ORDER NO. 92281

Maryland Energy Storage Program	*	BEFORE THE
	*	PUBLIC SERVICE COMMISSION
	*	OF MARYLAND
	*	
	*	
	*	Case No. 9715
	*	

ORDER ON INVESTOR-OWNED UTILITY ENERGY STORAGE PLAN PROPOSALS IN COMPLIANCE WITH THE NEXT GENERATION ENERGY ACT

Before: Kumar P. Barve, Chair
Frederick H. Hoover, Jr., Commissioner
Bonnie A. Suchman, Commissioner
Odogwu Obi Linton, Commissioner
Ryan C. McLean, Commissioner

Issue Date: April 8, 2026

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During the 2025 Session, the Maryland General Assembly passed Senate Bill 937 and House Bill 1035 (the "Next Generation Energy Act" or "NGEA"), which was signed by the Governor on May 20, 2025, and became effective on June 1, 2025. The Next Generation Energy Act set a goal for electric utilities to solicit 150 MW of distribution-connected energy storage devices.[1] The Next Generation Energy Act requires the Commission to approve, modify, or reject proposed energy storage plans by May 1, 2026.[2]

On October 31, 2025[3] and November 3, 2025,[4] The Potomac Edison Company ("Potomac Edison"), Potomac Electric Power Company ("Pepco"), Delmarva Power and Light Company ("Delmarva"), and Baltimore Gas and Electric Company ("BGE") filed with the Commission their respective requests for approval of energy storage plans.

The Commission invited interested stakeholders to file comments on the matter by January 2, 2026 and conducted a legislative-style hearing on January 7, 2026. At the conclusion of the hearing on January 7, the Commission again gave interested stakeholders the opportunity to submit written comments by Friday, January 16, 2026. The Commission ultimately received comments from numerous stakeholders.[5]

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[1] *See Annotated Code of Maryland*, Public Utilities Article ("PUA") § 7–216.2 as enrolled in Senate Bill 937 / House Bill 1035. Md. Laws 2025, Ch. 625.

[2] On June 24, 2025, the Commission issued Order No. 91705, providing guidance on various distribution-connected energy storage plan issues including notifying each investor-owned electric company in the State of its proportion of the 150 MW NGEA goal, based on the electric company's service load and requiring each investor-owned electric company to submit a plan by November 1, 2025 to achieve up to one third of its allocated goal. Each investor-owned electric company is required by the NGEA to submit a plan to achieve the balance of its allocated goal on or before November 1, 2026. Pursuant to the NGEA, the Commission must approve, modify, or reject proposed energy storage plans by May 1, 2026 for plans filed by November 1, 2025, and May 1, 2027 for plans filed by November 1, 2026.

[3] Maillog No. 323893.

[4] Maillog Nos. 323951 and 323963, respectively.

[5] TurningPoint Energy (Maillog No. 325796); Staff of the Public Service Commission (Maillog No. 325795); Solar Energy Industries Association, Chesapeake Solar & Storage Association and Advanced Energy United (Maillog No. 325794); Qcells (Maillog No. 325792); Maryland Joint Exelon Utilities, composed of the Baltimore Gas and Electric Company, Delmarva Power & Light Company, and Potomac Electric Power Company (Maillog No. 325791); Solar Landscape (Maillog No. 325788); Chaberton Energy Holdings, LLC

The Commission now approves the electric companies' energy storage plans subject to certain conditions and procedures as described herein.

I. BACKGROUND

The NGEA outlines a plan for the distribution of connected front-of-the-meter energy storage devices in the State with a goal for at least 150 megawatts of distribution-connected front-of-the-meter energy storage devices to be installed by investor-owned electric companies.[6] The Commission must notify each investor-owned electric company of its proportion of this goal by July 1, 2025, and again by July 1, 2026, based on service load or other criteria. Electric companies must submit two plans to the Commission. The first set of plans, for up to one-third of their required proportion, were filed November 1, 2025. The second set of plans, for the balance of their proportion, is due by November 1, 2026.

The Commission must evaluate the first set of plans by May 1, 2026, and the second set by May 1, 2027, including accepting public comments and issuing an order to approve, approve with modifications, or reject the plan.[7] Plans must include a combination of devices owned by the electric company and devices owned by a third party, with a goal of 30% of devices being third-party owned. Devices procured under the 2025 plan must be operational by November 1, 2027, and those under the 2026 plan by November 1, 2028. Deadlines may be extended for good cause.

(Maillog No. 325764); Office of People's Counsel (Maillog No. 325763); and NineDot Energy (Maillog No. 325726).
[6] PUA § 7–216.2(b)(1).
[7] PUA § 7–216.2(c)(3).

Each plan must demonstrate that the construction/procurement is cost-effective in consideration of a cost-benefit analysis, avoided costs, and avoided emissions measured using the social cost of carbon.[8] Each plan must also demonstrate that it can be completed within 18 months of approval, and complies with other factors. The NGEA also mandates prevailing wage rates for workers constructing or procuring both third-party and electric-company-owned devices. Electric companies must also meet and confer with the employee bargaining unit regarding maintenance and operation work. Contractors must offer health care and retirement benefits. Finally, every project must include a proposed decommissioning plan focused on maximizing the recycling or reuse of all qualifying components.[9]

II. ELECTRIC COMPANY PLAN PROPOSALS

A. Baltimore Gas and Electric Company[10]

BGE's current proposal calls for a 29 MW Battery Energy Storage System ("BESS") deployment, targeting a minimum deployment of 29 MW by November 2025, spread across three program models: (1) a 3 MW BGE-owned Utility Distribution BESS ("DBESS") Program, (2) a 15 MW Commercial and Industrial ("C&I") Customer-Sited Program ("CSP"), and (3) an 11 MW Third-Party Market Procurement Program (Indexed Storage Credit or "ISC Program").

