when a project is built, the capacity is allowed to degrade over time along with a certain schedule. Revenue can decrease alongside the BESS capacity so no side is being unfairly hurt or is reaping the benefits of under-degradation too severely. Contracts that force the Seller into an augmentation structure introduce a market risk premium that may not be necessary due to under-degradation of BESS, resulting in an unnecessarily borne cost to ratepayers.

3. Procurement Schedule

The NGEA requires that the first solicitation be issued on or before January 1, 2026 and end with the PSC issuing a decision whether to approve one or more proposals by October 1, 2026.

a. If three months are required to conduct the application evaluation process, is two months for the development of applications sufficient?

Yes, dependent on the scope of the application requirements.

b. What factors should be considered when designing the solicitation schedule, e.g., PJM interconnection queue processes?

Many projects will not be in the PJM queue until the Cycle 1 application deadline in April 2026.

Upon study completion, projects will not know the extent of their transmission upgrades until Decision Point 1 in December 2026. This may impact project timelines as transmission upgrades can span several months to several years.

i. Is two months sufficient time for proponents to submit an Application in response to this first solicitation?

Respondents should be able to provide primary project information including technology selection, layouts, single line drawings, permit matrices, schedules, and interconnection material within the two-month timeframe.

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[redacted]

[redacted]

[redacted]

4. Penalties for Non-Performance

As dictated by NGEA, penalties for non-performance and underperformance in the contract, including withholding of payment that reflect the degree of underperformance, will be made against energy storage devices that fail to meet availability metrics.

a. Should these availability metrics follow the framework employed by PJM?

From a capacity performance perspective, PJM considers year-round availability. All resources must be available to deliver energy during all emergencies, regardless of season. PJM factors this into the Effective Load Carrying Capacity (ELCC) rating of each resource, affecting how much capacity of each resource type can enter the capacity auction. PJM applies a penalty to resources that promise their capacity and enter the capacity market, but fail to meet critical event calls.

From an overall performance perspective, availability is typically a measure of the capacity available in the battery at any given moment, that is, is the battery fully able to charge or discharge to nameplate. Reasons the battery would not be available to charge or discharge could be utility outages, breaker trips, battery hardware issues, network communication issues, etc. Availability is looked at as an annual metric, summing any penalties to availability that occurred over the year. For example:

$$Power\ Availability\ Percentage = \frac{1}{\text{Operating Year Hours}} * \sum_{h=1}^{period\ hours} \text{APP (h)}$$

APP (h) = for any Hour (h), APP is calculated according to the following formula:

$$APP = \frac{\text{Available Power (h)}}{\text{Contract Capacity (h)} - Excused\ Power\ (h)}$$

Where Available Power is how much capacity the battery had access to utilize at that hour, Contract Capacity is the amount of power contracted to be used, and Excused Power is any downtime that occurred that was not applicable, such as Substation outage or work or reasons of Force Majeure.

Contract structure will then promise a certain Power Availability Percentage for the year, and performance below that percentage results in fines. This is the preferred method overall, as it captures not only missing dispatches or call windows, but any unexpected downtime as well that would impact the battery's ability to charge or discharge most effectively.

i. If so, how would this best be structured?

See answer to **4.a**.

b. Should contract penalties not apply if an energy storage project is unavailable after discharging for its proposed duration? Is it appropriate for customers to bear this risk?

The above methodology accounts for all potential reasons and resulting penalties if the battery may not be available to charge or discharge in any given hour.

Contracts could also be structured to only consider one cycle per day, and if that cycle is met, any additional downtime reasons would be excused. The reasoning and methodology behind what is considered excused and unexcused downtime that ultimately impacts the total availability percentage needs to be determined with each use case.

5. Eligible Bids

The NGEA requires projects to achieve commercial operation within two years of being selected by the MD PSC unless the Commission extends the operating deadline for good cause shown and requires the MD PSC to establish Energy Storage Capacity Credits (ESCCs) and require each electricity supplier to purchase these credits in proportion to the electricity supplier's capacity obligation.

a. Is the requirement of achieving commercial operation within two years of being selected by the MD PSC realistic?

