Agenda Date: 6/18/25
Agenda Item: 8E

STATE OF NEW JERSEY

Board of Public Utilities
44 South Clinton Avenue, 1st Floor
Post Office Box 350
Trenton, New Jersey 08625-0350
www.nj.gov/bpu/

CLEAN ENERGY

IN THE MATTER OF THE GARDEN STATE ENERGY STORAGE PROGRAM ("GSESP") PURSUANT TO P.L. 2018, C.17	))))	ORDER LAUNCHING THE GARDEN STATE ENERGY STORAGE PROGRAM DOCKET NO. QO22080540

The Garden State Energy Storage Program ("GSESP") is the new name for the program previously referred to as the New Jersey Storage Incentive Program ("NJ SIP")

Parties of Record:

Brian O. Lipman, Esq., Director, New Jersey Division of Rate Counsel

BY THE BOARD:[1]

By this Order, in conjunction with rulemaking in a related docket, Docket Number QX25050283 – In the Matter of a Rulemaking Proceeding to Establish the Garden State Energy Storage Program Pursuant to P.L. 2018, c.17, the New Jersey Board of Public Utilities ("Board" or "BPU") establishes the Garden State Energy Storage Program ("GSESP"). The GSESP will be open to qualifying stand-alone energy storage projects, as well as solar-plus-storage projects that are ineligible for storage incentives under the Board's Successor Solar Incentive ("SuSI") Program, thereby addressing a critical gap in the market. These projects are essential for mitigating the electric capacity supply crunch that is driving dramatic rate increases for New Jersey consumers, strengthening the resilience of New Jersey's electric grid, reducing carbon emissions, and facilitating the state's clean energy transition. The GSESP and its associated rules establish a critical foundation for a long-term energy storage effort in the State.

The Board is tasked by the Clean Energy Act of 2018 ("CEA")[2] with a mandate to deploy 2,000 megawatts ("MW") of energy storage by 2030.[3] This Order is a key part of a multi-year effort to

---

[1] Commissioner Marian Abdou recused herself due to a potential conflict of interest and as such took no part in the discussion or deliberation of this matter.

[2] P.L. 2018, c.17

[3] See N.J.S.A. 48:34-87.8. All megawatt or MW values in this Order are in alternating current or "AC."

implement this mandate and strengthen the electric grid by increasing the supply of dispatchable capacity that can firm up generation from clean but intermittent resources such as solar. A quantitative analysis that Board Staff ("Staff") performed, described in Appendix B to this Order, also indicates that the GSESP will provide net savings to ratepayers within the first few years of its operation.

The GSESP will consist of two to three distinct phases, each with its own timeline. Phase 1 will award Transmission Fixed Incentives to eligible transmission-scale energy storage systems via a competitive solicitation process that will determine both which projects are selected, and the size of the incentive awards each project receives. These incentives will be paid out at a constant annual rate denoted in dollars per megawatt per year for a 15-year award period. Phase 1 will target procuring at least 1,000 MW of transmission-scale energy storage over the course of multiple solicitations. The first solicitation ("Tranche 1") will aim to award 350-750 MW by October 31, 2025, with a pre-qualification process commencing on June 25, 2025, and a final bid submission deadline of August 20, 2025. The Board intends to award the remaining capacity necessary to achieve the 1,000 MW target in one or more solicitations in 2026. This order initiates Phase 1 of the GSESP.

Phase 2 will launch the distributed segment of the GSESP. Though the Board is not finalizing the design of Phase 2 in this Order, the distributed segment is anticipated to provide both Distributed Fixed Incentives and Distributed Performance Incentives to eligible energy storage systems. The Board also anticipates setting the size of fixed incentives and the amount of project capacity to award on an annual basis, offering fixed incentive through administratively determined capacity blocks. Phase 2 of the GSESP is expected to launch in 2026.

A potential Phase 3 would consist of a Transmission Performance incentive. However, the potential Phase 3 of the GSESP is currently deferred.

The GSESP will be a central part of the Board's efforts to rapidly promote the entry of new capacity online to maintain reliability and limit rate increases in the face of soaring demand for electricity. The program will also constitute a key component of New Jersey's continued national leadership in the fight against climate change.

BACKGROUND

The State of New Jersey has one of the most ambitious energy storage targets in the nation, with a statutory mandate to achieve 2,000 megawatts ("MW") of installed energy storage capacity by 2030. Energy storage resources are critical for mitigating electric capacity supply constraints that are driving dramatic rate increases, strengthening the resilience of New Jersey's electric grid, reducing carbon emissions, and facilitating the state's clean energy transition. Once launched, the Garden State Energy Storage ("GSESP") will lay the groundwork for a long-term energy storage initiative that is essential to achieving the State's clean energy goals.

In the short term, the GSESP will help alleviate the tight supply conditions that drove the dramatic electric rate increases that took effect this month. Specifically, these rate increases resulted from the record-high clearing prices in PJM Interconnection, LLC ("PJM")'s July 2024 capacity auction, formally known as the Base Residual Auction ("BRA").[4] These high clearing prices significantly increased the wholesale cost of power, a cost which Basic Generation Service ("BGS") providers passed on to ratepayers via higher prices in the February 2025 BGS auction.[5] Though most of the price increase in the July 2024 BRA was due to market design flaws that created artificial scarcity, a significant portion was the result of increasing electric demand and a decrease in the underlying amount of electric capacity.[6] These supply and demand trends are expected to continue due to rapidly accelerating load growth, especially from data centers, and the significant time required to build new generation capacity.[7] Energy storage resources are the most significant source of near-term capacity that can help address this situation, as they comprise the bulk of proposed New Jersey capacity with interconnection approval from PJM.[8] Energy storage resources can also be constructed faster than traditional power plants.[9] Consequently, deploying

---

[4] Ethan Howland, PJM Capacity Prices Hit Record Highs, Sending Build Signal to Generators, Util. Dive (July 31, 2024), https://www.utilitydive.com/news/pjm-interconnection-capacity-auction-vistra-constellation/722872/; Press Release, N.J. Bd. of Pub. Utils., NJBPU Announces Conclusion of New Jersey's Annual Electricity Supply Auction (Feb. 12, 2025), https://www.nj.gov/bpu/newsroom/2025/approved/20250212.html.

[5] Press Release, N.J. Bd. of Pub. Utils.

[6] See Monitoring Analytics, Indep. Mkt. Monitor for PJM, 2024 State of the Market Report for PJM Volume 2: Detailed Analysis 291 (2025), https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2024/2024-som-pjm-vol2.pdf (explaining that the BRA results "were significantly affected by flawed market design decisions" and "do not reflect supply and demand fundamentals" while acknowledging that "the tightening of supply and demand conditions in the PJM Capacity Market" also drove part of the price increase).

[7] See PJM Interconnection, 2025 Long-Term Load Forecast Report Predicts Significant Increase in Electricity Demand, PJM Inside Lines (Jan. 30, 2025), https://insidelines.pjm.com/2025-long-term-load-forecast-report-predicts-significant-increase-in-electricity-demand/.

[8] A Staff analysis of PJM data indicates that as of May 26, 2025, 29 New Jersey projects had interconnection approval. These included 11 standalone energy storage projects with a collective capacity of 905 MW, 12 standalone solar projects with a collective capacity of 294 MW, 5 solar-plus-storage projects with a collective capacity of 223 MW, and a single 51 MW uprate to an existing gas-fired power plant. See Serial Service Request Status, PJM, https://www.pjm.com/planning/service-requests/serial-service-request-status (last visited May 26, 2025).

[9] Compare Vilayanur Viswanathan, Pac. Nw. Nat'l Lab. et al., 2022 Grid Energy Storage Technology

energy storage resources is one of the fastest available means of addressing the cause of recent electric rate increases.

The National Renewable Energy Laboratory also expects storage to become "a critical element of a low-carbon, flexible, and resilient future electric grid."[10] Similarly, the New Jersey Energy Master Plan (EMP) recognizes energy storage as a key component of the state's clean energy future.[11] The EMP, along with the Integrated Energy Plan (IEP) modeling conducted by the Rocky Mountain Institute and Evolved Energy (RMI/Evolved), identifies energy storage investment as essential to achieving 100% clean energy by 2050.[12] Their analysis suggests that New Jersey will need at least 8.7 gigawatts (GW) of energy storage by 2050—far exceeding current state mandates.[13]

The Board has been considering incentivizing energy storage since at least 2015. The NJBPU issued a Board order on December 16, 2015, establishing the Renewable Electric Storage Incentive Program. This program aimed to support the integration of renewable energy sources with energy storage systems, enhancing grid reliability and promoting clean energy adoption in the state.[14]

On May 23, 2018, Governor Murphy signed the CEA,[15] which required the Board to ensure the deployment of 2,000 MW of energy storage by 2030 and conduct a statewide Energy Storage Analysis ("ESA").[16] The CEA required the ESA to identify opportunities, costs, and benefits of expanding energy storage resources in New Jersey.[17] The CEA required collaboration with the Laboratory for Energy Smart Systems ("LESS") in the Center for Advanced Infrastructure and Transportation at Rutgers, the State University of New Jersey, PJM Interconnection, and other public and private stakeholders.[18]

On November 1, 2018, the Board retained LESS to conduct the ESA. To ensure stakeholder input, the Board solicited public comments on March 6, 2019, and LESS hosted a public

---

Cost and Performance Assessment 122 tbl.6.2 (2022), https://www.pnnl.gov/sites/default/files/media/file/ESGC%20Cost%20Performance%20Report%202022%20PNNL-33283.pdf (noting that grid-scale battery storage projects can be constructed in one year), with Lazard, Levelized Cost of Energy+ 38 (2024), https://www.lazard.com/media/xemfey0k/lazards-lcoeplus-june-2024-_vf.pdf (noting that gas-fired, coal-fired, and nuclear power plants take 24 to 69 months to construct).

[10] Blair et al., Storage Futures Study: Key Learnings for the Coming Decades 1 (2022), https://www.nrel.gov/docs/fy22osti/81779.pdf.

[11] N.J. Bd. of Pub. Utils. et al., 2019 New Jersey Energy Master Plan: Pathways to 2050 at 287 (2019), https://nj.gov/emp/docs/pdf/2020_NJBPU_EMP.pdf ("2019 EMP").

[12] Id. at 15, 127.

[13] Id. at 127.

[14] In re the Renewable Electric Storage Incentives in the Renewable Energy Incentive Program-Revision to NJCEP Compliance Filing, BPU Docket Nos. QO15040477 & QO15121333, Order dated December 16, 2015.

[15] P.L. 2018, c.17.

[16] N.J.S.A. 48:3-87.8(a), (d).

[17] N.J.S.A. 48:3-87.8(a), (c).

[18] N.J.S.A. 48:3-87.8(a)-(b).

stakeholder meeting. On June 12, 2019, the Board accepted the LESS ESA, transmitted it to the Legislature, and directed Staff to initiate a proceeding to establish a process and mechanism for achieving the CEA's energy storage targets.

Staff then proceeded to work internally on a conceptual design for what would become the GSESP. This initial work culminated in a straw proposal that Staff released on September 29, 2022 ("2022 NJ SIP Straw"), which also launched the public stakeholder engagement process for the GSESP (at the time Staff referred to it as the NJ SIP).[19] Stakeholder feedback on the 2022 NJ SIP Straw convinced Staff that the Board would require the services of a consultant to preform modeling and design work for the program. On Staff's recommendation, the Board initiated a procurement and ultimately approved a contract with TRC Companies, Inc. ("TRC") to assist Staff in the design of the GSESP on September 18, 2023. Meanwhile, Staff continued with stakeholder engagement by issuing a Request for Information ("RFI") on August 8, 2023. Staff then used stakeholder feedback on the 2022 NJ SIP Straw, responses to the RFI, and TRC's recommendations to formulate a revised Straw Proposal for the GSESP ("2024 NJ SIP Straw") and the associated Draft Program Rules, both of which Staff released on November 7, 2024. Staff and the Board have used stakeholder feedback on the 2024 NJ SIP Straw to further refine the program design for this Order and the associated notice of proposed rulemaking in Docket Number QX25050283.

In addition to the GSESP, pursuant to the Solar Act of 2021 and in support of the State energy storage goal, the Board established the Competitive Solar Incentive ("CSI") Program by Board Order on December 7, 2022.[20] Rules codifying the CSI Program were adopted November 17, 2023 and published in the New Jersey Register on December 18, 2023.[21] The CSI Program is open to qualifying grid supply solar installations, to non-residential net-metered solar installations with a capacity greater than five (5) megawatts ("MW"), and to eligible grid supply solar installations in combination with energy storage. The CSI Program awards incentives through a competitive solicitation with five separate market tranches: 1) Tranche 1: basic grid supply projects; 2) Tranche 2: grid supply projects sited on the built environment; 3) Tranche 3: grid supply projects sited on contaminated sites and landfills; 4) Tranche 4: net metered non-residential projects greater than five (5) MW; and 5) Tranche 5: Storage Paired with Grid Supply Solar. Tranche 5 targets the procurement of 160MWh of energy storage annually. The fifth tranche pairs a storage project with a grid supply project eligible for Tranche 1, 2 or 3. The initial Tranche 5 award was made on April 17, 2024, to a 95 MW solar generation project paired with 80 MWh of energy storage.[22] Energy storage projects may be eligible for either the GSESP or the CSI Program but may not participate in both programs simultaneously, apart from narrow exceptions described below.

---

[19] Notice, In the Matter of the New Jersey Energy Storage Incentive Program, BPU Docket No. QO22080540, https://www.nj.gov/bpu/pdf/publicnotice/Notice_StakeholderMeetings_NewJerseyEnergyStorageProgram.pdf ("2022 NJ SIP Straw Proposal").

[20] In re Competitive Solar Incentive ("CSI") Program Pursuant to P.L. 2021, c.169, BPU Docket No. QO21101186, Order dated December 7, 2022.

[21] 55 N.J.R. 2555(a) (Dec. 18, 2023).

[22] In re Competitive Solar Incentive ("CSI") Program Pursuant to P.L. 2021, c.169, BPU Docket No. QO21101186, Order dated April 17, 2024

GSESP Stakeholder Proceedings (2022 – 2024)

The GSESP represents the culmination of two (2) years of extensive stakeholder engagement. Staff has placed special emphasis on conducting a thorough and multi-faceted outreach to stakeholders. Since October 2022, this outreach has included stakeholder meetings led by Staff on various topics related to energy storage in New Jersey, including its current state, use cases for bulk and distributed storage, and its potential role in grid modernization.

Additionally, discussions have focused on proposed portions of the GSESP related to transmission-scale energy storage, with particular attention to economic drivers for investment and operation of energy storage systems. These discussions have explored the components of the value stack, how those components can be monetized and accessed, and the potential use of the PJM marginal carbon intensity signal to drive investment in energy storage aimed at maximizing carbon reductions.

Further engagement has examined how the energy storage program can best be implemented at the distribution level, including how New Jersey's EDCs should establish distribution price signals and structure the program to optimize benefits. Stakeholders have also discussed strategies to maximize the impact of energy storage in supporting investment in distributed energy resources, as well as the emerging role of the DER Aggregator in energy storage asset enrollment and management.

On September 29, 2022, Staff released the 2022 NJ SIP Straw to initiate the public stakeholder engagement process for the initial conceptual design of the GSESP.[23] Written comments were due on December 12, 2022. Staff then conducted three virtual stakeholder meetings on October 21, November 4, and November 14, 2022, to discuss the 2022 NJ SIP Straw and solicit stakeholder feedback. The meetings were well attended, with 165, 90, and 90 participants respectively. Stakeholders were invited to provide written comments following the meeting, and Staff received feedback from representatives from Rate Counsel, electricity distribution companies, independent power producers, solar and storage installation companies, renewable energy developers, electric vehicle charging providers, fuel cell manufacturers, demand management service providers, associated industry and/or trade groups, renewable energy advocacy groups, and members of the general public.

On August 8, 2023, Staff issued a Request for Information ("RFI") to solicit additional stakeholder commentary. The RFI included a series of questions raised during the GSESP stakeholder comment period, for which Staff determined further input was necessary. The questions were categorized into 5 sections: Utility Ownership/Dispatch Control, Installed Storage Targets, Deployment Timelines and Capacity Blocks, Incentive Structure, Overburdened Community Incentives, and Other Questions. Written comments were due by September 12, 2023. The majority of commenters had previously provided feedback on the 2022 NJ SIP Straw. Over 100 comments were received from these documents representing 70 entities and 3 individual members of the public.

On November 7, 2024, Staff released a revised Straw Proposal for the GSESP ("2024 NJ SIP

[23] 2022 NJ SIP Straw Proposal.

Straw") and the associated Draft Program Rules.[24] These documents, developed with assistance from TRC, presented a revised energy storage incentive program and solicited additional stakeholder feedback to support the launch of well-developed program elements. Written comments were due by December 18, 2024. On November 20, 2024, Staff hosted a public stakeholder meeting to discuss the 2024 NJ SIP Straw. The meeting was well attended by over 300 participants, and approximately 30 stakeholders provided public comments. Staff received 60 oral and written comments representing 63 entities and 3 individual members of the public. Meeting attendees included representatives from public entities, electrical distribution companies, developers/industry, trade organizations/coalitions, environmental groups and individual members of the public.

Staff reviewed and considered these stakeholder comments. The recordings and materials from each stakeholder meeting are available on the Board's website at https://www.njcleanenergy.com/storage.

Comments and Written Responses

Staff received over 100 written comments from 73 entities on the 2022 NJ SIP Straw and the RFI, representing a diverse range of stakeholders, including developers, equipment manufacturers, lobby organizations, environmental groups, independent power producers, utilities, engineering firms, government entities, aggregators and members of the public.

The Board received sixty (60) oral and written comments on the 2024 NJ SIP Straw, representing entities across a range of stakeholders, including public entities, electrical distribution companies, developers/industry, trade organizations/coalitions and individual members of the public. The comments mostly supported the general approach but varied in how they interpreted the details of the proposals.

All comments filed in this proceeding are accessible through the Board's website via the Public Access System.[25] Commenters provided thoughtful and comprehensive feedback on energy storage matters. Each commenter's suggestions and concerns are part of the record reviewed and were considered by Staff.

Staff recognizes and appreciates the valuable contributions submitted by stakeholders in response to the concepts set forth in the Straw Proposals. Comments from the 2024 NJ SIP Straw are summarized and addressed in Appendix A.

RATEPAYER IMPACT CONSIDERATIONS

Both the Board and Staff recognize that with electricity rates rising sharply it is vital to do everything possible to control and ideally reduce cost burdens placed on ratepayers. For that reason, the Board intends to fund the GSESP using its existing Clean Energy Program ("CEP")

---

[24] Notice, In the Matter of the New Jersey Energy Storage Incentive Program, 2024 Straw Proposal, https://www.nj.gov/bpu/pdf/publicnotice/Notice-Stakeholder%20Meeting.pdf ("2024 NJ SIP Straw Proposal"). Associated comments can be found using the Board's Public Document Search tool at https://publicaccess.bpu.state.nj.us/CaseSummary.aspx?case_id=2111434.

[25] See Public Document Search, N.J. Board of Pub. Util., https://publicaccess.bpu.state.nj.us/CaseSummary.aspx?case_id=2111434 (last accessed May 29, 2025).

budget, Regional Greenhouse Gas Initiative ("RGGI") revenues,[26] and potentially other funding sources—*without* increasing Societal Benefit Charge ("SBC") rates. This means there would be no gross rate increase due to the GSESP. Staff believes funding the GSESP without SBC increases is feasible due to a combination of some leeway in the current CEP budget and the expected winding down of other CEP funding commitments in the next few years.

However, that alone does not establish that funding the GSESP actively contributes to *reducing* ratepayers' cost burden. Staff, therefore, decided to quantify, to the extent feasible, the savings funding the GSESP will likely provide to ratepayers compared to benefit of returning GSESP funding directly to ratepayers. To that end Staff conducted the analysis described in Appendix B, which compares plausible incentive costs for the Phase 1 transmission-scale segment initiated by this Order to modeled capacity cost savings produced by the resulting increase in the supply of capacity. The results indicate that in most scenarios capacity cost savings realized due to Phase 1 projects will exceed the cost of Phase 1 incentives, thus demonstrating that spending money on Phase 1 incentives will likely provide greater ratepayer relief than returning that money directly to ratepayers would.

The net ratepayer benefit is a result of capacity savings significantly exceeding incentive costs in years when the capacity market is tight, a finding that is robust to widely varying assumptions about the size of the necessary incentives. Importantly, this means that Phase 1 will provide more savings in the short-to-medium term when capacity prices and electric rates are higher than direct ratepayer relief would. However, in years when the capacity market is no longer tight, Staff's analysis consistently found that incentive costs exceeded capacity savings. Whether the lifetime savings provided by Phase 1 exceeds the lifetime costs of Phase 1 depends on the size of the incentives awarded to Phase 1 projects and how long the capacity market remains tight. Fortunately, in most scenarios lifetime capacity savings exceeds lifetime costs, indicating that Phase 1 will most likely be net beneficial to ratepayers in both the long run and the short term.

Staff also stresses that this capacity savings analysis is not a full cost-benefit analysis, as it only compares program costs to one single benefit. Though Staff expects capacity savings to be the main ratepayer benefit of the GSESP, the addition of energy storage resources is likely to provide other saving to ratepayers (e.g., reducing prices in the energy markets during periods of high demand) that this analysis does not quantify. This analysis also does not quantify the benefits of improved grid reliability and resilience that energy storage resources provide or the societal benefits of reducing carbon emissions and other forms of pollution. Staff, therefore, believes that this analysis should be seen as a conservative lower bound on the value of Phase 1 of the GSESP.

STAFF RECOMMENDATIONS FOR THE OVERALL GSESP

Staff has developed its recommendations for the design and implementation of the GSESP based on extensive stakeholder feedback on the Straw Proposals, design elements needed to align with bills pending in the Legislature, and consultation with other State Agencies.

Program Goals

Staff recommendations align with policy framework outlined in the Straw Proposal to achieve the

[26] The Board will only use RGGI revenues to fund the GSESP to that extent that such revenues are allocated to this purpose in accordance with the relevant provisions of the RGGI Act. See N.J.S.A. 26:2C-50 to -53.

following goals:

- Achieve, in conjunction with the Competitive Solar Incentive ("CSI") program and other state-supported programs, the 2030 energy storage goal of 2,000 MW by 2030, as set forth in the Clean Energy Act ("CEA"), in a manner that is consistent with New Jersey's competitive electricity markets.
- Promote deployment of low-cost private capital into New Jersey storage projects by establishing a stable market structure.
- Decrease Greenhouse Gas ("GHG") emissions by enabling higher levels of renewable resources to interconnect to the grid.
- Support deployment of energy storage systems interconnected to the transmission or distribution system of a New Jersey EDC.
- Grow a sustainable energy storage industry that gradually requires decreased incentives to deploy additional storage resources and ensure that the benefits of energy storage last well beyond the term of this initial program.
- Support overburdened communities with energy resilience, environmental improvement, and economic benefits derived from energy storage.
- Encourage storage deployment that accelerates the clean energy transition, including facilitating deployment of renewable energy, electric vehicle or other DERs, and resiliency.
- Establish a Program Administrator at the BPU who would oversee the efficient implementation of the program; and
- Reduce electricity costs for ratepayers.