BGE's proposed utility-owned DBESS will primarily function as Non-Wires Solutions ("NWS") to avoid or defer conventional distribution system upgrades, as

[8] PUA § 7–216.2(d).
[9] PUA § 7–216.2(f).
[10] Maillog No. 323963.

exemplified in BGE's proposal by a project at the Hereford Substation, with revenues sourced from PJM wholesale markets. The CSP, also utility-owned but sited on customer premises, aims to achieve targeted distribution peak shaving and participate in PJM markets, and is supported by various third-party organizations seeking to participate in the CSP[11] and who cite benefits like enhanced grid resilience, backup power, and support for decarbonization goals.

BGE's third-party program will procure developer-owned and operated projects via a competitive Request for Proposals ("RFP"), utilizing an ISC contract to provide predictable revenue certainty. These third-party projects, ranging from 100 kW to 5 MW with a minimum four-hour duration, are required to be active PJM participants. For its third-party programs, BGE proposes a procurement process that will incorporate non-price criteria in its RFP evaluation, factoring in grid value from locational benefits, vendor experience, environmental benefits, and cybersecurity.

A Benefit-Cost Analysis ("BCA")[12] conducted by BGE using the National Standard Practice Manual ("NSPM")[13] framework found all three models to be cost-effective under high-end PJM market revenue and Transmission & Distribution deferral scenarios. To ensure customer benefit, BGE has committed to returning 100% of PJM market revenues

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[11] Maryland Port Administration (Maillog No. 324240), Maryland Transit Administration (Maillog No. 324241), Goucher College (Maillog No. 324259), BreakGround Enterprises (Maillog No. 324337), Association of Science and Technology Centers (Maillog No. 324501), Public Storage (Maillog No. 324503), and Honeywell International Inc. (Maillog No. 326240).

[12] A Benefit-Cost Analysis, or BCA, is a study used to determine the viability of a project by comparing the total expected benefits against the total expected costs.

[13] The National Standard Practice Manual (NSPM) for Distributed Energy Resources (DERs) is a comprehensive, policy-neutral framework providing guidance for conducting cost-effectiveness evaluations of DERs. Developed by the National Energy Screening Project (NESP), it helps regulators and stakeholders assess benefits and costs—including energy efficiency, demand response, storage, and electrification—to align with specific utility or state policy goals.

directly to customers to reduce rates.

BGE requested regulatory asset treatment for incremental deployment costs not covered in their Multi-Year Rate Plan and estimated a bill impact on residential customers that will rise to approximately $0.29 per month by 2032. BGE also identified risk mitigation strategies, including seeking flexibility for ambitious deadlines, using diversified procurement and early sourcing for supply chain stability, and seeking Commission guidance if final bids materially exceed established cost caps.

BGE requested immediate Commission approval to proceed with the third-party market procurement and the C&I Customer-Sited Program, along with approval for the requested regulatory asset treatment for their total 29 MW deployment.

In post-hearing comments,[14] BGE outlined five key points regarding its energy storage deployment proposal: (1) BGE argued that regulatory asset treatment for cost recovery is essential for affordability and is the only current mechanism under the multi-year plan structure to ensure recovery of non-base rate program costs while preserving Commission prudency review, (2) BGE supported diverse ownership models, including both utility-owned and third-party-owned storage, (3) BGE emphasized the need for clarity on PJM Revenues in BCAs, arguing that PJM market participation via FERC Order 2222[15] offers the clearest path to a BCA above 1, and cautioning against reliance on speculative value streams, (4) BGE expressed concerns with the Joint Storage Parties'[16] "load

[14] Maillog No. 326345.
[15] FERC Order No. 2222, *Participation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations and Independent System Operators*, 172 FERC ¶ 61,247 (2020).
[16] The Joint Storage Parties collectively include third-party developers and industry trade organizations that were represented at the January 9, 2026 hearing by the Solar Energy Industries Association, the Coalition for Community Solar Access, TurningPoint Energy LLC, NineDot Energy LLC, Chaberton Energy Holdings LLC, and New Leaf Energy, Inc.

modifier" walk-up tariff,[17] calling it speculative and unlikely to impact PJM forecasting models significantly, and (5) BGE clarified that its CSP is a utility-owned, front-of-the-meter program focused on distribution system benefits and PJM market participation, not host customer energy management, justifying its inclusion in the rate base.

B. Pepco Holdings, Inc.[18]

For this initial phase, Delmarva and Pepco, through their parent company, Pepco Holdings, Inc. ("PHI"), proposed to procure 14.5 MW of front-of-the-meter, distribution-connected third-party owned and operated BESS, divided as follows: 10.5 MW in Pepco's service territory and 4.0 MW in Delmarva's service territory. PHI stated that the target is to have these systems energized by November 1, 2027, requiring an expedited process.

PHI's proposed procurement strategy relies exclusively on a competitive RFP process. PHI chose this model to ensure expedited deployment by leveraging developers' existing pipelines, minimize ratepayer risk by shifting execution and technology risk to developers, and access market specialization in BESS optimization.