A two-year timeline is fairly aggressive. Main Power Transformers (MPTs) which are required to connect to any infrastructure above 34.5 kV currently have a lead time of about 2-years. This requires bidders to release significant capital expenditures prior to understanding if they have a contracted project.

i. Is it a barrier to your participation in the procurement? If so, what aspect of the timelines poses the greatest barrier – PJM timelines, project development timelines, supply chain (energy storage and other), closing financing, RE project component (for hybrid RE + storage projects), federal policies (ITC, FEOC, etc.), other?

The risk associated with placing hardware payments early limits the number of projects that Ameresco will be submitting. The more transparency that can be provided early on to acceptable pricing, the higher confidence bidders will have with submitting multiple projects.

ii. How could any adverse impacts from this requirement be mitigated, by reducing penalties for missing your target commercial operation date (COD)?

Transparency into acceptable pricing or likelihood of selection will give bidders higher confidence and a better understanding of their return metrics. This will allow for an earlier capital outlay to bring in earlier CODs. Alternatively, milestone schedules can help significantly in reducing risk. Bidders have an easier time contracting around items in their control (permit submission date, construction schedule, interconnection payments made etc.) as opposed to things outside their control (interconnection upgrade timelines).

iii. Please identify and discuss appropriate good cause events that should allow the Commission to extend the operating deadline?

The Commission should extend the operating deadline for good cause events wholly outside of the developer's reasonable control and ability to predict with accuracy. The first category are utility-related delays: study delays or delays to the utility's schedule for the construction of grid upgrades that need to be completed prior to interconnection. The second category are those related to permitting such as material modifications requested by Affected Communities or new renewable energy or BESS moratoria that prolong the timeframe before permits are secured. A third category are tariffs and other federal actions that impact the renewable energy supply chain, hardware supply and demand dynamics and the labor market. The more flexibility that is provided in timing, the greater optimization of tariffs that can be achieved. The applicant would be responsible for laying out any potential upside here.

b. What schedule risks are reasonably beyond suppliers' control that should be included as reasonable causes for an extension of the two year commercial operation date specified in the NGEA?

See answer to **5.a**.

c. What are appropriate interconnection standards (e.g., Capacity Interconnection Rights) for participating projects.

Projects will need to follow the interconnection standards as dictated by the applicable utility.

i. What are appropriate minimum and maximum bid sizes in MW?

Projects over 100 MW pose significant concentration risk. Projects under 20 MW may have significant contracting costs on a per MW basis, unless single developers aggregate capacity.

20 MW to 100 MW projects do not pose as much concentration risk but still benefit from economies of scale.

6. Resource Types

a. How should the solicitation compare the benefits of co-located resources and stand-alone energy storage against one another?

The inclusion of *new* renewable energy co-located with the energy storage will further contribute to NGEA's stated goals and ensure that there is cheap charging energy, whether the system is DC or even AC-coupled (and depending on contract structure). However, solar PV (or wind) has a large footprint compared to batteries and an extensive permitting process, prolonging the duration to COD. Additionally, the smaller footprint of batteries alone allows them to be placed closer to significant load and provide a greater locational benefit.

i. Do you expect that a partial tolling contract may facilitate adding storage or increasing planned storage capacity with an existing or planned power plant?

Partial tolls may help facilitate the addition of BESS to non-contracted merchant assets.

7. Commission Approval

There are two separate but linked Maryland Commission approvals required for a project to receive ESCCs, the ESCC award process and construction approval process which are needed to bestow the same rights to the selected proposal that a generating system would otherwise be granted through a certificate of public convenience and necessity.

a. What information should be considered regarding the construction approval process in the ESCC approval process, if any?

An applicant should be able to provide the information in Sections 1.1, 1.2 and 1.3 of the draft construction approval application (dated October 10, 2025 and posted to MD PSC PC75 and Case No. 9715) as part of the ESCC process, and demonstrate that it has a considered plan with a timeline for obtaining the rest of the information and approvals.

b. Does an approval of ESCCs that is conditioned on completing the construction approval process introduce any barriers?

No, provided the timeline by which construction approval must be completed allows for sufficient engineering, development and construction planning.

c. Should a project be required to begin the Commission's construction approval process before it is awarded ESCCs, or should this only be started after ESCCs are awarded, or should this be left to the discretion of the applicant?