Due to the dramatic jump in capacity prices last year, following the release of the 2024 GSESP Staff decided to investigate the extent to which the GSESP could help alleviate ratepayer cost burdens. After concluding that capacity savings from accelerating the deployment of energy storage would likely exceed the cost of the necessary incentives, Staff added "reduce electricity costs for ratepayers" as a program goal.

<u>Program Structure, Installed Storage Targets and Timeframes</u>

Considerations

To meet the CEA's 2030 mandate, the Board aims to procure 2,000 MW of storage with at least four-hour continuous discharge capacity, totaling at least 8,000 MWh. Storage capacity under the GSESP will be measured as the lesser of nameplate capacity (MW) or energy storage capacity (MWh) divided by four hours to ensure accurate tracking. The Board plans to meet this mandate in part through the CSI solar-plus-storage program, which currently targets 160 MWh of energy storage capacity annually, or 40 MW using the same four-hour standard. Between 2022 and 2030, CSI procurements are expected to contribute 200 MW to 500 MW toward the 2,000 MW goal, though adjustments may be made as the Board gains experience. This means that the GSESP will need to procure 1,500 MW to 1,800 MW of energy storage to satisfy the CEA mandate.

Staff previously proposed that the GSESP comprise two segments: one for grid supply energy storage systems interconnected in front of the meter and the other for distributed energy storage systems interconnected behind a retail meter. The two segments are designed to provide incentives for eligible energy storage systems to help achieve New Jersey's target of deploying 2,000 megawatts ("MW") of energy storage by 2030. Staff also recommended implementing the

GSESP in two distinct phases, with the possibility of a third phase, each following its own timeline.

Stakeholders urged accelerating storage deployment to meet New Jersey's 2,000 MW goal. Some proposed raising the overall procurement targets to 4,000 MW or higher, citing larger goals in other states and the potential to leverage Inflation Reduction Act ("IRA") tax incentives. There was significant stakeholder support for the distributed segment, with recommendations that it be developed more urgently and launched in Phase 1. Many stakeholders advocated for shifting more capacity to distributed storage, especially net-metered projects, to avoid PJM delays. Some argued that distributed energy storage could help alleviate capacity issues and be connected more quickly, enabling the state to meet its storage goals faster. Others suggested prioritizing Front-of-the-Meter distributed generation and ensuring performance payments from EDCs for the services they provide – primarily reducing PJM capacity cost allocations.

Staff Recommendations

After considering relevant factors and stakeholder input, Staff recommends two segments within the GSESP: one for transmission-scale energy storage systems, directly interconnected to the bulk transmission system, and the other for distributed energy storage systems, interconnected to EDCs' distribution systems, either in front of or behind a retail meter. Staff also reaffirms its recommendation to launch the Transmission Fixed segment as Phase 1 in 2025. The Distributed segment requires further development and should launch as Phase 2 of the program in 2026. This will necessitate a shift in total transmission and distributed GSESP allocations by program year. Staff recommends that the Board procure 1,000 MW of transmission-scale storage in Phase 1 and 500 MW to 800 MW of distributed storage in Phase 2, but reserve the right to modify procurement targets and allocations between the Transmission-scale and Distributed segments based on economic conditions and market developments.

Staff also offers the following specific recommendations:

- Phase 1 (Transmission Fixed Incentive) should launch with an initial solicitation target of 350–750 MW and aim to procure at least 1,000 MW of transmission-scale energy storage over multiple solicitations. Staff recommends that the Board provide fixed incentive payments through an annual competitive bidding structure, distributed over 15 years. Staff had considered FTM "grid supply" connections to the electric distribution system for Phase 1 but now recommends limiting incentives to only transmission-scale energy storage systems to align with pending New Jersey Assembly Bill A5267 (2024). Staff recommends allowing both standalone storage as well as storage additions to existing solar, solar-plus-storage resources, and other Class I renewable energy resources to participate in Phase 1 solicitations, provided they are not receiving and will not receive incentives for the same storage capacity from the CSI program.
- Phase 2 (Distributed Fixed Incentive and Distributed Performance Incentive) should provide a combination of distributed fixed incentives and distributed performance incentives to eligible distributed energy storage projects. Staff recommends allowing both distributed standalone storage and any storage system paired with a distributed Class I renewable energy resource to qualify for distributed incentives, provided the energy storage system is installed after the effective date of Phase 2.
- Phase 3 should be deferred. This component would offer performance incentives to support transmission-scale energy storage systems in advancing the State's policy objectives.

Staff acknowledges the desire of many stakeholders to provide distributed storage incentives in Phase 1, but recommends against doing so for several reasons. First and foremost, Staff believes distributed storage will only provide benefits to ratepayers that are commensurate with incentive costs if their owners are both willing and able to use their energy storage systems in a manner that supports the larger grid. Supporting the grid requires some means of dispatching distributed energy storage systems in real-time, along with performance incentives or payments for the provision of grid flexibility services to motivate system owners to provide such benefits. The practical reality is that it will take time for EDCs to acquire the software and develop the processes necessary to implement such a system. This means any incentives for distributed storage provided in Phase 1 would have to be exclusively fixed incentives. But absent the ability to actively dispatch distributed storage to support distribution grids, such storage systems will not offer any materially greater value to the grid than transmission-scale storage. At the same time, distributed storage lacks the economies of scale that transmission-scale storage provides and therefore likely require much higher fixed incentives on a per-MW basis to close their revenue gap. Staff, therefore, believes that it is initially more cost-effective to focus on incentivizing transmission-scale storage until such a time as a performance incentive program for distributed storage can be launched.

Second, during the final stages of the GSESP's development, a significant amount of New Jersey transmission-scale storage capacity was able to secure interconnection approval from PJM. As such, there are now hundreds of MWs of "shovel-ready" transmission-scale energy storage capacity that can be built provided the necessary investment signals are sent. Another significant batch of transmission-scale energy storage capacity may be able to secure interconnection approval within the next year due to recent revisions to PJM's surplus interconnection service process.[27] A third group of transmission-scale projects should reach the final interconnection study phase in the first half of 2026 and have final interconnection approval by the end of that year. Staff, therefore, believes that PJM interconnection delays do not pose a significant obstacle to a Phase 1 transmission-scale storage procurement target of 1,000 MW. Thus, avoiding PJM interconnection queue delays is no longer a valid rationale for paying a premium for distributed storage.

For these reasons, Staff continues to recommend exclusively providing incentives to transmission-scale storage projects in Phase 1 and procuring most GSESP storage capacity from transmission-scale projects.

Table 1 below summarizes recommended program segments, deployment timeframes, and other key elements. This table has been updated from the version included in the 2024 NJ SIP Straw to reflect Staff's new recommendations that Phase 1 be limited to transmission-scale projects and payout incentives on an annual basis over a 15-year period instead pay a single upfront incentive.

[27] See PJM Interconnection, FERC Accepts Two PJM Proposals to Expedite Supply Additions, PJM Inside Lines (Feb. 12, 2025), https://insidelines.pjm.com/ferc-accepts-two-pjm-proposals-to-expedite-supply-additions/.

Table 1. Summary of Key Program Elements

Phase Incentive Type	Phase 1 Transmission Fixed	Phase 2 Distributed Fixed	Phase 2 Distributed Performance	Phase 3 Transmission Performance
Projected Launch Date	2025	2026	2026	Deferred
Incentive Timing	15-year payout	Upfront	Ongoing	Deferred
Form	Annual competitive bid	Annual block	Pay-for-performance	Deferred
OBC Adder	No	Yes	No	No

Business Model Considerations

Considerations

Staff highlights that ownership and operation of energy storage assets are central to energy storage program design. Both the 2022 NJ SIP and 2024 NJ SIP Straws recommended a private ownership model for energy storage, aligning with New Jersey's competitive market structure. While ratepayers will support storage investments, private investors will bear commercial and operational risks.

Some commenters supported a greater utility role, while others opposed it. All four (4) public electric utility companies (PSE&G, JCP&L, ACE and Rockland) favored increased utility involvement. Supporters argued that restricting utility ownership and operation of energy storage resources under the Straw proposal could hinder the State's ability to meet its energy goals. Some recommended that if the Board limits or excludes EDC ownership of storage resources under the GSESP, it should clarify that EDCs may still own and operate storage assets outside the program when used for distribution or transmission purposes. Additionally, GSESP projects should not receive preferential treatment over EDC-proposed storage projects. Other stakeholders expressed concerns about EDCs participating directly in GSESP, citing a potential conflict of interest due to their role in developing performance metrics and financial incentives for distribution-level storage. Some also recommended prohibiting EDC affiliates from participating in the program, arguing that they have competitive advantages. A few commenters suggested allowing utilities to own, develop, and operate projects that serve overburdened communities.

Staff Recommendations

Staff maintains its recommendation in the Straw Proposal that GSESP promote private ownership of energy storage systems, keeping risks with investors while using ratepayer support for funding. To that end, Staff recommends limiting eligibility for Phase 1 incentives to private (non-EDC) and governmental entities. Staff recommends addressing the question of whether and under what conditions EDC-owned distributed storage may qualify for GSESP incentives in a future order.

Staff clarifies that its recommendations regarding the ownership of energy storage systems apply only to those receiving Phase 1 GSESP incentives. Nothing in Staff's proposal prevents prudent EDC investment in or ownership of energy storage systems that do not receive GSESP incentives as a non-wires alternative to traditional distribution system investment.

Greenhouse Gas Considerations

Considerations

One of the goals of the GSESP is to reduce greenhouse gas emissions by incentivizing energy storage systems. However, challenges such as the lack of day-ahead emissions data, unreliable historical metrics, and excessive complexity have led Staff to recommend against launching the program with an emissions-based incentive for now, while leaving the option open to implement it later if reliable data becomes available.

Stakeholders suggested shifting to simpler and more predictable metrics like availability, peak discharge hours, and standard performance commitments instead of directly linking incentives to emissions. Many raised concerns that tying storage dispatch to GHG reduction could increase costs or reduce participation. System peak alignment was a commonly recommended alternative for a clearer and more effective structure. Some emphasized the need for any emissions-based incentive to support peaker plant displacement goals, even if introduced gradually. Overall, there was a strong push for greater clarity and simplicity in calculating and applying incentives.

Moreover, Staff expects that expanding energy storage will reduce GHG emissions even in the absence of an explicit GHG-based performance incentive. This is because deploying energy storage supports the growth of solar, wind, and EV infrastructure while reducing the need for new fossil fuel generation capacity. An analysis performed by TRC suggests that GSESP-supported storage could avoid 2–3.6 million metric tons of CO_2 over 20 years, from 2025-2044, averaging 100,000–180,000 metric tons per year for these reasons alone. This analysis assumes the GSESP will enable the deployment of 1,500 MW of energy storage by 2030, with non-GSESP mechanisms such as the CSI Program providing the remaining 500 MW necessary to meet the 2030 target.

More specifically, energy storage helps balance variations in renewable output, preventing curtailment (wasting excess clean energy) and reducing reliance on fossil plants that would otherwise be needed to stabilize the grid. By allowing surplus solar and wind power to be stored and used later, it is expected that storage systems would increase the technical and economic viability of renewable energy projects, thereby helping to increase clean energy deployment. Initially, storage operations may slightly increase emissions due to charging and discharging energy losses. This is because the difference in GHG intensity between peak and off-peak fossil generation may not be large enough to outweigh these losses in early years. However, as the supply of renewable energy grows, cleaner generation resources are the marginal generators in more hours and the difference in GHG intensity between peak and off-peak generation grows. As a result, TRC projected that GESP storage will begin reducing emissions by 2032, with 141,000 metric tons of CO_2 avoided through discharging compared to 131,000 metric tons emitted through charging—resulting in a net reduction of 10,000 metric tons in that year. The size of the annual net reduction continues to grow thereafter, which is why annual net GHG reductions average 100,000 to 180,000 metric tons over the 2025-2044 period. This confirms that expanding storage capacity through the GSESP program will lead to long-term emissions reductions, supporting a cost-effective clean energy transition.

Staff Recommendations

Staff recommends not launching the GSESP with an emissions-based incentive due to data limitations and TRC's projection that the GSESP will lead to GHG reductions even absent such an incentive. However, Staff also recommends that the Board reconsider this option if a reliable day-ahead Marginal Emission Rate ("MER") signal becomes available in the future. If a workable model is developed by PJM or a qualified third party, the Board may establish such an incentive for transmission-scale energy storage systems.

Definition of Energy Storage

Considerations

Staff proposes a broad definition of energy storage to encourage innovation and competition while minimizing costs for ratepayers. The GSESP will focus on commercially available technologies but remain open to emerging solutions if they are cost-competitive. Staff proposes to adopt the following definition for energy storage:

"Energy storage" means a device that is capable of absorbing energy from the grid or from a generation resource located behind the same point of interconnection, storing it for a period of time using mechanical, chemical, or thermal processes, and thereafter discharging the energy back to the grid or directly to an energy-using system to reduce the use of power from the grid.

The definition has changed from the one initially proposed in the 2024 NJ SIP Straw Proposal, which is shown in a footnote for reference.[28] Staff changed the "distributed energy resource" language to "generation resource located behind the same point of interconnection" text to reflect the fact that Staff now recommends allowing storage added to grid-scale class I renewable energy resources to qualify for GSESP incentives under certain conditions.

Staff Recommendations

Staff upholds its recommendation in the Straw Proposal to adopt a definition that directly reflects the role of energy storage, including energy storage additions to existing grid-scale generation resources.

STAFF RECOMMENDATIONS FOR THE GSESP TRANSMISSION-SCALE SEGMENT

Incentive Structure for Transmission-scale Energy Storage Systems

Considerations

The 2022 NJ SIP Straw proposed a mix of fixed and performance incentives for Grid Supply and Distributed storage projects. For Grid Supply projects, the 2022 NJ SIP straw proposed: (1) fixed

[28] Staff's previously proposed definition of energy storage was "[a] device that is capable of absorbing energy from the grid or from a Distributed Energy Resource (DER), storing it for a period of time using mechanical, chemical, or thermal processes, and thereafter discharging the energy back to the grid or directly to an energy using system to reduce the use of power from the grid." 2024 NJ SIP Straw Proposal at 9.

incentives tied to up-time performance metrics, paid annually based on $/kWh of storage capacity, and (2) a performance-based incentive that would reward emissions reductions. In the 2024 NJ SIP Straw, Staff proposed changing Grid Supply fixed incentive from annual payments to a one-time payment upon commercial operation, based on maximum usable storage capacity. In the 2024 NJ SIP Straw Staff also proposed not launching the GSESP with an emissions-based performance incentive due to stakeholder feedback on the 2022 NJ SIP Straw and the RFI.

In response to stakeholder feedback on the 2024 NJ SIP Straw, Staff now favors making fixed transmission incentive payments over 15 years instead of a single upfront payment. This change also allows more megawatts to be procured at the program's start. Staff also favors changing the name of Grid Supply Fixed incentives to Transmission Fixed incentives, given Staff's proposal to limit this GSESP to projects interconnecting at the transmission level. Finally, Staff continues to believe that the GSESP should not launch with a performance incentive for transmission-scale projects.

Fixed Incentives for Transmission Resources

Fixed incentives for energy storage systems help close the revenue gap between storage costs and the returns needed to attract developers. Staff determined that annual competitive solicitations are the best approach for the transmission segment of the GSESP, based on minimizing annual budget commitments, stakeholder feedback, and CSI Program experience. Under this approach, the Board would issue solicitations specifying MW targets or ranges for each solicitation. The solicitation would ask participants to quantify the fixed incentive needed to support their project revenue requirements. Transmission-scale storage developers would have to choose between the GSESP or CSI Program. For instance, a solar-plus-storage project that does not clear CSI could later opt into GSESP, and vice versa. A project that involves adding storage to a previously solar-only system that received CSI incentives would also qualify for GSESP incentives. However, GSESP incentives for transmission-scale solar-plus-storage projects or storage additions to existing solar projects would only apply to and be based on the storage component of the project, with no adder for the solar component of the project. This ensures originally solar-only projects that received CSI incentives are not paid twice for their solar capacity if they subsequently add a storage component. Recipients of fixed incentives during periods offering only fixed incentives would not qualify for future performance incentives. Figure 1 provides a decision tree for transmission-scale energy storage systems.

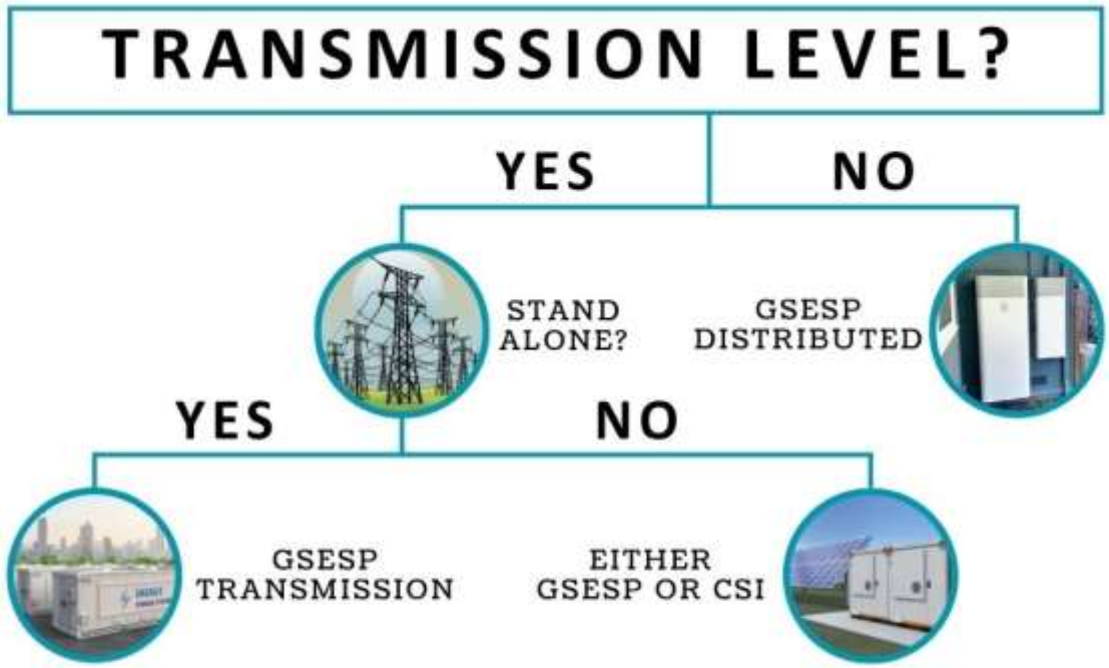


Figure 1. Garden State Energy Storage Program Selection

Staff believes that the key benefits of a competitively determined incentive program are (1) ensuring ratepayers support the most cost-effective projects; (2) using competitive market pressure to determine the lowest necessary incentive value; and (3) automatically adjusting incentives to reflect market conditions without the need for a separate administrative process.

Staff favors an initial solicitation target of 350-750 MW, and procuring at least 1,000 MW of transmission-scale energy storage over multiple solicitations. Staff likewise favors fixed incentives payments through an annual competitive bidding structure, disbursed over a period of 15 years. The 350 MW lower end of the target range for Tranche 1 serves to protect against the potential exercise of market power by enabling the Board to reject excessively high bids. At the same time, the 750 MW high end of the range would enable the quick deployment of a significant amount of energy storage if the Board receives a large amount of cost-effective bids.

Commenters support a competitive process for GSESP incentives, citing its success in solar financing and offshore wind development. They advocate for market-driven solicitation models instead of administratively set incentives like those used in the CSI program to ensure cost-effective investment and efficient resource allocation. Commenters generally favor 15-year contract terms, believing that such a duration would lower costs, allow access to the federal Investment Tax Credit (“ITC”) and attract sufficient project funding.

Staff Recommendations

Staff reaffirms its recommendation in the 2024 NJ SIP Straw that the Board should employ competitive solicitations for the transmission segment of the GSESP. Specifically, the Board should issue solicitations specifying MW targets or ranges for each state fiscal year, requiring participants to quantify the fixed incentive level necessary to support project revenue requirements. The solicitations should use a “pay-as-bid" model, in which winning bidders are awarded the incentives they request in their bid submission. Staff recommends an initial solicitation target of 350-750 MW and procuring at least 1,000 MW of transmission-scale energy storage over multiple solicitations. Staff further recommends that the Board pay out fixed incentives to winning bidders over a period of 15 years.

Staff recommends conducting Tranche 1 following the launch of the GSESP in accordance with the schedule below. Qualifying transmission-scale energy storage project applications and qualifying grid supply solar-plus-storage project applications that are ineligible for storage incentives under the Board's Successor Solar Incentive ("SuSI") Program will be eligible to compete in this initial and future solicitations. Table 2 presents the proposed schedule for this initial solicitation.

Table 2. GSESP 2025 Tranche 1 Transmission-scale Procurement Schedule

Event	**Date**
Pre-qualification window opens	June 25, 2025
Deadline for guaranteed pre-qualification review for deficiency and opportunity for correction	July 23, 2025
Pre-qualification deficiencies will be reported to bidders by this date for correction	August 13, 2025
Deadline for final bid submission*	August 20, 2025
Board Decision on Bids	October 2025

*Note: Bidders may submit new bids and prequalification information until the final deadline. However, only bidders who submit prequalification information by **July 23, 2025**, will be guaranteed a review for deficiencies and the opportunity to correct the deficiencies before the final bid deadline. After the final bid deadline, no changes to bids or prequalification information will be accepted.

Performance-based Incentive for Transmission-scale Resources

One of the stated goals of the GSESP is to leverage energy storage systems as a means of reducing greenhouse gas ("GHG") emissions. The September 2022 NJ SIP Straw proposed to advance this objective by explicitly linking GHG reductions to incentive payments. The straw proposed to accomplish this by using PJM's hourly GHG marginal emissions rates ("MER") data and date on energy storage charging and discharging to calculate GHG reduction performance incentives.