PHI's BCA valuation will adhere to the NSPM and the Maryland Jurisdictional Specific Test,[19] quantifying value streams such as avoided PJM capacity services, energy arbitrage, and societal impacts such as greenhouse gas emission reduction and public health. PHI's primary use case for this phase of BESS deployment is system peak

[17] A "walk-up" tariff provides a pre-determined, transparent payment structure based on the value an energy storage device provides and allows any project that meets defined technical and safety criteria to access predictable compensation rather than through competitive bidding. A "load modifier" tariff allows an energy storage device to derive value by reducing load as compared to deriving value as a capacity resource.
[18] Maillog No. 323951.
[19] The Maryland Jurisdictional Specific Test is a cost-effectiveness framework used in EmPOWER Maryland to evaluate energy efficiency and utility programs.

shaving—a focus chosen to minimize complexity and meet the ambitious 2027 deadline, reserving value stacking for future phases—but developers will be allowed to monetize secondary use cases to provide a financial anchor. PHI's proposal identified key project risks—including the challenging timeline, reliance on third-party execution, supply chain volatility, PJM market fluctuations, and the potential for costs to exceed the confidential cap—and proposed mitigation strategies such as expedited interconnection review, rigorous developer vetting, proactive market engagement, and contractual benchmarks.

PHI requested that all prudently incurred costs for distribution grid services contracts be treated as a regulatory asset, with full cost recovery plus a fair return on investment. PHI argued that this proposed regulatory treatment would allow for amortization over a longer period, mitigating immediate "rate shock" for customers. PHI proposed that the costs of the program be applied to the general rate base. In post-hearing comments,[20] PHI argued that an amortized regulatory asset approach is more affordable for customers than a surcharge with immediate expensing of costs, particularly in the early years of the battery storage programs, because an amortized asset results in significantly lower initial bill impacts. PHI acknowledged the regulatory asset's slightly higher total nominal cost but contended that its benefit lies in avoiding intense up-front bill pressure, comparing it to financing a house. It also argued that a regulatory asset ensures equitable rate treatment between utility-owned and third-party owned battery storage costs, noting that the deferral is only applicable to non-capital costs.

PHI estimated bill impacts to be similar for all customer classes. For a typical residential Pepco customer, PHI projected bill impacts to start at $0.10 per month in year

[20] Maillog No. 326346.

1 and steadily rise to a peak of $0.30 per month in years 6-15. For a typical Delmarva residential customer, PHI's projected impact is $0.14 per month in year 1, also steadily rising to $0.30 per month in years 6-15.

PHI committed to tracking and reporting investments in stakeholder engagement focused on disadvantaged communities.

PHI stated that, if the Commission approved its proposals by no later than May 2026, it would immediately trigger the release of the formal competitive RFP. Following the selection of proposals, PHI proposed a confidential technical conference with the Commission to review the execution plan before final contract execution.

PHI also addressed the potential for Performance Incentive Mechanisms ("PIMs"), stating it was not opposed but believed PIM development is too time-consuming to address the immediate need for cost recovery.

C. The Potomac Edison Company[21]

Potomac Edison proposed a distribution-connected energy storage plan that aims to secure a minimum of 6.5 MW, representing one-third of the utility's total 19.5 MW NGEA allocation requirement.

Potomac Edison proposed to secure 100% of this capacity through third-party developed, owned, and operated projects, significantly exceeding the 30% third-party statutory minimum. Potomac Edison's procurement strategy centers on a competitive RFP process for front-the-meter ("FTM")[22] projects, with the primary value targeted being peak

[21] Maillog No. 323893.
[22] A front-of-the-meter (FTM) project in the context of this proceeding is a utility-scale energy storage device that connects directly to the electric grid on the utility side of the customer meter.

load reduction services. Preference will be given to projects that can achieve operational status by the statutory deadline of November 1, 2027, which is within eighteen months of contract execution. Potomac Edison proposed using flat annual payments over a ten-year term but stated that it remained open to considering alternative contract structures. Potomac Edison stated that its project evaluation will be multi-factored, balancing price and financial viability with non-price factors like developer experience and safety standards, and placing a high value on NWS.

Potomac Edison stated that operational control of the storage assets will prioritize distribution system needs, with the primary dispatch signal synchronized with distribution, transmission, and PJM's five coincident peak load days ("PJM 5CP").[23] Potomac Edison stated that, while developers are encouraged to participate in the PJM wholesale market, this is strictly conditional on not conflicting with Potomac Edison's priority dispatch for peak reduction. PJM Locational Marginal Price revenues generated from energy sales will be passed directly back to the third-party developers.

Potomac Edison tested the economic viability of the plan through a BCA that aligns with the NEEP Unified BCA Framework,[24] uses EmPOWER Maryland avoided cost data, and incorporates the social cost of carbon, yielding a calculated BCA ratio of 0.307 for this initial phase. Potomac Edison further stated that its plan will comply with PUA § 7-216.2, satisfying requirements for cost-effectiveness via the BCA and demonstrability via the 18-month completion requirement.

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[23] PJM 5CP refers to the five highest, non-holiday weekday one-hour electricity demand intervals in the PJM regional transmission organization during the summer months (June through September). These peaks determine the PJM peak load contribution calculation for customers, directly impacting capacity charges for the following PJM Delivery Plan year.

[24] NEEP BCA refers to the BCA frameworks, models, and advocacy developed and supported by the Northeast Energy Efficiency Partnerships ("NEEP").

Regarding cost recovery, Potomac Edison proposed a "Grid Programs Surcharge," intended to be merged with an existing surcharge, and seeks approval for deferral accounting and placing initial costs into a regulatory asset until the surcharge is active, in line with Order No. 91812. Potomac Edison has not proposed a PIM at this initial stage but committed to evaluating one for subsequent phases.