The project should not be required to begin the construction approval process before it is awarded ESCCs, unless the applicant chooses to do so. However, it is reasonable to mandate the commencement of the construction approval process within 9-12 months of ESCC award to ensure the project stays on schedule.

8. Safety

a. Which safety standards should be required to be reviewed in the ESCC award process?

Besides NFPA 855 as required by statute, every BESS project should conduct a Hazard Mitigation Analysis and prepare a site-specific, technology-specific Emergency Response Plan. The project owner should train local emergency personnel on the Plan.

b. How should applicants' safety plans be evaluated in the ESCC award process??

The safety plan should be evaluated for implementation feasibility. For example, the plan must be site-specific, technology-specific, backed up by a remote operations center with around-the-clock qualified personnel, and should be approved by local emergency response departments.

c. Should compliance with insurance requirements; outreach to emergency responders and host communities; and emergency response plans be considered?

Outreach to emergency responders, including training, and emergency response plans that are backed by actual personnel who could implement the plan should be considered.

9. Project Viability and Other Qualitative Factors

a. What key elements should be considered in evaluating project viability and how should these be reflected in terms of minimum requirements for participation including:

i. Site Control

Full site control via lease, lease option, license or property ownership should be sufficient for participation.

ii. Interconnection studies/ Stage in the Interconnection Process

The applicant should have site control, a single-line diagram and a demonstrated understanding of the requirements and timeline for the electric utility with jurisdiction, as well as an ability to pay deposits and study fees. The applicant should be able to represent an active queue position within PJM or ability to complete their application by the Cycle 1 application deadline in April 2026.

iii. Environmental permits

The applicant should be able to demonstrate an understanding of the required permits that must be secured in order to proceed, but receipt of permits should not be a prerequisite for participation.

iv. Experience

Developer experience is key. The applicant should be able to demonstrate that it has reached commercial operation on at least two energy storage projects comparable to that proposed.

v. Stakeholder outreach to determine potential local opposition

The applicant should be able to demonstrate initial consultations and pre-application meetings with the AHJ and local fire department, and should have a plan for other relevant stakeholder consultation including the stakeholder engagement stipulated by the Renewable Energy Certainty Act and currently in development under RM85.

vi. Any other minimum requirements

The applicant should be able to demonstrate that it has a reasonable financing plan or a history of securing project financing for comparable projects to ensure that access to capital does not delay the development and construction timeline.

b. How should supply chain and tariff risks be incorporated when assessing project viability?

The applicant will not be able to fully de-risk a new project for supply chain and tariff risks unless it has already secured the equipment (which means it is aging) or the price is very high which will be suboptimal for Maryland ratepayers. The applicant should propose a plan to de-risk as much as possible, to cover some additional supply chain and tariff risk up to a defined threshold and other mitigation measures. If the applicant has a pipeline of comparable projects which may enable pivoting between suppliers or otherwise provide flexibility, that should be considered.

10. Cost-Benefit Analysis

a. What benefits, besides capacity, locational and avoided emissions value, should be quantified when assessing the cost-effectiveness of the energy storage price schedule?

Infrastructure support, or Non-Wires Alternatives, may also increase the value of certain projects. BESS that pay for system upgrades will then defer costs that would naturally be borne by the ratepayer when that infrastructure were to be upgraded solely for load-serving purposes.

i. How should locational benefits of projects be quantified given readily available data?

Upgrade value can be seen in a project's interconnection services agreement. Identifying the age of the infrastructure and likely upgrade timing, had the project not moved forward, could be the responsibility of the applicant via conversations with the utility.

ii. How should the value of longer duration storage (i.e., beyond 4 hours) be considered and if so, how?

Long duration storage may be valued by providing a higher ELCC value. Project could then be weighed on an applicable ELCC Capacity Value as prescribed by PJM.

iii. How should avoided/deferred transmission costs be considered and what commitments or assurances are needed to ensure that these transmission facilities are ultimately avoided or deferred?

See answer to **10.a.i**.

iv. How should the cost-benefit analysis assess the value of reliability during periods of system stress, including extreme weather, fuel scarcity and large unplanned resource outages?

This value should naturally be accounted for in arbitrage and reserves revenues for the project.

11. Interconnection

a. Would a requirement of projects needing to be a Maryland based project in PJM's expedited Fast Lane, Transition Cycle 1, or Transition Cycle 2 process be a barrier to solicitation participation?