However, this MER data is not forward-looking, as PJM does not provide day-ahead emissions signals. In response to stakeholder concerns that historical, hourly MER data cannot reliably project emissions or inform charge and discharge decisions for energy storage systems, Staff investigated whether PJM could publish a day-ahead emissions signal for use in a performance incentive. Due to the financial nature of the day-ahead energy market, PJM is currently unable to generate a unit-specific day-ahead MER signal. Additionally, Staff explored using real-time MER data, which is updated every two hours, but found the mathematical relationships unreliable.

Both stakeholders and Staff identified additional concerns regarding the feasibility of using PJM's existing MER data. First, it is unclear whether emissions rates can be reliably correlated with preliminary load or settled hourly prices to develop accurate predictive models. Second, a review of emissions data from January 1 to May 22, 2024, found instances where emissions rates contradicted expected outcomes. Third, PJM itself has cautioned that its marginal emissions data is not fully developed. Lastly, many stakeholders believe an MER-based incentive would be overly complex.

For these reasons, Staff concludes that launching the GSESP with a net avoided emissions performance incentive is not advisable at this time. However, Staff believes the Board should retain the flexibility to implement such an incentive if reliable data and analytics become available. If the Board determines that an accurate day-ahead MER signal has been developed—either by PJM or a third party capable of modeling security-constrained unit commitment and dispatch within PJM's transmission network—it may establish a net avoided emissions performance incentive for transmission-scale energy storage systems.

Staff Recommendations

Staff maintains its recommendation that the GSESP not launch with a net avoided emissions performance incentive at this time, as current data and analytics do not support its effective implementation. However, Staff recommends that the Board retain the flexibility to introduce such an incentive in the future if sufficiently accurate and forward-looking data become available.

Pre-qualification, Project Maturity and Bid Process for Transmission-scale Projects

Considerations

Pre-qualification is designed to eliminate projects unlikely to meet the solicitation's Commercial Operation Deadline. The process prioritizes low incentive costs while ensuring the timely and successful completion of projects. With these pre-qualification and maturity requirements, Staff aims to balance awarding projects early enough in development to mitigate risk while supporting projects with strong likelihood of completion.

Ratepayers benefit when incentivized projects are highly likely to succeed. Staff believes the transmission segment of the GSESP should include qualification and maturity requirements to ensure that awarded energy storage systems can be completed on time. Staff favors enforcing maturity standards and participation fees to prevent unviable projects from receiving incentives. To qualify for an incentive award, transmission-scale energy storage systems should have a planned commercial operation date (COD) that is no later than 30 months after the competitive solicitation application period closes - instead of 550 days after executing a generation interconnection agreement, as proposed in the 2024 NJ SIP Straw. A project should be considered operational only when it is fully constructed and interconnected with the PJM-managed transmission grid, including any necessary network upgrades. Projects failing maturity requirements in one solicitation should be allowed to reapply in future solicitations. Many stakeholders supported flexible milestones and longer COD timelines, for example, 40 months for certain projects. There was broad agreement that screening should ensure readiness without imposing financial or administrative barriers, especially for newer technologies and smaller developers.

For grid-supply projects, queue position serves as a transparent benchmark in the pre-qualification process. While not a perfect indicator, a more advanced PJM queue position increases the likelihood of success, assuming all other factors remain equal.

Beyond queue position, additional pre-qualification criteria should include having a fully executed interconnection agreement, completing at least Phase I of the PJM process or an equivalent study, or providing documentation demonstrating access to capacity interconnection rights ("CIRs") of a deactivating generation facility. Staff may also set additional eligibility criteria.

State-supported projects commonly require fees or deposits to ensure bid seriousness, encourage bidders to honor their project commitments, and help cover the administrative costs of state incentive programs.

GSESP-eligible facilities should be allowed to submit bids for fixed incentive awards, based on dollars per MW, after pre-qualification. Applications should include documentation proving site control, required permits, financial capability, compliance with safety standards, and eligibility for revenues through electricity markets. Additionally, projects should demonstrate any brownfield development or community benefits, including those impacting overburdened communities.

Staff Recommendations

Staff recommends conducting a pre-qualification step before the final bid submission deadline. The pre-qualification process would require developers to submit a preliminary set of documents to Staff or the Board's Program Administrator, addressing compliance with project maturity requirements and similar criteria. Staff recommends opening the pre-qualification window for Tranche 1 on **June 25, 2025**, and keeping it open until bids are due on **August 20, 2025.** Developers may submit their pre-qualification paperwork to Staff or the Board's Program Administrator, who will review the documents, identify any deficiencies, and provide developers the opportunity to rectify them before bids are due. Staff further recommends that only pre-qualification requests submitted by **July 23, 2025**, should be guaranteed to be reviewed for deficiencies and given the opportunity to correct the deficiencies before the final bid deadline. Final applications with unresolved deficiencies at the bid deadline may result in project disqualification from the solicitation.

As part of the pre-qualification request for Tranche 1, Staff recommends requiring developers to provide evidence that their proposed transmission-scale energy storage projects meet the following criteria:

- Be a planned resource or part of a planned resource that will interconnect to the PJM transmission network and be located within a transmission zone in New Jersey, or be an addition to an existing resource that is interconnected to the PJM transmission network and located within a transmission zone in New Jersey.
- Have a planned COD no later than 30 months after the solicitation's application period closes and a guaranteed COD no later than 150 calendar days after the planned COD.
- Not participate in any other energy storage program, except when seeking to pair with or interconnect behind the same meter as an existing solar project participating in the CSI Program. Such systems shall only qualify for an incentive award pursuant to this section if neither the existing solar project nor the transmission-scale energy storage system has received, is receiving, or will receive incentives from the SuSI Program for any energy storage capacity.

At the time of application, Staff recommends that projects should have a fully executed Generation Interconnection Agreement, fully executed Interconnection Service Agreement, a completed

Surplus Interconnection Study, or provide the Board with documentation demonstrating that the proposed project will be able to use the CIRs of a deactivating generation facility.

Staff recommends requiring Tranche 1 GSESP-eligible facilities to submit a final application and bid for an incentive award, calculated in dollars per MW, after they submit their pre-qualification request. The final application should include the following elements:

1. The proposed project's nameplate capacity in megawatts and energy storage capacity in megawatt-hours;
2. The number of CIRs that the project holds;
3. The proposed project's PJM interconnection queue ID number;
4. A copy of the proposed project's Generation Interconnection Agreement or Interconnection Service Agreement, completed Surplus Interconnection Study, or documentation demonstrating that the proposed project will be able to use the CIRs of a deactivating generation facility;
5. The proposed project's address, geographical information systems ("GIS") coordinates, address, and number of acres proposed for development;
6. For a storage facility paired with grid supply solar, a description of the associated solar facility;
7. Evidence reasonably satisfactory to the board of site control, such as a copy of a lease agreement or a property title;
8. Evidence reasonably satisfactory to the board that an applicant has or will obtain all required permits, which evidence shall include an execution plan to obtain all required permits that the applicant has not yet secured. Such evidence may include submitted applications, schedule projections and related correspondence with the Authority Having Jurisdiction (AHJ);
9. Evidence reasonably satisfactory to the board of the applicant's financial means to construct the transmission-scale energy storage system and ability to obtain revenues through electricity markets or non-ratepayer funding, including, but not limited to, energy arbitrage, ancillary services, and capacity revenues in PJM. Evidence of financial means to construct a transmission-scale energy storage system may include:
    - Audited financial statements from the applicant or project sponsor showing sufficient assets, liquidity, or net income to support project development;
    - Proof of committed funding, such as executed equity investment agreements or letters of credit;
    - Bank statements or financial institution letters demonstrating access to capital reserves;
    - Loan agreements or term sheets from lenders confirming project finance arrangements; and/or
    - Evidence of successful past development and operation of energy infrastructure projects of a similar scale.
    - Evidence of the ability to obtain revenues from electricity markets or non-ratepayer funding may include:
    - Market analysis or third-party revenue projections demonstrating potential earnings from energy arbitrage, frequency regulation, spinning reserves, and capacity market participation in PJM;
    - Letters of intent or executed contracts for energy or capacity sales, power purchase agreements (PPAs), or tolling agreements; and/or
    - Registration or enrollment of the project in PJM as a market participant or asset,

10. Assurances reasonably satisfactory to the board that the transmission-scale energy storage system will adhere to any safety requirements, standards, or measures that the board deems appropriate as well as to any nationally recognized minimum safety requirements, including, but not limited to, appropriate laboratory testing, and will comply with all manufacturers' installation requirements, applicable laws, regulations, codes, licensing, and permit requirements; such evidence may include:
    - Evidence that the project will utilize only energy storage systems certified by a Nationally Recognized Testing Laboratory (NRTL) such as UL 9540 and UL 9540A for thermal runaway testing;
    - A copy of a comprehensive compliance plan to ensure adherence to all applicable federal, state, and local codes (e.g., NEC, NFPA 855) and permitting requirements, and that all construction and operation activities will be carried out in coordination with the relevant AHJs;
    - Evidence that installation will be performed by certified technicians in accordance with all manufacturer specifications, such as copies of a commissioning report and ongoing maintenance plan aligned with manufacturer guidelines and industry best practices;
    - A signed and sealed letter by a New Jersey licensed professional engineer confirming that the system design, installation, and operation will adhere to all relevant building codes (e.g., NFPA, NEC), local permitting requirements, and the manufacturer's safety and installation guidelines; and/or
    - A detailed Safety and Code Compliance Plan outlining procedures for installation, commissioning, inspection, and ongoing maintenance, referencing specific applicable laws, permits, and standards (e.g., IEEE, NFPA 855), with confirmation of coordination with AHJ.
11. A statement describing the transmission-scale energy storage system's alignment with State and regional transmission and resource adequacy planning goals and demonstrating the transmission-scale energy storage system's coordination with PJM and the appropriate electric public utility; and
12. A non-refundable application fee of $200 per MW.

Staff further recommends using similar requirements for future solicitations. Staff, however, recommends allowing storage projects that do not have interconnection approval but have paid a Decision Point 1 interconnection deposit to PJM to qualify for future solicitations, as Staff is only recommending that Tranche 1 be limited to projects with interconnection approval to align with pending New Jersey Assembly Bill A5267. Expanding project eligibility would require minor changes to the application requirements listed above, which Staff recommends the Board specify in any future Order opening another GSESP solicitation.

Project Evaluation, Selection, Award, and Registration Processes for Transmission-scale Projects

Considerations

Staff recognizes the importance of structuring incentives to support transmission-scale energy storage systems in a manner that promotes efficiency, equity, and community benefits.

A competitively determined incentive program offers several advantages, including ensuring that New Jersey ratepayers support projects seeking the lowest possible incentive contribution, establishing a structured process that keeps incentive values aligned with the most current market conditions, providing a fixed, long-term, and guaranteed incentive framework that minimizes the risk of public investment while encouraging private capital investment.

To facilitate this approach, Staff recommends that the Board award incentives for transmission-scale energy storage systems through a competitive solicitation process. In each solicitation, the Board may evaluate bid price alongside other factors, including community benefits, brownfield redevelopment,[29] and/or demonstrated advantages to overburdened communities where such projects are proposed (collectively referred to as community benefits). Staff, however, believes there should be a quantitative limit on any premium the Board pays for such benefits.

Staff Recommendations

Staff reaffirms its recommendation that the Board award incentives for transmission-scale energy storage systems through a competitive solicitation process. This approach ensures that incentives are allocated cost effectively.

In each solicitation, Staff recommends the Board evaluate bid prices and retain the discretion to consider community benefits. By reaffirming this recommendation, Staff emphasizes the importance of maintaining a transparent, competitive framework that drives responsible energy storage development while advancing the state's clean energy and equity goals.

Only applications that are complete by the close of the application period will be considered for selection in the relevant solicitation.

Selection and Award Procedure for Transmission-scale Projects

Staff recommends selecting the lowest-cost projects in price-ranked order, subject to consideration of community benefits, until the Board awards enough transmission-scale energy storage systems to meet the solicitation's minimum target installed capacity. Staff further recommends exceeding the minimum target and awarding additional projects up to the maximum target installed capacity if the Board determines, based on the submitted bids, that awarding more capacity is in the best interest of ratepayers.

Staff recommends that the Board find awarding more capacity is in the best interest of ratepayers if doing so could enable meeting the CEA target at a lower total cost net of offsetting savings to ratepayers. If a final award would result in exceeding the maximum target installed capacity for the solicitation, Staff recommends that the Board exercise discretion in determining whether awarding the project would sufficiently benefit New Jersey to warrant exceeding the target. Similarly, if two (2) projects are bid with the same price and either can be awarded without exceeding the procurement target, but awarding both would exceed it, Staff recommends that the Board exercise its discretion in selecting one (1) or both of the projects and making the award(s).

Staff also recommends that the Board retain the authority to decline the award of fixed incentives to a transmission-scale energy storage system if the Board determines that funding the requested

[29] A "brownfield" may be a site on the New Jersey Department of Environmental Protection's Known Contaminated Sites List or Brownfield Inventory. See Contaminated Site Remediation & Redevelopment (CSRR), N.J. Dep't of Envtl. Protection, https://dep.nj.gov/srp/kcsnj/ (last updated Mar. 8, 2024); Brownfield Inventory for New Jersey, N.J. Dep't of Envtl. Protection Bureau of GIS, https://gisdata-njdep.opendata.arcgis.com/datasets/njdep::brownfield-inventory-for-new-jersey/about (last updated May 29, 2025).

incentive would constitute an unduly expensive means of achieving the State's energy storage goals. In making this determination, the Board shall consider factors, including, but not necessarily limited to, confidential gap analysis results, adjustments for market conditions (such as tariffs), and potential savings for ratepayers (such as capacity savings).

Staff recommends that the Board retain the discretion to award incentives to transmission-scale energy storage systems that do not have the lowest per-unit bids on the basis of community benefits if:

- The per-unit bid price is no more than ten percent higher than the lowest rejected bid price in the same solicitation; and
- The Board determines that awarding incentives to these more expensive transmission-scale energy storage systems instead of lower bidders is in the public interest after considering qualitative factors such as brownfield redevelopment, demonstrated benefits to overburdened communities where a transmission-scale energy storage system is proposed to be located, and/or other community benefits.

For Tranche 1, Staff recommends determining the lowest price bid on a per-unit basis by dividing the applicant's requested annual incentives by the expected average accredited capacity of the transmission-scale energy storage systems over the first five years of the system's commercial operation. Staff recommends using expected accredited capacity, rather than the lesser of nameplate capacity or energy storage capacity divided by 4 hours, to account for the additional resource adequacy value provided by storage projects with greater CIRs or longer durations. If this approach proves too unwieldly in Tranche 1, Staff recommends the Board consider using the lesser of nameplate capacity or energy storage capacity divided by 4 hours in future solicitations.

Staff recommends determining a project's expected average capacity value by multiplying the number of CIRs a proposed projects holds by the average of PJM's forward projections of Effective Load Carrying Capability ("ELCC") rating for the relevant storage resource's ELCC class in that five year-period.[30] PJM provides these ELLC class rating projections on its website.[31] A storage resource's ELCC class (4-hour, 6-hour, 8-hour, or 10-hour) would be determined by dividing the proposed project's energy storage capacity by the number of CIRs it holds.

For example, a 100 MW/400 MWh project with 40 MW of CIRs would be assigned ELCC Class Ratings for the 10-hour storage class. This is because 400 MWh divided by 40 MW equals 10 hours. Assuming the project will begin commercial operation in early 2028 in time for the 2028/2029 delivery year, its expected average ELCC Class Rating for the first five years of its

---

[30] Pursuant to PJM's Reliability Assurance Agreement ("RAA"), the accredited capacity of a "Limited Duration Resource," which includes storage resources, is equal to its Effective Nameplate Capacity multiplied by the applicable ELCC Class rating, and multiplied again by the ELCC Resource Performance Adjustment. RAA § 1; Sch. 9.2(D)(1)(a). A Limited Duration Resource's Effective Nameplate Capacity is capped at the greater of its CIRs or transitional system capability. Id. § 1. Staff's understanding is that in practice a storage resource's Effective Nameplate Capacity will equal its CIRs and so for simplicity recommends using CIRs as a proxy for Effective Nameplate Capacity. Staff likewise recommends ignoring the ELCC Resource Performance Adjustment component because PJM does not provide the necessary data to include it in this calculation.

[31] Preliminary ELCC Class Ratings for Period Delivery Year 2026/27 – Delivery Year 2034/35, PJM, https://www.pjm.com/-/media/DotCom/planning/res-adeq/elcc/preliminary-elcc-class-ratings-for-period-2026-2027-through-2034-2035.pdf (last visited May 27, 2025).

commercial operation would be 71% when rounded to the nearest full percentage point.[32] It would therefore have an expected accredited capacity of 71% times 40 MW or 28.4 MW.

In contrast, if the same project held 100 MW of CIRs it would be assigned the ELCC Class Ratings for the 4-hour storage class, as 400 MWh divided by 100 MW equals 4 hours. Its expected average ELCC Class Rating would thus be 48% when rounded to the nearest full percentage point.[33] Its expected accredited capacity would then be 48% times 100 MW, or 48 MW. If the project in question had both 100 MW of CIRs and 1,000 MWh of energy storage capacity, it would again be assigned ELCC Class Ratings for the 10-hour storage class. Its expected accredited capacity would then be 71% times 100 MW or 71 MW.

After determining which projects to award incentives to, Staff recommends Board Staff, or the Program Administrator send an award letter (in addition to an email) to all winning bidders within five (5) business days following the Board Order announcing the award. Staff further recommends notifying all bidders that did not receive an incentive award via a letter and/or email of the Board's decision and of their option to reapply in a future solicitation.

Staff further recommends that recipients of fixed incentives during the period when only fixed incentives are offered should be ineligible to receive future performance incentives.

Staff recommends that the Board aim to issue awards under Tranche 1 no later than October 2025 to enable participation in the May 2026 BRA.

GSESP Program Registration Process and Requirements

Staff recommends requiring applicants to submit a complete GSESP registration after they receive an award through the solicitation. Staff or the GSESP Program Administrator would then send applicants notice of conditional approval before they commence construction of their projects.

For awarded projects, Staff proposes creating a new registration process and portal for the GSESP in coordination with a Staff or the GSESP Program Administrator. All forms and instructions regarding the GSESP registration process would be posted on a subpage of the Board's Clean Energy Program website at www.njcleanenergy.com. The website already has a dedicated page for GSESP at https://www.njcleanenergy.com/storage.

Bidders awarded a GSESP transmission-scale incentive will have 30 days following the Board Order announcing the award to register their GSESP-eligible facility with the Board. Within 30 days of receiving notice of a fixed incentive award, the applicant must submit a report to the Board detailing the estimated dates for the following project milestones, as applicable:

- Fully executed interconnection agreement;

---

[32] This is because the projected ELCC class ratings for 10-hour storage for the 2028/2029, 2029/2030, 2030/2031, 2031/2032, and 2032/2033 delivery years are 75%, 72%, 73%, 68%, and 69% respectively. Ibid.

[33] This is because the projected ELCC class ratings for 4-hour storage for the 2028/2029, 2029/2030, 2030/2031, 2031/2032, and 2032/2033 delivery years are 55%, 51%, 49%, 42%, and 42% respectively. Ibid.

- Fully executed engineering, procurement and construction agreement;
- Developer financial closing;
- Commencement of energy storage system construction;
- Planned COD; and
- Guaranteed COD.

Before beginning construction on a GSESP-eligible facility, developers or project owners must submit a complete registration package. Staff recommends that the registration package include the following:

- A registration form;
- A description of the project, including type of proposed installation, MW or MWh capacity of project, GIS coordinates, project address, and number of acres proposed for development;
- A contract between the primary installer or the third-party owner, as applicable, and the bidder or customer of record;
- A site plan signed and sealed by a licensed professional engineer, as defined in the pre-qualification section of this order, showing all proposed and installed GSESP-eligible facilities;
- A Milestone Reporting Form;
- Evidence of the project's accepted bid into the GSESP; and
- For storage paired with grid supply solar, MWh of proposed storage facility, description of the storage technology, and project ID or confirmation of solicitation of paired solar project must be included.

Staff recommends that registration packages submitted to the GSESP follow the same general review process as the CSI Program. Specifically, registration packages would be reviewed by Staff or the GSESP Program Administrator, who would verify the project's eligibility to participate in the GSESP and determine whether the registration package is complete, incomplete, or deficient. Registrations deemed incomplete due to a minor deficiency, would be flagged by Staff or the GSESP Program Administrator, with the applicant notified of the deficiency and granted seven (7) business days to correct it. Registrations deemed incomplete, containing a major deficiency, or failing to correct minor deficiencies within the allotted time would be rejected.

For the purposes of the GSESP, minor deficiencies would include such items as an inconsistency between the signatures on different sections of the registration form; failure to complete one or more sections on the registration form; failure to label technologies or to indicate system components on the site plan; a missing or incorrect premise address or missing installer information on the site plan; failure to enter complete equipment information in the relevant registration materials; an incomplete section or sections on any required form; or other similar clerical error.

Major deficiencies would include such items as failure to submit the registration form or failure to include all signatures on that form; failure to submit the certified site plan; failure to submit the Milestone Reporting Form or to include all signatures; failure to submit any other required form or documentation or to include all required signatures on such forms or documentation; and failure to provide evidence of an accepted bid.

Registrants that submit a complete registration package or that corrected all minor deficiencies in the time allowed, and that meet the eligibility and qualification requirements for a GSESP project, would be issued a conditional approval letter by Staff or the GSESP Program Administrator. Staff recommends that the conditional approval letter indicate under which solicitation the energy storage system was awarded.

After issuance of the conditional approval letter, construction of the energy storage system as described in the initial registration package may begin. Staff recommends that an on-site inspection be performed, at a minimum, upon construction completion. If the energy storage system is built as described in the initial registration package, Staff or the GSESP Program Administrator will issue a final approval letter. This final approval will be granted once Staff or the GSESP Program Administrator receives a complete post-construction certification package and verifies that the system has passed the program inspection and obtained permission to operate.

Application Fees, and Compliance Requirements for Transmission-scale Projects

Considerations

Fees or deposits for projects applying for incentives are commonly used to ensure bidder commitment, encourage follow-through on project obligations, and to help offset the cost of administering the incentive program. The GSESP program establishes a non-refundable application fee of $200 per MW for Tranche 1.

Should the Board award a transmission-scale energy storage system a fixed incentive, Staff favors requiring the system owner to provide a pre-development security for transmission projects upon application approval beginning in Tranche 2. The pre-development security may be used to impose a deduction for delays on project development milestones for non-excused events. Pre-development security, project development milestones, fees, and deductions will be established prior to each solicitation. The methodology used to calculate these values will remain consistent across all projects within the solicitation.