A significant component of Potomac Edison's plan is its focus on equity and community engagement. Potomac Edison will use the Maryland EJScreen Tool[25] to identify overburdened and underserved communities. Potomac Edison's RFP proposal mandates that developers detail how their projects will provide specific benefits, such as economic opportunity and workforce development, to these communities. The equitable distribution of benefits will be a substantial and material component in Potomac Edison's overall RFP scoring.

III. STAKEHOLDER COMMENTS

A. <u>Office of People's Counsel</u>[26]

The Office of People's Counsel ("OPC") advocated for a regulatory approach centered on rigorous customer protection, transparency, and accountability, particularly regarding the utilities' burden of risk. OPC argued that regulatory plan approval is *not* an endorsement of costs or a final finding of prudency, but merely authorizes development under specified conditions and budget ceilings. Toward this end, OPC argued that budget caps should be imposed immediately as non-negotiable ceilings, and utilities must preserve

[25] The Maryland Environmental Justice Screening Tool is a mapping application developed by the Maryland Department of the Environment and the University of Maryland to identify communities disproportionately burdened by pollution, climate change, and social vulnerabilities.
[26] Maillog No. 323893.

comprehensive documentation to bear the full burden of proving that all costs incurred were prudent and necessary in future cost recovery proceedings. Furthermore, OPC argued that utility-owned projects must be subject to ongoing monitoring and benchmarking against objective metrics to inform the ultimate prudence review. OPC expressed concern that utility budgets do not match their revenue requirements.

OPC also requested that the Commission set a standardized, rigorous, and transparent methodology for measuring cost-effectiveness, in order to ensure fair and consistent evaluation. OPC recommended that utilities be required to update all program-level BCAs using the NSPM, with consistent inputs and necessary technical adjustments, such as the removal of inconsistent factors like reserve margins. OPC argued that this standardized BCA methodology should be applied at the individual project level for effective prioritization.

OPC also expressed concerns about utility ownership of battery storage, calling for competitive neutrality. In the specific case of BGE, OPC recommended that capacity be reallocated between utility-owned and third-party-owned programs based purely on BCA results to maximize overall net customer benefits following the RFP process. OPC also asked that the Commission require BGE to detail how it will manage PJM performance risks to protect ratepayers.

OPC expressed uncertainty regarding how PJM will value retail load reductions for capacity market purposes, due to the fact that it takes a multi-year period of load modification to impact the capacity obligations of load serving entities whereas market participation has a more direct and immediate impact through PJM tariff compensation that can improve BCAs. OPC also recommended that BGE describe how it will manage PJM performance risks to protect ratepayers.

OPC opposed the notion of a fully confidential procurement, and it instead recommended that the Commission create a public record that includes mandatory written summaries of evaluation results being made available to the Commission, Staff, and OPC *before* contract finalization. OPC recommends a pre-award summary and post-award public filing of contract price metrics and evaluation rationale. Following contract execution, utilities must publicly disclose key metrics, including awarded capacity, total expected customer cost, contract price metrics, and a detailed explanation of non-price criteria influence. Narrative status updates must also be provided at all key milestones.

OPC strongly opposed the utilities' proposal for regulatory asset treatment for recurring operating costs, insisting that routine Operations and Maintenance ("O&M") and third-party contract payments be annually expensed in the year they are incurred. OPC argued that regulatory asset treatment of those costs would be inconsistent with past practice, including the treatment of Qualified Facilities under the Public Utility Regulatory Policies Act of 1978 ("PURPA"), and would ultimately increase total customer costs through added financing charges. It further argued that cost allocation must be based on the clear principle of cost causation and the distribution of benefits, requiring a project-by-project analysis to identify the specific constraint, causal customer classes, and expected benefits. OPC stated that this framework necessitates that C&I customers or large load users bear a commensurately greater share of costs if they are the primary drivers of grid need. OPC explained that its overarching equity focus is preventing increased energy burdens for low- and moderate-income ("LMI") households.

While supporting a long-term retail grid-services tariff, OPC recommended a competitive RFP solicitation for the near term due to methodological inconsistencies in BCAs and uncertainty regarding PJM's valuation of retail load reductions.

B. **Commission Technical Staff**[27]

The Commission's Technical Staff ("Staff") identified material technical and financial deficiencies across all utility submissions. Based on those concerns, Staff recommended conditional approval or deferral on the utility proposals.

A core Staff concern was the inadequacy of the BCA methodologies employed. Staff criticized PHI's BCA for failing to incorporate critical value stacking elements like distribution-level resilience and NWS opportunities, leading Staff to recommend mandating a new, comprehensive, NSPM-aligned framework. Staff's analysis of BGE's BCAs showed a material downside risk, with the Benefit-Cost ratio potentially falling below 1.0 in a low-case scenario with conservative assumptions and a failure to adequately monetize all reliability benefits. Potomac Edison's proposal was cited by Staff as non-compliant, relying on the outdated NEEP BCA framework instead of the NSPM, lacking alignment with Maryland's stated goals, and employing an inconsistent, flat annual payment structure. Staff criticized BGE's portfolio as exhibiting uneven benefit distribution. Staff also criticized Potomac Edison's assertion of specific grid value as being internally inconsistent with Potomac Edison's finding of no identified NWS in its service territory.

In terms of bill impacts, Staff criticized PHI's analysis as incomplete and argued

[27] Maillog No. 325795.

that BGE significantly understated costs by excluding mandated prevailing wage obligations, while Potomac Edison offered only a highly limited first-year estimate.