Requiring projects to be in Maryland will, at its base, reduce supply but it will also come with several benefits. Projects in Maryland will be contributing to the Maryland economy in the form of labor, infrastructure, taxation, and lease revenue. Additionally, stipulating project be located in Maryland reduces transmission constraints and more directly supports resilience for Maryland ratepayers. Situating facilities close to load also provides a level of protection against potential policy changes by having a more direct ability to offset and serve loads.

Not allowing projects that participate in Cycle 1 to participate will vastly reduce the pool of viable projects. Many speculative projects sit in Transition Cycle 1 and Transition cycle 2. However, projects that are sited directly to serve this Maryland solicitation will be more applicable for this use case and take into account more recent market standards than legacy projects.

b. Does the requirement of being a project in the PJM New Services Queue pose a potential barrier to solicitation participation?

Requiring projects to be in the PJM New Services Queue could present a moderate barrier to solicitation participation. Given the backlog and delays in the interconnection queue, many credible developers may be unable to participate simply because their projects have not yet reached that milestone. As a result, such a restriction may exclude viable, near-term projects and reduce competitive pressure in the solicitation. To mitigate this barrier, the solicitation could allow for conditional participation—accepting projects with evidence of pending queue entry or those expected to secure queue positions within a specified timeframe—while still prioritizing projects that are further along in the PJM interconnection process.

c. If a project is in the PJM SIS (Surplus Interconnection Service) initiative or the PJM RRI (Reliability Resource Initiative), how should this be factored into the ESCC awards process and are their any special PJM requirements for participating in either of these PJM initiatives that need to be considered.

A project utilizing SIS relies on existing interconnection capacity from another facility and is limited to using only the surplus capability available without triggering new network upgrades. While this pathway may offer a shorter timeline to interconnection, it also introduces dependencies on the continued operation of the original resource and caps the total deliverable capacity. As a result, the ESCC evaluation should confirm that any SIS project has completed the required PJM studies, that no new upgrades are necessary, and that its proposed capacity aligns with PJM's technical and operational limits. In particular, it will be important to understand the dispatch restrictions a resource like this may have.

12. Community Benefit Agreement

a. What requirements from MD Code, Public Utilities, § 7-1202 Community benefit agreements should be considered in the ESCC award process as opposed to conditioning an ESCC approval on providing a Community Benefit Agreement?

The successful completion of a CBA should be a requirement of all selected applicants, but not a prerequisite for submitting an application. The CBA should meet the broad outlines of § 7-1202, but should allow for creativity and community specificity. Therefore it will take time to develop the CBA, thus if the CBA is scored rather than just required, prescriptive scoring criteria have the potential to limit the ultimate benefit to the affected community.

All things equal, other concrete benefits to the affected community such as the stream of revenue from sales and personal property taxes should be taken into account for scoring.

13. Energy Storage Industry

a. Any trends in or around the energy storage industry that may impact the procurement and how should these trends be accounted for in the solicitation.

The BESS industry is in a space of high tariff volatility. Even for American-made products, tariffs are not locked in until the upstream components cross the border. This can lead to significant price uncertainty on hardware. Some level of tariff share and/or schedule flexibility to allow for tariff optimization, would greatly help alleviate this risk.

14. Future Application Periods

a. How can efficiencies be realized in the Round 2 Energy Storage Capacity Credit Application given that it will open about one year after the Round 1 Application Period?

The Commission could realize efficiencies in the Round 2 Energy Storage Capacity Credit Application by maintaining benefit cost analysis factors and application requirements across the two procurements and enabling projects not selected in the Round 1 procurements to automatically resubmit a previously submitted application for consideration in the Round 2 selection or to provide for limited application material updates (such as pricing) without full reapplication.

15. Non-Price Factors

a. What non-price factors should be considered by the Commission and how should these non-price factors be incorporated into the evaluation process.

Factors including distance to residences and parcel coverage percentages may help in prioritizing projects.

16. Voluntary Information

We are seeking voluntary information regarding projects likely to be proposed, which will be treated confidentially.

a. Please provide details of the size, duration, and location of the proposed project.

[redacted]

17. Other

a. Any additional comments that you believe should be known or would be helpful in drafting the Request for Applications.

Ameresco has no additional comments.