Staff also believes that continued payment of annual fixed incentives should be contingent on a transmission-scale energy storage system satisfying minimum availability metrics.

Staff Recommendations

Staff recommends that security, milestones, and fees should be set consistently before each solicitation to ensure fairness across all projects. These requirements shall be posted on the Board's website. The requirements for Tranche 1 are also described in this order.

Application Fees

Staff recommends that transmission-scale energy storage projects be required to pay a non-refundable application fee of $200 per MW for Tranche 1, with funds used to offset administrative costs of the GSESP. Staff further recommends that projects benefiting public entities be exempt from the application fee.

Pre-Development Securities and Delay Penalties

For Tranche 2 and any further GSESP solicitations, Staff recommends requiring pre-development security for transmission-scale projects. Staff does not recommend requiring any pre-development security for Tranche 1 as Tranche 1's eligibility will be limited to projects that have interconnection approval from PJM, which also requires them to have site control.

For Tranche 1, Staff nonetheless recommends that Staff retain the ability to reduce the first annual incentive payment if the project does not achieve commercial operation by its planned COD date, unless the Division Director grants an extension of the planned COD deadline of up to 180 calendar days. An applicant experiencing a delay must submit evidence and demonstrate to Staff's satisfaction that the applicant sought to avoid said delays and advance the project in good faith to qualify for an extension of up to 180 calendar days. Staff may only extend the COD deadline by more than 180 calendar days if the applicant submits evidence and demonstrates to the Division Director's satisfaction that the applicant experienced a force majeure[34] event that the applicant took all possible steps to avoid. The deduction from the first annual incentive payment shall equal the lesser of the entire first annual incentive payment or $1,000 per MW of the project's installed capacity for each calendar day of delay, beginning on the calendar day after the project's planned COD if the Division Director does not grant an extension, or the calendar day after the date to which Staff extended the COD deadline if the Division Director granted an extension. The Board, or the Program Administrator if the Board decides to delegate this authority, may revoke the incentive award if the applicant misses their guaranteed COD by 36 months, or adjusted for any grace period otherwise established by the Board, though the Board may waive this penalty if the applicant demonstrates good cause for relief in writing.

For Tranche 2 and any subsequent solicitations, the pre-development security may be used to impose a deduction for delays on project development milestones for non-excused events. Any pre-development security requirements and penalties will be defined in a subsequent Board Order.

<u>Post COD Dispatch Availability Requirements and Incentive Payment Deductions for Lack of Dispatch Availability</u>

Staff recommends that a transmission-scale energy storage project's continued receipt of the full value of its annual fixed incentive award payments should be contingent on being available for dispatch in a minimum number of hours per year. Specifically, Staff recommends requiring awarded transmission-scale energy storage projects to be available for dispatch for at least 7,900 hours per year (approximately 90% of the 8,760 hours in a non-leap year) to receive their full annual fixed incentive payment.

If a project is available for dispatch for less than 7,900 hours in a given year, Staff recommends proportionately reducing the annual incentive payment for the relevant year by an amount equal to the number of hours the project fell short of the 7,900-hour requirement divided by 7,900 hours. For example, if a project was only available for dispatch for 7,505 hours in the relevant year, it would have fallen short of the requirement by 495 hours. As 495 hours is 5% of 7,900 hours, the project's annual fixed incentive payment would then be reduced by 5%.

For the purposes of determining dispatch availability, Staff further recommends defining the relevant year as an energy year (June 1 to May 31). Staff also recommends designating the first full energy year following the date a project achieves commercial operation as the first energy year in which its compliance with dispatch availability requirements is assessed. Thus, if a project achieves commercial operation anytime between June 1, 2027, and May 31, 2028, Staff or the

[34] "Force majeure" means an event that is not attributable to the fault or negligence of the system owner and is caused by factors beyond the system owner's reasonable control.

Program Administrator would start to assess compliance with the 7,900-hour requirement on June 1, 2028. Staff or the Program Administrator would then continue to assess the project's compliance every energy year through May 31, 2043 (the end of the 15-year period in which the project receives fixed incentives).

Staff notes that this requirement will also enable the Board to cease making incentive payments to transmission-scale projects that outright fail to continue operating. A project that, for any reason, failed to continue functioning would not be available for dispatch in any hours. If such a project was out of service for an entire year, it would have its annual incentive payment reduced to zero. Thus, this requirement will also ensure ratepayers are not forced to pay for failed projects that provide no ongoing benefit to the grid.

<u>Procurement Timelines</u>

Staff recommends holding Tranche 1 on the schedule shown in Table 2 and described below. Staff further recommends holding a Tranche 2 solicitation in the first half of 2026, with the exact schedule to be specified in a future Board order. Staff also recommends the Board retain the discretion to conduct additional transmission-scale storage solicitations if the Board finds that doing so is part of the most cost-effective strategy for meeting the CEA's 2,000 MW energy storage target.

<u>Tranche 1 and Tranche 2 Procurement Targets</u>

For Tranche 1, Staff recommends a procurement target of 350-750 MW. Staff recommends a procurement target for Tranche 2 equal to 1,000 MW minus the amount of capacity procured in Tranche 1.

<u>Tranche 1 Timing</u>

Staff recommends opening the pre-qualification window at 12:00:00 PM on June 25, 2025, and closing the bid submission portal on August 20, 2025, at 11:59:59 PM. Additionally, Staff recommends that for all successful bids, the bidding party, and bid prices be made public at the time of the award announcement. Staff further recommends that the Board issue awards in Tranche 1 by the end of October 2025 to enable participation in the May 2026 BRA.

<u>Siting and Permitting for Transmission-scale Energy Storage Systems</u>

Considerations

Staff's recommendations in the Straw Proposal were based on consultation with AHJs and the siting criteria used in the CSI Program. After deliberation, Staff recommends removing the siting restrictions and waiver provisions from GSESP to eliminate additional barriers to accessing incentives, which could otherwise delay the processing of incentive awards. This does not exempt GSESP projects from complying with all relevant local and state regulations.

Staff Recommendations

Staff recommends the removal of siting restrictions and waiver provisions from the GSESP to mitigate additional obstacles to incentive access, which may otherwise hinder the timely processing of incentive awards. However, GSESP projects remain subject to all applicable local and state regulations.

<u>Technical Requirements for Transmission-scale Projects</u>

Considerations

To qualify for incentives, Staff recommends that transmission-scale storage applicants must be government or private entities (not EDCs). The energy storage systems must consist of new equipment and be planned resources interconnecting to the PJM transmission network in a New Jersey transmission zone. System owners must meet COD requirements by submitting as-built drawings and proof of permission to operate. They must also comply with manufacturers' installation guidelines and adhere to all applicable federal and state laws, regulations, codes, standards, licensing, and permitting requirements. All incentivized energy storage systems must be certified to UL 9540, and tested against UL 9540A, or another applicable standard. Systems not covered under UL 9540A must demonstrate equivalency in safety through third-party testing and compliance documentation. All systems receiving a GSESP incentive award must also meet the NFPA 855 fire safety standards. Inverters must meet UL 1741 SB and IEEE 1547 standards. Staff notes that the Board reserves the right to update certification requirements if a new or revised standard is deemed superior.

Staff Recommendations

Staff maintains its recommendation that, to qualify for incentives, transmission-scale energy storage applicants must be government or private entities (not EDCs). Staff further recommends that eligible systems use new equipment and be planned resources interconnecting to the PJM transmission network in a New Jersey transmission zone that have not yet commenced construction at the time they apply for incentives. System owners must meet COD requirements by submitting as-built drawings and proof of permission to operate. They must follow installation guidelines and comply with all applicable federal and state laws, regulations, codes, standards, licensing, and permitting requirements. All incentivized energy storage systems must be certified to UL 9540, and tested against UL 9540A, or an equivalent standard. Systems not covered under UL 9540A must demonstrate safety equivalency through third-party testing. All systems receiving a GSESP incentive award must also meet the NFPA 855 fire safety standards. Inverters must meet UL 1741 SB and IEEE 1547-2018 standards. Staff notes that the Board reserves the right to update certification requirements if a new or revised standard is deemed superior.

<u>Monitoring and Reporting for Transmission-scale Projects</u>

Considerations

Staff recommends that transmission-scale energy storage system owners submit construction reports from the notice to proceed until the commercial operation date to help the Board track project milestones. During the delivery term, owners must provide monthly operational reports within five business days of the end of each month. The Board must be notified in writing of any change in project ownership, developer, or operator due to sale, transfer, or contract modification. New owners or operators must submit their corporate details, tax ID, contact information, and ownership percentage within 30 days of a material change. This is to ensure oversight, transparency, and compliance with regulatory requirements.

Stakeholders emphasized the need for performance reviews and the establishment of key operational metrics. Rate Counsel suggested tracking projects against the overall program goals.

Staff Recommendations

Staff recommends that transmission-scale energy storage project reporting requirements include project-level reporting by system owners and program-level reporting by the Board or the Program Administrator. System owners must submit construction updates before operation and provide monthly reports on system performance once active. They must also notify the Board of any changes in ownership, development, or operation. Specifically:

- During system operation, the system owner shall provide a report with key operational metrics, including the number of hours it was experiencing a forced outage and the number of hours it was out of service due to a planned outage, to the Board or the Program Administrator within five business days after the last day of each month.
- Within 30 days of a change in system owner, the new system owner shall notify the Board of their individual and/or corporate names, tax identification number, address, contact telephone number, and the percentage of the energy storage system they own. The new system owner shall update any pre-development security as necessary.
- Within thirty (30) days of a material change in the project operator, either the system owner or the new project operator shall notify the Board of their individual and/or corporate names, tax identification number, address, and contact telephone number.
- Within thirty (30) days of a material change in the project developer, including a change in a subcontractor, either the system owner or the new project developer shall notify the Board of their individual and/or corporate names, tax identification number, address, and contact telephone number.

Additionally, transmission-scale energy storage systems must have meters and telemetering equipment to track energy exchange and report data. At the program level, the Board will review the GSESP annually to ensure it meets its goals, with adjustments made as needed. A public website will provide regular updates on the program's status.

If a transmission-scale energy storage system receiving a fixed incentive award is co-located with an existing generation resource, or an electric generator is subsequently co-located with the transmission-scale energy storage system, Staff recommends that the Board require the system owner to install a revenue-quality meter or meters capable of measuring the power and energy discharged by the transmission-scale energy storage system separately from the power and energy produced by the generation resource, along with telemetering equipment and data acquisition services sufficient for producing monthly operating reports, pertaining to the transmission-scale energy storage system.

The project-level reporting requirements should track progress against the GSESP goals. Specific reporting requirements will be contained in the program application, and may include, but are not necessarily limited to the following elements found in Table 3.

Table 3. Project-Level Reporting Requirements

GSESP Goals: Transmission Projects	Metrics: Per year and cumulative to date
(1) Achieve the 2030 energy storage goal of 2,000 MW by 2030	Installed capacity in total and by technology type, number of projects and identification of applications awarded and not awarded.
(2) Promote deployment of low-cost private (non-utility and non-NJBPU) capital into New Jersey storage projects	1. Total project cost ($, $/kW, $/kWh) 2. Fixed, performance, and total Incentives ($, $/kW, $/kWh) 3. Percent of total project cost funded by New Jersey ratepayers, private capital, and other federal and state funding sources
(3) Decrease Greenhouse Gas ("GHG") emissions by enabling higher levels of renewable resources to interconnect to the grid	GHG emissions related to peak, non-peak, and total MWh charged and discharged, as can be reasonably measured or estimated
(4) Support deployment of energy storage systems interconnected to the transmission or distribution system of a New Jersey EDC	1. Timeliness: Days from application to completion 2. Capacity: Rates of participation in each PJM market available to storage (i.e., energy, capacity, ancillary services) 3. Generation Shifting: Peak, non-peak, and total MWh charged and discharged
(5) Grow a sustainable energy storage industry that gradually requires decreased incentives to deploy additional storage systems and ensure that the benefits of energy storage last well beyond the term of the GSESP	Incentive levels as a percentage of installed cost over time.
(6) Support overburdened communities with energy resilience, environmental improvement, and economic benefits derived from energy storage	Transmission-scale systems that asserted they will provide these community benefits should provide quantitative evidence that those benefits were realized to the extent feasible, using metrics tailored to the specific claimed benefits.
(7) Encourage storage deployment that accelerates the clean energy transition, including facilitating deployment of renewable energy, electric vehicle or other DERs, and resiliency	N/A for individual projects; applicable to program-level reporting only
(8) Establish a Program Administrator at the Board who would oversee the efficient implementation of GSESP	N/A for individual projects;
(9) Reduce electricity costs for ratepayers	N/A for individual projects; applicable to program-level reporting only

DISCUSSION AND FINDINGS

Energy storage is a critical component of New Jersey's clean energy transition, supporting grid stability, decarbonization, and economic growth. The GSESP is expected to provide a modest boost to New Jersey's economy by reducing electricity costs, attracting investment in new infrastructure, modernizing the state's grid, improving reliability, reducing environmental impact, enhancing public health, and creating new jobs. The GSESP will also comprise the centerpiece of the Board's strategy to implement the CEA's directive to deploy 2,000 MW of energy storage by 2030 in a manner that maximizes benefits to ratepayers.

Furthermore, the Board believes it is critical to deploy as much new capacity as fast as possible to maintain both reliability and affordability in the face of rapidly accelerating load growth. The transmission-scale energy storage projects that Phase 1 of the GSESP will constitute the bulk of the new capacity that be brought online in the next three to four years due to the fact that such energy storage capacity comprises most of the capacity in New Jersey that either has or is close to having interconnection approval, in addition to the fact that supply chain constraints likely make the commercial operation of new greenfield gas-fired capacity infeasible until the early 2030s.[35] It is therefore essential to launch a competitive procurement process for large-scale energy storage in New Jersey as soon as possible.

The Board also recognizes the significant benefits associated with the expansion of local, distributed, renewable, non-polluting sources of energy. In addition to the reduction of emissions that contribute to climate change, storage can induce reduction of air pollutants and the associated health benefits, increased resilience in the form of distributed generation, and the economic growth fueled by local job creation.

The Board has carefully reviewed the extensive record created through the stakeholder proceedings. The various stakeholders who participated in this proceeding have brought considerable dedication and passion to the process of expanding the energy storage market. That dedication is reflected in the extensive record that forms the basis for the actions taken today. The Board commends and thanks all stakeholders for their active participation in this proceeding. Public participation is invaluable to the Board's decision-making process, and each contribution made in a public meeting or in written comments has helped inform the Board's conclusions.

After reviewing the record and Staff's recommendations, the Board **HEREBY ORDERS** the establishment of Phase 1 of the GSESP pursuant to the CEA. The Board **FURTHER ORDERS**

---

[35] See Samuel A. Newell et al., The Brattle Grp., Brattle 2025 CONE Report for PJM: Informing Parameters for PJM's RPM Auctions for Delivery Year 2028/29 through 2031/32 at 2 (2025), https://www.pjm.com/-/media/DotCom/committees-groups/committees/mic/2025/20250411-special/item-1-02-revised-cone-report-final.pdf ("The supply of gas-fired combustion turbines, transformers, and switch gear is scarce . . . .
Supply shortages and volatile price premiums may last for several years until supply chains can develop sufficient capacity to support demand. . . . [This] limit[s] the pace of new supply entry of gas-fired generation plants . . . ."); Mitchell Beer, Turbine Shortage Could Crimp Canadian Utilities' Plans to Scale Up Gas, The Energy Mix (Mar. 27, 2025) (noting that gas turbine manufacturers have backlogs for new turbine deliveries stretching to 2029 or later and that "NextEra CEO John Ketchum [advised] investors that new gas projects 'won't be available at scale until 2030, and then only in certain pockets' of the United States").

that Phase 1 GSESP incentives shall be provided to eligible projects selected through the competitive procurement process recommended by Staff and established by this order. The Board **FURTHER ORDERS** that Phase 1 of the GSESP shall include no performance incentive for transmission-scale energy storage systems, consistent with Staff's recommendation to delay this program element to a future Phase.

The Board **HEREBY ORDERS** that the GSESP be open to qualifying transmission-scale energy storage projects and qualifying transmission-scale solar-plus-storage projects that are ineligible for storage incentives under the Board's SuSI Program. The Board **FURTHER ORDERS** Staff and the GSESP Program Administrator to conduct a Tranche 1 solicitation for 350 MW to 750 MW of energy storage capacity on the schedule recommended by Staff to enable the Board to issue Tranche 1 awards no later than October 31, 2025. Awarded projects shall receive fixed incentives payments disbursed over a period of 15 years, subject to the conditions and limitations recommended by Staff.

The Board **HEREBY DIRECTS** Staff and the GSESP Program Administrator to prepare to conduct a Tranche 2 solicitation in the first half of 2026 for the remaining energy storage capacity needed to meet an overall Phase 1 procurement target of at least 1,000 MW of transmission-scale energy storage capacity. The Board shall issue a separate order to open the Tranche 2 solicitation, which shall specify the schedule for the solicitation and its MW procurement target or target range.

The Board **HEREBY DIRECTS** Staff to establish eligibility criteria for energy storage systems seeking to qualify for Phase 1 GSESP incentives that are consistent with Staff's recommendations stated above. The Board **FURTHER DIRECTS** Staff and the GSESP Program Administrator to ensure that, at the time of application, transmission-scale energy storage systems meet the established eligibility criteria, including any additional requirements the Board may set by future order. The Board **HEREBY ORDERS** all Phase 1 GSESP-eligible project entities to comply with the pre-qualification application and application criteria set forth in this Order.

The Board **HEREBY DIRECTS** Staff to determine if awarding requested incentives to a transmission-scale energy storage system in Tranche 1 would constitute an unduly expensive means of advancing the State's energy storage goals. In making this determination, Staff shall consider factors, including, but not limited to confidential gap analysis results, adjustments for market conditions (such as tariffs), and potential savings for ratepayers (such as capacity savings). The Board shall retain the authority to decline to award a requested incentive if Staff determines it would constitute an unduly expensive means of advancing the State's energy storage goals, notwithstanding the impact such a decision would have on the Board's ability to meet the minimum Tranche 1 procurement target of 350 MW, unless doing so would conflict with any applicable statutory requirement.

If a recipient of a Tranche 1 incentive award misses their planned COD, the Board **HEREBY ORDERS** Staff or the GSESP Program Administrator to impose deductions from the first-year incentive award in the amounts that Staff recommended. The Board **HEREBY GRANTS** the Division Director the authority to extend the COD deadline by up to 180 calendar days due to project delays if an applicant demonstrates to the Division Director's satisfaction that the applicant sought to avoid said delays and advance the project in good faith. The Board **FURTHER GRANTS** Staff the authority to extend the COD deadline by more than 180 calendar days if the applicant demonstrates to the Division Director's satisfaction that the project was delayed by more than 180 calendar days due to a force majeure event that the applicant took all possible steps to avoid. The Board **FURTHER ORDERS** that any deductions from the first-year incentive award shall be calculated using the date of the extended COD deadline instead of planned COD in the event that Staff grants an extension.

The Board **HEREBY ORDERS** that any applicant awarded an incentive shall lose their award if they fail to achieve commercial operation within 36 months of their guaranteed COD, or within another period of time established by a future Board Order, though the Board may waive this penalty if the applicant demonstrates good cause for relief in writing.

The Board **HEREBY ORDERS** Staff or the GSESP Program Administrator to establish a non-refundable application deposit in the amount of $200 per MW of installed capacity for Tranche 1, and adjust it as necessary for future solicitations.

The Board **HEREBY ORDERS** Staff or the GSESP Program Administrator to establish the applicable pre-development security, project development milestones, fees, and deductions prior to each subsequent Phase 1 solicitation in accordance with Staff's recommendations. The methodology used to calculate these values shall be the same for and consistently applied to all projects within the same solicitation.

The Board **HEREBY DIRECTS** Staff and the GSESP Program Administrator to develop all program documents and resources that shall be necessary for the operation of GSESP Phase 1 solicitations, including but not limited to creation of a new registration portal for GSESP solicitations, updates to the NJCEP website, and development of application forms and checklists. The Board **FURTHER DIRECTS** Staff and the GSESP Program Administrator to develop all program documents and resources that are necessary for the registration of qualified projects in Phase 1 of the GSESP and to ensure consistency for market participants.

The Board **FURTHER DIRECTS** Staff and the GSESP Program Administrator to take action to communicate the establishment of Phase 1 of the GSESP to the public. Communication may include listserv messages, website notices, and informational webinars.

Finally, unless stated otherwise in this section, the Board **HEREBY APPROVES** all recommendations made by Staff above and **HEREBY DENIES** any conflicting stakeholder comments.

The effective date of this Order is June 25, 2025.

DATED: June 18, 2025

BOARD OF PUBLIC UTILITIES

BY:

CHRISTINE GUHL-SADOVY
PRESIDENT

DR. ZENON CHRISTODOULOU
COMMISSIONER

MICHAEL BANGE
COMMISSIONER

ATTEST:

SHERRI L. GOLDEN
BOARD SECRETARY

I HEREBY CERTIFY that the within document is a true copy of the original in the files of the Board of Public Utilities.