Staff also questioned the proposals by BGE and PHI for full cost recovery via regulatory asset treatment, particularly for third-party contract payments which are operating expenses. Staff criticized this approach as shifting undue financial risk to ratepayers and increasing costs through carrying charges. Staff also argued that PHI and Potomac Edison failed to produce completed distributional equity analyses ("DEA"), as they could not demonstrate corresponding, measurable benefit incidence for vulnerable populations.

Staff also expressed concern about inadequate project governance, including non-robust non-price criteria that needed refinement to fully credit resilience attributes and incorporate clear equity metrics. Staff also highlighted systemic understatements of costs and insufficient equity analysis.

Staff also highlighted significant, system-wide delivery risks posed by the strict November 1, 2027, in-service deadline, especially due to potential interconnection and permitting delays.

Staff characterized the proposed cost caps as non-binding planning estimates that lacked clear regulatory guardrails, concluding that they did not function as robust or enforceable cost-containment mechanisms.

Operational preparedness was another Staff concern. For instance, Staff highlighted PHI's reliance on a future Distributed Energy Resource Management Systems ("DERMS") without a clear fallback plan.

Based on these findings, Staff recommended conditional approval for PHI's proposal, requiring performance-based compensation, limitations on regulatory asset treatment, enhanced bill impact and DEA, and minimum contractual protections.

Staff also recommended conditional approval for BGE's proposal, mandating stronger cost caps, clearer prioritization of distribution grid services, conditioning regulatory asset treatment on demonstrated performance, and requiring periodic reporting. Nonetheless, Staff criticized BGE's portfolio for uneven benefit distribution, with only 3 MW dedicated to NWS. Staff recommended that BGE prioritize distribution grid services over PJM market participation.

Staff recommended against approval for Potomac Edison's proposal, instead requesting that the Commission order Potomac Edison to refile its proposal with amendments that address NSPM compliance, demonstrate actionable grid value, strengthen cost caps, provide a complete bill impact/equity assessment, and clarify risk mitigation strategies.

In post-hearing comments,[28] Staff argued that the Commission should balance timely energy storage deployment with ratepayer protection, compliance, and cost-effectiveness. Staff emphasized that the focus of its critiques was on ensuring grid procurements are based on demonstrated value, credible benefit-cost analysis, and prudent risk allocation, not on impeding implementation. Staff argued for the need for guardrails like transparent cost caps, clear performance requirements, and enforceable remedies to prevent shifting risk to ratepayers. Staff also stressed that equity requirements demand commensurate benefits for low-income customers from front-of-the-meter storage and argued that relying on future rate design is insufficient. Staff reiterated that regulatory asset

[28] Maillog No. 326351.

treatment should be limited and that PJM market revenues must accrue to customers unless an approved Performance Incentive Mechanism is in place.

C. Maryland Energy Administration[29]

The Maryland Energy Administration ("MEA") prioritized ratepayer affordability, prudent risk allocation, efficient cost recovery, and a grid-aligned procurement strategy for energy storage deployment.

MEA argued for denying utilities a full equity return on O&M expenses for energy storage. MEA argued that O&M costs are recurring and controllable, and allowing a full return would weaken incentives for cost discipline. MEA argued this is a necessary measure to prevent unfairly shifting operational risk from shareholders onto ratepayers.

MEA argued that early energy storage deployments should be strategically integrated into utility distribution system planning. The primary goal of these deployments should be to demonstrate tangible grid benefits, such as peak load reduction and improved reliability, in order to achieve operational learning, validate the technology's effectiveness, and guarantee alignment with the specific needs of the electric system.

MEA opposed the premature adoption of a "walk-up" tariff[30] or standard-offer structure for energy storage. MEA argued that implementing such a structure too early risks decoupling deployment from genuine system needs, thereby increasing financial risk for ratepayers. MEA also argued that it risks favoring third-party developers without properly

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[29] Maillog No. 326311.

[30] A "walk-up" tariff is a compensation structure that allows energy storage projects to be compensated for the value their device provides the grid for various layers of grid services. In the context of the utility programs proposed, a "walk-up" tariff is a direct offering from the utility with clear eligibility requirements rather than a competitive utility solicitation process.

establishing and incorporating locational value signals. Instead, MEA advocated for competitive, needs-driven procurements to be the primary method for storage deployment, which should subsequently inform and precede the development of any future tariff structure.

D. Joint Storage Parties[31]

The Joint Storage Parties ("JSP") advocated for a market-driven approach to utility programs, primarily representing the interests of third-party developers and stakeholders. They recommended moving away from what they characterized as the high-risk, one-off RFP model toward more stable, standardized tariff-based structures or standard offer contracts. They argued that these new structures must feature transparent, pre-determined incentive prices directly linked to established standardized BCAs. They also argue against mandatory participation in the PJM wholesale market, asserting that local asset management as a load modifier[32] often provides superior consumer benefits compared to the complexity, financial risk, and high transaction costs associated with mandatory PJM involvement. However, despite the JSP opposition, several developers, notably Form Energy[33] and Zenobe Americas,[34] endorsed the ISC concept in filings associated with the Case No. 9715 energy storage hearings in April 2025.

[31] The JSP are collectively the Solar Energy Industries Association, Advanced Energy United, Chesapeake Solar & Storage Association and Coalition for Community Solar Access (Maillog No. 325796), TurningPoint Energy (Maillog No. 325796), Qcells (Maillog No. 325792), Solar Landscape (Maillog No. 325788), Chaberton Energy Holdings, LLC (Maillog No. 325764), and NineDot Energy (Maillog No. 325726). While each party filed its own comments that were reasonably aligned among the JSP parties, this summary represents collective feedback and not the feedback of any particular party.
[32] In the context of the PJM capacity market, a load modifier is a resource that acts to reduce the amount of electricity demand that must be served by traditional generation resources instead of adding generation to meet capacity needs.
[33] Maillog No. 318229.
[34] Maillog No. 317127.

The JSP argued in favor of strict limits on utility ownership, which they argue should be the distinct exception, approved only if the utility can unequivocally demonstrate it is the most cost-effective option and if a third-party is fundamentally incapable of providing the required service. The JSP particularly critiqued BGE's proposed CSP utility ownership, which the JSP argued is inherently anti-competitive and would require strict organizational firewalls and complete cost transparency if approved. The JSP also argued that there were major issues with BGE's ISC, deeming its excessive complexity "unfinanceable" due to the conflicting signals of requiring simultaneous PJM market participation and distribution service availability. Cost recovery was not a primary focus for the JSP, but they favor mechanisms that ensure financial certainty for developers.

The JSP also called for critical structural and timeline reforms to facilitate deployment. They requested that the current November 1, 2027, project in-service deadline be extended to at least November 1, 2028, to account for the likelihood of delays stemming from the RFP process, required regulatory reviews, and persistent interconnection hurdles. The JSP also recommended interconnection reform that would require utilities to immediately accept and study standalone storage applications. The JSP also asked the Commission to affirm that adding storage to an existing solar project is not considered a "material modification" that would trigger lengthy re-study requirements. Finally, the JSP recommended that all programs be designed for future scalability, high-volume deployment, and for transition to "walk-up" tariff models.

In a post-hearing filing,[35] the Solar Energy Industries Association, Chesapeake Solar & Storage Association, and Coalition for Community Solar Access argued that if the

[35] Maillog No. 326344.

Commission opts for an RFP, it should require electric companies to follow PHI's proposal, provided it focuses solely on distribution system benefits and avoided costs, and excludes direct wholesale market participation. They argued that storage's primary value is as avoided capacity in Maryland, not as a direct PJM capacity resource. They proposed working with PJM to immediately adjust the load forecast downward to reflect installed distributed storage and realize capacity obligation reduction benefits sooner. They advocated for incorporating all grid service values, including locational and NWS deferral value, into a single, comprehensive tariff to minimize administrative burden, citing the New York VDER[36] tariff as a model. Finally, while supporting C&I customer-sited storage, they opposed exclusive utility ownership like BGE's proposal, arguing it shifts risk to ratepayers and harms competition. They recommended a competitive model where utilities identify eligible feeders and provide leads, but independent power providers own and operate the assets, reserving utility ownership for assets performing essential distribution grid functions like volt/var support.

E. **Other Parties**[37]

Several other organizations—the Maryland Port Administration, the Maryland Transit Administration ("MTA"), Goucher College, BreakGround Enterprises, the Association of Science and Technology Centers, and Public Storage—submitted

[36] VDER (Value of Distributed Energy Resources) is New York's compensation mechanism for solar, energy storage, and other clean energy projects. Compensation is calculated based on specific components, including energy value, capacity, environmental benefits, demand reduction value, and locational system relief value.

[37] Maryland Port Administration (Maillog No. 324240), Maryland Transit Administration (Maillog No. 324241), Goucher College (Maillog No. 324259), BreakGround Enterprises (Maillog No. 324337), Association of Science and Technology Centers (Maillog No. 324501), Public Storage (Maillog No. 324503), Honeywell International Inc. (Maillog No. 326240) and Edison Electric Institute (Maillog No. 326342).

statements expressing strong support for BGE's proposed utility-owned battery storage program including a strong endorsement of BGE's CSP. These organizations anticipated a range of benefits, including enhanced grid resilience and reliability, support for MTA's zero-emission bus fleet electrification, lower grid costs, and improved power quality. They argued that the CSP is a vital step toward achieving Maryland's decarbonization goals and fostering economic opportunities by removing barriers to renewable energy adoption. They cited specific benefits including providing backup power for critical facilities like transit depots, college campuses, and museums, which can then act as community resilience centers; and addressing the State's aging infrastructure. Goucher College and Public Storage confirmed their willingness to host the storage assets for compensation and emphasized the necessity for the Commission to approve adequate cost recovery for BGE's investment. All supporting organizations expressed eagerness to collaborate with BGE and other stakeholders to ensure the program's success.

The Edison Electric Institute ("EEI") (a trade organization representing investor-owned electric companies) contended that a well-designed, long-term framework is essential to deliver value and maintain customer affordability. Specifically, EEI recommended against recovering costs contemporaneously through a surcharge, arguing this "front-loads" rate impacts and creates immediate affordability challenges. Instead, EEI advocated for regulatory asset treatment, which allows costs to be deferred and amortized over multiple years. It argued that this would result in more gradual, manageable rate changes, lower bill impacts for customers in the early years of the program and promote efficient investments.

Honeywell also supported BGE's plan, labeling it a "best-in-class approach" that complements its own development objectives. It expressed its intent to actively participate in BGE's RFPs as a turnkey implementer for both the DBESS and CSP programs, and also as an owner/operator for the ISC program and participation in PJM markets. Honeywell stated that it believes the plan will significantly boost grid resilience, foster market innovation through the ISC model, and advance Maryland's climate goals. Honeywell urged the Commission to approve the plan and the associated cost recovery mechanisms, specifically stressing the need for robust regulatory asset treatment to ensure timely deployment and affordability, with PJM market revenue offsets flowing back to benefit customers.