IN THE MATTER OF THE GARDEN STATE ENERGY STORAGE PROGRAM ("GSESP") PURSUANT TO P.L. 2018, C.17

DOCKET NO. QO22080540

SERVICE LIST

New Jersey Division of Rate Counsel	New Jersey Board of Public Utilities
Brian O. Lipman, Esq., Director Division of Rate Counsel 140 East Front Street, 4th Floor Trenton, NJ 08625-0003 blipman@rpa.nj.gov Megan Lupo, Esq., Assistant Deputy Counsel mlupo@rpa.nj.gov **New Jersey Division of Law** Deputy Attorney General Department of Law and Public Safety R.J. Hughes Justice Complex Public Utilities Section 25 Market Street, P.O. Box 112 Trenton, NJ 08625 Daren Eppley, Section Chief daren.eppley@law.njoag.gov Pamela Owen, Assistant Section Chief pamela.owen@law.njoag.gov Matko Ilic, DAG matko.ilic@law.njoag.gov Jack A. Ventura, DAG jack.ventura@law.njoag.gov **Atlantic City Electric Company** 92DC42 500 North Wakefield Drive Newark, DE 19702 Neil Hlawatsch, Assistant General Counsel neil.hlawatsch@exeloncorp.com Michael Wallace, Senior Manager Government and External Affairs michael.wallace@exeloncorp.com	44 South Clinton Avenue, 1st Floor P.O. Box 350 Trenton, NJ 08625-0350 www.nj.gov/bpu/ Sherry L. Golden, Secretary board.secretary@bpu.nj.gov Bob Brabston, Esq., Executive Director robert.brabston@bpu.nj.gov Stacy Peterson, Deputy Executive Director stacy.peterson@bpu.nj.gov Taryn Boland, Chief of Staff taryn.boland@bpu.nj.gov General Counsel's Office Ava-Marie Madeam, General Counsel avamarie.madeam@bpu.nj.gov Colin Emerle, Deputy General Counsel colin.emerle@bpu.nj.gov Ian Oxenham, Legal Specialist ian.oxenham@bpu.nj.gov Alexander Cary, Legal Specialist alexander.cary@bpu.nj.gov Jacqueline Hardy, Esq., Senior Counsel jacqueline.hardy@bpu.nj.gov Office of the Economist Dr. Ben Witherell, Chief Economist benjamin.witherell@bpu.nj.gov

Jersey Central Power and Light Company 300 Madison Avenue Morristown, NJ 07962 Michael J. Martelo, Counsel for Jersey Central Power and Light Company mmartelo@firstenergycorp.com **Public Service Electric and Gas Company** 80 Park Plaza, T5 P. O. Box 570 Newark, NJ 07102 Katherine E. Smith, Esq Managing Counsel, State Regulatory katherine.smith@pseg.com **Rockland Electric Company** Margaret Comes, Associate Counsel 4 Irving Place Suite 1815-S New York, NY 10003 comesm@coned.com	Division of Clean Energy Véronique Oomen, Director Veronique.Oomen@bpu.nj.gov Earl Thomas Pierce, Administrative Analyst earl.pierce@bpu.nj.gov Katharine Perry, Deputy Director katharine.perry@bpu.nj.gov Matthew Rossi, Bureau Chief matthew.rossi@bpu.nj.gov Michael Hornsby, Chief Project Development Officer michael.hornsby@bpu.nj.gov Paul Heitmann, Program Manager paul.heitmann@bpu.nj.gov Stella Oluwaseun-Apo, Research Scientist stella.oluwaseunapo@bpu.nj.gov Dr. Natalie Stuart, Research Scientist natalie.stuart@bpu.nj.gov Diane Watson, Research Scientist Diane.watson@bpu.nj.gov Justin Kohley, Chartered Financial Analyst justin.kohley@bpu.nj.gov Kevin Dillion, Project Manager kevin.dillon@bpu.nj.gov Jesse Kolodin, Research Scientist jesse.kolodin@bpu.nj.gov Jack Streppone, Project Manager jack.streppone@bpu.nj.gov

APPENDIX A: STAKEHOLDER COMMENTS AND STAFF RESPONSES

Garden State Energy Storage Program Straw Proposal Comments

Note: The GSESP is being rolled out in phases, as described above. Responses to Phase I are contained herein. Phases 2 and 3 of the GSESP remain under development. BPU will further respond to comments regarding Phase 2 and Phase 3 in a subsequent Board Order.

Stakeholder comments and responses are grouped by the following topics:

- The list of stakeholder questions posed within the November 7, 2024, Straw Proposal
- Stakeholder questions grouped by Straw Proposal subsections
- Other comments

Staff has attempted to include the substance of many of the relevant comments into the summaries below as a courtesy to commenters. Comments raised in multiple sections are addressed once. Staff also sought to align the GSESP with New Jersey Legislature bill A5267/S4289 (2024) at https://www.njleg.state.nj.us/bill-search/2024/A5267, rather than having to withdraw the program and recast it to conform to the bill.

The Board voted at the May 21, 2025, agenda meeting to approve a contract between the Board and an energy storage consulting firm. The consulting firm will assist Staff in administering the GSESP and further developing Phases 2 (Distributed Incentive Segments) and 3 (Transmission Performance Incentive) of the program. As part of that program development, the consultant will be tasked with further evaluating stakeholder comments for prospective incorporation into the GSESP.

The Board received sixty comments on the Garden State Energy Storage Program Straw Proposal posted on the Board's website on November 07, 2024, BPU Docket No. QO22080540. Comments were received from:

Public Entities

1. New Jersey Division of Rate Counsel (Rate Counsel)
2. Highlands Water Protection and Planning Council

Electrical Distribution Companies

3. Public Service Electric & Gas Company (PSE&G)
4. Rockland Electric Company (RECO)
5. Jersey Central Power & Light Company (JCP&L)
6. Atlantic City Electric Company (ACE)

Developers / Industry

7. Exact Solar
8. Cogentrix Energy Power Management, LLC (Cogentrix)
9. Generac Power Systems, Inc. (Genarac)
10. CPower Energy Management (CPower)
11. Intelligent Generation (IG)
12. Stem, Inc.
13. Energy Management Inc. (EMI)

14. Lotus Infrastructure Partners (Lotus)
15. Hecate Grid, LLC
16. Calibrant Energy
17. TigerGenCo, LLC (TigerGenCo)
18. Gabel Associates, Inc.
19. New Jersey Resources Clean Energy Ventures Corporation (NJRCEV)
20. Solar Landscape
21. Donnelly Energy
22. Prologis
23. Zenobe Americas
24. Jupiter Power LLC (Jupiter)
25. Convergent Energy and Power (Convergent)
26. PowerFlex Inc.
27. REV Renewables (REV)
28. Elevate Renewables F7, LLC (Elevate)
29. Tierra Climate Inc. (Tierra Climate)
30. Form Energy, Inc. (Form Energy)
31. Plus Power
32. Icetech Energy Services
33. NineDot Energy
34. BMG Law
35. Stack Energy Consulting
36. Core Renewables
37. Opal Energy Group
38. ELM Microgrid
39. Scale Microgrids
40. Steptoe
41. SolarStone
42. Qcells
43. Pfister Energy Consulting
44. Helios Solar

Trade Organizations / Coalitions

45. InClime
46. The Coalition for Community Solar Access (CCSA)
47. American Clean Power (ACP)
48. Mid-Atlantic Renewable Energy Coalition Action (MAREC Action)
49. New Jersey Utilities Association (NJUA)
50. Solar Energy Industries Association (SEIA)
51. Mid-Atlantic Solar & Storage Industries Association (MSSIA)

NGOs / Community Organizations / Environmental Groups

52. New Jersey League of Conservation Voters (LCV)
53. Vote Solar
54. New Jersey Solar Energy Coalition (NJSEC)
55. Clean Energy Group (CEG)
56. Southern New Jersey Development Council (SNJDC)
57. EmpowerNJ (Joint Statement signed by)
    a. Delaware Riverkeeper Network
    b. Clean Water Action
    c. Don't Gas the Meadowlands Coalition
    d. Environment NJ
    e. David Pringle Associates LLC
    f. Blue Wave NJ
    g. Food & Water Watch

Individuals

58. Michael Winka
59. Kirk Frost
60. Walter Chang

Please note commenters will be identified in each topic by their corresponding number.

STAKEHOLDER QUESTIONS POSED IN THE NOVEMBER 7, 2024, STRAW PROPOSAL

In Section 1 of the November 7, 2024, NJ SIP Straw Proposal, Staff requested comments on all elements of the proposal, including program design, administrative processes, financial proposals, as well as any other comments on items not specifically addressed. Staff's questions, stakeholder comments, and Staff's responses follow.

1. Should a performance incentive based on net avoided emissions be proposed only if PJM or another entity produces a day-ahead, marginal emissions signal?

Commenters largely agreed that a day-ahead PJM marginal emission signal should not be used. Stakeholders commented that it is too complex, not fully developed, not based on economic dispatch, not forward-looking, and otherwise unworkable.

Commenter 1 did not support performance incentives for grid supply projects at this time. They supported deferring payment of performance incentives paid to grid supply systems until suitable datasets can be created to inform such programs. They also suggested that the Board should only proceed with offering avoided emissions incentives when the necessary data is available to ensure the mechanisms are reasonable and properly aligned with New Jersey's energy storage goals and ratepayer interests, while taking into consideration all possible market revenue streams.

(Rate Counsel)

Commenter 3 emphasized strong opposition to performance incentives for grid supply projects, even if PJM provides a day-ahead marginal emissions signal. They specifically argued that PJM's Marginal Emissions Rate (MER) is unreliable, non-predictive, and could unintentionally lead to increased emissions. (PSE&G)

Commenter 4 stated that it does not support using PJM's Marginal Emissions Rate as a mechanism for performance incentives. They argued that standalone storage may actually increase emissions under current grid conditions and that such a signal would not reliably drive emissions benefits. (RECO)

Commenter 5 agreed that a performance incentive based on net avoided emissions should only be implemented if PJM, or a comparable governmental entity, provides a sufficiently accurate, day-ahead marginal emissions signal. Without this type of signal, they emphasized that aligning dispatch with GHG goals would be unreliable. Commenter 5 also requested an opportunity for further stakeholder input, should this signal become available in the future. (JCP&L)

Commenter 6 does not support incentives based on net avoided emissions without sufficient forward-looking data but is in favor of Grid Supply performance incentives modeled after California's Resource Adequacy Program. (ACE)

Commenter 21 commented that the PJM marginal emissions signal is a transitional metric that may introduce unwanted complexity for boots on the ground commercial entities that are looking to execute projects. (Solar Landscape)

Commenter 52 encouraged the Board to maintain an explicit commitment towards incentivizing avoided emissions through the GSESP and that the BPU should commit to a multistakeholder incentive design process that can establish an incentive for net avoided emissions in lieu of an existing day-ahead marginal emissions signal. (LCV)

Commenter 59 stated that emissions-based incentives should be implemented, however, improvements are needed in reporting and verification procedures to accurately capture GHG data. (Kirk Frost)

(1, 4, 5, 6, 8, 9, 12, 17, 21, 22, 26, 27, 29, 32, 47, 48, 50, 53, 54, 55, 58, 59)

Response: Staff agrees with the general consensus that the PJM Marginal Emissions Rate signal will not be used as a means to provide performance incentives. Staff agrees that further development of the grid supply performance incentive is needed and believe the Board should defer it pending further refinement in a future phase (Phase 3 – Transmission Performance Incentive) of the program.

2. In the absence of a day-ahead emissions signal, should the GSESP institute another form of performance incentive for Grid Supply projects?

Commenters generally agreed that other prospective forms of performance incentive could include delivering capacity to the PJM market or peak reduction. The Massachusetts Clean Peak Standard (CPS) program was cited by multiple Commenters as a good reference for grid supply resources because it uses a transparent market pricing mechanism.

Commenter 1 stated that no performance incentive is needed for grid supply projects at this time and opposes any other form of performance incentive for grid supply projects. (Rate Counsel)

Commenter 4 recommended that in the absence of a day-ahead emissions signal, the Board should institute a performance incentive based on peak load reduction, number of discharges during peak periods, or a 95% availability requirement. These metrics, they believe, would more effectively recognize the grid value of storage. (RECO)

Commenter 5 chose not to propose a specific alternative performance incentive but emphasized that withholding incentives alone is insufficient to ensure reliability. They encouraged development of minimum performance standards and recommended workshops to further explore viable accountability mechanisms. However, Commenter 5 expressed concern that current fallback options (e.g., incentive withholding) are inadequate and could fail to ensure performance. (JCP&L)

Commenter 6 supports performance-based incentives for Grid Supply storage systems, linking compensation to availability during critical events and alignment with grid resilience goals, similar to California's Resource Adequacy Program. Electric distribution companies (EDCs) should be authorized to implement and manage these incentives, using metrics like peak load reduction, system stability, and resilience to reward operational performance and enhance grid reliability. (ACE)

Commenter 8 commented that the Massachusetts Clean Peak Standard (CPS) program is a good reference for grid supply resources because it uses a transparent market pricing mechanism. Massachusetts's energy goals are similar to New Jersey's, and the CPS aims to reduce on-peak energy prices and on-peak emissions to maximize the value of renewable resources investments. (Cogentrix)

Commenter 17 suggested a temporary incentive based on locational marginal price or locational marginal emissions could be used until an avoided emissions process is developed. (TigerGenCo)

Commenter 19 suggested that a dedicated program for front-of-the-meter distribution connected projects should be created. (NJRCEV)

Commenter 28 suggested that the BPU implement a partial toll procurement mechanism. (Elevate)

Commenter 29 endorsed use of historic real time marginal emissions rates to quantify realized avoided emissions. (Terra Climate)

Commenters 47 and 48 jointly commented that absent a satisfactory day-ahead emissions signal informing a performance-based incentive and in the interim development period of such signal, the BPU might consider utilizing a peak reduction framework to provide performance payments to grid supply energy storage resources. (ACP) (MAREC Action)

Commenter 59 proposed calculating incentives based on the percentage reduction from natural gas. (Kirk Frost)

(1, 4, 5, 6, 8, 9, 12, 13, 14, 17, 20, 21, 22, 28, 32, 47, 48, 50, 53, 54, 55, 59)

Response: Staff appreciates these comments and acknowledges that further development of the grid supply performance incentive is needed. As a result, Staff is recommending that the Board defer implementation of such performance incentives pending further refinement in a future phase (Phase 3 – Transmission Performance Incentive) of the program. Staff will continue to examine delivering capacity, peak reduction and emission reduction strategies as key issues in the development of Phase 3 of the program.

3. What other changes or alternatives would you propose to the GHG Performance Incentive?

Most stakeholders recommended shifting away from a direct emissions-based incentive design toward simpler, more predictable metrics such as availability, peak discharge hours, or standard performance commitments. A common suggestion was that the Indexed Storage Credit in New York and the Clean Peak Standard in Massachusetts may be suitable models.

Commenter 1 stated that performance incentives for grid supply projects are not needed and therefore does not propose any alternatives to the GHG Performance Incentive for grid supply projects. (Rate Counsel)

Commenter 3 stated no alternatives are necessary, as they oppose any GHG-based performance incentive for grid supply. They maintained that incentives should only be considered when a clear market need is demonstrated. (PSE&G)

Commenter 4 reiterated its preference for performance metrics tied to grid services, such as peak load reduction and system availability, rather than emissions modeling. They emphasized that these alternatives are more predictable and actionable. (RECO)

Commenter 5 did not offer specific alternatives but supported further stakeholder dialogue to refine or reimagine the incentive structure. However, while not directly opposing the GHG model, they expressed discomfort and uncertainty, calling for workshops. (JCP&L)

Commenter 6 recommends an incentive framework that links emissions reductions with local benefits, like avoided infrastructure upgrades and improved reliability in overburdened communities and supports dual-use storage for both wholesale markets and local distribution needs. (ACE)

Commenter 17 expressed that any incentive must account for unforeseen implications to the model as the grid continues to add more clean resources, as it could become difficult to achieve the required abatement levels. (TigerGenCo)

Commenter 28 suggested the BPU implement a partial toll procurement mechanism. (Elevate)

Commenter 29 recommended that existing grid supply storage systems should be eligible for any GHG performance incentives. (Tierra Climate)

Commenters 50 and 54 jointly commented that using “net” GHG reduction metrics and the value of carbon reduction can be used to broadly calculate an incentive level. (SEIA) (NJSEC)

Commenter 53 suggested that a carveout for projects that reduce reliance on peaker plants should be established. (Vote Solar)

Commenter 59 stated an alternative is to identify power sourced from storage in contrast to power sourced from natural gas plants. (Kirk Frost)

(1, 4, 5, 6, 8, 17, 22, 24, 28, 29, 32, 47, 48, 50, 53, 54, 59)

Response: Staff welcomes these alternative suggestions and will consider them during the development of Phase 3 – Transmission Performance Incentive of the Program.

4. How can the Board mitigate the risk of Grid Supply projects not operating/performing after receiving upfront incentives?

a. Are the reporting requirements proposed herein sufficient?

Stakeholder comments included that performance reviews should be conducted, and that key operational metrics should be established, while not being overly burdensome to developers.

Commenter 1 stated that the proposed reporting requirements were insufficient. They stated that annual reporting would likely be adequate for most projects, however, certain projects may require the submission of monthly performance reports. Additionally, Commenter 1 suggested the adoption of additional metrics related to generation shifting, participation rates in the PJM market, and project timelines, among others. Commenter 1 further commented that reporting requirements should be aligned with program goals. (Rate Counsel)

Commenter 3 responded that current reporting requirements are insufficient. They suggested a broader, annual metric framework with a small subset of monthly reporting but cautioned against monthly operational metrics as burdensome. (PSE&G)

Commenter 4 agreed that the reporting requirements in the Straw Proposal are sufficient and did not recommend changes. (RECO)

Commenter 6 recommended supplementing the reporting requirements with operational performance reviews. (ACE)

b. Should there be a clawback clause to recover fixed incentive payments from energy storage systems that cease operating shortly after coming online?

Stakeholders were generally, though not universally, opposed to clawbacks. Stakeholders cited both the difficulty in executing clawbacks and the significant upfront capital investment required for those energy storage projects. Additionally, these projects are subject to PJM capacity penalties, making it unlikely that these projects will fail to operate after applying for and receiving a state-funded incentive.

Commenter 1 opposed use of a clawback clause as they can be difficult to enforce and could add tracking and enforcement costs to the program. (Rate Counsel)

Commenter 3 opposed implementing a clawback mechanism. They argued that such provisions are difficult to enforce and administratively expensive and reiterated their overall opposition to upfront incentives that would necessitate clawbacks. (PSE&G)

Commenter 4 cautioned against implementing a clawback mechanism, citing administrative complexity and enforcement challenges. Instead, they proposed distributing incentives over a 3–5-year period to better balance developer and ratepayer risk. However, the commenter opposed clawbacks, suggesting an alternative payout structure is needed. (RECO)

Commenter 5 voiced clear support for a clawback mechanism and recommended extending it to cover both early project failure and long-term underperformance. (JCP&L)

Commenter 6 agreed that the clawback clause is appropriate, which will improve accountability and protect customer investments. (ACE)

Commenter 21 supported recovery of incentives through a clawback mechanism. (Donnelly Energy)

Commenter 22 highlighted that there should be a 12-month grace period built into any clawback provision due to complexities in project development. (Prologis)

Commenter 52 was supportive of a clawback clause for projects that cease operations shortly after coming online and a financial penalty for projects that never come to operation. (LCV)

c. What should be the metric of success for a specific project be (e.g. discharging power during peak demand periods) for Grid Supply energy storage systems? In other words, what metrics should the Board consider when evaluating operation?

Common metrics sited by Commenters were operational availability and discharging of power during peak load events.

Commenter 1 reiterated their response to 4b, opposing the use of a clawback clause due to enforcement challenges and the potential for increased tracking and enforcement costs within the program. (Rate Counsel)

Commenter 3 deferred to their comment in 4a, which suggested a broader annual metric framework with a small subset of monthly reporting but cautioned that monthly operational metrics would be burdensome. They did not recommend specific metrics here but instead emphasized the need for streamlined outcome-focused reporting systems. (PSE&G)

Commenter 4 recommended measuring success based on peak load reduction, the number of discharges during peak periods, or maintaining 95% availability. They emphasized these metrics are practical and relevant to grid performance. (RECO)

Commenter 5 proposed a comprehensive suite of performance indicators including availability, discharge performance, and resilience contributions. They encouraged further refinement through stakeholder workshops. (JCP&L)

Commenter 6 recommended a few metrics such as percentages of hours available, hosting capacity improvement, frequency/duration of discharge, contribution to local reliability improvements, and power quality. (ACE)

Commenter 29 suggested use of a cumulative impact assessment as part of grid supply projects. (Tierra Climate)

Commenter 55 stated that in the absence of emissions data, success could be defined as charging from renewable sources or charging during low demand/high renewable production hours. (CEG)

(1, 3, 4, 5, 6, 8, 17, 21, 22, 24, 27, 29, 32, 47, 48, 50, 52, 54, 55, 59)

Response: Program performance reporting reviews were changed from Year 1 to annually. Key operational metrics were added to Staff's recommendations for the Distributed segment. Additional project-specific reporting requirements were added. Program-level reporting requirements for BPU were added. Tables were added for both project level reporting and BPU program level reporting, showing specific reporting requirements for each program goal. Clawbacks were not specifically added to the program, given the difficulties of implementing them as cited by stakeholders. Instead, the GSESP will use alternative means to protect ratepayers from paying for projects that fail to continue operating. Specifically, these measures include: 1) using an annual fixed incentive payment conditioned on dispatch availability metrics instead of a single upfront payment subject to clawback for transmission-scale projects, 2) adding a prequalification step to screen out projects with a lower likelihood of success, and 3) changing the application fee to be non-refundable instead of refundable.

5. Should Grid Supply energy storage projects that replace or demonstrably reduce the runtime of fossil-based peaker plants in overburdened communities be evaluated solely on price or receive additional weight or a preference in competitive solicitations? If additional weight or preference is warranted, please specify how.

Several supportive Commenters asked for brownfield-sited incentives, stated that linking peaker plant dispatches with storage projects is impractical due to complex GHG calculations, and that the GSESP should incorporate price and non-price criteria. Some potential criteria sited were assigning a social cost of carbon, emissions reductions and resilience contributions, and use thresholds established by the New Jersey Department of Environmental Protection's series of regulatory reforms called NJ PACT (New Jersey Protecting Against Climate Threats).

Commenter 1 did not support exempting projects in overburdened communities from a cost-based competitive solicitation process. They felt projects should demonstrate their localized benefits in the solicitation process to maximize benefits to overburdened communities (OBCs) while reducing costs that are felt more by low-income ratepayers. (Rate Counsel)

Commenter 3 highlighted the difficulty of quantifying the impact of energy storage on fossil fuel generation in specific communities and noted that proving a storage system directly reduces peaker plant runtime in overburdened communities is nearly impossible. Despite this difficulty, they stressed the importance of considering energy storage for these communities and recommended that the Board develop a methodology to measure the reduction in fossil-based peaker plant runtimes, assigning a party to perform or verify these calculations. Additionally, they advocated for operational performance incentives that align with this methodology to ensure goals are met. While they supported incentives for Grid Supply energy storage projects in overburdened communities to mitigate plant runtimes, they opposed adding preference or weight in solicitations for projects in these areas and instead strongly endorsed a strictly cost-based competitive process to maintain fairness and transparency. (PSE&G)

Commenter 6 supported prioritizing Grid Supply storage projects that lessen reliance on fossil-fuel peaker plants in overburdened communities, citing their environmental and health benefits. Commenter 6 also recommended a scoring system that considers both price and non-price factors, including emissions reductions and resilience. (ACE)

Commenter 17 did not support additional weighting of preference based on proximity to overburdened communities. (TigerGenCo)

Commenter 21 stated that benefits to overburdened communities should be converted to a price value to be incorporated into price in the solicitation process. (Donnelly Energy)

Commenter 55 recommended requiring community benefit plans to accompany bids in overburdened communities. (CEG)

(1, 2, 3, 6, 8, 9, 17, 20, 21, 22, 24, 29, 31, 32, 47, 48, 50, 54, 55, 59)

Response: The transmission segment solicitation application will now request information and qualitatively consider information on how the application will support community benefits, brownfield redevelopment, and/or demonstrated benefits to overburdened communities where a transmission-scale energy storage system is proposed to be located. The Board will have the discretion to issue an incentive award to a project that provides greater community benefits than a competing project, but only if the resulting increase in the cost of the award is less than ten percent on a per-unit basis.