IV. COMMISSION DECISIONS

This Order will address the major topic areas highlighted by specific stakeholders as perceived gaps in the utility proposals.

A. Procurement Model

The Commission directs utilities to utilize an RFP model for this first tranche of distribution-connected energy storage deployments.

PUA § 7-216.2(c)(4) states: "The energy storage devices constructed or procured under each plan shall include a combination of devices owned by the investor-owned electric company and devices owned by a third party, with a goal of 30% of the devices being owned by a third party." There is no strict legislative mandate requiring procurements, however, there is no guarantee that tariffs would attract enough storage projects to meet PUA § 7-216.2 targets.

All utilities propose to use a competitive RFP for third-party capacity. Only the JSP opposes procurements via competitive RFP. The Commission notes that the Maryland Energy Storage Program Workgroup ("MESP WG") is using a consultant to develop a walk-up tariff framework and the MESP WG recommendation is due to the Commission by July 1, 2026. The Commission is concerned that without a standardized "walk-up" tariff framework, the JSP proposal for utilities to use their BCAs in this proceeding to develop their own walk-up tariffs will yield inconsistent tariff proposals, especially since their proposed BCAs are currently inconsistent. If a consistent "walk-up" tariff framework can be adopted before November 1, 2026, when electric companies submit their proposals for the balance of their PUA § 7-216.2 allocated targets, the use of "walk-up" tariffs can be revisited for the next round of distribution-connected energy storage deployments.

B. Procurement Transparency

The Commission agrees that procurement transparency is essential to the extent possible, but also recognizes that some competitive elements of the utility procurements will need to be confidential. Therefore, the Commission will hold, for each electric company, a pre-award confidential conference[38] where the companies will provide an overview of their proposed project awards based on non-price factors including equity, cost-effectiveness, bill impacts and other key metrics. Program budget and bill impact will

[38] Pursuant to PUA § 2-309, the Commission and OPC have a duty not-to-disclose confidential information learned from public service companies. PUA § 2-309 provides, "Except as directed by the Commission or a court or as authorized by law, an individual subject to § 2-302 of this subtitle may not divulge information learned while inspecting the plant or examining the records of a public service company." Since the MEA is not subject to PUA § 2-302, MEA may need to execute a non-disclosure agreement with the electric companies to attend a pre-award confidential conference.

also need to be recalibrated by utilities and shared in these pre-award confidential conferences based on RFP responses.

The electric companies are directed to meet and confer with Staff, OPC, MEA, and the Commission's Executive Secretary regarding the scheduling of these conferences. There may be one or more conferences needed for BGE so as not to delay implementation of projects, because BGE has three different proposed programs. Regarding OPC's recommendation for post-award public filings, utilities are directed to recommend for Commission consideration what information can be made public at their pre-award confidential conference.

C. BCA Methodology

PUA § 7-216.2(d)(1) provides that the Commission shall require each plan to demonstrate that the construction or procurement of each energy storage device is cost-effective in consideration of a cost-benefit analysis. COMAR 20.50.15.02B(6) states that "Cost-effective means having projected benefits that are greater than projected costs while considering other factors as determined by the Commission."

The Commission finds that more standardization of BCAs is needed before pre-award confidential conferences, using the NSPM in alignment with the previous Commission direction given in Case No. 9674 docket regarding the work of the UBCA Work Group.[39] In particular, Potomac Edison's BCA using a NEEP framework is not acceptable to the Commission, which is also concerned that the company's approach yielded a low 0.39 BCA ratio.

[39] Case No. 9674, *Unified Benefit Cost Analysis (UBCA) Framework for Distributed Energy Resources*.

The Commission is currently performing a study of the utility submitted BCAs via its consultants assisting with the energy storage implementation of the NGEA and will provide further direction after the study is completed.

D. <u>Program Budget/Cost Caps</u>

The Commission directs utilities to refine their budget estimates after RFP selections are made for discussion at their pre-award confidential conferences. In addition, once a program budget and cost cap is approved, each utility will be expected to run its program(s) within its budget and to notify the Commission if it expects to exceed its initial caps along with its recommendation for next steps, such as increasing the cost cap or reducing or modifying program scope to remain within the budget. Commission approval of a budget does not imply a prudency review as prudency will be evaluated for each program in a future rate case.

E. <u>Bill Impact</u>

The Commission directs the electric companies to revise their bill impact analyses after RFP selections are made. Furthermore, the utilities not using surcharges are directed to estimate monthly bill impacts ($/month) by cost recovery mechanism using a similar methodology employed by OPC in its comments for discussion at their pre-award confidential conferences.

F. <u>Cost Recovery</u>

Because this is a new program with potentially non-recurring capital costs, the Commission will defer any decisions on cost recovery for BGE and PHI pending a bill impact analysis as described earlier, to be discussed at the utility pre-award confidential conferences. While the Commission is not opposed to Potomac Edison's surcharge proposal, decisions on the matter are also deferred pending discussion of updated bill impacts at its pre-award confidential conference.

G. In-Service Deadline

PUA § 7-216.2(e)(5)(i) states that "The energy storage devices that are constructed or procured under a plan submitted by November 1, 2025, shall be operational by November 1, 2027." PUA § 7-216.2(e)(5)(iii) states that: "The Commission may extend a deadline under this paragraph for good cause."

Although the Commission notes concerns raised about the possibility of delivery risk with the current November 1, 2027 deadline, given that all three electric companies are still targeting November 1, 2027 in-service dates, the Commission declines to alter that deadline until a utility petitions for an extension. Utilities should alert the Commission of any new circumstances that may impact their ability to make their in-service targets.

H. Utility Ownership

PUA § 7-216.2(c)(4) provides: The energy storage devices constructed or procured under each plan shall include a combination of devices owned by the investor-owned electric company and devices owned by a third party, with a goal of 30% of the devices being owned by a third party.

Utility ownership varies among the electric company proposals. BGE proposed a diversified strategy with BGE ownership of 3 MW of DBESS and 15 MW of CSP devices and an 11 MW Third-Party Market Procurement Program. BGE will target a minimum of

11 MW of its 29 MW target through third-party procurement, which is above the 30% minimum. Both Potomac Edison and PHI proposed 100% third-party projects.

The Commission conditionally approved BGE's CSP in Order No. 91705, subject to BGE providing further details on these plans in its November 1, 2025 filings. The Commission is now persuaded that BGE's current proposal meets both NGEA ownership requirements and the Commission's requirements in Order No. 91705. The Commission affirms BGE's DBESS and CSP proposals for the first tranche of NGEA distribution-connected projects. This approval does not pre-authorize or pre-judge the question of future utility-owned FTM BESS, however.

I. <u>PJM Market Participation</u>

In Order No. 91812, the Commission did not preclude market participation but directed that the electric companies submit for approval any proposed revenue sharing mechanisms with third-parties. The Commission encourages PJM market participation where beneficial to help reduce program costs. Therefore, the Commission approves BGE's ISC program market compensation proposal—the only market compensation proposal before the Commission at this time—for the first tranche of projects where PJM market participation does not conflict with peak load reduction to address local grid needs. BGE is directed to also describe how it will manage PJM performance risks to protect ratepayers in the pre-award confidential conferences. BGE's ISC program proposal will be revisited for the second tranche of project plans due November 1, 2026, based on BGE's lessons learned based on its procurement for this first tranche using the ISC methodology.

J. Equity

Equity should be a substantial and material component of the overall RFP non-price scoring, and its analyses should be updated by the electric companies in the pre-award confidential conferences. More equity impact information will be available once RFP responses for specific projects are received. The utility RFPs should require developers to describe how their proposed projects will specifically provide benefits for economic opportunity and workforce development, or otherwise impact these communities. The Maryland EJScreen Tool should be used to track project investments in marginalized or disadvantaged communities.

K. Interconnection Reform

The JSP recommended that utilities must accept standalone storage applications without an identified "buyer" or tariff to obtain queue position and to begin the study process in advance of tariffs being developed or utility procurement programs being launched. The JSP also recommended that adding storage to an existing solar project does not constitute a "material modification" that triggers lengthy re-study. In a separate filing,[40] BGE and PHI highlight the challenges of BESS projects that lack an established tariff in a joint filing. The companies state that without an established tariff and defined interconnection study parameters, a worst-case scenario must be assumed which can lead to higher upgrade costs and competition with solar for limited hosting capacity.

The "material modification" issue has already been addressed by the Interconnection Workgroup in the RM94 rulemaking proceeding where regulations to

[40] Maillog No. 325791.

change the current definition of a “Minor Equipment Modification” were approved by the Commission on March 18, 2026. The Commission declines to further consider the utility acceptance of standalone storage applications before a buyer of the grid services is identified. These projects are speculative until a buyer is identified, and study of these projects could consume utility resources already focused on expediting interconnection reviews for projects to meet deadlines for the expiration of federal renewable energy tax credits associated with H.R.1, Public Law No: 119-21, otherwise known as the One Big Beautiful Bill Act.

V. CONCLUSION

The Maryland General Assembly passed the Next Generation Energy Act’s distribution-connected energy storage provisions in 2025 to address capacity issues in PJM, target grid reliability challenges, help stem rising electricity costs for consumers, and support renewable energy in the State. The electric companies have made proposals largely in accordance with the NGEA as codified in PUA § 7-216.2, and Commission Order Nos. 917053 and 918124. Stakeholders in this proceeding have also provided valuable feedback to be considered in curing and implementing these proposals. Some stakeholders such as OPC proposed ongoing monitoring and benchmarking against objective metrics. The Commission agrees and will address this in a future Order.[41]

Finally, the Commission concludes that these utility plans, as amended by the direction contained herein in this Order, are aligned with the legislative intent of the NGEA but require cures for certain aspects as described herein. While the utility plans are

[41] *See* the Commission's Notice of Opportunity to Comment, Maillog No. 326686.

approved, final project approvals within these plans are deferred until confidential pre-award conferences are convened to consider more granular analysis that is informed by the evaluation of the utility RFP responses.

IT IS, **THEREFORE**, this 8th day of April, in the year of Two Thousand Twenty-Six, by the Public Service Commission of Maryland, **ORDERED**:

(1) that BGE, Pepco, Delmarva and Potomac Edison are approved to issue RFPs for their energy storage plans subject to certain conditions and modifications as described herein; and

(2) that BGE, Pepco, Delmarva and Potomac Edison shall schedule confidential pre-award conferences with the Commission's Executive Secretary when it is appropriate to proceed with their RFP project selections. These confidential pre-award conferences shall contain revised program BCA analyses, program Budget/Cost Caps, and Bill Impact and Equity analysis as described herein. These analyses and a description of each utility's price and non-price criteria used in making their RFP selection proposals shall be filed at least one week prior to each confidential pre-award conference.

/s/ Kumar P. Barve

/s/ Frederick H. Hoover, Jr.

/s/ Bonnie A. Suchman

/s/ Odogwu Obi Linton

/s/ Ryan C. McLean
Commissioners