6. The distributed incentive level breakdown provides varying incentive levels for different sized energy storage systems to account for cost differences. Are the proposed incentive levels appropriate?

Some stakeholders commented that the current levels are insufficient or called for refinements based on system size and segment type. A few stakeholders advocated for a specific residential segment.

Commenter 1 stated they were unable to comment on the appropriateness of incentive levels due to the lack of information provided to them. However, they did discourage additional upfront payments as part of incentives for projects before proper analysis is completed. Additionally, Commenter 1 suggested requirement of financial reporting for any developer granted an incentive to ensure ratepayer dollars are spent responsibly. (Rate Counsel)

Commenter 3 stated they could not evaluate the appropriateness due to lack of access to the underlying gap analysis. They emphasized the need for transparency in assumptions and warned against over-incentivizing projects without cost-justification. (PSE&G)

Commenter 4 responded that the proposed retail (i.e., distributed) incentive levels appeared appropriate. They did not offer changes or express concerns. (RECO)

Commenter 6 found the proposed incentive levels reasonable but recommended regular reviews to ensure alignment with market trends. They supported higher incentives for smaller systems to address scale challenges. Commenter 6 stressed the need for a clear framework that defines and quantifies the full value of distributed storage—such as peak load reduction, voltage support, and resilience. Linking incentives to these benefits will help maximize grid and ratepayer value. Without this clarity, the program may undervalue distributed systems. Commenter 6 urged collaboration among the Board, utilities, and stakeholders to develop and refine this framework. (ACE)

Commenter 9 commented that, as proposed, there is a disconnect between incentive levels (kWh) and block eligibility (kW), which could encourage developers to undersize inverters for larger systems. Instead, the scale of battery energy storage systems should be market-based such that the incentives do not create a barrier to larger system sizes. (Generac)

Commenter 10 expressed concern that the 500kW upper bound for medium projects and proposed net present value incentive is insufficient. They suggested a 1MW minimum capacity level for large projects, in order to achieve economies of scale. Alternatively, the GSESP can mirror the sizing used in the Board's modernized interconnection rules: 25kW or less – level 1, 25kW to 2MW – level 2, and >2MW – level 3. (CPower)

Commenter 11 commented that the price demarcation between residential, small commercial and large commercial (which pertains to small, medium and large in the Straw Proposal at page 11) occurs at 100 kW and 1 MW. (IG)

(1, 4, 6, 9, 10, 11, 20, 21, 22, 26, 32, 50, 53, 54, 59)

Response: Further revision to the distributed segment will be made during the further development of the Phase 2 – Distributed Incentive Segments element of the program. Staff felt that smaller, residential-size projects is not the most direct pathway to achieve the legislatively mandated goal of 2,000 MW at this stage of program development.

7. Are the incentive adders for OBCs too high, too low, or should the proposed OBC incentive otherwise be modified?

Stakeholders were overwhelmingly supportive of adders and/or set-asides for OBCs. Other commenters either criticized the current levels as insufficient or called for refinements based on system size and segment type. Additionally, other stakeholders highlighted that the OBC adder must be justified by measurable grid or community benefits. There were also requests for the program to describe the standards the BPU will use to determine eligibility for overburdened community status.

Commenter 3 reiterated their disagreement with additional fixed payments as part of incentives for projects. Commenter 3 opposed fixed incentive adders for distributed projects in overburdened communities, calling them likely windfalls for developers. They argued such payments lack accountability and do not guarantee benefits to OBC residents, for which they reject any additional upfront OBC adders, as they are ineffective and potentially wasteful. (Rate Counsel)

Commenter 4 stated that the proposed OBC adders are appropriate and did not recommend modifications (RECO)

Commenter 5 declined to comment on whether the proposed incentive adders for OBCs are too high, too low, or should otherwise be modified. They support the Straw Proposal's goal of incenting the placement of Distributed Resources in OBCs; they said that the Board should be mindful of the impact that incentive adders may have on customer bills. Commenter 5 agreed with the Straw Proposal's recommendation of not providing additional incentives to place Grid Supply resources in OBCs. (JCP&L)

Commenter 6 noted that the incentive adders for OBCs are reasonable but could be slightly increased to drive more projects. (ACE)

Commenter 9 recommended against establishing a specific capacity block for projects in OBCs for fear that the capacity may be under-subscribed, considering the limited capacity allocation of the program generally. (CPower)

Commenters 13 and 14 jointly suggested that the proposed locational adder would be more appropriate if allocated to the federal category of "Energy Community" rather than the New Jersey-specific category of "Overburdened Community", due to the federal category being focused more specifically on communities that face hardships resulting from the retirement of traditional energy facilities. (EMI) (Lotus)

Commenter 51 supported a 33 percent adder of incentives for overburdened communities. (MSSIA)

(1, 4, 5, 6, 10, 13, 14, 20, 21, 22, 26, 28, 32, 50, 52, 53, 54, 59)

Response: Overburdened community, or "OBC," has been defined to mean "any census block group, as determined in accordance with the most recent United States Census, in which: (1) at least 35 percent of the households qualify as low-income households; (2) at least 40 percent of the residents identify as minority or as members of a State-recognized tribal community; or (3) at least 40 percent of the households have limited English proficiency". Further revision to the OBC adder will be made during the further development of the Phase 2 – Distributed Incentive Segments element of the program.

8. How far along are the EDCs in implementing the technology needed to issue calls for the performance incentive portion of the GSESP? Will this affect the design of the performance incentive?

A consistent theme among stakeholders was the need for flexibility, clarity, and alignment with PJM/FERC Order No. 2222 frameworks. Other stakeholders commented that aggregators should be eligible to respond to calls.

Although Commenter 1 was unable to comment on EDC implementation of technology needed to issue battery dispatch calls, they stressed the importance of siting projects near constrained areas of the grid to maximize value to ratepayers by helping to defer grid upgrade costs. They recommended that incentives not be offered to distributed batteries unless there is a clear locational need, as determined by the EDCs. (Rate Counsel)

Commenter 3 acknowledged they could not assess EDC readiness but raised concerns that the proposed performance incentive fails to properly value distribution-level benefits. They emphasized the need for location-specific project siting and planning integration to avoid grid upgrades. They criticized the disconnect between proposed incentives and the actual benefits of distributed storage. (PSE&G)

Commenter 4 indicated uncertainty, stating they could not assess readiness without further direction from the Board regarding required technologies. (RECO)

Commenter 5 stated they currently lack the technology, modeling systems, and staffing to implement automated call systems as proposed. They urged the Board to convene workshops and allow time for infrastructure development. However, they strongly opposed any near-term mandate for automated calls due to lack of readiness. (JCP&L)

Commenter 6 commented that while this technology is under development, the timeline for the performance incentive should account for the lengthy process that will be required to fully implement DERMS capabilities. (ACE)

Commenter 22 recommended a phased rollout, potentially starting with a pilot in early 2025, to refine EDC capabilities and ensure equitable implementation. (Prologis)

Commenter 10 encouraged the Board to approach EDC requests for technology upgrades with skepticism. (CPower)

(1, 3, 4, 5, 6, 10, 20, 22, 31, 32, 53, 59)

Response: Further revision to the distributed segment of the GSESP will be made during the further development of the Phase 2 – Distributed Incentive Segments element of the program. The current order directs the EDCs to develop design proposals based on a general program framework but does not determine what the final details of any distributed performance incentive design will be. Staff appreciates the comment to locate storage near constrained areas of the grid and will engage the EDCs on that point during Phase 2 development, including but not limited to the review of EDC performance incentive design proposals.

9. Should the Board require EDCs to implement a designated distributed energy resources management system (DERMS) to effectively manage and dispatch resources across their systems?

Stakeholders appear split on the implementation of DERMS. Some stakeholders felt that DERMS are necessary, other stakeholders had the opposite view citing cost, complexity, and redundancy concerns. Stakeholders expressed a preference for avoiding delaying the program launch, favoring use of existing systems while DERMS implementation is being developed. Utilities favored recovery for developing such systems.

Commenter 1 did not know whether DERMS were necessary for dispatch or if other existing measures were adequate to respond. They felt a passive dispatch program for performance incentives is better for addressing transmission costs and system-wide constraints. There was a preference for the Board to explore the cost effectiveness of the program's use of DERMS and/or other alternatives. (Rate Counsel)

Commenter 3 did not oppose DERMS outright but recommended a careful cost-benefit analysis before mandating its implementation. They noted that passive dispatch systems might suffice for certain use cases and warned against overinvestment without proven locational need. However, they expressed concern about the cost and necessity of requiring DERMS across all cases. (PSE&G)

Commenter 4 did not recommend that the Board mandate DERMS deployment on a specific timeline or scope. Instead, they advocated for allowing EDCs to determine system needs and potentially use third-party aggregators. While they opposed a DERMS mandate, they supported flexible alternatives that offer adaptability and choice in implementation. (RECO)

Commenter 5 affirmed the need for DERMS to manage and dispatch GSESP resources effectively. They noted system complexity and supported full cost recovery through a regulatory mechanism. (JCP&L)

Commenter 6 asserts that DERMS are essential and that the Board should provide clear guidelines and establish cost recovery mechanisms to support their deployment. (ACE)

Commenter 9 did not deem DERMS necessary for EDCs to successfully implement the GSESP and stated that doing so may delay the program's launch. (Generac)

Commenter 11 stated a better approach is for an EDC to send one alert or dispatch signal to energy storage aggregators or curtailment service providers (CSP) and empower them to dispatch the fleet of batteries under their management, mirroring an already successful approach used in PJM. (IG)

(1, 3, 4, 5, 6, 9, 10, 11, 16, 20, 21, 22, 26, 32, 50, 53, 54, 55, 58, 59)

Response: Further revision to the distributed segments will be made during the development of Phase 2 – Distributed Incentive segments of the program. Staff agrees that workshops with EDCs would be helpful in order to work out the implementation details of Phase 2. Staff added specific cost recovery language relative to EDC investments.

10. Do any aspects of this program need to be modified to address New Jersey Legislature Bill S225/A4893, should the bill be signed into law?

Stakeholders identified several areas of the program that should be modified in order to address Senate/Assembly Bill S225/A4893. Several stakeholders commented that the 550-day timeline from application approval to commercial operation was too short and favored a schedule extension of up to 60 months. Others commented that multi-year or phased-in incentive frameworks would better support project financing, permitting, and interconnection timelines aligned with legislative intent. Overall, there was general agreement that the GSESP should be refined to mirror the legislative goals more closely, especially around timing, structure, and eligibility.

Commenter 1 identified several areas of the program that would need to be modified to address Senate/Assembly Bill S225/A4893. They stated that the amount or share of projects located in overburdened communities should specify the amount or share of this segment to ensure it makes up at least one third of upfront incentives. They stated that the 40% requirement would apply as a cap on both grid supply solicitations and administratively established rates for distribution systems. Additionally, completion timelines for distributed and grid supply projects would need to be adjusted to match the 18- and 40-month requirements outlined in the bill. They asked for clarity regarding the treatment of rejected applications. Finally, Commenter 1 highlighted a few other areas of the Straw Proposal that would need to be maintained to comply with S225, including eligibility of solar plus storage projects, payment of fixed up-front incentives, and project sizing requirements related to refundable deposit requirements. (Rate Counsel)

Commenter 3 stated that several aspects of the Straw Proposal would need to be adjusted if Senate/Assembly Bill S225/A4893 becomes law. They provided recommendations on timelines, funding allocations, caps on incentive percentages, and expanded eligibility criteria. Commenter 3 further stated that the GSESP program rules need to clearly define how the EDCs will recover expenditures related to supporting this program. (PSE&G)

Commenter 6 noted that if Senate/Assembly S225/A4893 is enacted, it may require GSESP adjustments to support greater utility involvement in storage GSESP should allow utility-owned projects, streamlined cost recovery, and stronger utility–developer collaboration, while remaining flexible to adapt to new mandates or goals. (ACE)

(1, 3, 6, 8, 10, 11, 13, 20, 22, 26, 47, 48, 50, 54, 59)

Response: Fixed incentives for Phase 1 – Transmission Fixed Incentive were modified from an upfront incentive to a phased incentive. A new section was added, providing specific cost recovery language and detailing the expected role of the EDCs. The 550-day timeline from application approval to commercial operation was extended to 30 months. Staff also notes that the recently proposed A5267/S4289 bill now appears to be the likely source of legislative guidance for the GSESP, and that Staff has worked to align the design of Phase 1 with its requirements.

PROGRAM GOALS

The program proposed an array of goals; foremost among them was a goal of the program is to achieve 2,000 MW of energy storage by 2030. A recurring theme amongst commenters was support for establishing clear, ambitious MW targets with annual procurement milestones to ensure progress towards New Jersey's goal. Common goals for the program identified was to incent peak load reduction and address the capacity crisis. Some commenters stated the overall program size is too small to accomplish the State's storage goals.

Commenter 1 expressed support for incenting projects where necessary, siting distribution level projects as likely in need of incentives. However, they also stated that there is no need for incentives for grid supply projects as the current PJM queue currently exceeds the state's 2000 MW goal. (Rate Counsel)

Commenter 3 supports EDC involvement in energy storage investments, alongside private developers, arguing that utility ownership would foster a mixed ownership model, encourage innovation, ensure cost-effective solutions, and provide long-term operational certainty for storage and solar. They contended that excluding EDCs could jeopardize New Jersey's 2,000 MW by 2030 target. To facilitate this involvement, Commenter 3 proposed that EDCs be explicitly permitted to submit accelerated storage investment proposals, subject to BPU review. They recommended that storage policy, similar to smart meters, promote grid-enabling technologies to enhance safety and reliability. Additionally, they advocated for timely cost recovery and incentives, allowing EDCs to invest in internal resources and systems. To encourage participation, they suggested permitting returns at the Weighted Average Cost of Capital, asserting that EDCs are the best positioned to maximize storage value and cost-effectiveness. (PSE&G)

Commenter 5 had no direct comment related to program goals but covered their storage goals in the Installed Storage Targets and Timelines section (below). (JCP&L)

Commenter 6 advocated for a balanced mix of utility-and third party-owned energy storage to meet New Jersey's goals. Utility-owned systems enhance grid reliability and fill gaps left by limited private investment. For third-party systems, they recommended adopting "pay-for-performance" models to better align with grid reliability needs, calling this approach more holistic for energy storage deployment. (ACE)

Commenter 24 expressed that the Board should avoid procurement fragmentation and that the 2025 solicitation should be as large as possible. (Jupiter)

Commenter 31 emphasized the importance of launching the GSESP promptly in 2025 to account for finance milestones of storage projects currently in the PJM queue. (Plus Power)

Commenter 60 echoed several other stakeholders that commented that the 2,000 MW goal is too low. (Walter Chang)

(3, 18, 24, 31, 32, 48, 49, 50, 51, 52, 54, 55, 56, 57)

Response: Staff continues to evaluate the economics of energy storage, particularly in terms of incentive levels versus impacts on capacity prices. The size of the Phase 1 Transmission-Scale Energy Storage Segment of the program has been increased. Staff may recommend further increasing the quantity of MWs of storage procured if it proves to benefit ratepayers. Staff appreciates the other comments and believes that the program will achieve the other recommended goals as well. The Phase 1 Transmission Fixed Incentive segment is expected to accomplish peak load reduction and address capacity.

Staff believes that the presence of a storage project in the PJM queue is not a guarantee that a storage project will be placed into service or that they are commercially viable without incentives. Indeed, a review of PJM queue data indicated that all New Jersey storage projects in the PJM queue entered following the enactment of the CEA storage mandate in 2018. Furthermore, PJM only implemented significant readiness deposit requirements for projects seeking interconnection after Staff released the 2022 NJ SIP straw. Consequently, none of those storage projects in the PJM queue had to make a significant financial commitment to remain in the queue until after Staff announced a storage incentive program was under development. The PJM queue data thus does not provide any evidence or information on how much storage capacity could reach commercial operation in the absence of any incentives and therefore fails to show that the GSESP is unnecessary to achieve the CEA's storage mandate.

Furthermore, one of the primary reasons the Board hired TRC as a program design consultant was so the Board could have the benefit of an expert, independent analysis estimating the likely revenue gap transmission-scale storage projects faced. That analysis consistently found that there was a revenue gap across a wide range of plausible assumptions, though the magnitude of the revenue gap varied depending on the specific assumptions used. Given the results of that analysis and the fact that storage projects likely remained in the queue *because* of the GSESP, Staff concludes that the PJM queue data cited by Rate Counsel provides no reason to believe that incentives for transmission-scale storage are unnecessary.

Lastly, incentive levels can be further adjusted over time to ensure that the New Jersey legislative goal will be met, while not over incenting the program. Staff added significant reporting requirements at the project level and program level to track performance against program goals. Staff added a section addressing the EDC role and associated cost recovery. Staff continues to recommend precluding EDC ownership of energy storage under this program, consistent with the Board's long-standing preference for competitive markets.

GHG CONSIDERATIONS

Many stakeholders commented that the use of the PJM Marginal Emission Rate signal is currently unworkable as a means to provide performance incentives.

Commenter 1 stated they do not support GHG based incentives for grid supply projects and support the Board deferring payment of performance incentives until suitable datasets are available to better inform program design. (Rate Counsel)

Commenter 3 agreed that current emissions-based performance metrics are not yet implementable. They explicitly stated that the PJM Marginal Emissions Rate signal is unworkable and recommended focusing on operational metrics like peak reduction and solar hosting capacity instead. They suggested the Board should explore alternative criteria to align incentives with policy goals. (PSE&G)

Commenter 5 agreed that a performance-based incentive for net avoided emissions should only be considered if PJM or a comparable entity provides a sufficiently accurate day-ahead marginal emissions signal. They emphasized that without such a signal, aligning dispatch with GHG-reduction goals would be compromised. They also suggested that trade-offs between environmental benefits and grid cost impacts should be addressed in workshops. (JCP&L)

(1, 4, 5, 8, 22, 32, 47, 48, 50, 53, 54, 59)

Response: Staff has recommended deferring the transmission-level performance incentive development until Phase 3 – Transmission Performance Incentive of the program.

BUSINESS MODEL CONSIDERATIONS

The key issue with respect to business models was whether utilities should be allowed to own energy storage. The stakeholders were in two camps on this issue:

- Utilities and some developers argue that utilities should be allowed to own storage.
- Most private developers argue against utilities owning storage.

Commenter 3 supports EDCs managing and expanding GSESP with cost recovery to accelerate progress toward the 2,000 MW goal. They advocate for aligning performance incentive with time-of-use rates and finalized net metering rules and propose EDC-run on-bill repayment programs to help cover remaining system costs. Additionally, they emphasize the importance of allowing all behind-the-meter batteries to participate in incentives and call for clarity on the duration of performance incentives, noting that limited timelines reduce long-term grid reliability. Commenter 3 also urges the Board to consider operational criteria beyond emissions reductions, recommending that storage resources be required to respond to EDC or PJM signals to avoid purely profit-driven behavior. They propose that EDCs administer the up-front incentives, given their expertise and infrastructure, and highlight the need for additional investments. To ensure grid stability, they advocate for performance metrics or revenue-based incentives in the grid supply segment of the program. However, they object to the exclusion of utility ownership, arguing that it undermines grid reliability and slows program success. As a result, they call for explicit inclusion of utility participation in storage development and operations. (PSE&G)

Commenter 5 highlighted the need for utilities to play a central role in dispatch and grid reliability and noted that unmanaged distributed resources could pose operational risks if not subject to utility oversight. They made a strong case that EDCs require visibility, dispatch control, and DERMS infrastructure to safely integrate distributed storage. This implies their support for utility-centric dispatch control over energy storage, aligning with stakeholders who believe utilities should be allowed to own or control storage for grid benefit. (JCP&L)

Commenter 6 emphasizes that investments in DERMS are essential for managing energy storage assets' reliability. They advocated for the Board to establish clear, transparent cost recovery mechanisms to support upfront investments in these technologies, ensuring integration, maintenance, and scaling as GSESP evolves. Additionally, they stressed the importance of predictable funding for ongoing system updates and program administration. Without a well-defined cost recovery path, utilities may face financial barriers, leading to project delays or resource diversion that could impact storage deployment goals. The process should align with customer benefits and incentivize utilities to invest in DERMS and related technologies to enhance storage reliability and grid performance. (ACE)

Commenter 13 emphasized the need for a level playing field, stating that EDCs have structural advantages (including insulation from shareholder risk), implying concerns that utility ownership could distort market fairness. (EMI)

Commenter 19 favored competitive solicitations over administratively set rates, implicitly suggesting that utility-owned projects could result in less cost-effective or flexible outcomes. (NJRCEV)

Commenter 20 recommended tariff structures that provide equal incentive treatment for distributed and front-of-the-meter storage systems, advocating for non-discriminatory access that would prevent utilities from having an unfair advantage. (Solar Landscape)

Commenter 23 highlighted the benefits of long-term contracts and competitive market participation, indirectly advocating against utility preference or dominance. (Zenobe Americas)

Commenter 28 explicitly opposed utility ownership of storage assets, citing concerns about utilities' disproportionate market power and its negative impact on competition. They advocated for independent ownership, aligning with the broader goal of maintaining a competitive market. (Elevate)

Commenter 31 supported a competitive, market-based incentive structure, reinforcing the idea that utility-led development could undercut private competition if not carefully structured. (Plus Power)

Commenter 58 suggested that utility control overcompensation structures should align with New

Jersey's competitive energy market framework, signaling caution against reintroducing centralized or utility-dominated structures. (Michael Winka)

(3, 4, 5, 6, 13, 19, 20, 23, 28, 31, 65)

Response: Staff agrees with commenters who support a competitive, market-based incentive structure, as well as those advocating for utility oversight in dispatch and grid reliability and the integration of DERMS for safe storage.

However, Staff disagrees with commenters supporting EDC participation in GSESP, arguing that a private ownership model better aligns with a competitive market structure and will provide greater benefits to New Jersey.

In alignment with the Board's preference for competitive markets, utilities will not be eligible to apply for the program. Staff emphasizes that ownership and operation of energy storage assets are central to program design and believes a private ownership model aligns with New Jersey's competitive market structure. Private ownership—while keeping commercial and operational risks with investors and using ratepayer support for funding—is expected to better serve the GSESP.

Staff believes EDCs should oversee grid integration, ensuring interconnection and performance-based incentives within a flexible framework. Staff also believes that encouraging private investment, promoting value stacking, and allowing storage owners, especially distributed storage owners, to combine revenue from wholesale markets, retail bill savings (demand charge management), and investments in DERs, EV charging, and other technologies will benefit both the GSESP and New Jersey residents. These revenues will supplement GSESP incentives, including price signals and grid performance incentives. Additionally, Staff clarifies that its recommendations regarding energy storage system ownership apply only to those receiving GSESP incentives unless otherwise noted. Nothing in Staff's proposal prevents prudent EDC investment in or ownership of energy storage systems that do not receive GSESP incentives as a non-wires alternative to traditional distribution system investment.

To ensure effective storage integration at both distribution and transmission levels—especially within the Distributed Segment of the GSESP—Staff recommends that EDCs oversee interconnection and establish pay-for-performance incentives. Programs will follow a common framework while adapting to utility-specific needs. Although Staff does not propose utility ownership, EDCs would play a key role in developing the necessary infrastructure for efficient dispatch under Staff's proposal.

INSTALLED STORAGE TARGETS AND TIMELINES

This section of the program describes how the storage goal will be achieved through the GSESP and the CSI Program. Several stakeholders urged the BPU to adopt more aggressive and clearly defined MW targets, establish annual goals, and accelerate deployment. There was broad support for establishing annual procurement schedules to provide certainty to the market.

While not suggesting alternate MW targets or year-by-year milestones, Commenter 3 stressed the urgency of accelerating program implementation to meet the 2030 goal. They implied that excluding utilities will slow progress and urged the Board to revisit its deployment assumptions in light of utility capabilities and barriers to market entry for some developers. (PSE&G)

Commenter 4 urged the Board not to mandate specific DERMS timelines, noting that each utility's integration varies and such mandates could raise costs and delay progress. Finally, Commenter 4 calls for clear cost recovery mechanisms for EDCs implementing GSESP, especially if DERMS become required. (RECO)

Commenter 5 acknowledged the State's 2,000 MW target but did not suggest alternative figures or detailed annual milestones. However, they repeatedly stressed the importance of realistic implementation timelines, particularly regarding performance incentive systems and DERMS deployment, suggesting phased rollouts and workshops before implementation to avoid premature commitments. (JCP&L)

Commenter 9 noted it was difficult to assess their market experience against the gap analysis results and called for transparency, implying concern about how gaps and targets were defined. (Generac)

Commenter 10 implied skepticism that the current incentive design would be sufficient to drive adoption at the required pace without more transparent justification. (CPower)

Commenters 13 and 14 cautioned that the 2024 Straw Proposal lacks a rigorous cost-based gap analysis, raising doubts that the proposed incentives and procurement budget will be sufficient to achieve the program's storage goals. (EMI) (Lotus)

Commenter 16 recommended that the gap analysis process be used to back-calculate incentives after establishing performance rates, implying concern that the current approach may be misaligned with project needs. (Calibrant Energy)

Commenter 18 flagged grid readiness concerns that could pose barriers to implementation if storage is not integrated thoughtfully, hinting at deployment pacing misalignment. (Gabel Associates)

Commenter 22 recommended a sooner pilot start (2025 instead of 2026) and urged interconnection streamlining and early block visibility — signaling concern that administrative readiness may not align with the GSESP's ambitions. (Prologis)

Commenter 25 flagged uncertainty around access to performance incentives and caps, stating it may reduce developers' ability to plan and develop projects in line with timelines. (Convergent)

Commenter 26 expressed concern that the current block size is too small to meaningfully support market adoption, warning that such sizing may undermine deployment pacing and recommended reassessing goals based on market capacity and demand. (PowerFlex)

Commenters 50 and 54 recommended the BPU set specific MW targets, and a clearer program launch timeline, warning that the lack of clarity could delay deployment. (SEIA) (NJSEC)

Commenter 53 called for greater transparency around targets and incentive structures and emphasized the importance of incorporating developer perspectives into pace-setting decisions. (Vote Solar)

Commenter 56 advocated for expanding the current goal to at least 4,000 MW by 2030, arguing that the 2,000 MW target is insufficient to meet climate and grid reliability needs. (SNJDC)

(3, 4, 5, 6, 9, 10, 13, 16, 18, 22, 25, 26, 50, 53, 54, 56)

Response: Staff fully understands the benefit of setting annual goals. At present, however, Staff does not believe the Board should commit to trying to exceed the CEA's statutory target of 2,000 MW by 2030. At present, it is unclear whether they will be sufficient transmission-scale storage that can achieve commercial operation prior to 2030 to support transmission-scale procurement targets that significantly exceed 1,000 MW. It also not yet clear if significantly increasing distributed storage procurements beyond the 500 MW to 800 MW Staff anticipates will be needed to be meet the rest of the CEA goal will be beneficial to ratepayers. In particular, Staff is concerned that materially increasing overall storage targets beyond the 2,000 MW target would require an increase in the SBC absent additional sources of non-ratepayer funding, and Staff recommends the Board not increase the SBC in light of the substantial rate increases ratepayers are already being forced to bear. Nonetheless, Staff may recommend increasing the future procurements beyond the goal if it can be established that the additional storage will likely produce savings to ratepayers that exceed the cost of necessary incentives or additional non-ratepayer sources of funding become available.

INCENTIVE STRUCTURE

Stakeholder comments included: a multi-year program size should be established to create certainty, set performance incentives to be paid over a ten-to-twenty-year period, identify block sizes and to change the year one review to an annual review, support long-term, fixed price contracts, support partial toll agreements, and quantify the program size. Most stakeholders seemed to agree that the incentive levels were sufficient. Fewer stakeholders argued that incentive levels were too low.

Commenter 51 commented that incentive levels were sufficient, as long as the federal investment tax credit remains in place. (MSSIA)

Commenter 44 expressed opposition to a declining block structure, stating that the incentive buckets would be too small and short-lived. (Helios Solar)

Commenter 18 stated that public entitles should be eligible to apply for incentives, that the incentive levels should be higher, and that incentives for storage associated with electric vehicle charging should be provided. Stakeholders asked for the program to specify the duration for which performance incentives will be paid. (Gabel Associates)

Commenter 1 comments included that batteries must be located in areas with a constraint on the system. These locations must be determined by the EDCs and shared with developers upfront. They did not support upfront incentives for grid supply projects. (Rate Counsel)

Commenter 4 supported an incentive model that attracts private capital, leverages value streams, and gradually reduces incentives. They advocated for upfront and performance-based incentives while cautioning against dual compensation from other markets. Additionally, they recommended using availability, dispatch frequency, and peak load reduction as guiding metrics for incentives rather than PJM's Marginal Emission Rate, at least until renewables become more prominent. While Commenter 4 supported performance-based incentives tied to grid benefits, they opposed penalties at this early market stage, suggesting a future review as the market matures. Incentives should be balanced, not overly generous, and ideally paid over 3–5 years to reduce developer risk. They also opposed clawback mechanisms as overly burdensome but support reducing or removing incentives for systems failing to meet availability standards. (RECO)

Commenter 5 supported a two-part structure (fixed upfront payment + performance incentive) but emphasized the need for flexibility and careful alignment with PJM's evolving implementation of FERC Order No. 2222. They supported a $/kW-year performance incentive, suggested beginning with a uniform statewide rate, and endorsed evolving toward geographically variable pricing over time. They stressed that program design should account for tradeoffs between environmental goals and infrastructure costs, and recommended EDC cost recovery through a rider mechanism. In addition, they suggested that without clear performance metrics and system modeling capabilities, performance incentives might fail to deliver expected grid benefits, while calling for specific stakeholder workshops to refine this structure. (JCP&L)

Commenter 6 recommended expanding incentive metrics and standard agreements to fully capture storage's resource adequacy benefits. While supporting a focus on carbon abatement, they cautioned against making it the sole basis for incentives, as this could overlook more impactful, near-term storage solutions. Instead, incentives should prioritize performance during critical grid events and support grid resilience. To maximize energy storage value, Commenter 6 suggested that GSESP empower EDCs to administer pay-for-performance incentives, modeled after California's Resource Adequacy Program. These incentives should include expanded performance metrics for resilience and reliability, limits on opt-outs during critical events to reduce free-ridership, and locational adders for projects in high-need areas. Additionally, they emphasized the importance of standardized agreements between utilities and third-party owners to streamline collaboration, define roles, ensure data sharing, and enhance performance monitoring. These agreements should support technical interoperability with utility DERMS and related systems. (ACE)

Commenter 9 stated that establishing a performance incentive based on net avoided emissions may conflict with the grid's immediate need for load relief and suggested locational marginal price as an alternative way to benchmark. In addition, Commenter 9 is concerned that sizing incentives to the ESS systems themselves could inadvertently encourage developers to optimize for the incentives, rather than for full system benefits. (Generac)

Commenters 13 and 14 jointly commented that incentives should be in the form of long-term fixed-price contracts (tolling agreements) or Power Purchase Agreements (PPA) between the energy storage resource owners and the Program Administrator. The Index Storage Credit energy storage program in New York and Maryland Energy Storage workgroup's price contract structure were cited as examples. They also commented that larger projects are cheaper per MW due to economies of scale, and that the State should pursue these types of projects to minimize ratepayer impacts. (EMI) (Lotus)

Commenter 17 advised against implementing a performance incentive based on net avoided emissions. Commenter 17 suggested that the program design remain agnostic regarding when a BESS charges or discharges, allowing the market to optimize operations. (TigerGenCo)

Commenter 19 stated a fixed incentive needs to be paid over time for applicants to access the federal investment tax credit. (NJRCEV)

Commenter 19 and Commenter 20 commented that there should be distributed front of meter tranche. (NJRCEV) (Solar Landscape)

Commenter 20 did not agree with the proposed incentive value for the distributed segment and noted that it is too low to meet the Board's battery storage goals, particularly for FTM distributed resources. (Solar Landscape)

Commenter 22 believes that the distributed incentive levels will not be adequate to meet the 2030 goal. They suggested a revised approach that could involve increasing initial incentives to cover at least 40% of actual installed costs and introducing a dynamic system to adjust incentives based on market response and project viability. (Prologis)

Commenter 24 opposed a program that only partially addresses the revenue gap for projects, relying on a future performance-based program to cover the remainder. In addition, Commenter 24 believed a GHG Performance Incentive is unnecessary for ensuring long-term project commitment and recommended a simpler alternative. Commenter 24 also believed an upfront incentive is inherently flawed, as it risks projects ceasing operations after receiving the initial payment. (Jupiter)

Commenter 27 opposes minimum targets or carve-outs for storage classes, advocating for a neutral procurement approach guided by market response. In addition, Commenter 24 did not believe a performance incentive based on net avoided emissions should be implemented. (REV)

Commenter 26 stated storage-specific tariffs are needed. The California Time of Use tariff and the New York Value of Distributed Energy Resource were cited as examples. (PowerFlex)

Commenter 28 commented that both price and non-price factors should be considered in applications. They further commented that energy storage projects that replace or demonstrably reduce the run-time of fossil-based peaker plants in overburdened communities should receive additional weight or a preference. (Elevate)

Commenter 37 supported the limitation of awards per developer and recommended fixed incentives as opposed to declining block incentives, to provide more investor confidence. (Opal Energy Group)

Commenter 38, however, recommended that early projects be eligible for both upfront and performance incentives, as “early movers” in the industry. (ELM Microgrid)

Commenters 50 and 54 argued that distribution-level projects yield greater benefits. (SEIA) (NJSEC)

Commenter 48 included that distributed storage projects 1) should be emphasized; 2) will contribute substantially to increasing capacity and transmission supply; 3) the most valuable role storage can play is voltage control, which can be delivered by volt-VAR control or volt-Watt control; and 4) declining block incentive programs can make investment in project development very difficult and high-risk. (MSSIA)

Commenter 58 commented that the more efficient and effective way to administer the GSESP would be as a renewable energy credit. (Michael Winka)

Commenter 53 stated that the GHG performance-based compensation is inappropriate and may increase bids; further discussion is needed to assess if additional GHG-related measures are necessary later. In addition, they noted that the incentive levels are too low and must be increased for the distributed storage program. (Vote Solar)

(1, 4, 5, 6, 7, 8, 9, 10, 11, 12, 13, 14, 16, 17, 18, 19, 20, 21, 24, 25, 26, 27, 28, 29, 30, 37, 44, 45, 46, 47, 48, 50, 51, 53, 54, 56, 57, 58, 59)

Response: The transmission level fixed incentive was changed from an up-front payment to a payment paid out over 15 years. The year one program review was changed to an annual review. The program was clarified to specify that public entities could apply to the program, i.e., only utilities are excluded. The year one program size was quantified. Establishing future year program size remains a challenge due to the State’s year-by-year appropriation process. Internal discussions continue on how to address this recognized problem. The program specifically identified that both price and non-price community benefit-related factors will be considered in applications. The Phase 1 – Transmission Fixed Incentive program application was changed from a non-competitive to a competitive protocol. Staff declined to institute PPAs, tolling agreements or other contract mechanisms in the interest of meeting the June 2025 launch timeframe.

The incentive levels for Phase 2 – Distributed Incentive Segments and 3 – Transmission Performance Incentive will be set to reflect market conditions at the time those phases of the program are released. The Distributed segment requires further development and will launch as Phase 2 of the program in 2026. An FTM component for the Distributed segment will be considered during the further development of Phase 2.

PROJECT MATURITY REQUIREMENTS AND PARTICIPATION FEES

Stakeholders overwhelmingly commented that the 550-day timeframe from award to commercial operation was too short. The lengthy interconnection process was often cited as a concern. Stakeholders asked for timelines ranging from 30 to 60 months. Some stakeholders asked for a reduced security deposit as upfront costs for development are already capital intensive. Many stakeholders also asked the Board to define the term “Major Permit”.

Commenter 1 cited concerns about application fees being refundable, as it minimizes the meaning of the application process, and supported incorporation of pre-development fees. (Rate Counsel)

Commenter 3 emphasized that performance incentives must be tied to verifiable system benefits and resource availability over time. They raised concerns about the lack of clear policy for how long incentives would apply and questioned how predictable grid benefits would be without well-defined operational expectations. While they did not explicitly discuss application fees or pre-development costs in the preamble, they made a strong case that storage investments require structured financial recovery and long-term resource certainty. (PSE&G)

Commenter 5 recommended stronger maturity standards to ensure viable projects are selected. For Grid Supply, they requested that a project’s system impact study be “completed,” not just “executed,” and that the wording around interconnection jurisdiction be clarified to avoid FERC conflicts. For Distributed Resources, they proposed requiring a fully approved interconnection agreement, not just a complete application. They also supported non-refundable application fees and significant pre-development securities to discourage unserious bidders. (JCP&L)

Commenter 8 supported project maturity standards but urged that bid participation fees be made refundable to encourage broader participation. They recommended a pre-development fee instead, warning that non-refundable fees may deter otherwise viable projects. (Cogentrix)

Commenter 10 expressed general support but emphasized the importance of recognizing real-world development timelines and financing constraints, cautioning against maturity criteria outside developers’ control. (CPower)

Commenters 13 and 14 supported maturity standards in principle but emphasized avoiding allocations to speculative projects while also acknowledging that projects must be given a reasonable timeframe to reach commercial operation. (EMI) (Lotus)

Commenter 17 voiced concern about clawback provisions or aggressive fee structures, warning they could raise the perceived risk of financing and increase costs. (TigerGenCo)

Commenter 22 encouraged streamlined interconnection processes, implying that infrastructure readiness issues may impact a project's ability to meet maturity thresholds. (Prologis)

Commenter 26 warned against waitlist structures tied to block incentives, which they say introduce uncertainty and undermine project financing. (PowerFlex)

Commenter 30 stated that the current project maturity requirements may be prohibitive, especially for emerging technologies, and recommended increasing flexibility. (Form Energy)

Commenter 42 cited concerns that the program may privilege grid-supply projects that are already in the PJM queue, which may not need incentives at all due to potential prior financing. (Qcells)

Commenters 47 and 48 highlighted the need for flexibility around commercial operation dates due to external factors such as PJM queue changes, interconnection delays, and labor constraints. (ACP) (MAREC Action)

Commenters 50 and 54 called for longer planned COD/guaranteed COD timelines to reflect permitting and construction realities, viewing the proposed 550-day limit as too restrictive. (SEIA) (NJSEC)

Commenter 56 supported the idea of refundable bid participation fees, stating it balances commitment and flexibility while avoiding unnecessary deterrents. (SNJDC)

(5, 8, 10, 13, 15, 16, 17, 21, 22, 24, 26, 27, 28, 30, 42, 45, 47, 48, 50, 54, 56, 57)

Response: The proposed 550-day timeframe from the award to commercial operation was changed to 30 months. The term "Major Permit" was eliminated. Application fees were changed from refundable to non-refundable. A preapplication process was established to accept projects with a high likelihood of success and reject projects with a low likelihood of success. Streamlining the interconnection process is being managed via the Grid Modernization proceeding. Please see In the Matter of Modernizing New Jersey's Interconnection Rules, Processes, and Metrics, BPU Docket No. QO21010085 and In the Matter of Developing Integrated Distributed Energy Resource Plans to Modernize New Jersey's Electric Grid, BPU Docket No. QO24030199 on the Board's website at https://publicaccess.bpu.state.nj.us/.

REQUIREMENTS

Some Commenters recommended that a performance incentive be granted to batteries that have already been deployed to better leverage storage resources on the grid.

Commenter 5 requested that further details be published for technical requirements and that workshops be conducted to further discuss. (JCP&L)

(5, 7, 50, 54)

Response: Staff declined to modify the GSESP to provide performance incentives for storge project batteries that have already been deployed, as this will allow for a greater quantity of new storage projects to be deployed. Staff agrees that workshops, especially with the utilities, will be valuable in further scoping Phases 2 (Distributed Incentive Segments) and 3 (Transmission Performance Incentive) of the program.

ADMINISTRATION OF PROGRAM AND ASSIGNMENT OF BLOCK PRIORITY DATES

Many Commenters called for the GSESP to be launched in 2025 to account for deadlines faced by projects currently in the PJM queue. There was also broad support for flexibility in block sizing to account for market conditions that may arise. There was also a desire for the size of the program, expressed in megawatts (MWs) and dollars, to be specified for both grid supply and distributed segments. More specifically there was a request for block amounts to be defined by the Board, with the initial block being substantial.

Commenter 1 recommended that the Program Administrator be required to submit annual reports of annual and cumulative-to-date performance metrics to the Board or a designee. (Rate Counsel)

Commenter 3 raised operational readiness concerns related to dispatch calls and the timeline for implementing the performance incentive. They noted that EDCs do not yet have the DERMS platforms needed to meet the Straw Proposal's timelines. They recommended that the Board phase implementation and integrate GSESP with broader efforts like time-of-use rates and net metering reforms to avoid grid misalignments. (PSE&G)

While not addressed using these exact terms, Commenter 5 did recommend structured workshops before implementing any automated dispatch systems or timeline-based block assignment methods. They emphasized that utilities currently lack the staffing, modeling tools, and information technology systems necessary for real-time dispatch and recommended additional comment rounds post-workshop before assigning operational responsibilities. (JCP&L)

Commenter 16 commented that to avoid projects gaming the "first come, first served basis" a similar mechanism to New York's Energy Storage program, which opens an initial 14-day window to submit applications to a block, which are prioritized based on their interconnection application date, should be adopted. After that initial 14-day window, if the block is still undersubscribed, then projects are evaluated on a first-come, first-served basis. (Calibrant Energy)

Commenter 18 asked that the state allocate adequate budgeting and that capacity blocks are set to meet the 2000 MW by 2030 goal. They also requested the initial block be filled on a rolling basis to maximize the number of projects competing in the solicitation. (Gabel Associates)

(1, 5, 8, 10, 12, 15, 16, 18, 24, 27, 28, 30, 32, 45, 56, 57)

Response: The application fee of $200 per MW was changed from refundable to non-refundable. The GSESP was modified to state that Phase 1 – Transmission Fixed Incentive will launch with an initial solicitation target of 350-750 MW and will seek to procure at least 1,000 MW of transmission-scale energy storage over multiple solicitations. The size of the Phase 2- distributed energy storage incentives and Phase 3 –transmission-scale performance incentives were not specified due to the need for further program development. Staff recognizes deadlines faced by projects in the PJM queue and has requested that the Board vote on the program at the June 18, 2025, meeting for that reason. The establishment of future block sizes cannot be readily accomplished due to the challenges created by the annual CEP budgeting process. However, Staff is provisionally recommending that the Distributed Segment of the GSESP target procuring 500 MW to 800 MW of distributed energy storage capacity over the 2026-2030 period, depending upon how much storage capacity is obtained through GSESP transmission-scale and CSI procurements. Phase 1 of the program will be based on competitive applications, rather than a first-come, first-served approach. A new comprehensive project-level and program-level reporting protocol matching program goals has been established. Staff agrees that workshops will be helpful in further scoping Phases 2 and 3 of the program.

OTHER COMMENTS

Commenter 36 urged the BPU to speed up the interconnection process. (Core Renewables)

Commenter 5 raised critical gaps in Net Metering Rules that could undermine the implementation of GSESP. They questioned how storage systems co-located with solar would interact with net metering and requested clarity on storage operation standards, charging behavior, and certification requirements. Additionally, they emphasized the need for training programs for both customers and utility staff and cautioned against excessive revenue stacking across overlapping incentive programs without clear benefits. (JCP&L)

Commenter 3 raised significant concerns about Net Metering rules, noting that existing tariffs prohibit behind-the-meter exports, which could conflict with how GSESP proposes to credit customer storage. They also referenced their upcoming Virtual Power Plant initiative under the Board's Clean Energy Future – Energy Efficiency II (CEF-EE II) program and asked that it be allowed to run in parallel with GSESP. Finally, they recommended a formal cost-benefit analysis of GSESP to assess implied carbon reduction value, resiliency gains, and ratepayer costs. They also flagged a conflict with Net Metering rules, which prohibit BTM storage exports under current tariffs. They also referenced other programs like their Virtual Power Plant pilot, requesting clarity on how such programs can coexist with GSESP. (PSE&G)

Response: The concern regarding interconnection delays is understandable and is being addressed in the Grid Modernization proceeding. For more information, please review BPU proceedings In the Matter of Modernizing New Jersey's Interconnection Rules, Processes, and Metrics, BPU Docket Nos. QO21010085 and In the Matter of Developing Integrated Distributed Energy Resource Plans to Modernize New Jersey's Electric Grid, BPU Docket No. QO24030199 on the Board's website at https://publicaccess.bpu.state.nj.us/. The BPU has a docket open regarding net metering, where that issue will be addressed:

In the Matter of Net Metering for Class I Renewable Energy Systems, BPU Docket No. QO24090723.

A partial cost-benefit analysis (partial because the only benefit it considers is capacity savings to ratepayers) of Phase 1 of the GSESP has been performed, and is included as Appendix B.

Staff agrees that conducting workshops to further scope program Phases 2 (Distributed Incentive

Segments) and 3 (Transmission Performance Incentive), including Virtual Power Plants, will be helpful.

APPENDIX B: GARDEN STATE ENERGY STORAGE PROGRAM – ANALYSIS OF POTENTIAL CAPACITY MARKET NET SAVINGS FOR TRANSMISSION-SCALE STORAGE RESOURCES

I. Introduction

The Garden State Energy Storage Program (GSESP) is designed to provide incentives for the installation of eligible energy storage systems. The program establishes two incentivized market segments: a transmission segment for large energy storage systems that interconnect directly to the bulk electric grid and a distribution segment for smaller systems that interconnect either behind-the-meter (BTM) or in front-of-the-meter (FTM) to a distribution grid.

Transmission-scale energy storage systems are considered a capacity resource by the Pennsylvania-Jersey-Maryland Interconnection (PJM) and can participate in PJM's wholesale capacity market. Recently, capacity shortages have contributed to an increase in the clearing price of the PJM Base Residual Auction (BRA) resulting in an increase in electricity prices for New Jersey ratepayers. Energy storage is one of the few resources that can provide new dispatchable capacity in the near-term,[36] thereby lowering the clearing price in upcoming capacity auctions. As a result, incentivizing energy storage systems has the potential to decrease electricity costs for New Jersey ratepayers.

This appendix describes the results and key assumptions underlying the analysis of the potential capacity market savings from the GSESP incentives for transmission-scale energy storage systems. While smaller energy systems incentivized by the distribution segment of GSESP are also likely to add capacity and reduce ratepayer costs, the launch of the distribution segment is further into the future and its impact is more difficult to model at this time. For these reasons, the analysis focuses solely on the potential capacity market savings from transmission-scale energy storage systems. Likewise, energy storage systems provide other benefits to New Jersey including increased energy resilience, enhanced reliability, economic development, and avoided environmental costs. These other benefits are highlighted in the main body of the GSESP launch order, but they are outside the scope of this analysis.

II. Background on the Capacity Market

PJM's capacity market ensures long-term grid reliability by securing power supply resources needed to meet predicted energy demand in the future.[37] The BRA is meant to be an annual auction conducted by PJM to secure electricity capacity for a delivery year three years in the future, though auction delays in recent years have altered the schedule. Capacity providers, such

---

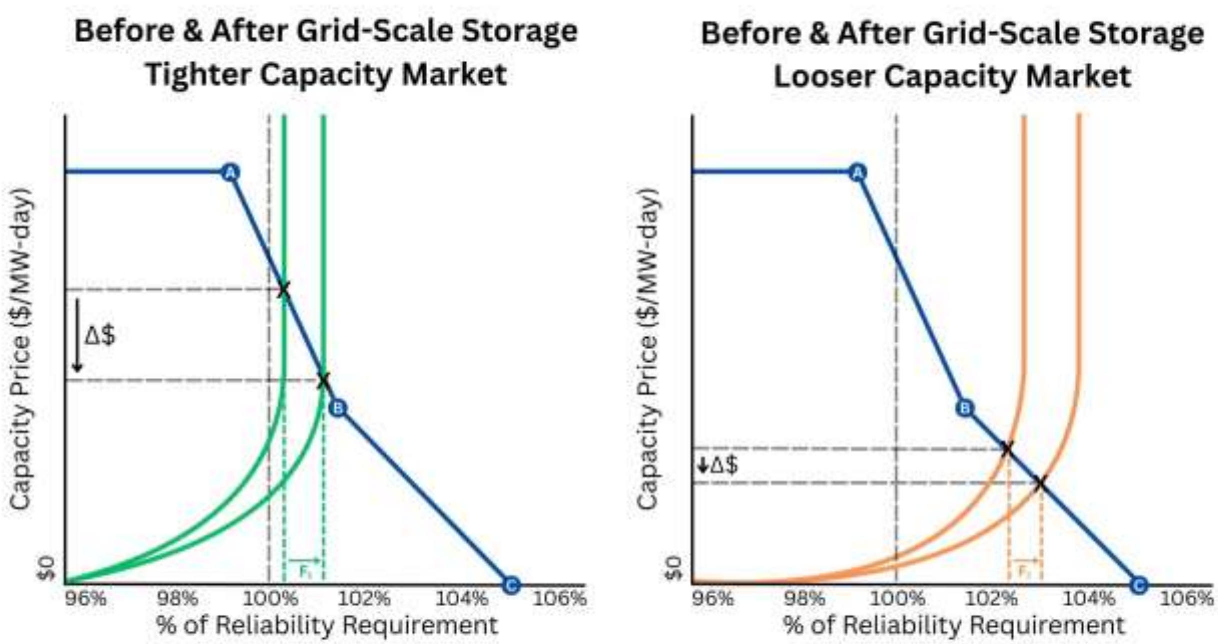
[36]Storage resources account for one-third of generation in the PJM interconnection queue and have shorter development lead times compared to other resources. For example, new gas-fired power plants face significant order backlogs for necessary equipment, pushing development timelines to seven to eight years. Kevin Clark, Long Lead Times are Dooming Some Proposed Gas Plant Projects, Power Engineering, (Feb. 20, 2025), https://www.power-eng.com/gas/turbines/long-lead-times-are-dooming-some-proposed-gas-plant-projects/. Likewise, building additional nuclear capacity is expected to take at least seven years, and likely substantially longer, depending on various factors. See Global Nuclear Industry Performance, (World Nuclear Assoc., https://world-nuclear.org/our-association/publications/world-nuclear-performance-report/global-nuclear-industry-performance?utm_source=chatgpt.com (last updated Aug. 20, 2024).

[37] An Introductory Guide for Participation in PJM Processes, Fed. Energy Reg. Comm'n, https://www.ferc.gov/introductory-guide-participation-pjm-processes (last updated April 11, 2025),

as energy storage systems, bid the amount of capacity they can offer and the price they are willing to accept. The BRA results in a clearing price across the PJM region, with some variability in Locational Deliverability Areas (LDAs) to account for transmission constraints that limit the ability of some parts of the grid to import capacity from other areas.

The demand for capacity in the market is administratively determined by PJM and modeled as the Variable Resource Requirement (VRR) curve. The shape of the VRR curve is based upon the reliability requirement which represents the amount of capacity needed to serve load during peak demand and other stressed system conditions. PJM calculates the reliability requirement by considering forecasts for peak loads, the periods of greatest reliability risk, and the ability of the expected generation mix to serve load during those periods. The capacity supply curve includes all capacity providers bidding into the auction, based upon their aggregate accredited unforced capacity (UCAP). Figure 1 provides illustrative insight into the behaviors of the supply and demand curves, where fluctuations in pricing within the PJM capacity market are highlighted by the changing intersections (i.e., the clearing price) from before and after transmission-scale storage enters the market.

Figure 1 – The capacity market shifts are a function of the capacity pricing and percent (%) reliability required to meet peak capacity demand.



The addition of energy storage systems to aggregate capacity in PJM will likely shift the supply curve to the right (F_1 and F_2) resulting in a lower market clearing price (Δ$). The magnitude of the shift depends upon the degree to which supply is constrained. If supply is tightly constrained, as occurred in the 2025/2026 delivery year BRA, the clearing price will fall between points A and B on the demand curve (assuming PJM is not critically short capacity such that the market clears to the left of point A at the maximum possible price). As more supply comes online in response to market signals, the clearing price may fall between points B and C, resulting in a looser capacity market and reducing potential savings.

The following analysis attempts to quantify the potential capacity market savings resulting from energy storage systems bidding additional capacity in future BRAs. This analysis focuses solely on the addition of transmission-scale storage and its impact on the capacity market. Deployment of distributed energy storage, as incentivized in the second phase of GSESP, will also likely result in capacity market savings due to its ability to reduce peak load. While PJM accounts for the load reducing impact of distributed storage in the peak load forecast it uses to determine the amount of capacity BRAs need to procure,[38] modeling the potential savings from distributed resources is beyond the scope of this analysis and will likely be explored in the future.

III. Assumptions

- **Capacity Interconnection Rights for Transmission-scale Energy Storage Resources**
  - Capacity Interconnection Rights (CIRs) represent the amount of generation output or storage discharge from a capacity resource that is deliverable to load under all system conditions. The number of CIRs limits a capacity resource's accredited unforced capacity (UCAP) value.
  - This analysis assumes 4-hour transmission-scale storage projects have CIRs equal to 40% of their nameplate capacity due to restrictions imposed on storage from a prior PJM rule that was effective when most storage projects entered the queue. While this policy has changed, the long lead time for the PJM interconnection queue dissuades storage resources in the queue from requesting additional CIRs. Some 10-hour storage projects have cleared the queue with CIRs equal to their full nameplate capacity and new storage projects in the queue will likely receive higher CIRs. Therefore, a maximum 40% CIR is a conservative assumption that may underestimate the capacity value of energy storage resources. Under PJM's current rules, a storage project's effective nameplate capacity used for capacity accreditation is limited to the number of CIRs it holds.

- **Effective Load Carrying Capacity (ELCC) Rating**
  - The ELCC metric quantifies a resource's ability to contribute to grid reliability. The value is estimated for each resource type and is used to determine the accredited UCAP eligible to bid into the BRA. Specifically, the amount of UCAP a resource can bid into the BRA is equal its ELCC class rating multiplied by its effective nameplate capacity, subject to certain unit specific adjustments. Importantly, PJM allows storage resources to choose their ELCC class based on how long they can sustain output at their effective nameplate capacity.
  - Given the assumption that a 4-hour duration energy storage resource will have an effective nameplate capacity equal to 40% of its nameplate capacity due to CIR limitations, a 4-hour storage resource could continuously discharge at its effective nameplate capacity for 10 hours. This analysis therefore assumes that such storage resources will elect to be treated as part of the 10-hour duration class and

[38] PJM Res. Adequacy Planning Dep't, 2025 Long-Term Load Forecast Report 6 (2025), https://www.pjm.com/-/media/DotCom/library/reports-notices/load-forecast/2025-load-report.pdf.

be assigned the corresponding ELCC class ratings. For that reason, this analysis utilizes PJM's projections for the ELCC class rating of 10-hour duration energy storage resources through the 2035/2036 delivery year. Subsequent delivery year values assume a 1% annual reduction in the ELCC class rating. The values utilized in the analysis for each delivery year are displayed in Table 1, below.

Table 1 – ELCC Class Rating Projections

Delivery Year	Predicted 10-hour Storage Resource ELCC
2028/2029	75%
2029/2030	72%
2030/2031	73%
2031/2032	68%
2032/2033	69%
2033/2034	70%
2034/2035	70%
2035/2036	69%
2036/2037	68%
2037/2038	67%
2038/2039	66%
2039/2040	65%
2040/2041	64%
2041/2042	63%
2042/2043	62%
2043/2044	61%
2044/2045	60%

- **Load Forecast**
  - PJM's 2025 load forecast is utilized to estimate peak load over the period.

- **New Jersey Zones' Capacity Purchase Obligations**
  - Capacity Purchase Obligations are based upon the 2025/2026 BRA values. A 0.86% annual growth rate is applied to the Capacity Purchase Obligations based upon the weighted average of projected summer load growth in PJM's 2025 load forecast for ACE, JCP&L, PSE&G, and RECO. This assumption likely errs on the side of underestimating the growth in Capacity Purchase Obligations for New Jersey zones, as winter peak load is growing at a much faster rate and winter risks are increasingly driving capacity needs. Underestimating future Capacity Purchase Obligations in turn underestimates savings from lower future capacity prices, making this a conservative assumption.

- **GSESP Energy Storage Capacity Deployment**
  - The analysis assumes nameplate capacity of 600 MW participates in the BRA for 2028/2029 delivery year, and 1,000 MW nameplate capacity participates in the BRA for each subsequent delivery year through 2044/2045. Under the assumptions stated above, this corresponds to 240 MW of effective nameplate capacity and 180 MW of UCAP participating in the 2028/2029 BRA and 400 MW of effective nameplate capacity and 288 MW of UCAP participating in the 2029/2030 BRA. 400 MW of effective nameplate capacity is assumed to participate for each subsequent delivery year through 2044/2045, with the UCAP value varying based on ELCC changes. In capacity constrained periods, the ratio of the change in cleared capacity to the change in offered UCAP is assumed to be 1:1. In less constrained periods, this ratio is assumed to be 0.5:1.

- **Discount Rate**
  - 7.0% discount rate is assumed for net present value calculations.

- **Reliability Requirement**
  - Based upon PJM's projections for peak load growth, the Reliability Requirement is derived by multiplying the estimated peak load for a given delivery year by the Forward Pool Requirement (FPR) value for the 2026/2027 delivery year and subtracting the capacity needs met outside the capacity market.

- **VRR Curve**
  - This analysis is informed by the VRR parameter recommendations in Brattle's Sixth Quadrennial Review report to PJM.[39] The report provides recommendations for an updated methodology to determine the VRR Curve, including the adoption of a Marginal Reliability Impact (MRI) VRR Curve with prices reflective of incremental reliability value. Additionally, the report advocates for adopting a "Reference Price" to replace the Net Cost of New Entry (CONE) parameter and a price cap in the range of 1.5-1.75 x Reference Price. A linear approximation of the "Curve 2" version of MRI VRR Curve is the basis for the BRA modeling in the scenarios presented below.[40]
  - Note that adoption of the MRI curve would result in a less steep VRR curve that is less sensitive to changes in the amount of capacity that is offered into the BRA. Were PJM to simply apply Brattle's updated CONE parameter recommendations to its existing VRR curve design, the resulting VRR slopes and the sensitivity of pricing outcomes to the amount of capacity offered into the market would be higher. Thus, assuming PJM adopts the MRI curves reduces the projected capacity savings of deploying storage, making this a conservative assumption.

---

[39] See Kathleen Spees et al., the Brattle Grp., Sixth Review of PJM's RPM VRR Curve Parameters for Planning Years 2028/29 through 2031/32 at 6-12 (2025), https://www.brattle.com/wp-content/uploads/2025/04/Sixth-Review-of-PJMs-Variable-Resource-Requirement-Curve.pdf.

[40] Id. at 6, fig.2.

- **LDA Curves**
  - LDA curves follow a similar methodology to the broader Regional Transmission Organization (RTO) VRR Curves but account for capacity resource and transmission constraints in regional areas. New Jersey is within the Eastern Mid-Atlantic Area Council (EMAAC) LDA, under the parent Mid-Atlantic Area Council (MAAC) LDA. LDA parameters only affect capacity auction results if the LDA “price separates” due to greater capacity constraints compared to the PJM region. The smaller reliability requirements in the LDA result in clearing prices that are significantly more sensitive to the amount of capacity that clears within the LDA if price separates.

IV. Methodology

The following analysis estimates the total net capacity savings, defined as gross capacity savings from GSESP transmission-scale storage less GSESP transmission-scale incentive costs from additional energy storage resources in the capacity auctions for delivery years 2028/2029 through 2044/2045. It does so by comparing the estimated cost of capacity with and without additional energy storage resources incentivized by GSESP.

Total Capacity Savings (CS) for GSESP is described as a total CS throughout the lifetime of the program (n=17-years), including the Net Present Value NPV_{CS}, with a discount rate r=7.0%, defined as:

$$NPV_{CS} = \sum_{t=0}^{n} \frac{CS}{1+r^n}$$

Total Transmission-Scale Incentive Costs (TIC) for GSESP is described as a total TIC throughout the lifetime of the program (n=17-years), including the Net Present Value NPV_{TIC}, with a discount rate r=7.0%, defined as:

$$NPV_{TIC} = \sum_{t=0}^{n} \frac{TIC}{1+r^n}$$

Total Transmission-Scale Net Benefit (TNB) for GSESP, is described as a function of $TNB = CS - TIC$ throughout the lifetime of the program n=17-years, including the Net Present Value NPV_{TNB}, with a discount rate r=7.0%, defined as:

$$NPV_{TNB} = \sum_{t=0}^{n} \frac{TNB}{1+r^n}$$

V. Scenarios

This analysis presents four potential scenarios for future BRAs in delivery years from 2028/2029 to 2044/2045:

Scenarios 1: 2031/2032 Less Constrained with LDA Price Separation

- This scenario is based upon the MRI VRR Curve recommended by Brattle. It assumes a reference price of $350 with a price cap of 1.75 x the reference price (i.e., $612.50 per MW-day) for PJM as a whole. The clearing price is assumed to occur between points A and B on the VRR Curve until delivery year 2030/2031. Thereafter, the clearing price is assumed to occur between points B and C on the VRR curve.
- Localized capacity constraints are assumed to create price separation between LDAs resulting in higher clearing prices in years with MAAC and EMAAC separation from the RTO VRR Curve. In this scenario, EMAAC price separates before delivery year 2029/2030 and MAAC price separates before delivery year 2030/2031. EMAAC is assumed to have a reference price of $600 per MW-day and a price cap of $900 per MW-day, while MAAC is assumed to have a reference price of $425 per MW-day and a price cap of $637.50 per MW-day.

Scenario 2: 2031/2032 Less Constrained without LDA Price Separation

- This scenario utilizes the same assumptions for the VRR curve as Scenario 1 except for LDA price separation. In this scenario, MAAC and EMAAC do not separate from the RTO VRR Curve for any delivery year. This scenario thereby assumes similar levels of capacity constraint in MAAC and EMAAC compared to the entire PJM region.

Scenario 3: 2032/2033 Less Constrained with LDA Separation

- This scenario utilizes the same VRR assumptions as Scenario 1 except the clearing price is assumed to occur between points A and B until delivery year 2031/2032. Thereafter, the clearing price is assumed to occur between points B and C on the VRR curve.
- In this scenario, EMAAC price separates before delivery year 2029/2030 and MAAC price separates before delivery year 2030/2031.

Scenario 4: 2032/2033 Less Constrained without LDA Separation

- This scenario utilizes the same VRR curve assumptions as Scenario 3 with the exception that MAAC and EMAAC do not price separate from the RTO VRR curve.

These scenarios are evaluated with three potential values for incentives for transmission-scale storage systems:

- $40,000 per MW per year for 15 years
- $65,000 per MW per year for 15 years
- $90,000 per MW per year for 15 years

These incentive values are for illustrative purposes only and are not indicative of any specific minimum or maximum value. Actual incentives values will be determined by the results of competitive solicitations.

VI. Results

Table 2 - Results for the Net Present Value of the Total Net Benefit (TNB) across four scenarios and three incentive levels modeled.

Scenario	PJM Capacity Constraint	LDA Capacity Constraint	Incentive Value ($/MW per Year)		
			$40,000	$65,000	$90,000
1	2031/2032 Less Constrained	Price Separation	$1,128,201,433	$904,227,613	$680,253,793
2		No Price Separation	$314,301,278	$90,327,458	($133,646,362)
3	2032/2033 Less Constrained	Price Separation	$1,243,893,355	$1,019,919,535	$795,945,715
4		No Price Separation	$429,993,200	$206,019,380	($17,954,440)

The Total Net Benefit (TNB) in capacity savings is positive across the four scenarios and three incentive levels, except for Scenarios 2 and 4 at an incentive value of $90,000 per MW per year. These results indicate that the potential additional capacity supply provided by energy storage systems would likely provide capacity market savings to New Jersey ratepayers that exceed the cost of GSESP incentives. Note that the TNB is measured against a counterfactual scenario in which the money that would be spent on the GSESP is instead allocated to direct ratepayer relief, not a scenario in which the overall Clean Energy Program budget is held constant. A positive TNB thus indicates that funding the GSESP transmission-scale incentive will ultimately save ratepayers more money than simply reducing societal benefits charge collections by the same amount.

The TNB is inversely correlated with the incentive value based upon the assumption that each incentive level would result in the same value of energy storage entering the market. The actual incentive level will be determined by open solicitation. The TNB is higher in scenarios with a greater shortage of capacity in the early years. More significant savings are projected in scenarios in which LDA price separation occurs in the early years of the analysis. In both scenarios with price separation, the TNB more than doubles compared to scenarios without price separation. The existence of ongoing transmission constraints in New Jersey's LDA increase the likelihood of price separation occurring in the near term.

Furthermore, across all scenarios annual net benefits are significant and positive in the shorter term. For example, net savings in the 2028/2029 delivery year are estimated to be ~$88 million even without price separation and with an incentive value of $90,000 per MW per year. With an incentive value of only $40,000 per MW per year and price separation the net savings in the 2028/2029 delivery year could be as high as $760 million. This indicates that the GSESP could provide meaningful near-term ratepayer relief, especially if New Jersey would otherwise be facing a capacity shortage that is more dire than the rest of PJM.

VII. Conclusion

Energy storage systems provide a valuable capacity resource to meet peak load and increase grid reliability.[41] By incentivizing additional energy storage capacity to enter the market in the near-term, GSESP has the potential to lower ratepayers' costs by reducing the clearing price in upcoming capacity market auctions.

If capacity markets remain constrained, then the amount of potential savings will increase. Given the supply constraints for new capacity resources, such as natural gas and nuclear, it is likely capacity supply will remain constrained into the next decade.[42] Based upon this analysis, even if the capacity constraints are alleviated by 2031 and do not materialize again for the next fifteen years, additional energy storage capacity still provides net savings to New Jersey ratepayers in most scenarios.

The opportunity to ease the constrained supply of capacity in the PJM market and thereby lower costs for ratepayers is one potential benefit of GSESP. The likelihood that these savings will materialize is dependent upon the program successfully facilitating the rapid deployment of new storage facilities in the State.

[41] N.J. Bd. of Pub. Utils. et al., 2019 New Jersey Energy Master Plan: Pathway to 2050 at 127 (2020), https://www.nj.gov/emp/docs/pdf/2020_NJBPU_EMP.pdf.

[42] Advait Arun, The Natural Gas Turbine Crisis, Heatmap (Feb. 26, 2025), https://heatmap.news/ideas/natural-gas-turbine-crisis; Mitchel Beer, Turbine Shortage Could Crimp Canadian Utilities' Plans to Scale Up Gas, The EnergyMix (Mar. 27, 2025), https://www.theenergymix.com/turbine-shortage-could-crimp-canadian-utilities-plans-to-scale-up-gas/.